STP-PT-011

INTEGRITY MANAGEMENT OF STRESS CORROSION CRACKING IN GAS PIPELINE HIGH CONSEQUENCE AREAS

ASME STANDARDS TECHNOLOGY, LLC

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FOREWORD

In response to concerns about managing the threat of stress corrosion cracking (SCC) in high-pressure gas transmission pipelines, and in the light of recently introduced legislation concerning integrity management plans focusing on high consequence areas (HCAs), a group of five major gas transmission companies initiated a joint industry project (JIP) in January 2006 to develop technical rationales to support the key processes of SCC integrity management, including hydrostatic testing, in-line inspection (ILI) and SCC direct assessment (DA). These partner companies include Spectra Energy (formerly Duke Energy Gas Transmission), El Paso Pipeline Group, Panhandle Energy, TransCanada Pipelines Ltd. and Great Lakes Gas Transmission.

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ABSTRACT

This report includes a compilation of results obtained through a series of white papers developed as part of a gas transmission company JIP addressing specific issues related to SCC in gas pipeline HCAs. This report presents the overall project approach, findings and outcomes. The overall outcome of the JIP has been the development and collation of a significant body of supporting information, made available to pipeline operators and to the pipeline industry, providing the basis for sound decision making regarding the issues to be addressed when managing the integrity of pipelines that are potentially subject to the threat of SCC. In particular, this report includes:

- A review and update of SCC experience in 130,000 miles of high-pressure gas pipelines.
- Validation of the ASME B31.8S criteria for determining segments and HCAs most likely to be susceptible to high pH SCC.
- Demonstration that the modified ASME B31.8S criteria also are applicable to near-neutral pH SCC.
- Development of guidelines and algorithms for prioritizing pipeline segments and HCAs for SCC assessment, and for selecting excavation sites most likely to show evidence of SCC.
- Development of guidance for conducting SCC hydrostatic tests.
- Development of a categorization scheme for determining crack severity and mitigation response.
- Development of a method for determining the intervals between re-tests when using hydrostatic testing, ILI or SCC DA to manage SCC.
- Provision of guidance for determining how many excavations are necessary during SCC DA.
- Development of a process for utilizing condition monitoring activities for SCC management when low levels of SCC are experienced.
- Identification of revisions to improve the existing ASME B31.8S guidance for SCC.

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1 SUMMARY

In response to concerns about managing the threat of stress corrosion cracking (SCC) in high-pressure gas transmission pipelines, and in light of recently introduced legislation concerning integrity management plans focusing on high consequence areas (HCAs), a group of five major gas transmission companies initiated a joint industry project (JIP) to develop technical rationales to support the key processes of SCC integrity management, including hydrostatic testing, in-line inspection (ILI) and SCC direct assessment (DA).

The JIP commenced in January 2006. This report summarizes the overall approach adopted during the JIP and presents the findings and outcomes obtained in a series of white papers addressing the specific issues that were identified by the JIP Steering Committee.

The overall outcome of the JIP has been the development and collation of a significant body of supporting information, made available to pipeline operators and to the pipeline industry, providing the basis for sound decision making regarding the issues to be addressed when managing the integrity of pipelines that are potentially subject to the threat of SCC. In particular, the JIP has delivered the following:

- A review and update of SCC experience in 130,000 miles of high-pressure gas pipelines, incorporating data extending over more than 50 years and including 87 in-service ruptures and leaks. This database represents a substantial proportion of the relevant operating experience in North America.
- Validation of the ASME B31.8S criteria for determining segments and HCAs most likely to be susceptible to high pH SCC, and demonstration that the modified ASME B31.8S criteria also are applicable to near-neutral pH SCC, based on the accumulated service experience.
- Development of guidelines and algorithms for prioritizing pipeline segments and HCAs for SCC assessment, and for selecting excavation sites most likely to show evidence of SCC, using the accumulated service experience and latest research information.
- Development of guidance for conducting SCC hydrostatic tests so as to deliver optimized benefits for SCC integrity management.. These test conditions may differ from those for hydrostatic tests conducted for other operational reasons.
- Development of a categorization scheme for determining crack severity and mitigation response, based on predicted failure pressure and estimated remaining life at the operating pressure. The sensitivity of crack severity to input parameters (pipeline attributes, crack growth rate and assumptions made during calculations) has been examined.
- Development of a method for determining the intervals between re-tests when using hydrostatic testing, ILI or SCC DA to manage SCC.
- Provision of guidance for determining how many excavations are necessary during SCC DA.
- Development of a process for utilizing condition monitoring activities for SCC management when low levels of SCC are experienced, consistent with the requirements of “Other Technology” for Integrity Management.
- Identification of revisions to improve the existing ASME B31.8S guidance for SCC and preparation of alternative wording for consideration and balloting by the ASME Committee.

2 BACKGROUND AND OBJECTIVES

As pipeline companies prepare integrity management plans for SCC, they are faced with the challenge of complying with the regulatory requirements of US Federal Regulation 49 CFR Part 192 Subpart O and, at the same time, minimizing the risk of failures due to SCC. In some cases, the required procedures may not be optimally effective to reduce such risks and, as such, they may divert resources from more effective procedures. In other cases, it is not obvious what specific procedures would be most cost effective for the industry to employ to comply with the regulations. Some of the most important questions relate to the most effective way to deal with a large number of high-consequence areas (HCAs), and determining appropriate procedures and re-test intervals for hydrostatic testing, in-line inspection (ILI) or SCC direct assessment (SCC DA).

While it is recognized that each pipeline company must have individual integrity management plans that are tailored to the specific characteristics and history of the pipeline system, a common approach to some of the key issues would be beneficial in dealing with the regulatory agencies, as well as providing guidance for developing an effective integrity management plan. Such an approach would draw upon the key processes of integrity management outlined in ASME B31.8S, including:

- Defining the basis for SCC susceptibility
- Prioritizing HCA segments susceptible to SCC
- Selecting the appropriate assessment method and assessment location for each segment
- Defining mitigation of SCC when found (including assessing the severity of the SCC)
- Determination of and basis for reassessment interval
- Determination of additional preventive and mitigative measures.

In response to these issues, five major gas transmission companies initiated a joint industry project (JIP) to develop a common approach to managing stress corrosion cracking in HCAs for natural gas transmission. The five companies are:

- Spectra Energy (formerly Duke Energy Gas Transmission)
- El Paso Pipeline Group
- Panhandle Energy
- TransCanada Pipelines Ltd.
- Great Lakes Gas Transmission.

The overall aim of the JIP has been to develop the technical rationale to support each of the key processes identified above. Emphasis has been placed on the need for operators to show consistency in their technical approach to SCC management, particularly regarding the development of compliant solutions for HCAs where SCC is a threat of concern. Technical consistency does not imply a uniform response, but rather a consistent framework enabling each operator the flexibility to adopt an approach tailored to the attributes and SCC history of each line. The rationale has been based, to the extent possible, on scientific knowledge of SCC, analytical models of behavior of pipe containing stress-corrosion cracks and field experience from as many companies as possible.

It has been intended from the outset that the rationale will be made available for use by operators in establishing their respective plans for managing SCC in HCAs. It has also been intended that the JIP will develop any materials required to support the technical rationale, such as modifications to completed recommended practices and standards.

3 APPROACH

The JIP commenced in January 2006 and has been managed by BIZTEK Consulting, Inc. (Dr. Raymond Fessler), with Dr. David Batte (Macaw Engineering Ltd.) and Mr. Mark Hereth (PPIC) as technical advisers and project team members. The project has consisted of the following tasks.

- Task 1. In consultation with the JIP Steering Committee, establish which issues should be addressed and whether the technical rationale is already strong enough or whether more data or analyses are needed. For those answers for which there is insufficient technical justification, determine what additional data or analyses are needed and possible, and whether the participants can provide any necessary additional field data.
- Task 2. Prepare a “white paper” addressing each identified issue, including, where necessary, analysis of additional field data or construction/refinement of predictive models. Each white paper is thoroughly discussed and finalized in conjunction with the JIP Steering Committee.
- Task 3. Present the provisional outcomes of the JIP at meetings with industry experts (operators and technical consultants) to provide detailed technical scrutiny of the findings and their implications and build a broader consensus across the industry.
- Task 4. Present the provisional outcomes of the JIP at meetings with DOT/OPS/PHMSA to provide updates and understanding of the findings and their implications for the integrity management of gas pipelines.
- Task 5. Identify needs or opportunities for modifying and improving the existing guidance and legislation and develop technology packages to support changes.

4 TASK 1 - CLARIFICATION OF ISSUES

The initial discussions with the JIP Steering Committee identified seven questions that are faced by operators seeking to implement sound SCC management practices in line with integrity management regulations. These questions were of particular concern because, in each case, the existing regulations and guidance leave the decision on precisely how to proceed at the discretion of the operator. The seven questions are set out below, and their significance in the context of the integrity management process is illustrated schematically in Figure 1:

Question 1: On what basis should HCAs and segments be defined as SCC-susceptible?

Question 2: How should SCC-susceptible HCAs and segments be prioritized for assessment?

Question 3: Where hydrostatic testing, SCC DA or crack detection ILI have been chosen as the assessment methods, what are the appropriate re-test intervals?

Question 4: What is the appropriate procedure for hydrostatic testing?

Question 5: When using SCC DA, where is the best place to dig and how many digs should be conducted? (This question was subsequently divided into two parts.)

Question 6: How should crack severity be defined, and how should severity determine what kinds of remedial actions are appropriate?

Question 7: What additional preventive and mitigative measures are appropriate for SCC condition monitoring, and how can they be used to enhance confidence in the management of SCC?

A further question concerning the performance of ILI tools for detecting and sizing SCC was deferred pending future developments in ILI technology.

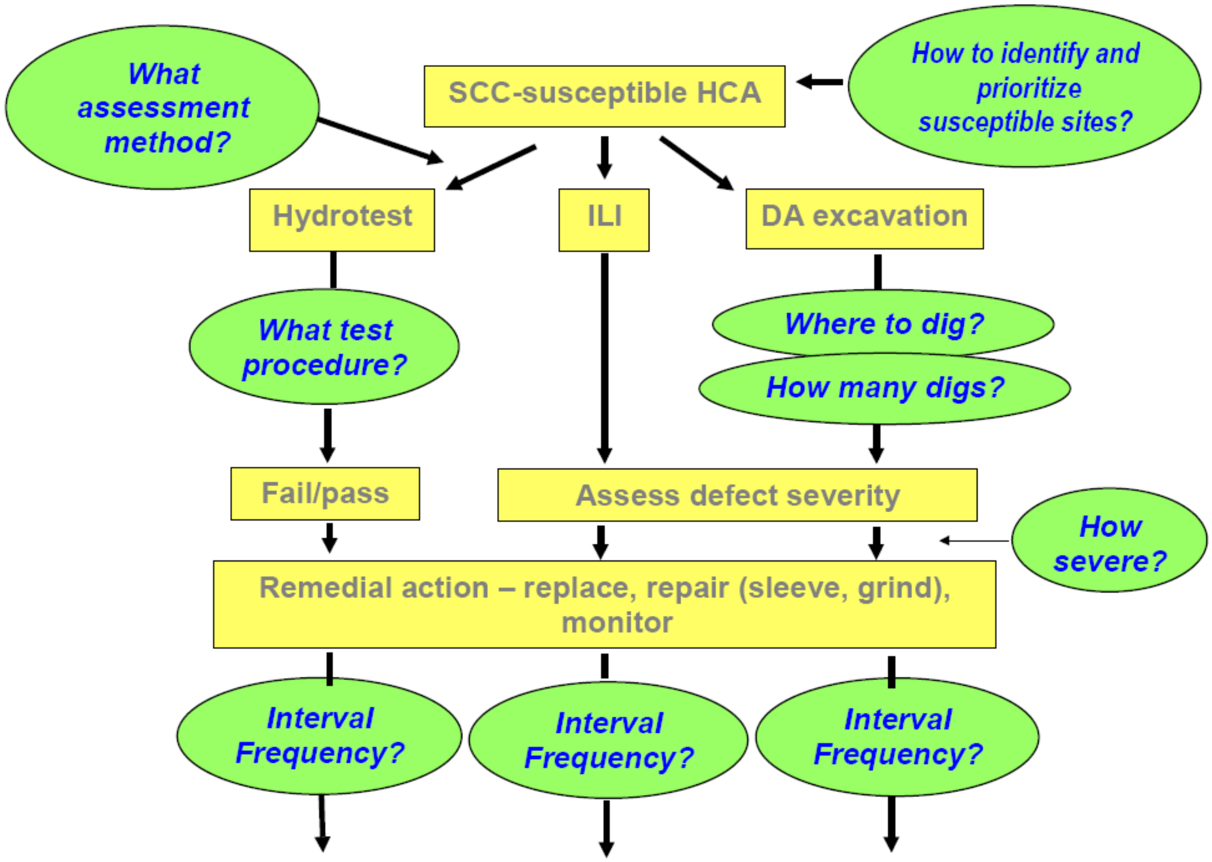

Figure 1 - Questions Arising During SCC Integrity Management

5 TASK 2 - RESPONSES TO QUESTIONS

For each of the questions identified above, a white paper was prepared and finalized in consultation with the Steering Committee, after presentation and discussion of the findings at a meeting of industry experts, and after several meetings with PHMSA representatives. The white papers are attached as appendices to this report and are summarized below.

5.1 Question 1: On what basis should HCAs and Segments be defined as SCC-susceptible?

ASME B31.8S gives guidance as to which gas pipeline segments should be considered at risk due to SCC. The guidance, developed more than five years ago, utilizes operating stress and temperature, distance downstream from the compressor discharge, age, coating type and prior SCC history, and has been incorporated into the integrity management rules in 49 CFR Part 192 Subpart O.

To provide a platform for addressing Question 1, a large body of up-to-date information from in-service failures, hydrostatic tests, excavations and in-line inspections relating to 130,000 miles of natural gas pipelines operating in North America has been collated and reviewed and is presented in the attached Background Report (Appendix A).

The collated information has been used to assess the effectiveness of the ASME criteria in providing the initial definition of SCC-susceptible segments, including the implications of the recently proposed modifications. The results of this analysis are presented in Appendix B.

Many of the engineering judgments embodied in the original ASME criteria are still applicable to high pH SCC and are substantiated by the up-to-date field experience. It appears that with the proposed revisions the ASME criteria still provide a good basis for the initial definition of SCC-susceptible segments. The revised ASME criteria address over 80% of the in-service failures attributable to high pH and near-neutral pH SCC in natural gas pipelines, and this figure rises to around 90% when the specific circumstances of the outlying occurrences are taken into account. The revised criteria also address over 95% of the hydrostatic test failures, and around 85% of the SCC cracks exceeding 10% through-wall depth found during excavations.

5.2 Question 2: How should SCC-susceptible HCAs and Segments be prioritized for assessment?

Once the SCC-susceptible HCAs and segments have been identified for a pipeline system it is necessary to determine in what order of priority they should be assessed.

The amount of information available to enable prioritization varies considerably from situation to situation. For the first assessment, there may be little information other than basic pipeline attributes, although some operators may have access to data from CP monitoring, above-ground surveys or ILI runs. For subsequent assessments, information from excavations of the HCA/segment of interest, together with excavation results from adjacent or similar segments, may enable better discrimination.

Guidance on prioritizing segments has been developed to take these variations into account and is presented in Appendix C. A three-tiered approach has been adopted, based on the level of information available:

Tier 1: Prioritization based solely on pipeline attributes and operating history, with no information available from excavations or surveys

Tier 2: Prioritization incorporating additional information available from monitoring and surveys, ILI, excavations for other operational reasons, and any prior hydrostatic testing

Tier 3: Prioritization augmented by feedback from previous SCC assessments, leading eventually to a series of pipeline-specific, weighted risk factors incorporated in an overall ranking model; such a model could form the basis for quantitative risk analysis.

The individual factors have been identified, based on collective industry knowledge and up-to-date operational experience, taking into account the independent risks from high pH and near-neutral pH SCC. Their integration into Tier 1 and Tier 2 Prioritization Protocols is illustrated.

5.3 Question 3: Where Hydrostatic Testing, SCC DA or Crack Detection ILI have been chosen as the assessment methods, what are the appropriate re-test intervals?

For HCAs that are classified as possibly susceptible to SCC, pipeline companies are required to undertake periodic assessments using hydrostatic testing, in-line inspection or direct inspection. Re-assessment intervals should be short enough to assure the safety of the pipeline but not so short that they involve needless effort and expense or subject the pipeline to needless pressure fluctuations.

In principle, the maximum re-inspection interval could be determined from the crack growth rate, the size of the largest flaw that could exist in the pipeline and the size of a flaw that would cause a failure at the operating pressure. For companies that do not have specific information about possible crack growth rates on their pipelines, it is necessary to find another means of determining the appropriate intervals for reassessment; this is presented in Appendix D.

A model has recently been developed that provides a technical basis for establishing subsequent hydrostatic re-test intervals based upon the test pressure, the maximum allowable operating pressure (MAOP), the tensile properties of the steel and the length of previous intervals. The principal assumption upon which the model is based is that a crack that already exists in the pipeline has a greater chance of reaching critical size than a crack that might initiate some time in the future. On that basis, subsequent intervals can be calculated as

$$t_n = t_p(\alpha/\beta)$$

where

t_n = length of the next interval

t_p = sum of the lengths of the previous intervals

α = difference between the test pressure and MAOP

β = difference between the pressure corresponding to the flow stress and the test pressure.

Predictions from the model have been tested against histories of 13 valve sections that have experienced either high-pH or near-neutral-pH SCC and have been subjected to multiple hydrostatic re-tests. Within those 13 valve sections, eight in-service failures occurred after the initial hydrostatic tests. Five or six of those eight probably would have been prevented if the intervals from this method had been used rather than the ones that were, but no more re-tests, in total, would have been required. The only two service failures that would have occurred with a 3-year first interval and subsequent intervals determined from this method occurred on a valve section that had been tested to only 90% SMYS.

Reassessment intervals for ILI can be established in two alternative ways. If accurate measurements of crack sizes are available from successive runs, crack growth rates can be calculated by comparing the sizes of specific cracks at the two different times. However, if sufficiently accurate data are not available to follow the growth of individual cracks, the maximum size crack that is left in the line can be used to calculate an equivalent hydrostatic test pressure, and then the hydrostatic re-test model above can be used to establish subsequent intervals.

The appropriate action following SCC DA will depend upon the severity of cracks that are discovered. A scheme of responses has been developed based upon the severity categories developed in answer to Question 6 (see below). For the most severe cracks, an immediate pressure reduction should be implemented, followed as soon as possible by an assessment that covers 100% of the segment. If cracks of intermediate severity are found, the response takes into account the possibility that a more severe crack may exist (undiscovered) elsewhere in the segment. If inconsequential cracks are found, more digs should be conducted until no larger flaws are found. If no cracks are found at the location that is expected to be most susceptible, no additional actions should be required before the next scheduled assessment.

5.4 Question 4: What is the appropriate procedure for Hydrostatic Testing?

Hydrostatic testing has proved to be a very effective way of managing SCC in buried gas transmission pipelines. Appendix E sets out the issues to be considered in determining the optimum test procedure.

From a technical perspective, the optimum procedure for a hydrostatic test involves a short pressure spike at a relatively high pressure followed by a leak test. The spike pressure should be as high as possible within the range of 100 to 110% SMYS but should not be so high as to cause bulging of the pipe or a large number of failures. The hold time should be only long enough to verify the pressure and not more than 1 hour.

The leak test can be performed either by maintaining a lower water pressure for a longer time or with flame ionization after the pipeline is re-pressured with gas. If a water-pressure test is used, the pressure should be at least 10% lower than the spike pressure and 10% higher than the maximum allowable operating pressure. Typically, 8 hours is sufficient to stabilize the pressure, but shorter times may be enough if the pressure remains constant.

Occasionally, multiple failures have occurred when testing a given valve section. Over 70% of the repeat failures have occurred at pressures equal to or greater than the previous failure pressure. Of the remainder, none of the pressure reversals has exceeded 5% of the previous pressure.

5.5 Question 5: When using SCC DA, where is the best place to dig and how many digs should be conducted?

The assessment of SCC-susceptible segments may utilize hydrostatic testing, ILI or excavations, either individually or in combination. When excavations are used, it is necessary to determine where the excavations should be located and how many digs are necessary to establish the severity of any SCC found.

Appendix F sets out an approach for determining where excavation sites should be located along a segment or HCA.

The amount of information available to select excavation sites varies considerably from situation to situation. For the first assessments, there may be little information other than basic pipeline attributes; for subsequent assessments, information from excavations of the HCA/segment of interest, together with excavation results from adjacent or similar segments, may enable better discrimination.

Guidance on selection of excavation sites has been developed to take these considerations into account. A three-tiered approach to site selection has been adopted, based upon the level of information available:

Tier 1: Site selection based on pipeline attributes and operating history, with no prior experience of SCC assessments and no information available from excavations or surveys.

Tier 2: Site selection incorporating additional information available from local monitoring and surveys, ILI and excavations for other operational reasons.

Tier 3: Site selection augmented by feedback from previous SCC assessments, leading eventually to a series of pipeline-specific, weighted risk factors incorporated in an overall ranking model; such a model could form the basis for quantitative risk analysis.

The individual factors are identified, based on collective industry knowledge and up-to-date operational experience, taking into account the independent risks from high pH and near-neutral pH SCC. Their integration into Tier 1 and Tier 2 site selection protocols is illustrated.

An approach for determining how many sites should be excavated in a segment or HCA is set out in Appendix G. It is important to recognize that the purpose of SCC DA is to provide assurance that a service failure will not occur before the segment is re-assessed. It is not to find or remove every stress-corrosion crack in the segment; none of the assessment approaches can do that.

The guidelines are based upon the condition that the first dig must be at the location in the segment where the probability of SCC is judged to be highest, thus increasing the chance of finding one of the most severe cracks. However, because there is a distinct possibility of missing the largest crack, extra conservatism has been added for SCC DA compared to hydrostatic testing or ILI. That conservatism involves assuming the existence of larger cracks than are found.

If severe cracks are found, there is a possibility of a service failure in the near future; therefore, an immediate pressure reduction should be implemented, followed as soon as possible by an assessment that covers 100% of the segment. If cracks of intermediate severity are found, the possibility of more severe cracks existing elsewhere in the segment should not be ignored, and the procedure is set accordingly. If no cracks are found at the location that is expected to be most susceptible, no additional actions should be required before the next scheduled assessment.

5.6 Question 6: How should crack severity be defined and how should severity determine what kinds of remedial actions are appropriate?

When cracks are found during excavation or ILI, it important to establish their severity in order to determine what the mitigating actions should be and how urgently they should be undertaken. A hierarchy of crack severity categories and response categories has been developed, thereby ensuring a coherent overall process for timely, effective and safe mitigation whenever cracking is discovered. These are set out in detail in Appendix H and summarized below.

Threshold depths and lengths are defined below which cracks are not considered to present any immediate threat to integrity. The term “Noteworthy” has been applied to cracks that exceed these thresholds, and is defined as follows:

An SCC crack or colony is of Noteworthy size if the maximum crack depth is greater than 10% of the wall thickness and if the maximum interacting crack length (defined below) is more than the critical length of a 50% through-wall crack at a stress level of 110% SMYS.

For Noteworthy cracks, categories of crack severity are based upon critical cracks at other stress levels, using the actual interacting length and maximum depth. For example, taking 125% and 110%

of MAOP in addition to 110% SMYS gives rise to a hierarchy of crack severity based on Predicted Failure Pressure (PFP)[1] as follows:

Category 1:	Predicted Failure Pressure is above110% SMYS
Category 2:	Predicted Failure Pressure is above 125% MAOP and below 110% SMYS
Category 3:	Predicted Failure Pressure is above 110% MAOP and below 125% MAOP
Category 4:	Predicted Failure Pressure is below 110% MAOP
Category Zero:	Is used to describe those cracks that are below the threshold for Noteworthy cracks.

Finally, cracks of any length that are greater than 30% through-wall depth, for which grinding is often not allowed by regulations, are grouped separately (These Deep Cracks also are categorized as Noteworthy).

The formulation of these severity categories enables an estimate to be made of the minimum remaining life at operating pressure, for each severity category.[2] Estimates are based on the time taken for the crack depth to increase to the critical depth to cause failure at the operating pressure. For example, for a typical pipeline operating at 72% SMYS, using a representative growth rate of 0.012 inch/year (0.3 mm/year) the following estimated minimum lives are obtained for each severity category:

Category Zero:	failure life exceeds 15 (short) to 25 (shallow) years
Category 1:	failure life exceeds 10 years
Category 2:	failure life exceeds 5 years
Category 3;	failure life exceeds 2 years
Category 4:	failure may be imminent.

Cracking revealed by excavation will normally be ground or buffed out in accordance with established procedures. Mitigation of the remainder of the pipeline segment should constitute a measured response to the severity of the crack discovered, reflecting the predicted failure pressure and the estimated life at the operating pressure. For example, Category Zero cracks may warrant no more than ongoing SCC condition monitoring and reassessment after a period of 7 years. Intermediate category cracks may, in addition, benefit from exploratory excavations or information from “opportunistic” excavations conducted for other operational reasons. Severe cracks may be best addressed by hydrostatic testing or immediate ILI rather than SCC DA. The most severe cases would necessitate an immediate pressure reduction, and urgent hydrostatic testing or ILI, followed by appropriate discrete or general mitigation. Deep Cracks will require immediate engineering critical assessment to determine the appropriate pressure reduction and immediacy of response.

5.7 Question 7: What additional preventive and mitigative measures are appropriate for SCC Condition Monitoring, and how are they to be used to enhance confidence in the management of SCC?

The aim of SCC condition monitoring is to identify any evidence that the SCC risk is changing over time. SCC condition monitoring is a structured process for collecting, regularly reviewing, interpreting and responding to all the SCC-relevant information obtained during ongoing operational and integrity management activities; the process is set out in detail in Appendix K. It is principally directed towards those segments that have been identified as SCC-susceptible but which, when examined, are found to contain little or no cracking.

1 Various technical issues related to predicting failure pressure are discussed in Appendix I.

2 Various technical issues related to estimating remaining life are discussed in Appendix J.

The main information sources for SCC Condition Monitoring are

Site surveys and ILI results
Excavations undertaken for reasons other than SCC
Operational records
Terrain, drainage and land usage reviews
Other operator experience
Research and development outcomes.

The SCC Condition Monitoring process leads to an auditable overall procedure for recording and reporting the results and outcomes. The process either validates or drives changes to the operator's integrity management plan and enhances confidence in the management of SCC threats.

It is recommended that SCC condition monitoring should be considered as an "equivalent technology" for those pipeline segments that require ongoing SCC threat management, but which on first assessment reveal little or no SCC, for as long as the risk of SCC is demonstrated not to increase.

6 TASK 3 - INDUSTRY AND PEER REVIEWS

It was considered important at the outset that the findings of the JIP should be subjected to critical peer review both by technical experts and by experienced staff in other pipeline operating companies. The primary objective was to ensure that the final outcomes would be technically and operationally sound, and that they would be acceptable to the gas pipeline industry at large.

In January 2007, a three-day workshop was held in Houston to present the interim results of the JIP and obtain comments. Approximately 40 people, including representatives from 15 pipeline operating companies, attended the workshop. A series of presentations was made, focusing on the draft white papers addressing the seven questions. The opportunity was taken to update attendees on the experience of SCC in gas pipelines in North America and to demonstrate how the information had been used to develop responses to the identified SCC integrity management issues.

During the course of the workshop, several other gas pipeline operators offered to submit data describing their experiences of SCC to be included alongside that of the JIP sponsors. This allowed the broadening of the database of background experience to include operational experience for over 130,000 miles of high-pressure gas transmission pipelines, extending over more than 50 years and including details of 87 in-service ruptures and leaks. This database represents a substantial proportion of the relevant operating experience in North America.

Between October 2006 and April 2007, the individual draft white papers were reviewed in detail by technical experts (who also attended the Industry Workshop). These included Dr. John Beavers of CC Technologies, Dr. John Kiefner and Mr. John MacKenzie of Kiefner and Associates and Dr. Brian Leis of Battelle. Comments received from the reviewers together with those received during the Industry Workshop were used, to revise and finalize the white papers.

7 TASK 4 - INTERACTIONS WITH DOT PHMSA

From the outset of the JIP, it was considered important to maintain an active dialogue with PHMSA, to ensure that the most up-to-date information was available both to Washington staff and to the local audit teams during the program of Integrity Management Audits. The dialogue was initiated soon after commencement of the project, and continued throughout.

In October 2006, two meetings were held between the JIP Steering Committee and representatives of PHMSA in Washington. A series of presentations was made to PHMSA, focusing on the draft white papers addressing the seven questions. The opportunity was taken to update PHMSA on the experience of SCC in gas pipelines in North America and to demonstrate how the information had been used, together with other analyses, to develop sound procedures and practices for addressing the key issues arising during SCC integrity management. Ways to achieve broader industry exposure of the work were also discussed, as well as the possible implications of the results for the existing guidance and legislation concerning SCC.

8 TASK 5 - INTERACTIONS WITH ASME

During the course of the JIP it became clear that it would be appropriate to seek revisions to ASME B31.8S based on some of the findings. Accordingly, a small task force of JIP members and project team members was formed in February 2007 to progress the issue. In June 2007, an initial presentation was made to ASME concerning the outcomes of the JIP and the proposed revisions to ASME B31.8S Appendix A. Further discussions and balloting by ASME on the proposed changes are continuing.

9 CONCLUDING REMARKS

The overall outcome of the JIP has been the development and collation of a significant body of supporting information, made available to pipeline operators and to the pipeline industry, providing the basis for sound decision-making regarding the issues to be addressed when managing the integrity of pipelines that are potentially subject to the threat of SCC.

In particular, the JIP has delivered the following:

- A review and update of SCC experience in 130,000 miles of high-pressure gas pipelines, incorporating data extending over more than 50 years and including 87 in-service ruptures and leaks. This database represents a substantial proportion of the relevant operating experience in North America.
- Validation of the ASME B31.8S criteria for determining segments and HCAs most likely to be susceptible to high pH SCC, and demonstration that the modified ASME B31.8S criteria also are applicable to near-neutral pH SCC, based on the accumulated service experience.
- Development of guidelines and algorithms for prioritizing pipeline segments and HCAs for SCC assessment, and for selecting excavation sites most likely to show evidence of SCC, using the accumulated service experience and latest research information.
- Development of guidance for conducting SCC hydrostatic tests so as to deliver optimized benefits for SCC integrity management. These test conditions may differ from those for hydrostatic tests conducted for other operational reasons.
- Development of a categorization scheme for determining crack severity and mitigation response, based on predicted failure pressure and estimated remaining life at the operating pressure. The sensitivity of crack severity to input parameters (pipeline attributes, crack growth rate and assumptions made during calculations) has been examined.
- Development of a method for determining the intervals between re-tests when using hydrostatic testing, ILI or SCC DA to manage SCC.
- Provision of guidance for determining how many excavations are necessary during SCC DA.
- Development of a process for utilizing condition monitoring activities for SCC management when low levels of SCC are experienced, consistent with the requirements of “Other Technology” for Integrity Management.
- Identification of revisions to improve the existing ASME B31.8S guidance for SCC and preparation of alternative wording for consideration and balloting by the ASME Committee.

APPENDIX A - FIELD EXPERIENCE OF SCC IN GAS TRANSMISSION PIPELINES

1. Introduction

In the 40-year period since external stress-corrosion cracking (SCC) was first experienced in gas transmission pipelines, a considerable body of field experience has been obtained in North America. Some of this information has been published, but much more has been retained in company archives and used to develop in-company practices and procedures for managing the threat of SCC.

With the advent of regulatory requirements for formal integrity management plans for gas transmission pipelines, it has been necessary to develop guidance for addressing SCC. Guidance such as that embodied in ASME B31.8S [1] has been based on the collective experience and knowledge of industry experts, incorporating such operational experience as was available at the time. For example, the ASME guidance on identifying which high consequence areas are SCC-susceptible is based on the information available five years ago.

During recent years, a substantial amount of additional field knowledge has been obtained by gas pipeline operators. Hydrostatic testing programs and excavation programs have generated a large number of records, and in-line inspection (ILI) crack detection vehicles have been run on a developmental basis in several pipelines. Hence, it is timely to collate the information now becoming available and establish/confirm the patterns and trends that can be used to maximize the effectiveness of SCC Integrity Management Plans.

The opportunity to undertake such an exercise has arisen during the ongoing Joint Industry Project (JIP) on “Management of Stress-Corrosion Cracking in High Consequence Areas.” This report collates the detailed records from SCC investigations (hydrostatic tests, excavations and ILI) made available by the JIP participants, and compares them with those seen in other published work. The resulting trends and patterns in field experience will be used to form the basis for guidance on the critical decisions to be made by operators during the implementation of their SCC management plans.

2. Data Sources

2.1 Data Provided by the JIP Participants and Other Operators

All the JIP participants are operators of substantial systems for the transmission of dry natural gas in various locations in North America. All the JIP participants have some prior experience of SCC in their pipelines; in some instances this dates back to the earliest in-service ruptures and leaks in the mid-1960s. Experience spans both high pH and near-neutral pH SCC.

During the course of the JIP, several other operators with similar operational experience of SCC offered detailed information for inclusion in the survey. This information has been added to that provided by the JIP participants and is included in the analyses presented below.

All these operators have taken active steps to manage the threat of SCC. As a result, the individual operators have amassed substantial amounts of field information from hydrostatic testing, excavations and ILI, relevant to their individual operational needs.

The information gathered from the JIP participants covers several types:

- Pipeline attribute information:
  - Pipeline age, diameter and wall thickness
  - Pipe grade and coating type
  - Operating pressure

How and where SCC was discovered:
- Date and means of discovery
- Location

The extent and nature of SCC found:
- Type of SCC
- Size, depth and number of crack colonies
- Size, depth and number of individual cracks.

During this exercise, no attempt was made to collect information on the environmental, electrochemical and conditioning parameters that might correlate with the location and extent of cracking, such as coating degradation, CP system performance, terrain and soil texture/type.

Similarly, no attempt was made to collect information relating to operating temperatures at or immediately downstream of compressor discharges. Previous work [2]-[6] has indicated the relevance of temperature to coating degradation and crack formation, particularly for high pH SCC. However the key information relates to historical operating practices, before operators reduced their compressor discharge temperatures in the 1980s, and this is extremely difficult to obtain from company archives. Distance downstream from compressor discharge is a valid surrogate for the missing information.

The information provided by the JIP participants is best described as a series of individual datasets, as follows:

(a) In-Service Ruptures and Leaks, Hydrostatic Tests

Dataset 1

Consisted of around 135 records from in-service failures and hydrostatic test failures dating from the 1960s to 2005, on pipelines coated with coal tar. All the occurrences were recorded as high pH SCC.

Dataset 2

Consisted of around 380 records from hydrostatic tests conducted between 1985 and 2005, on pipes that were predominantly coal tar coated. SCC failures occurred in about 4% of the hydrostatic tests; the rest were completed without SCC failures. All the SCC was recorded as high pH type.

Dataset 3

Consisted of around 90 records from in-service occurrences and hydrostatic test failures, occurring between the mid-1960s and 2002, on pipes that were predominantly coal tar coated. All the failures were recorded as due to high pH SCC.

Dataset 4

Consisted of around 65 records from in-service occurrences and hydrostatic test failures, occurring between the mid-1960s and 2000, on pipes that were tape-coated. All the in-service occurrences and hydrostatic test failures were recorded as due to high pH SCC.

Dataset 5

Consisted of around 60 records from in-service occurrences and hydrostatic test failures, occurring between the late-1960s and 2005, on pipes that were coal tar coated. All the failures were recorded as due to high pH SCC.

Dataset 6

Consisted of over 360 records from in-service failures and hydrostatic tests conducted between the mid-1980s and 2005, on tape-wrapped, asphalt and coal tar coated pipelines. Around 11% of the hydrostatic tests produced failures; the rest were completed without SCC failures. All the SCC occurrences were recorded as near-neutral pH SCC.

Dataset 7

Consisted of around 20 records from in-service failures and hydrostatic tests dating from 1995 to 2005, on pipelines coated predominantly with asphalt. The failure occurrences were recorded as near-neutral pH SCC.

Dataset 8

Consisted of records of 7 in-service occurrences and 3 hydrostatic test failures, occurring between 1993 and 2003, on pipelines predominantly coated with asphalt. The occurrences were recorded as SCC having a mixture of transgranular and intergranular fracture features, and, because the type of SCC is uncertain, they have not been included in the analyses that follow.

Dataset 9

Consisted of around 20 records of in-service occurrences and hydrostatic test failures, occurring between the early 1970s and 2005, on pipelines coated predominantly with asphalt. Most were recorded as near-neutral pH SCC, and a few were recorded as high pH SCC.

(b) Excavations

Dataset 10

Consisted of over 4000 excavation records, dating from 1994 to 2006, on pipes that were predominantly coated with coal tar. The excavations were "opportunistic," having been undertaken for other operational reasons. Around 140 (~3.5%) of the excavations had revealed SCC, all of it high pH SCC.

Dataset 11

Consisted of around 450 excavation records, dating from 1994 to 2005, on pipes that were predominantly coated with coal tar. All of the excavations had been undertaken in response to SCC issues and all revealed high pH SCC.

Dataset 12

Consisted of over 4000 records from SCC excavations, dating from 1995 to 2006, predominantly on asphalt-coated pipes but including small proportions of most other coating types. Around 16% of the excavations revealed SCC colonies, all of it near-neutral pH SCC.

Dataset 13

Consisted of nearly 5000 records from 125 excavations conducted on tape-wrapped, asphalt and coal tar coated pipes between 1997 and 2005. Around 45% of the excavations revealed SCC, all of it recorded as near-neutral pH SCC.

(c) Crack Detection ILI

Dataset 14

Consisted of information from three developmental ILI crack detection runs totaling around 85 miles, on coal tar coated pipelines with a history of high pH SCC.

Dataset 15

Consisted of information from three developmental ILI crack detection run totaling around 26 miles, on tape-wrapped and asphalt-coated pipelines with a history of near-neutral pH SCC.

Dataset 16

Consisted of information from a developmental ILI crack detection run totaling around 140 miles, on tape-wrapped and asphalt-coated pipelines with a history of near-neutral pH SCC.

The total content of all of the datasets is summarized in Table 1.

Table 1 - Summary of Information Provided by the JIP Participants and Other Operators

	High pH SCC	Near-neutral pH SCC
In-service ruptures and leaks	61	19
Hydrostatic test failures due to SCC	308	52
Hydrostatic test passes	367	331
Total hydrostatic tests	675	383
Total miles hydrostatically tested	N/A	2396
Excavations finding SCC	583	757
Total excavations	4485	4351
SCC colonies recorded	Several thousand	8894
Total miles excavated & examined	N/A	46
Number of ILI Crack Detection runs	3	4
Number of miles inspected	80	165
Number of SCC defects >10% deep found	6500	800

2.2 Similar Information Available from Other Sources

There are several important sources of similar information concerning the field experience of SCC that can be used to reinforce and corroborate the experience of the JIP participants. Among these are the following:

Wenk [2]

Following the first occurrences of high pH SCC in pipelines in the mid-to-late 1960s, PRCI NG-18 Committee commissioned Battelle to collect and review information relating to the in-service and hydrostatic test failures. The field investigations relating to around 25 in-service failures and around 250 hydrostatic test failures were presented in 1974; the effects of proximity to compressor discharge, year and location of installation, and circumferential position, on SCC occurrence were examined. Some of these results are included in the datasets provided by the JIP participants.

Eiber and Leis [3], [4]

In preparation for developing a protocol to prioritize sites for high pH SCC, Eiber and Leis reviewed the information for around 40 in-service leaks and ruptures due to high pH SCC that had occurred before 1997. The data were used to determine the effects of operating stress, distance downstream from compressor discharge, coating type and age since installation on the likelihood of high pH SCC. Some of these 40 in-service occurrences are included in the datasets provided by the JIP participants.

Canadian NEB Report [5]

The NEB Report into occurrences of SCC in Canadian pipelines reviewed the information for 10 in-service ruptures and leaks that were due to axially oriented SCC in gas transmission lines; all had occurred in the period from 1985 to 1996. The data were used to explore the relationship between

SCC and operating stress, coating type, pipeline age and other potentially controlling parameters. All these occurrences are included among the datasets provided by the JIP participants.

Fessler [6]

In a report for PRCI examining the state of the art of SCC research, Fessler reviewed the information presented in the two reports above, together with several other published reports describing aspects of in-service experience of both high pH and near-neutral pH SCC. Fessler examined the observed trends and presented theoretical and experimentally derived analyses to support the observed service experience.

CEPA Trending Studies [7]

Following the experience of SCC in Canadian oil and gas pipelines, CEPA initiated a program to collect information from excavations in which evidence of SCC had been sought. The CEPA database included information on over 13,000 near-neutral pH SCC colonies found in over 98 km of exposed and inspected pipe. In the trending studies, the relationships between SCC occurrence and operating stress, coating type, pipe grade and diameter, distance from compressor discharge and other potentially correlating parameters, were explored. This information predates the corresponding datasets provided by the JIP participants.

Baker Study [8]

In a study undertaken for DOT RSPA, Michael Baker conducted a survey of a large number of pipeline operators in North America concerning their experiences of the occurrence of SCC and its management. 23 of the 42 respondents had experienced SCC; totals in excess of over 50 in-service occurrences and several hundred hydrostatic test failures were reported, though the extent varied widely between respondents (and detailed information from individual operators is not available). Both high pH and near-neutral pH SCC were experienced; high pH SCC predominantly in the U.S. and near-neutral pH SCC predominantly in Canada. Seven operators were interviewed in depth, revealing that in some instances extensive hydrostatic test and excavation programs have been initiated as part of the threat management process.

Duke Energy Survey of Operator Experience [9]

As part of the program to develop and enhance their SCC Integrity Management Plan, Duke Energy conducted a survey of operator experience concerning the occurrence and management of SCC. During this survey, information was obtained on around 50 in-service leaks and ruptures, and several hundred hydrostatic test failures, due to high pH or near-neutral pH SCC. In addition, several operators provided information on their ILI and excavation programs (Several of the operators had also participated in the Baker study reported above). Some of this information is included among the data provided by the JIP participants.

Field-Related Studies for PRCI [10]-[19]

During the last twenty years PRCI has initiated several studies that have included the collection, review and analysis of information from field investigations of SCC. Information from these studies can be used to comment, for example, on the shape, size and number of SCC defects recorded in the datasets provided by the JIP participants.

Published Papers by Individual Companies [20]-[28]

During the last ten years or so several pipeline operators have published papers describing their in-service experiences with SCC and the steps taken to manage the ongoing threat. These have included details of in-service occurrences of both high pH and near-neutral pH SCC, and explorations of the factors that correlate with them. Some papers have explored the application of ILI and excavation programs for SCC threat management.

3. Data Review and Analysis

3.1 Approach

The data review focuses principally on the detailed records provided by the JIP participants, and explores the key parameters that have previously been found to correlate with high pH and near-neutral pH SCC:

Where is cracking found?
- Proximity to compressor discharge
- Operating pressure
- Coating type, pipe diameter
- Pipeline age

What cracking is found?
- Type of SCC
- Numbers of colonies, depths, lengths and aspect ratios
- Crack depths and lengths

To facilitate the analysis cracking has been grouped where possible according to severity, as follows:

Serious cracking:
- Cracking that has already resulted in an in-service rupture or leak, or a hydrostatic test failure

Noteworthy cracking:
- Cracking that could develop into serious cracking during the life of the pipeline. Specifically, this is taken to include all cracks deeper than 10% of wall thickness and all cracks longer than that which, if 50% deep, would fail a hydrostatic test at 110% SMYS (2 inches has been taken as typical)

Inconsequential (Category Zero) cracking:
- Cracking that is less than 10% deep or less than 2 inches long.

The definitions of Noteworthy and Inconsequential cracking are broadly consistent with those in the CEPA Guidance document [29], and are described in detail in a separate JIP Report “Defining crack severity and remedial action.”

It should be noted that the records provided by the JIP participants do not always contain all the specific information necessary for full analysis. In the sections that follow, the reduced numbers of records appearing in the tables, compared to the overall summary table above, reflect this lack of specific information. Every attempt has been made to avoid introducing bias by selective use of the data.

3.2 High pH SCC

3.2.1 In-Service Ruptures and Leaks

<u>Proximity To Compressor Discharge</u>

Within a few years after the discovery of high pH SCC in gas pipelines, it became apparent [2], [3], [4], [6] that almost all of the in-service failures and hydrostatic test failures occurred within the first few valve sections downstream from compressor discharges. Eiber and Leis [3], [4] reported that 65% of the 42 occurrences they reviewed were within 5 miles of a compressor discharge and 92% were within 10 miles.

The detailed information from the JIP participants reinforces this general trend, although the spread is somewhat broader, as Table 2 shows, 89% of all in-service failures and 95% of all hydrostatic test failures occurred within 20 miles downstream from compressors.

Table 2 - Effect of Proximity to Compressor Discharge on Failure Frequency (Datasets 1-6, 9)

Distance, miles	In-service failures		Hydrostatic test failures	
	Coal tar enamel	Tape	Coal tar enamel	Tape
0-5	19	8	107	3
5-10	10	2	88	7
10-20	10	1	17	29
20-30	2	1	3	5
30-40	0	1	0	2
40-50	1	0	0	0
>50	1	0	2	1

It would appear that the slight change in the pattern, compared with that found by Eiber and Leis, stems largely from the results from one or two "problem" lines which have more extensive SCC than the rest; in some instances the failures beyond 20 miles are preceded by failures within the 20-mile region. Also, several of the failures at long distance have been associated with "bad" pipe or hard spots.

For hydrostatic tests, it is necessary to take into account the bias introduced by the higher proportion of tests undertaken near compressor discharges. An indication of the overall situation is given by comparing the numbers of failures and passes obtained during the first tests on each section. Table 3 shows that, notwithstanding the significantly reduced number of tests in the more distant valve sections, the proportion of failures is lower.

Table 3 - Proportion of Hydrostatic Tests Failing due to High pH SCC in Each Valve Section (Dataset 2)

Valve section	Number of failures	Total number of tests	Total mileage tested
1	13	183	~500
2	1	11	40
3-5	0	10	40
>5	0	4	5

Operating Stress

Eiber and Leis [3], [4] presented data for 39 in-service occurrences, indicating that, while they have occurred at hoop stresses from 25% to 72% of SMYS, approximately two-thirds of them occurred at hoop stresses above 60% SMYS.

The records provided by the JIP participants show that, overall, 87% of in-service failures and 96% of hydrostatic test failures were in pipelines designed to operate at 60% SMYS or above. Almost all the reported failures below this threshold, at 33-60% SMYS, were in pipes with diameters of 12 inches or less, as Table 4 shows. Also, only leaks (i.e., no ruptures) occurred below 48% SMYS.

Table 4 - Effect of Operating Stress on Failure Frequency for High pH SCC (Datasets 1, 3, 4, 5, 6, 9)

% SMYS	In-service failures		Hydrostatic test failures	
	<12" diam	>12" diam	<12" diam	>12" diam
<30	0	0	0	0
30-40	2	0	0	1
40-50	3	0	10	0
50-60	2	0	0	1
60-70	0	9	0	37
>70	4	33	0	250

Pipe age

There has been a steady number of in-service failures due to high pH SCC ever since the earliest in-service occurrences. As Table 5 shows, the number averaged around 1.5 occurrences per year over the 40-year period from 1965 to 2005.

Table 5 - Frequency of In-Service Failures due to High pH SCC in the last 40 Years (Datasets 1, 3, 4, 5, 9)

Year	1965-70	1971-75	1976-80	1981-85	1986-90	1991-95	1996-00	2001-05	2006-
Number of failures	7	12	1	11	7	10	8	4	1

Eiber and Leis [3], [4] presented data for 42 in-service occurrences showing that, while the earliest incident occurred 6 years after installation, in more than 80% of the affected pipelines, SCC failures did not occur until after 20-30 years service. The information provided by the participants is consistent with this pattern; as Table 6 shows, all but two of the in-service failures have been on pipe more than 10 years old.

Table 6 - Age of Pipelines When In-Service or Hydrostatic Test Failures Occurred due to High pH SCC (Datasets 1, 3, 4, 5, 6, 9)

Age at time of occurrence, years	Number of in-service failures	Number of hydrostatic test failures
0-10	2	0
10-20	10	100
20-30	17	59
30-40	10	70
40-50	14	49
>50	4	22

The information for hydrostatic test failures is also included in Table 6 and shows that no hydrostatic test failures have occurred within 10 years of installation. It also shows that hydrostatic test failures are continuing to occur, up to more than 50 years after installation.

The information provided by the JIP participants shows that the minimum life prior to failure was 6 years for tape-wrapped pipe and 18 years for coal tar coated pipe, and that no in-service occurrences and only one hydrostatic test failure have occurred on lines installed after 1960. However, no hydrostatic tests have been undertaken on recently installed lines, and those installed since around 1980 have largely utilized fusion bonded epoxy (FBE) coatings.

Coating Type

Eiber and Leis [4] reported that, out of 30 in-service occurrences for which information on coating type was available, 22 had coal tar or asphalt coatings and 6 had tape coatings, with one each for bitumastic-coated and bare pipe. We now suspect that the failure in bare pipe probably was due to near-neutral-pH SCC. The one SCC service failure in bare pipe occurred about 20 years before it was recognized that there were two forms of SCC—high pH and near-neutral pH. The original failure analysis, which was conducted by Fessler, merely indicated that the cause was SCC without specifying which type. However, the failed pipe had the common features that now are associated with near-neutral pH SCC.

The information provided by the JIP participants included 61 in-service occurrences where the coating type was identified; 44 were coal tar coated, 16 were tape-coated and one was asphalt-coated (an improperly-coated tie-in weld). There were also 298 hydrostatic test failures where the coating type was recorded; 52 were tape-coated and the rest were coal tar coated.

The proportionately high number of coal tar coatings associated with hydrostatic test failures is largely due to the high number tested. It is also clear that a substantial proportion of the tape-coated valve sections also failed; however, none of the three asphalt-coated valve sections that were tested failed.

3.2.2 Excavations

Two datasets consisted of records from excavation programs on pipeline systems coated predominantly with coal tar. The first contained over 4000 "opportunistic" excavations, of which around 3.5% revealed cracking. The second contained 495 excavations that had been undertaken in response to SCC issues (ILI indications or adjacent in-service, hydrostatic test failures) on the line, and that had revealed SCC.

The excavation records are dominated by those for coal tar coated pipe. In the second dataset, for example, more than 95% of those that found SCC were on coal tar coated pipe, with the remainder on wax (8), asphalt (1) and tape-wrapped pipe (1).

Excavations revealing cracking were concentrated in the regions immediately downstream from compressors, in the same way as for hydrostatic test failures. Table 7 shows that 90% of the cracking was found within 20 miles of the compressor discharge.

Table 7 - Effect of Proximity to Compressor Discharge on High pH SCC Found by Excavation (Dataset 11)

Distance, miles	Number of excavations with SCC
0-5	111
5-10	54
10-20	43
20-30	13
30-40	2
40-50	1
>50	2

Excavations revealed that the extent of cracking depended upon both pipe diameter and operating stress. Table 8 shows that, for pipes larger than 12 inches diameter, 90% of the cracking was found at 60% SMYS or above. However, for pipes smaller than 12 inches diameter, half of the cracking has been found at 30-50% SMYS.

Table 8 - Effect of Pipe Diameter and Operating Stress on High pH SCC Found by Excavation (Dataset 11)

Operating stress, % SMYS	Number of excavations revealing cracking	
	<12-inch diameter	>12-inch diameter
<30	1	0
30-40	3	1
40-50	15	2
50-60	2	27
60-70	13	199
>70	0	132

The excavations on coal tar coated pipe revealed anything from one to 200 or more colonies of SCC. Colony dimensions ranged from a few inches to 10 inches or more in both axial and circumferential directions and contained anything from a few to 100 or more individual axial cracks. In a few instances, the colony shape appeared to have been influenced by the presence of local residual stresses, for example at dents or adjacent to girth or seam welds.

There were a few excavations where cracking was found under asphalt or wax coatings. These showed considerably less extensive cracking; around 10-30 colonies in each excavation.

Crack depth measurements were only recorded very infrequently. However, an indication of the distribution of crack depths is obtained from the remedial action taken (where recorded), as follows:

Cut out and replace pipe section	40%
Grind and sleeve repair	20%
Grind and re-coat	40%
Re-coat only	10%

For those colonies that were remediated by grinding, the grind depth averaged 15% of the wall thickness (maximum 30%).

Taken overall, this information suggests that at least half of the SCC found by these excavations were less than 20% deep.

3.2.3 ILI

One dataset was provided by the participants, comprising three developmental ILI runs. The first two runs were from a trial in 1995. Two pipeline lengths totaling 55 miles were inspected, revealing seven locations with SCC colonies/cracks exceeding 25% deep and six more with colonies/cracks 10-25% deep (only the 20 deepest defects of all types were reported). The colonies were generally a few inches long (maximum 15 inches).

The third developmental ILI run was completed in 2004, on a 30-mile section immediately downstream from a compressor; this section had experienced a hydrostatic test failure some years earlier. The ILI run revealed over 6500 indications exceeding the detection threshold of 15% depth, characterized as high pH SCC colonies. The colonies were 1-50 inches long, and around 10% of them were deeper than 30% through wall; cracking occurred around the entire pipe circumference but tended to be concentrated in the bottom quadrant of the pipe. Colonies occurred out to 30 miles, where the run terminated, but were less deep and less densely spaced as the distance downstream from the compressor discharge increased (subsequent hydrostatic testing produced five test failures between 7 and 25 miles downstream).

3.3 Near-Neutral pH SCC

3.3.1 In-Service Ruptures and Leaks

The NEB Report [5] identified ten pipeline failures in Canada that were due to axially oriented near-neutral pH SCC, occurring between 1985 and 1996. Seven of these were on polyethylene-tape-wrapped pipe, with two on asphalt-coated pipe and one on coal tar coated pipe (One of the asphalt failures was associated with mechanical damage and the coal tar failure was at an ERW long seam weld). The great majority of these were reported to have occurred within the first valve sections downstream from compressor discharges.

The JIP participants provided details of 19 in-service ruptures and leaks due to near-neutral pH SCC (several of these were also reported by NEB). All but one of the pipes were in the range 20-40 inch diameter; they all had been installed between 1957 and 1981 and had all been operated at 69-78% SMYS. Table 9 shows that there has been an average of one failure per year over the 15 years from 1990 to 2005.

Table 9 - Occurrence of In-Service Ruptures and Leaks due to Near-Neutral pH SCC (Datasets 6, 7, 9)

Year	1975-80	1981-85	1986-90	1991-95	1996-00	2000-05	2006-
Number of failures	0	2	1	5	6	5	0

Table 10 - Influence of Proximity to Compressor Discharge on In-Service Failures due to Near-Neutral pH SCC (Datasets 6, 7, 9)

Distance from compressor, miles	Coating type		
	Tape-wrapped*	Asphalt	Wax
0-5	2	1	0
5-10	2	0	1
10-20	1	3	0
20-30	1	0	0
30-40	0	1	0
40-50	0	0	0
>50	0	5	0

*Excludes one failure on a 8.625 inch diameter gathering line with no compressor

The age at which near-neutral pH SCC failures start to occur on a pipeline is dependent upon coating type. For tape-wrapped pipes, the first in-service failures occurred after 12 years, whereas for asphalt coatings the first failures occurred after 20 years, as Table 11 shows.

Table 11 - Age at Which In-Service and Hydrostatic Test Failures Have Occurred due to Near-Neutral pH SCC (Datasets 6, 7, 9)

Pipe age, years	Number of in-service and hydrostatic test failures							
	Tape-wrapped		Asphalt		Wax		Coal tar	
	In-service	Hydro-test	In-service	Hydro-test	In-service	Hydro-test	In-service	Hydro-test
0-10	0	0	0	0	0	0	0	0
10-20	4	4	1*	0	0	0	0	0
20-30	3	6	3	1	0	0	0	0
30-40	0	4	5	21	1	0	0	1
40-50	0	0	2	15	0	0	0	0
>50	0	0	0	0	0	0	0	0

*Failure at mechanical damage

3.3.2 Hydrostatic Tests

The JIP participants provided details of 383 hydrostatic tests on a total of around 2400 miles of pipeline, in response to concerns about near-neutral pH SCC. Of these, 52 failed due to near-neutral pH SCC; as

Table 12 shows, two-thirds of the tape-wrapped failures occurred within 20 miles downstream of compressor discharges, but the failures in asphalt-coated pipe were distributed along the entire pipeline length.

Table 12 - Proximity of Near-Neutral pH SCC Hydrostatic Test Failures to Compressor Discharges (Datasets 6, 7, 9)

Distance, miles	Number of hydrostatic test failures			
	Tape-wrapped*	Asphalt	Wax	Coal tar
0-5	3	1	0	0
5-10	3	0	0	0
10-20	0	2	0	0
20-30	2	18	0	0
30-40	1	7	0	1
40-50	0	2	0	0
>50	0	7	0	0

* Excludes 5 failures on a 8.625 inch diameter gathering line with no compressor

All the hydrostatic tests occurred on pipelines that had been operated at 70-80% SMYS and the great majority were on 20-42 inch diameter pipe.

3.3.3 Excavations

Following the experiences of near-neutral pH SCC in Canadian oil and gas pipelines, CEPA collected data from excavations by pipeline operators in Canada. In total, over 13,000 colonies were recorded in over 98 kilometers of exposed and inspected gas pipelines (predominantly from one operator). Trending studies completed by CEPA [7] focused on colony density, expressed as the number of colonies per meter of pipeline inspected, and revealed the following:

Colony densities averaged around 0.3/m for tape-wrapped pipe but were generally less than 0.1/m for asphalt-coated pipe.

Colony densities were higher in pipe operated above 50% SMYS, for both tape-wrapped and asphalt-coated pipe.

Colonies were found in tape-wrapped pipes ranging in age from less than 10 years to more than 30 years, and colony densities did not change significantly with pipe age.

Colonies were found in asphalt-coated pipes over 10 years old.

Colony densities generally did not change with increasing distance from compressor discharges, but there was a sharp peak for asphalt-coated pipes at 25-30 km.

The ratios of deep (>10%) to shallow (<10%) cracks were 1:10 or less for both tape-wrapped and asphalt-coated pipes.

The JIP participants provided two substantial datasets containing a total of over 4300 excavations on 20-42 inch diameter pipelines, 17% of which revealed near-neutral pH SCC colonies. These datasets were not included in the CEPA trending studies described above. Because the two datasets were obtained during targeted excavation programs and the site selection criteria were different, the results are presented separately.

The first dataset included records for four main coating types. As Table 13 shows, asphalt-coated pipes were excavated most frequently and showed the highest proportion of SCC "hits."

Table 13 - Relationship Between Coating Types and Near-Neutral pH SCC "Hits" from Excavations (Dataset 12)

Coating type	Number of excavations	Number finding SCC
Asphalt	3185	591
Wax	640	61
Coal tar	126	2
FBE	89	0

It is noteworthy that none of the excavations on FBE-coated pipe revealed any evidence of SCC. Some of these pipes had been installed as early as 1980.

Table 14 indicates that SCC colonies were found a considerable distance downstream from compressor discharges, although the majority were within 50 miles. Table 15 indicates that all the colonies were in pipelines installed over 20 years ago, while Table 16 shows that all the colonies were in pipelines designed to operate at above 60% SMYS.

Table 14 - Proximity of Near-Neutral pH SCC "Hits" to Compressor Discharges (Dataset 12)

Distance, miles	Number of excavations	Number of excavations finding SCC			
		Asphalt		Wax	
		All depths	>10% deep	All depths	>10% deep
0-10	2773	280	19	19	8
10-20	488	71	22	4	2
20-40	573	218	57	10	6
40-80	471	26	2	28	9

Table 15 - Effect of Pipeline Age on Near-Neutral pH SCC Found by Excavation (Dataset 12)

Installation date	Number of excavations	Number finding SCC
1965-1970	3031	420
1970-1980	286	36
1980-1985	828	238
1985-2000	81	0

Table 16 - Effect of Op. Stress on Near-Neutral pH SCC Found by Excavation (Dataset 12)

Stress, % SMYS	Number of excavations	Number finding SCC
40-50	18	0
50-60	45	0
60-70	143	17
72	4208	679

Table 17 through Table 20 show the corresponding information for the second dataset, in which the largest proportion of records were for tape-wrapped and asphalt-coated pipe. For this dataset, the majority of the colonies were found within 30 miles downstream of compressor discharges, in pipes operating at above 60% SMYS and installed over 30 years ago.

Table 17 - Effect of Coating Type on Near-Neutral pH SCC Found by Excavation (Dataset 13)

Coating type	Number of excavations	Number finding SCC
Tape-wrapped	54	41
Asphalt	47	15
Coal tar	22	5

Table 18 - Proximity of Near-Neutral pH SCC "Hits" to Compressor Stations (Dataset 13)

Compressor proximity, miles	Number of excavations	Number of excavations finding SCC					
		Tape-wrapped		Asphalt		Coal tar	
		All depths	>10% deep	All depths	>10% deep	All depths	>10% deep
0-10	80	20	7	7	1	1	0
10-20	30	20	3	6	4	2	0
20-40	11	1	1	2	2	2	2
40-80	0	0	0	0	0	0	0

Table 19 - Effect of Pipeline Age on Near-Neutral pH SCC Found by Excavation (Dataset 13)

Installation date	Number of excavations	Number finding SCC
1950s	5	1
1960s	51	15
1970s	43	26
1980s	21	18
1990s	1	1

Table 20 - Effect of Op. Stress on Near-Neutral pH SCC Found by Excavation (Dataset 13)

Operating stress, %SMYS	Number of excavations	Number finding SCC
50-55	8	8
55-60	1	1
60-65	8	2
65-70	8	1
70-75	50	24
75-80	34	17
80-85	13	8

The datasets indicate that the extent of cracking exposed by excavation depends on the coating type. For tape-wrapped pipe, each excavation (typically one or two pipe joints in length) frequently revealed large numbers of crack colonies, sometimes up to 100; each colony could be up to 15 inches or more in both axial and circumferential directions and could contain a large number of closely spaced individual cracks. For asphalt-coated and wax-coated pipe, each excavation revealed typically 10-30 individual colonies, while for coal tar fewer than five colonies were generally found.

An illustration of the frequency of occurrence of large and small colonies and cracks can be obtained from these two datasets. Table 21 and Table 22 show the distributions of lengths and depths found; for both datasets it is apparent that only 10-20% of the colonies and cracks found on excavation were sufficiently deep (>10%) and long (>2 inches) to be classified as noteworthy.

Table 21 - Distribution of Near-Neutral pH Stress Corrosion Crack Depths and Lengths Found by Excavation (Dataset 12)

Length, inches	Number of cracks according to depth, % of wall thickness				
	<10%	10-15%	15-20%	20-25%	>25%
<2”	320	7	6	0	1
2-5”	93	115	15	3	3
5-10”	36	5	12	8	9
10-20”	15	3	1	0	2
20-30”	16	0	0	2	3
30-50”	13	0	1	0	1
>50”	4	0	0	0	0

Table 22 - Distribution of Near-Neutral pH SCC Colony Depths and Lengths Found by Excavation (Dataset 13, Asphalt-Coated Pipe Only)

Length, inches	Number of colonies according to depth, % of wall thickness				
	<10%	10-15%	15-20%	20-25%	>25%
<2”	46	13	4	2	1
2-5”	38	8	4	1	0
5-10”	16	0	0	0	0
10-20”	11	0	0	0	0
20-30”	0	0	0	0	0
30-50”	0	0	0	0	0
>50”	0	0	0	0	0

3.3.4 ILI

Further information on the size and occurrence of SCC can be obtained from Crack Detection ILI. Results from four ILI runs totaling around 165 miles have been provided by the JIP participants (Table 23). These results provide a useful indication of the extent and depth of cracking in the individual pipeline segments; for example, one dataset shows that 95% of the cracks discovered were too small to be classified as Noteworthy. However, the information is too limited to be of general value.

Table 23 - Summary of Near-Neutral pH SCC Results Obtained from ILI Crack Detection (Dataset 14)

Number of miles inspected	Number of joints inspected	Number of joints with SCC cracks/colonies			
		All depths	0-10% deep	10-25% deep	>25% deep
~20	2252	36*	4	32	0
16	2200	24*	-	22	2
105	10500	92*	79*	12	1

*Not all the smaller defects were confirmed as SCC.

4. Field Experience from Other Operators

The Baker study [8] reviewed responses from 23 operators who had experienced SCC. In total they apparently identified over 50 in-service occurrences and around 300 hydrostatic test failures due to high pH and near-neutral pH SCC.

Elboudjaini, et. al. [24] reported on detailed studies following 22 hydrostatic test failures on a 16-inch line operated by Williams Northwest, constructed in 1960. The majority of the leaks, thought to be due to high pH SCC, occurred within the first six miles downstream of the compressor. Williams NW have also reported [8] an in-service leak on the line, and have conducted Crack Detection ILI to explore the extent of cracking.

Spitzmacher and Leeson [28] reported on detailed excavation and ILI studies following the in-service rupture of a 16-inch diameter liquids line due to near-neutral pH SCC. A total of 282 crack-like features were found immediately downstream of a pump station.

Marr and Davis [26] reported on the development of a predictive model for near-neutral pH SCC following the failure of a 30-inch, X60 asphalt-coated line. (Kinder Morgan has reported separately [8] that a total of six in-service failures and eight hydrostatic test failures were experienced). The model focused on using MFL to identify areas of light corrosion, together with above-ground survey data to identify outwardly sound coating; these in combination led to SCC-promoting conditions. Kinder Morgan has also explored the possibility that SCC correlates with pipe manufacturer.

Beavers [8] reported on the development of a predictive model based on an initial program of 450 excavations, on tape-wrapped and asphalt-coated pipes experiencing near-neutral pH SCC. The strongest correlations were obtained with pipe manufacturer and soil type.

Youzwishen et al [23], [25] and Waker, et. al. [22] described the development of predictive models based on combinations of excavation results and ILI (crack detection and MFL). MFL was used to identify areas of light corrosion, and crack detection data were used to identify possible areas of disbonding, to form the basis of the model.

Kresic and Ironside [27] describe the Enbridge program for managing the threat of corrosion fatigue and SCC on their oil pipelines, using ILI crack detection validated with excavations. Cracking is endemic throughout the system, but in-service failures have been avoided through active management.

Duke Energy commissioned a survey [9] of the occurrence of SCC and the approaches to its management in 11 pipeline systems operated by a number of companies, all of which had experienced SCC. Information reviewed related to 30 in-service occurrences, around 300 hydrostatic test failures, several thousand excavation records and several hundred miles of ILI crack detection. Much of this information has been incorporated in the present work.

This information has been taken into account, together with the analyses described above, in identifying the main patterns and trends reported below.

5. Identification of Main Patterns and Trends

The key findings from this collation and review are as follows:

High pH SCC

- Around 90% of the in-service ruptures and leaks due to axially oriented SCC are within 20 miles of compressors, but the spread has increased a little since the analysis by Eiber and Leis.
- Around 95% of hydrostatic test failures are also within 20 miles downstream of compressors. The total is biased due to the high proportion of tests on first valve sections.
- Over 85% of in-service failures and over 95% of hydrostatic test failures have been in pipe designed to operate above 60% SMYS. Most of the exceptions are pipes less than 12 inches in diameter.
- In-service failures have continued to occur at a steady rate over the last 40 years, as pipeline age increases. Only two in-service failures, and no hydrostatic test failures, have been in pipes less than 10 years old. In more than 90% of the affected pipelines, SCC did not start to occur until after 20-30 years service.
- Over 70% of the in-service failures have been on coal tar coated pipe, with the remainder being on tape-wrapped pipe. Elsewhere there have occasionally been reported instances on asphalt coated and wax coated pipe.
- Where SCC has been found on coal tar coated pipe, excavations have revealed anything from a few colonies to 200 or more. Colonies ranged from a few inches to 10 inches or more in axial and circumferential directions. Each colony contained from a few to 100 or more closely spaced individual cracks.

- In a dataset of "opportunistic" excavations, less than 5% of the excavations revealed SCC, and estimates suggested that more than half of the colonies were less than 20% deep. In one developmental ILI run on a line with a history of high pH SCC, around half the pipe joints contained cracks 15-30% deep but only one tenth of the cracks found were more than 30% deep.

Near-Neutral pH SCC

- Ten of the in-service ruptures and leaks due to axially oriented SCC have been on asphalt-coated pipe, with seven on tape-wrapped pipe and one on wax-coated pipe.
- In-service failures on tape-wrapped pipes have mostly been within 20 miles downstream of compressor discharges, whereas those on asphalt-coated pipe have been distributed along the entire pipeline length.
- Hydrostatic test failures on tape-wrapped pipes have mostly been within 30 miles downstream of compressor discharges, whereas those on asphalt-coated pipe have been distributed along the entire pipeline length.
- All the in-service failures and all the hydrostatic test failures have been on lines designed to operate at above 70% SMYS.
- In-service failures first occurred in 1985 and have continued at an average rate of one per year since the early 1990s.
- For tape-wrapped pipes, the first in-service failures occurred 12 years after installation, whereas, for asphalt-coated pipes, the first failures occurred after 22 years (excepting a failure at mechanical damage after 13 years).
- In targeted excavation programs, between 5% and 80% of the excavations have revealed SCC.
- Excavations have revealed only limited cracking in pipes operated below 60% SMYS.
- Where SCC has been found on tape-wrapped pipe, excavations have revealed anything from a few colonies to 100 or more; each colony could be up to 15 inches or more in both axial and circumferential directions and could contain a large number of closely-spaced individual cracks.
- Where SCC has been found on asphalt-coated pipe, excavations have revealed typically around 10-30 colonies, while on coal tar coated pipe less than 5 colonies have generally been found.
- Around 10% of the colonies and cracks found by excavation were sufficiently deep (>10%) and long (>2 inches) to be classified as Noteworthy. This is consistent with the findings of the CEPA Trending Study.

General

Pipe joints that fail in service or during hydrostatic test due to SCC typically contain several deep secondary cracks. Whenever deep cracks have been found, whether in conjunction with a failure or not, there always have been much larger numbers of shallow cracks (typically around 10 times as many) in the vicinity. Therefore, if a portion of a pipeline is found to be free of shallow cracks, then it is highly unlikely that nearby unexamined portions of the pipeline contain deep cracks and especially near-critical cracks.

6. Discussion and Comments

6.1 Implications Concerning the ASME Criteria

The results presented above indicate that the up-to-date information from service experience, hydrostatic testing and excavation programs largely substantiates the judgments made when the ASME criteria were first formulated, and that in most instances they can be applied both to high pH and to near-neutral pH SCC. However it is important to recognize the influence of the systemic bias in the testing and excavation data that results from focusing tests on the areas where SCC has been found. There is a real danger that some of the findings become self-reinforcing. The true test of the criteria, on which the main findings are based, comes from the in-service ruptures and leaks.

The ASME compressor proximity criterion is substantially reinforced by the up-to-date information for high pH SCC, but not for near-neutral pH SCC. The proximity criterion incorporates the possible influences of several factors such as operating temperature, pressure cycling and coating degradation, so it is not surprising to find differences appearing as the pipeline systems get older. Also, it must be remembered that the proximity criterion is not a sharp discriminator; there will continue to be exceptions, as there were before. In particular, local situations such as the presence of residual stress (near girth of seam welds, dents and wrinkles) or poor coating application may override the general influence of compressor proximity, for some pipelines.

Likewise, the ASME threshold stress criterion is substantially reinforced by the up-to-date information, with the exception of smaller-diameter pipes. There are difficulties in combining and interpreting data from different sources when % SMYS, MAOP and actual operating pressure (including pressure history) can all give slightly different pictures. Hence it must be expected that the stress criterion is not a sharp discriminator and there will continue to be exceptions. In particular, substantial load cycling such as that due to demand swings (power stations, etc.) may change the pattern considerably for particular parts of a pipeline system.

The ASME pipeline age criterion is now generally seen as over-conservative except for tape-wrapped pipes. The initial identification of the SCC problem was followed by a burst of “worst case” occurrences before the early mitigation strategies could take effect, for both high pH and near-neutral pH SCC. Cracking is continuing to develop in the older pipelines, and to some extent the problem is becoming more evident in areas where it was slower to initiate and grow, but there is not a need to apply the same age restriction to more recently installed pipe. It is encouraging that there have been no in-service or hydrostatic test failures on pipes installed since 1981. For pipe that has been re-coated after some time in service, it appears more appropriate to consider the age as the time since re-coating rather than the time since construction, because the coating may deteriorate over time, but the steel does not.

The influence of coating type on SCC occurrences is strongly evident in the patterns of in-service failures, hydrostatic tests and excavations. Coal tar coated pipe appears at first sight to be most prone to high pH SCC, but this in part reflects the high proportion of coal tar coatings used; tape-wrapped pipe may be equally prone, but there is not sufficient information to draw this conclusion. It should also be noted that other coating types (asphalt and wax) are not completely immune to high pH SCC. Tape-wrapped and asphalt-coated pipes are most prone to near-neutral pH SCC; wax and coal tar are much less affected, but are not completely immune.

The immunity of FBE-coated pipe to SCC is confirmed; up to 25 years experience has now been obtained, both for originally coated (plant-applied) and recoated (field-applied) pipe. For other plant-applied coatings (polyurethanes, extruded polyethylenes), there is no negative experience, but very few of these pipes have been excavated. There is probably more extensive experience for liquid epoxy (field joints, repairs) but, again, there is not yet sufficient positive evidence to justify ranking liquid epoxy alongside FBE.

In the preceding sections in this report, each of the ASME B31.8S criteria have been considered individually. While this is informative in determining the applicability of each criterion, the overall ASME approach utilizes all the criteria in combination. Hence it is appropriate to examine the accumulated service experience in the same way and, in particular, to examine the reasons for the "outlier" results.

In total, 87 in-service failure records were provided by the JIP participants and other operators; 61 are due to high pH SCC and 19 are due to near-neutral pH SCC. A further 7, from one operator, are described as mixed-mode and include 3 instances of circumferential cracking; as was indicated earlier, these 7 results have been omitted from all the analyses.

One failure was due to SCC at mechanical damage, one was SCC at a wrinkle bend, one was SCC at a hard spot, two were SCC associated with a seam weld and one was SCC at an improperly-coated tie-in weld; these 6 results have also been discounted from further analysis.

Of the remaining 74 failures, there are 8 below the 60% stress criterion, 5 beyond the 20-mile distance criterion for high pH SCC and two within the 10-year age criterion; all are due to high pH SCC. One outlier appears in two categories, giving a total of 14. Hence, overall, 60/74 = 81% are included when all the criteria are taken together; this figure reduces to 77% if only high pH SCC is considered.

Looking at the 14 outliers in detail, the following points emerge:

- Only four of the 14 outliers are ruptures; the rest are leaks (one is not recorded).
- Eight of the outliers are in pipelines with diameters less than 12 inches.
- Four of these occurred in close proximity to one another, in a production gathering line that experienced elevated temperatures from the production facilities.
- The only two short-life failures are in tape-wrapped lines and occurred over 30 years ago.
- One high pH SCC failure at 22 miles is in a line that had already experienced two earlier ruptures within the 20-mile limit.

Depending on the weight given to these considerations, the overall figure for failures addressed by the ASME criteria ranges from a minimum of 81% to around 90%.

The data for hydrostatic test failures have also been re-examined on the same basis. There are 363 results: 308 for high pH SCC, 52 for near-neutral pH SCC and 3 described as mixed-mode. Among these results there are 25 outliers, 7% of the total; 12 of the outliers are below 60% stress and 13 are beyond 20 miles. Some of the special circumstances applying to the in-service failures also apply to the hydrostatic tests. This supports the conclusion that around 95% of the hydrostatic test failures are addressed by the ASME criteria.

6.2 Comparison of Information from In-Service Failures, Hydrostatic Tests, Excavations and ILI

The information from excavations and ILI gives considerable insight into the relative frequencies of occurrence of differently sized colonies and cracks. CEPA used the measure of colonies/meter as a useful comparator of the extent of cracking, but it has limited overall applicability; a colony density of 0.1/m equates on average to every pipe joint containing one colony. The reported numbers of excavations revealing cracking varied considerably in the present work; from 3% in an opportunistic program to 80% in a targeted program. Hence it is difficult to make useful generalizations. Nevertheless, it appeared that the ratio of deep shallow cracks found on excavation was around 1:10. This gives the initial basis for estimating a "risk pyramid" relating event severity and frequency, as follows:

Event	Experience	Approximate Frequency Range
In-service failures	50 in 100,000 miles	I joint in 100,000 to 1 joint in 10,000,000
Hydrostatic test failures	300 in 5000 miles tested	1 joint in 500 to 1 joint in 50,000
Noteworthy cracking (> 10% Deep)	10% of Inconsequential cracking	1 joint in 10 to 1 joint in 1000
Inconsequential cracking	3% to 80% of excavations	Every joint to 1 joint in 100

Clearly, this is illustrative rather than quantitative, and the band-widths of estimated frequency of occurrence have been kept broad to reflect all the uncertainties. Nevertheless, it gives an indication of the magnitude of the problem to be addressed though SCC threat management.

The information presented, and trends developed, during the study formed the basis for developing guidance for operators in determining SCC susceptibility, prioritizing segments and High Consequence Areas and selecting sites for excavation as part of their SCC integrity management programs.

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APPENDIX B - DEFINITION OF SCC SUSCEPTIBLE HCA'S AND SEGMENTS

Question 1: On what basis should HCAs and Segments be defined as SCC susceptible?

1. Summary

ASME B31.8S gives guidance as to which gas pipeline segments should be considered at risk due to SCC. The guidance is based on operating stress and temperature, distance downstream from the compressor discharge, age, coating type and prior SCC history. This guidance has been incorporated into the Integrity Management rules in CFR 192 Sub-part O.

The ASME Guidance was developed more than five years ago and was based on the experience of in-service failures and hydrostatic test failures between the mid-1960s and mid-1990s. Since that time, additional in-service and hydrostatic test failures have occurred and a substantial number of SCC excavations have been conducted.

To provide a platform for the development of sound, practical SCC integrity management plans, meeting the requirements of DOT PHMSA, a large body of up-to-date information from in-service failures, hydrostatic tests, excavations and in-line inspections relating to 130,000 miles of natural gas pipelines operating in North America has been collated and reviewed. This information has been used to assess the effectiveness of the ASME criteria in providing the initial definition of SCC-susceptible segments. It has also been used to consider the implications of the recently proposed modifications to the ASME criteria that will extend their applicability to include near-neutral pH SCC as well as high pH SCC.

Many of the engineering judgments embodied in the original ASME criteria are still applicable to high pH SCC and are substantiated by the up-to-date field experience. Hence there is no overriding need to make changes to the criteria for susceptibility to high pH SCC. Most of the same criteria are also applicable to near-neutral pH SCC.

On the basis of the information now available, it appears that, with the proposed revisions, the ASME criteria still provide a good basis for the initial definition of SCC-susceptible segments. The revised ASME criteria address over 80% of the in-service failures attributable to high pH and near-neutral pH SCC in natural gas pipelines, and this figure rises to around 90% when the specific circumstances of the outlying occurrences are taken into account. The revised criteria also address over 95% of the hydrostatic test failures, and around 85% of the SCC cracks exceeding 10% through-wall depth, found during excavations.

2. Introduction and Background

One of the first steps undertaken during a SCC Integrity Management Program is to determine for which segments in the pipeline system SCC should be considered a threat (i.e., it may cause the pipeline to leak or burst within its lifetime). The primary reference for determining this is the guidance in ASME B31.8S:

HCAs must be assessed for risk of SCC if all of the following conditions are present:

1. *Operating Stress > 60%*
2. *Operating temperature > 100°F*
3. *Distance from compressor station ≤ 20 miles*
4. *Age ≥ 10 years*
5. *All corrosion coating systems other than fusion bonded epoxy (FBE).*

In addition, ASME B31.8S requires that each segment that has experienced a service incident or hydrostatic test break caused by SCC must be evaluated unless the conditions that led to SCC have been corrected (e.g. by pipe replacement).

The ASME Guidance was formulated by an ASME Task Force in 2001. It was based on sound engineering judgment taking into account the information and experience available at the time. The susceptibility criteria specifically address only high pH SCC and, since 2001, considerable additional knowledge and experience have been accumulated both for high pH and for near-neutral pH SCC. However, recently proposed revisions to the ASME criteria will extend their applicability to include near-neutral pH SCC as well as high pH SCC. In the proposed revisions, the same criteria are applied to both types of SCC, with the exception of the distance criterion, which is disregarded if there is evidence of near-neutral pH SCC or if conditions conducive to near-neutral pH SCC are thought to exist.

Hence it is timely to revisit the criteria and examine the extent to which they can now be used to define SCC-susceptible segments.

To address these issues, field experience concerning the occurrence of SCC in around 130,000 miles of natural gas pipelines operating throughout North America has been provided by the JIP participants (and by a few other operators), much of it obtained since the ASME Guidance was originally developed; in total, the data include records of 87 in-service ruptures or leaks, more than 1100 SCC hydrostatic tests, almost 9000 excavations and over 200 miles of ILI, undertaken to investigate high pH or near-neutral pH SCC. This has been augmented where possible by published information. The detailed analyses of all the information and the key findings are presented in the JIP Background Report.[4]

This information has been used to explore the "validity" of each individual criterion in the ASME Guidance, in the light of the information now available. In particular, it has been used to examine whether each criterion is relevant to both structurally significant cracks and smaller less-threatening cracks, and whether similar criteria can be applied for both high pH and near-neutral pH SCC.

3. Comparison of Service Experience with Individual ASME Criteria

3.1 High pH SCC

<u>Location With Respect to Compressor Stations</u>

Within a few years after the discovery of high pH SCC on gas pipelines, it became apparent that almost all of the service failures and hydrostatic test failures occurred within the first valve sections downstream from compressor stations. The recent and updated information substantiates this general trend for in-service leaks and ruptures; 90% of in-service leaks and ruptures and 95% of hydrostatic test failures have occurred within 20 miles downstream of compressors. A similar picture is obtained when the data are presented in terms of valve sections.

The in-service failures are spread slightly further downstream than was described by Eiber and Leis (1997)[5], who reported that 65% of the 42 occurrences they reviewed were within 5 miles of a compressor discharge and 92% were within 10 miles. Also, excavations have revealed that shallow

4 All the detailed information and analyses supporting the statements in this report, together with references to all published documents, are set out in the JIP Background Report "Summary and Review of Operator Experience."

5 "Protocol to identify potential areas of high pH stress corrosion cracking," R.J. Eiber and B.N. Leis, paper presented at 11th PRCI/EPRG Joint Technical Meeting on Pipeline Research, Arlington, May 1997. Also, "Protocol to prioritize sites for high pH stress corrosion cracking on gas pipelines," R.J. Eiber and B.N. Leis, PRCI Report L51864, September 1998.

cracking can be present at distances extending beyond 20 miles. However, several of the in-service and hydrostatic test failures that appear to be "outliers" are associated with hard spots or mechanical damage.

On the basis of the information now available, the 20-mile limit is still considered to be appropriate. However, it should be remembered that the 20-mile limit does not incorporate all the failures experienced. For some "problem" lines, operators may decide to evaluate SCC beyond the 20-mile limit depending on the perceived level of risk; there are several instances where failures beyond 20 miles have been preceded by failures within the 20-mile limit.

Operating Stress

The review of 38 high pH SCC service incidents by Eiber and Leis showed that, while incidents occurred at hoop stresses from 25% to 72% SMYS, more than 70% of them occurred at greater than 60% SMYS.

The recent and updated information shows that over 85% of the in-service failures, over 95% of the hydrostatic test failures and over 85% of the excavations revealing SCC are in pipelines designed to operate at 60% SMYS or above. The in-service and hydrostatic test results below this threshold have predominantly been in pipes with diameters of 12 inches or less, although the reasons for this are not clear. Furthermore, the in-service failures on pipes operated below 48% SMYS have all been leaks, as opposed to ruptures.

On the basis of the information now available, there is no need to change the 60% SMYS threshold criterion for large diameter pipelines. However, it should be remembered that the 60% SMYS threshold does not incorporate all the failures experienced; in addition, operators may wish to adopt a more cautious approach for some smaller-diameter pipelines.

Pipe Age

Eiber and Leis presented data for 42 high pH service incidents, showing that, while the earliest incident occurred 6 years after installation, in more than 80% of the affected pipelines SCC did not start to occur until after 20-30 years in service.

There have been a steady number of in-service failures due to high pH SCC ever since the earliest in-service occurrences in the mid-1960s, and hydrostatic test failures are also continuing to occur up to more than 50 years after installation. Overall, 98% of the in-service failures and 100% of the hydrostatic test failures have been on pipes more than 10 years old; tape-coated pipes have failed in the shortest times, while other coating types have generally not started to fail until after around 20 years.[6.] The recent in-service failures and hydrostatic test failures have all been on older pipelines; there have been no high pH SCC in-service failures or hydrostatic test failures on lines installed after 1960.

On the basis of this information, a case could now be made for increasing the age restriction for high pH SCC from 10 to 20 years, with the exception of tape-coated lines. However, since around 1980, tape coating has been applied infrequently and pipelines have largely utilized FBE coatings, so this may not be an issue of practical concern.

It has been suggested that, if a length of pipe has been recoated since the original installation date, then the "age" of the recoated pipe should be calculated from the re-commissioning date. The evidence from repeated hydrostatic tests on repaired and recoated pipes indicates that such an

6 Failures due to SCC at mechanical damage, and at an improperly coated tie-in, have occurred in shorter times than this.

approach is satisfactory. Excavations of repaired and recoated pipe could further reinforce this conclusion but, to date, there have been few such cases recorded.

Coating Type

The majority of early in-service incidents and hydrostatic test failures were on coal tar coated lines and this trend is substantiated by the new and updated information. Over 75% of in-service occurrences and hydrostatic test failures have been on coal tar pipe, with most of the remainder being on tape-wrapped pipe; taking into account the estimated proportions of coal tar and tape-wrapped pipe in service, this suggests that tape-wrapped pipe may be at least as susceptible as coal tar coated pipe. Only very occasional instances have been reported on asphalt-coated pipe.

Results from excavations are dominated by those for coal tar coated pipe but indicate that other coating types are not completely immune from SCC. Although relatively fewer excavations have been undertaken on these types of coatings, both wax and asphalt have shown occasional instances of SCC.

Eiber and Leis reported that FBE coated pipes had not experienced high pH SCC. This conclusion is still valid; there have been no in-service occurrences due to high pH SCC in FBE-coated pipes[7] nor have there been any hydrostatic tests failures or discoveries during excavations.

Discharge Temperature

It is well established that coal tar and asphalt coatings tend to degrade with time, particularly if they are subjected to temperatures greater than about 125˚F. Many of the older pipelines in the southern and southeastern U.S. were coated with coal tar or asphalt and were initially operated with compressor discharge temperatures above 125˚F, some for many years. Although, since the 1980s, discharge temperatures have generally been reduced to 125˚F or below, the prior damage to coatings and the risk of SCC are still present.

Discussions with the JIP participants have highlighted the difficulties of applying the ASME temperature criterion to older pipelines for which the necessary information is patchy or unavailable. While the criterion can still be applied to recently constructed lines, and to any lines for which a reliable temperature history is available, it may be better for older lines to assume that thermal damage has occurred unless it can be proved otherwise (e.g., by operating records or excavations).

History of SCC

ASME B31.8S requires that each segment[8] that has experienced a service incident or hydrostatic test leak caused by SCC is considered to be SCC susceptible. The accumulated service experience for high pH SCC indicates that this requirement is still valid. In particular, hydrostatic re-testing programs have demonstrated that the SCC risk is still present and continuing to develop, sometimes over many years following the first occurrence. The up-to-date experience also includes several examples where in-service failures in one segment are followed by hydrostatic test failures in adjacent segments, reflecting the similarity of conditions for SCC development along the length of the pipeline.

The up-to-date service experience suggests that it would be prudent to extend the application of the "history" criterion to include adjacent segments (upstream as far as the compressor and downstream to the end of the valve section) as SCC susceptible when a service incident has occurred. It is probably also appropriate to extend it if a hydrostatic test failure has occurred or if cracks with the potential to cause hydrostatic failure have been found by excavation. The implications of less serious

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7 Failures due to SCC at mechanical damage have occurred in FBE-coated pipe.

8 Segments are defined in the JIP Report "How should segments be prioritised?"

cracking revealed by excavation are best considered at other stages in the SCC risk assessment and integrity management process; for example, when segments are prioritized for assessment or sites are selected for excavation.

3.2 Near-Neutral pH SCC

Location with Respect to Compressor Stations

The NEB Report on SCC in Canadian Oil and Gas Pipelines identified ten pipeline failures in Canada that were due to axially oriented near-neutral pH SCC, occurring between 1985 and 1996. Seven of these were on polyethylene-tape-wrapped pipe, with two on asphalt-coated pipe and one on coal-tar-coated pipe (One of the asphalt failures was associated with mechanical damage and the coal tar failure was at an ERW long seam weld). The great majority of these were reported to have occurred within the first valve sections downstream from compressor discharges.

In the present study, details were available for 19 in-service ruptures and leaks (many of these were also reported by NEB). Seven of the failures occurred on tape-wrapped pipe, eleven on asphalt-coated and one on wax-coated pipe; all the tape-wrapped and wax-coated failures occurred within 20 miles downstream of compressor discharges, but the failures on asphalt-coated pipelines were spread along their entire lengths.

The situation is similar for hydrostatic tests. Details for around 385 tests included 52 failures; 14 occurred on tape-wrapped pipe, 37 on asphalt-coated pipe and one on coal-tar-coated pipe. Two thirds of the failures on tape-wrapped pipelines occurred within 20 miles downstream of compressor discharges, but the failures in asphalt-coated pipe were distributed along the entire pipeline lengths.

A large number of excavation records were available for pipelines with near-neutral pH SCC. The review of the results showed that, while the frequency of occurrence of SCC diminished with increasing distance downstream from compressors, cracking extended well beyond 20 miles. Cracking was found up to 72 miles downstream from compressors, but the large majority of cracks more than 10% deep were found within 40 miles. Again, cracking was more widely spread in asphalt-coated pipe than in tape-wrapped pipe.

Hence the overall situation for near-neutral pH SCC is that, while in-service and hydrostatic test failures on tape-wrapped pipe are less than 20-40 miles downstream from compressor discharges, those for asphalt-coated pipe are more evenly distributed along the pipeline length. On the basis of this information, it would appear that to discount the distance criterion for near-neutral pH, as is proposed in the revisions to the ASME criteria, is the most appropriate course of action.

Operating Stress

The NEB Report indicated that, for the ten in-service failures in Canada involving axial SCC on gas pipelines, the hoop stresses at the time of failure varied between 60% and 77% of SMYS. The recently provided information from 19 in-service failures and 52 hydrostatic test failures revealed no failures in pipelines designed to operate at stresses below 70% SMYS.

Review of the recently provided excavation records revealed that the great majority of cracking was in pipes designed to operate at 60% SMYS or above. However there were instances of mainly shallow cracking at 50-60% SMYS in tape-wrapped, asphalt- and coal-tar-coated pipelines. (It is necessary to take into account that the great majority of records are for pipes operating above 60% SMYS).

Overall, this information indicates that a stress threshold of 60% SMYS is an appropriate criterion for near-neutral pH SCC. However, it should be remembered that the 60% SMYS threshold does not incorporate all the cracking experienced, and operators may wish to adopt a more cautious approach for some pipelines.

Pipe Age

The information available for in-service failures and hydrostatic test failures indicates that while the shortest duration between installation and failure was 12 years, the most recently installed pipeline to fail was installed in 1981; both these figures relate to tape-wrapped pipes. For asphalt-coated pipe the shortest duration between installation and failure was 22 years and the most recently installed pipeline to fail was installed in 1973. The coal-tar- and wax-coated pipes failed about 35 years after installation.

The excavation records present a complementary picture. Cracking has been seen in tape-wrapped pipes installed as recently as 1993 (12 years after installation), in asphalt-coated pipes installed as recently as 1982 (22 years after installation), in coal tar coated pipes installed as recently as 1974 (31 years after installation) and in wax-coated pipes installed as recently as 1968 (35 years after installation).

Overall, this information suggests that an age criterion for near-neutral pH SCC could be set at 10 years for tape-wrapped pipe and 20 years for asphalt, coal tar and wax coatings. However, the proposal to apply the ASME 10-year criterion, set originally for high pH SCC, is a conservative overall approach.

It has been proposed that, if a length of pipe has been recoated since the original installation date, then the "age" of the recoated pipe should be calculated from the re-commissioning date. The evidence from repeated hydrostatic tests on repaired and recoated pipes indicates that such an approach is satisfactory. To date there have been few, if any, excavations of repaired and recoated pipe that could further reinforce this conclusion.

Coating Type

Around two thirds of the in-service and hydrostatic test failures have been in asphalt-coated pipe and around one third in tape-wrapped pipe. There was only one in-service failure in wax-coated pipe and only two hydrostatic test failures in coal tar coated pipe.

The excavation records include many occurrences of SCC in tape-wrapped and asphalt-coated pipes. Individual excavations (usually around 40 feet in length) often revealed in excess of 100 individual SCC colonies in tape-wrapped pipe, whereas those in asphalt-coated pipe often revealed 10-30 colonies or fewer. Individual colonies up to 15 inches long in both axial and circumferential directions, and more than 30% through-wall depth, were found, but around 90% of them were less than 2 inches long and less than 10% through-wall depth.

Of 140 excavations on coal tar coated pipe, only five showed evidence of SCC. In most cases, each excavation exposed less than five individual colonies, up to 10 inches long and less than 10% through-wall depth.

Excavation records also provide an indication of the relative frequency of occurrence of large and small colonies and cracks. From the distributions of depths found in the present work, it is apparent that the ratio of deep to shallow cracks (greater or less than 10% deep) is generally around 1:10. These observations are consistent with those found by CEPA during its Trending Studies.

These observations indicate that, while cracking can be extensive in both tape-wrapped and asphalt-coated pipe, it is much less evident in wax and coal tar coated pipe. However wax and coal tar cannot be classified as immune from near-neutral pH SCC.

It is noteworthy that 89 excavations of FBE-coated pipes, installed as early as 1980, did not reveal any evidence of cracking; these observations confirm the continued validity of the ASME criterion exempting FBE.

Discharge Temperature

As was noted in the case of high pH SCC, coal tar and asphalt coatings tend to degrade with time, particularly if they are subjected to temperatures in excess of 125˚F. It is also possible that high temperatures will accelerate the degradation and disbonding of tape-wraps. However, for the same reasons as were noted for high pH SCC, it is often impractical to substantiate and apply a temperature criterion for near-neutral pH SCC; while it might be feasible for newly constructed pipelines, for older pipelines the necessary operational history details are often patchy and incomplete. In the absence of strong evidence from service (or from research results), there is no justification for seeking to extend the temperature criterion to near-neutral pH SCC (the influence of temperature is implicit within the compressor proximity distance criterion).

History of SCC

ASME B31.8S requires that each segment that has experienced a service incident or hydrostatic test leak caused by SCC is considered to be SCC-susceptible. The accumulated service experience indicates that this requirement is also valid for near-neutral pH SCC. In particular, hydrostatic re-testing programs have demonstrated that the SCC risk is still present, sometimes for many years after the first occurrence. The up-to-date experience also includes several examples where in-service failures in one segment are followed by hydrostatic test failures in adjacent segments, reflecting the similar conditions for SCC development along the length of the pipeline.

This up-to-date service experience supports a case for extending the application of the “history” criterion, to include adjacent segments (upstream and downstream as far as the next compressor) as SCC-susceptible when a service incident has occurred. However, it is not appropriate to extend it in situations where a hydrostatic test failure has occurred or cracks have been found by excavation. The implications of hydrostatic test failures and cracking revealed by excavation are best considered at other stages in the SCC risk assessment and integrity management process; for example when segments are prioritized for assessment or sites are selected for excavation.

4. Comparison with the Combined ASME Criteria

In the preceding sections, each of the ASME B31.8S criteria have been considered individually. While this is informative in determining the applicability of each criterion, the overall ASME approach utilizes all the criteria in combination. Hence it is appropriate to examine the accumulated service experience in the same way and, in particular, to examine the reasons for the “outlier” results.

In total, 87 in-service failure records were provided by the JIP participants and other operators; 61 due to high pH SCC and 19 due to near-neutral pH SCC. A further 7, from one operator, are described as mixed-mode and include three instances of circumferential cracking; these 7 results have been excluded from the subsequent analyses.

One failure is due to SCC at mechanical damage, one is SCC at a hard spot, one is SCC at a wrinkle bend, two are SCC associated with ERW seam welds and one is SCC at an improperly coated tie-in weld; these 6 results have also been discounted from further analysis, leaving 74.

Of the remaining 74 failures, there are 8 below the 60% stress criterion, 5 beyond the 20-mile distance criterion for high pH SCC and two within the 10-year age criterion. One outlier appears in two categories, giving a total of 14. All the outliers are described as high pH SCC. Overall, 60/74 = 81% are included when all the criteria are taken together; this figure reduces to 77% if only high pH SCC is considered.

Looking at the 14 outliers in detail, the following points emerge:

- Only four of the 14 outliers are ruptures; the rest are leaks (one is not recorded).
- Eight of the outliers are in pipelines with diameters less than 12 inches.

- Four of these occurred in close proximity to one another, in a production gathering line that experienced elevated temperatures from the production facilities.
- The only two short-life failures are in tape-wrapped lines and occurred over 30 years ago.
- One high pH SCC failure at 22 miles is in a line that had already experienced two earlier ruptures within the 20-mile limit.

Depending on the weight given to these considerations, the overall figure for failures addressed by the ASME criteria ranges from a minimum of around 81% to around 90%.

The records for hydrostatic test failures have also been re-examined on the same basis. There are 363 results; 308 for high pH SCC, 52 for near-neutral pH SCC and 3 described as mixed-mode. Among these results there are 24 outliers, 7% of the total, when all the ASME criteria are considered together; 12 of the outliers are below the 60% stress threshold and 13 are beyond the 20-mile limit (one result appears in both categories). Again, some of the points identified above also apply to the hydrostatic test outliers. This reinforces the conclusion that around 95% of the hydrostatic test failures are addressed by the criteria.

5. Implications for Defining SCC-Susceptible Segments

5.1 Summary of Findings

The ASME B31.8S Guidance criteria were originally developed as a basis for focusing attention on those segments of gas pipeline systems that are most likely to be at risk from SCC. It is clear from the information available at that time that the criteria did not define a precise go/no-go boundary between susceptible and non-susceptible segments; rather they identified the areas of highest risk, as a starting point for SCC risk management. While the great majority of the then-known service incidents were identified by the ASME criteria, it was understood from the outset that there were a number of outlying occurrences.

The present JIP activities have enabled collation of much of the now-available service experience, including for the first time extensive datasets from ongoing excavation and ILI programs. This has enabled a thorough reassessment of the effectiveness of each criterion in the light of accumulated service experience, including their applicability to both large cracks that have caused failures and smaller cracks found by excavation or ILI. This has reinforced the view that, while the ASME criteria provide good guidance concerning the starting point for SCC risk management, cracking can extend beyond the thresholds and limits in situations that are particularly prone to SCC.

Many of the engineering judgments embodied in the original ASME criteria are still applicable to high pH SCC, and are substantiated by the up-to-date field experience. Hence there is no overriding need to make changes to the criteria for susceptibility to high pH SCC.

Recent field experience indicates that most of the same criteria are also applicable to near-neutral pH SCC, in line with the recently proposed modifications to the ASME criteria. Although a higher proportion of the in-service failures due to near-neutral pH SCC has occurred within the original ASME distance criterion of 20 miles, the trends are dependent on coating type; in any case, the results from hydrostatic testing, excavations and ILI indicate that it is prudent to disregard the distance criterion for near-neutral pH SCC. Application of the temperature criterion to near-neutral pH SCC is not appropriate, but its inclusion in the ASME criteria does not present an issue of practical concern.

5.2 Significance of Outliers

Although the ASME criteria do not catch all of the SCC failures that have occurred, on a statistical basis, it can be shown that the risks associated with the 10 to 20 percent that might be missed are very low. Historically, the SCC failure rate in the approximately 300,000 miles of gas transmission pipelines in the U.S. has been about two per year. That number has been remarkably constant, even though there have been a few years with higher or lower numbers. Thus, the historical failure rate has been 1 per 150,000 miles per year.

For the JIP member companies, their total HCA mileage is about 2 percent of their total mileage. Assuming that that percentage is representative of the entire industry, there probably are about 6000 miles of HCAs in the U.S. gas transmission pipelines. There is no reason to believe that SCC would have any particular preference for, or aversion to, HCAs. Therefore, multiplying the average failure frequency by the 6000 miles of HCAs suggests that one could expect about one SCC failure in an HCA every 25 years. Based upon past experience, 80 to 90 percent of them would be caught by the ASME criteria. The 10 to 20 percent that fall outside the ASME criteria would represent one failure in 125 to 250 years.

The present survey also indicated that, of the total length of HCAs, only about 10 percent, or 600 miles, qualify as SCC HCAs. Since that qualification is based upon the ASME criteria, 80 to 90 percent of the SCC failures occur in only 10 percent of the HCAs. To give the remaining 90 percent of the HCAs a comparable level of attention to address the low probability of failure would mean that 90 percent of the effort would be spent on 10 to 20 percent of the problem. That seems disproportionate and counter productive.

Nevertheless, those 90 percent should not be ignored. While applying assessment techniques such as hydrostatic testing, ILI or SCC DA seems excessive, some method of condition monitoring would be appropriate. Various approaches to condition monitoring are described in the answers to Question 7.

6. Conclusions

The overall conclusions from this review are as follows:

- The ASME criteria still provide a good basis for the initial definition of SCC-susceptible segments.
- The criteria are largely substantiated by the updated service experience so far as high pH SCC is concerned, and most of the criteria are also applicable to near-neutral pH SCC.
- With the recently proposed revisions, the ASME criteria address over 80% of the in-service failures attributable to high pH and near-neutral pH SCC in natural gas pipelines, and this figure rises to around 90% when the specific circumstances of the outlying occurrences are taken into account.
- The revised criteria also address over 95% of the hydrostatic test failures, and around 85% of the SCC cracks exceeding 10% through-wall depth, found during excavations.

APPENDIX C - PRIORITIZING SCC SUSCEPTIBLE HCA'S AND SEGMENTS

Question 2: How should SCC-susceptible HCAs and Segments be prioritized for assessment?

1. Summary

Once the SCC-susceptible HCAs and segments have been identified for a pipeline system, it is necessary to determine in what order of priority they should be assessed.

The amount of information available to enable prioritization varies considerably from situation to situation. For the first assessment, there may be little information other than basic pipeline attributes, although some operators may have access to data from CP monitoring, above-ground surveys or ILI runs. For subsequent assessments, information from excavations of the HCA/segment of interest, together with excavation results from adjacent or similar segments, may enable better discrimination.

Guidance on prioritizing segments, based on the likelihood of SCC occurring, has been developed to take these variations into account. A three-tiered approach has been adopted, based on the level of information available:

- Tier 1: Prioritization based solely on pipeline attributes and operating history, with no information available from excavations or surveys
- Tier 2: Prioritization incorporating additional information available from monitoring and surveys, ILI, excavations for other operational reasons, and any prior hydrostatic testing
- Tier 3: Prioritization augmented by feedback from previous SCC assessments, leading eventually to a series of pipeline-specific, weighted risk factors incorporated in an overall ranking model; such a model could form the basis for quantitative risk analysis.

The individual factors are identified, based on collective industry knowledge and up-to-date operational experience, taking into account the independent risks from high pH and near-neutral pH SCC. Their integration into Tier 1 and Tier 2 Prioritization Protocols is illustrated, and the issues associated with incorporating new excavation data in Tier 3 are highlighted.

2. Introduction

The management of SCC risk commences with the determination of how many segments within a pipeline system are SCC-susceptible according to the ASME B31.8S or an equivalent approach (see Appendix B). The second step is to determine, within the group of SCC-susceptible segments, in what order of priority they should be assessed when developing the baseline assessment or reassessment plans. The prioritization should be based on risk, which is the product of probability times consequence. This paper addresses the probability of SCC occurring. It will be up to the operator to evaluate the consequence of a failure in a particular segment and consider both probability and consequence in the final prioritization.

The definition of a pipeline segment varies somewhat from operator to operator. In all instances a segment is a continuous length of a pipeline with nominally common attributes such as installation age, operating pressure and pressure history. However, in some instances, operators may elect to separate segments on the basis of pipe wall thickness and grade, or even to discriminate down to the level of individual pipe joints (such as a replaced or recoated section or a thick-walled road crossing), whereas, in other instances, operators may elect to consider an entire compressor-to-compressor length as one segment. Depending upon this definition, operators may be faced with prioritizing anything from a few segments to several hundred.

It follows from this that the relationship between segments and HCAs also varies from situation to situation. An HCA may contain several segments or may be an entire segment; in some instances several HCAs may be within a single segment.

Notwithstanding these important issues of definition, the key principle is that a single ranking of priority should be valid for a known length of pipeline, defined in this report as a "segment."

The amount of information available to assist prioritization will vary considerably from one situation to another. For the first assessments, there may be little information other than basic pipeline attributes such as location, age, construction details and operating history. However, in some instances operators may have access to information from CP system monitoring, above-ground surveys, ILI, opportunist excavations and even prior hydrotests, not only for the segment of interest but also for adjacent and similar segments.

For subsequent assessments, information from targeted excavations of the segment of interest, together with targeted excavation results from other segments, will enable improved discrimination and re-evaluation of the initial prioritization.

The guidance on prioritizing segments, based on the likelihood of SCC occurring, has been developed to take these variations into account. A three-tiered approach has been adopted, based on the level of information available:

Tier 1: Prioritization based on pipeline attributes and operating history, with no information available from excavations or surveys.

Tier 2: Prioritization incorporating additional information from any above-ground surveys, ILI, excavations for other operational reasons and any prior hydrostatic tests, in particular, information concerning coating condition and evidence of environmentally-assisted degradation.

Tier 3: Prioritization augmented by feedback from previous SCC assessments, leading eventually to a series of pipeline-specific, weighted risk factors incorporated in an overall ranking model; such a model could form the basis for quantitative risk analysis.

The individual factors in each tier are based on the collective industry knowledge embodied, for example, in the NACE SCC DA Guidelines [1] and the CEPA Guidance [2], augmented by the up-to-date review of service experience undertaken by the Joint Industry Project participants.[9] Each tier takes into account the independent risks from high pH and near-neutral pH SCC. The individual factors are discussed in the sections that follow and are used to develop illustrative examples of the Tier 1 and Tier 2 Prioritization Protocols.

3. Prioritization Factors

3.1 Tier 1

Proximity to Compressor Station Discharge

Segments have been defined as SCC-susceptible because they are within 20 miles downstream from compressor discharges.[10] Operational experience (indicates that the likelihood of structurally significant SCC being present is dependent upon distance downstream), coating type and the type of SCC experienced. A scale based on this experience is included.

9 The JIP Background Document "Survey and Review of Operator Experience."

10 In the proposed revisions to ASME B31.8S, the distance criterion is disregarded for near-neutral pH SCC.

Segment Length

For a given expectation of SCC, the likelihood of a structurally significant SCC colony being present within a segment will increase in proportion to its length. A simple scale is included.

Operating Stress

Operational experience indicates that, for both high pH and near-neutral pH SCC, the likelihood of SCC occurring is significantly greater in lines operated above approximately 60% SMYS. For high pH SCC, some cracking has been found and occasional failures have been experienced (largely confined to small-diameter lines), in lines operated at 40-60% SMYS. For near-neutral pH SCC, only occasional instances of mainly shallow cracking have been found at 50-60% SMYS; the frequency of colonies increases as the operating stress increases to 80% SMYS, with in-service and hydrostatic test failures being experienced above around 65% SMYS. A scale based on this pattern of experience is included.

Pipeline Age

Pipelines installed over 10 years ago have been identified as SCC-susceptible. Operational experience indicates that the likelihood of finding SCC increases with increasing age, but is also linked to coating type. A scale based on age and coating type reflects this experience.

Coating Type

Operational experience indicates that the type of coating has a strong influence on the likelihood of SCC occurring. Coating type is included as a primary factor as well as being a secondary factor combined with the age and compressor proximity factors. Coal tar and tape-wrapped coatings are associated with the great majority of high pH SCC occurrences, while asphalt and tape-wrapped coatings are associated with the great majority of near-neutral pH SCC occurrences. A scale based on the operational experience is included.

Where a segment includes more than one type of coating, the segment priority should be based on the weighted average of coating types and risk scores.

SCC History

Operational experience indicates that there is a higher probability of finding more SCC in the vicinity of previously-discovered SCC, not only on the same line but also, in some instances, on other lines in the same geographical region (provided that both lines have similar attributes). Scales are included, dependent upon the structural significance of the other cracking and its distance from the segment being assessed.

3.2 Tier 2

Coating Condition

Operational experience [1] - [4] indicates that coatings can degrade and become disbonded with time, especially if the operating temperature exceeds 125˚F or if the soil loading results in creep/cracking. Evidence for poor coating condition may come indirectly from above-ground surveys or directly from excavations. However, some coatings may appear physically and electrically sound from the outside, but still allow liquid-filled crevices at the metal surface; if the coating is electrically shielding, this has been known to result in near-neutral pH SCC in association with ILI-detectable shallow corrosion [5].

A scale has been included for coating condition based on local expert knowledge and interpretation of the information from sources such as those identified above.

Cathodic Protection

Operational experience [1], [2], [4] indicates that inadequate cathodic protection can allow the electrochemical conditions for near-neutral pH SCC to develop at the pipe surface, either occasionally or continually. The precise conditions for SCC are dependent upon coating type, soil resistivity and possibly also on groundwater chemistry. Evidence of poor CP system design, inadequate control or ineffective performance may come from system monitoring or from above-ground surveys. (Disbonded CP-shielding coatings may be strongly detrimental to the effectiveness of CP systems, which may be determined by direct examination). A scale has been included for CP system effectiveness, based on local expert knowledge and interpretation of the information from sources such as those above.

Operating Pressure Fluctuations

While operating pressure itself is not included as a discriminating factor for segment prioritization, service experience has pointed to pressure fluctuations in the immediate vicinity of compressor discharges as a contributory factor, particularly for near-neutral pH SCC [3], [4], [6]. A factor is included to reflect this issue.

Operating Temperature

Service experience has indicated that high operating temperatures downstream from compressors correlate with occurrences of high pH SCC [3], [6]. However this has already been taken into account in the factors on coating condition and compressor proximity, and no further factor relating to operating temperature is necessary.

Terrain

The opportunities for SCC-promoting conditions to develop at local regions within the segment are dependent upon the water content of the surrounding ground, which depends upon topography and drainage [1], [4], [6], particularly for near-neutral pH SCC. If available, information from ground surveys and exploratory excavations can be used to explore this possibility. A factor is included to reflect this issue; again, it requires local expert knowledge and interpretation of the information.

SCC History

In some instances, previous integrity management activities such as hydrostatic tests, excavations and ILI crack detection will have been undertaken and can be taken into account. A successful hydrostatic test or excavations/ILI revealing only inconsequential SCC can reduce the priority for further assessments. A positive (risk-reducing) factor is introduced to incorporate the benefit of prior testing; the factor reduces as time elapses, reflecting the increasing opportunity for further cracking to develop.

3.3 Tier 3

The fundamental difference between Tier 3 and Tier 2 stems primarily from the availability of information from excavations already conducted on the segment, or on other segments with the same attributes and SCC experience, as part of the ongoing SCC assessment process. Hence, Tier 3 is primarily directed towards reassessments rather than first assessments.

The NACE SCC DA document [1] lists a large number of measurements and observations that form part of the assessment. While many of these are primarily relevant to the review and improvement of the Site Selection Protocol (see Question 5a), some are also relevant to the Segment Prioritization Protocol. These include the following:

- Coating Condition
  - Confirmation of the coating type

Pipe surface condition (presence of oxide scale, corrosion, old or new iron carbonate, old or new shiny metal, under-coating pH, calcareous deposits)
Evidence of disbondment (poor application, in-service degradation)
Faults and holidays, creep and cracking

Cathodic Protection
Evidence of inadequate protection (now, or previously)
Presence of locally low CP or shielding
Evidence of CP-shielding coating with a tendency to disbond
Terrain

Soil Type and Texture
Drainage, soil moisture, aeration, and resistivity
Groundwater conductivity, presence of agro-chemicals

History –Update
Has SCC been found?
If so, what type, what extent; no. of colonies, depths
Has the segment been hydrotested or inspected by Crack Detection ILI.

This new information does not require additional factors; instead it necessitates a complete review and update of the Tier 2 factors based on expert analysis and interpretation of the new data. In some instances this process will allow sub-division of some of the factors identified in Tier 2 and clarification of the discriminatory features needed for the expert interpretations. In order for this to be sound and successful, it is necessary to acquire a considerable number of fully documented records (as described by NACE, [1]) relevant to the segment being assessed.

4. Development and Application of Prioritization Protocols

The preceding section identified the individual factors to be considered when developing a prioritization scale for SCC-susceptible segments, both for the simpler Tier 1 approach and for the more detailed Tier 2 approach. Table 24 and Table 25 illustrate how these factors might be combined into Tier 1 and Tier 2 Protocols respectively, incorporating a simple High-Medium-Low ranking for each factor.

The Tier 1 Protocol is based on the comparatively small number of key factors that are known to have a significant bearing on the likelihood of SCC and that will provide segment-by-segment discrimination in the absence of any further local knowledge of pipeline condition. The Tier 2 Protocol includes additional information, obtained indirectly from standard system monitoring and above-ground surveys, or obtained directly from examination of the exposed pipe and coating; in either case, such information needs to be interpreted by experts. Either Tier 1 or Tier 2 can be used at the outset of the SCC assessment process, before any specific knowledge about SCC occurrence has been obtained for the segment being assessed.

If only partial Tier 2 information is available, it should still be used wherever possible. However, the selective use of additional information must not be allowed to penalize particular segments.

In the first instance, and in the absence of any other information, an overall ranking for Tier 1 or Tier 2 can be obtained by replacing High-Medium-Low with 5-3-1 (and Good with –2). Based on the overall operational experience of many operators, this may be a satisfactory starting point. However, such an approach arbitrarily allocates equal weight to each factor; with the passage of time, individual operators will select and apply weight to the individual factors for the Tier 1 and Tier 2 Protocols according to the attributes, operational history and service experience of their own pipeline systems.

The Tier 1 and Tier 2 Protocols are structured to provide two separate prioritizations for high pH and near-neutral pH SCC. There is no in-built relative priority between the two types of SCC; operational experience indicates that, in almost all cases, high pH and near-neutral pH SCC are mutually exclusive occurrences. It is important that, in the absence of any prior knowledge, an operator will assess the segments with the highest risk of both types of SCC. Once the first assessments have been completed, an understanding of the relative risks of high pH and near-neutral pH SCC will have been obtained, and this can be incorporated into the overall protocol.

The Tier 3 approach is primarily applicable to reassessments. It provides the route for incorporating the results from the ongoing SCC assessments, modifying the weightings, sub-dividing the definitions of each factor in the Tier 1 and Tier 2 Protocols and developing statistically sound predictive models. The manner in which this continuous improvement process is undertaken will be determined by each individual operator. Several operators have initiated an ongoing process for reviewing and updating their segment prioritization Protocols as excavation results become available, as described above. Some operators have been undertaking extensive excavation programs for many years and have already obtained a sufficiently large database of SCC records to enable the development of quantitative risk assessment models based on this type of approach; for most operators, however, this is still a long way off.

It was indicated at the outset that the rankings of priority for SCC susceptibility are based on the likelihood that SCC will occur. Apart from a bias towards ruptures as opposed to leaks, they do not incorporate consideration of the factors determining the consequences in the event of an in-service failure due to SCC. Consideration of the consequences of failure is a requirement applicable to all types of integrity threat, and it is expected that this will be taken into account by operators as part of their overall prioritization of segments for integrity management.

5. Next Steps

Once the prioritization of segments has been completed, the next steps will be to conduct the assessments of the highest priority segments. Assessment may utilize hydrostatic testing, crack detection ILI or excavations (SCC DA) depending upon operator preferences and expectations concerning the extent of SCC present. Issues concerning the application and re-application of hydrostatic testing and ILI are addressed in the JIP Report “Re-test intervals”; issues concerning site selection for excavations are addressed in the JIP Report “Excavation site selection.”

6. REFERENCES[11]

[1] "Standard Recommended Practice, Stress Corrosion Cracking (SCC) Direct Assessment Methodology," NACE Standard RP0204-2004 Item No. 21104, 2004.

[2] "SCC Recommended Practices," Canadian Energy Pipeline Association (CEPA), 1997.

[3] R. R. Fessler, "Stress corrosion cracking gap analysis," PRCI Report L52038, September 2002.

[4] "State-of-the art report – external stress corrosion cracking of underground pipelines," NACE Task Group T-10E-7.

[5] J. D. Davis, J. E. Marr and D. Venance, "SCC integrity management case study – Kinder Morgan Natural Gas Pipeline of America," paper 0586 presented at ASME International Pipeline Conference, Calgary, October 2004.

[6] "Stress corrosion cracking on Canadian oil and gas pipelines," NEB Report MH-2-95.

11 Some of the referenced PRCI reports may not be available to non-members.

Table 24 - Illustrative Example of Tier 1 Protocol

Factor	Near-neutral pH SCC Tape-wrap	Near-neutral pH SCC Asphalt	Near-neutral pH SCC Others*	High pH SCC All coating types*
Proximity to compressor discharge				
0-5 miles	H	M	L	H
5-10 miles	H	M	L	M
10-20 miles	M	M	L	M
20-40 miles	M	M	L	L
Over 40 miles	L	M	-	-
Segment length				
0-0.5 miles	L	L	L	L
0.5- 5 miles	M	M	M	M
Over 5 miles	H	H	H	H
Operating stress				
Below 50% SMYS	-	-	-	L
50-60% SMYS	L	L	L	M
60-70% SMYS	M	M	M	H
Above 70% SMYS	H	H	H	H
Age since installation/recoating				
10-20 years	M	L	L	L
20-30 years	H	M	M	M
30-40 years	H	H	M	M
Over 40 years	H	H	H	H
Coating type				
Tape-wrap	H	-	-	H
Asphalt	-	H	-	L
Coal tar	-	-	L	H
Wax	-	-	M	L
Bare	-	-	L	L
History of SCC: on the same line				
In-service failure within 20 miles	H	H	H	H
Hydrostatic test failure within 20 miles	M	M	M	M
In-service failure within 20-100 miles	M	M	M	M
History of SCC nearby: different line with similar attributes in the same geographic region				
In-service failure within 20 miles	M	M	M	M
Hydrostatic test failure within 20 miles	L	L	L	L

* The terms "Others" and "All" refer to coatings from the group asphalt, wax, coal tar, tape-wrap that are not identified in the preceding columns and are not exempted from assessment (e.g., fusion bonded epoxy).

Table 25 - Illustrative Example of Tier 2 Protocol

Tier 2 incorporates all the Tier 1 factors, and, in addition, those identified below.

Factor	Near-neutral pH SCC		High pH SCC
	Tape	Others	All coating types
Coating condition			
Poorly bonded, wrinkled, cracked	H	H	H
Average; some disbond and holidays	M	M	M
Well-bonded; as-new	-	-	-
Evidence of shallow corrosion under intact but disbonded coating	H	H	-
Cathodic protection (now or previously)			
Ineffective, shielded	H	M	M
Partially effective, variable, some shielding	M	L	L
Always good	-	-	-
Operating pressure fluctuations			
High cyclic fluctuations (More than +/– 20% MAOP)	M	M	L
Intermediate cyclic fluctuations (10-20% MAOP)	L	L	-
Low (less than +/–10% MAOP) or zero fluctuations	-	-	-
Terrain			
Hilly topography, locally poor drainage	M	M	L
Seasonally wet/dry	M	L	L
Uniform topography, well-drained	L	-	-
SCC remediation history			
SCC Hydrotest, Crack Detection ILI within 5 years	G	G	G
SCC Hydrotest, CD ILI more than 5 years ago	-	-	-
Inconsequential SCC found on excavation within 5 years	G	G	G
Inconsequential SCC found more than 5 years ago	-	-	-

* The term “All” refers to other coatings from the group asphalt, wax, coal tar and tape-wrap, and others that are not exempted from assessment (e.g., fusion bonded epoxy).

G (Good) is a risk-reducing factor.

APPENDIX D - REASSESSMENT INTERVALS

Question 3. Where Hydrostatic Testing, DA or Crack-Detection ILI has been chosen as the assessment method, what are the appropriate reassessment intervals?

1. Summary

For high-consequence areas (HCAs) that are classified as possibly susceptible to stress-corrosion cracking (SCC), pipeline companies are required to periodically assess those HCAs with hydrostatic testing, in-line inspection or direct inspection.

Reassessment intervals should be short enough to assure the safety of the pipeline but not so short that they involve needless effort and expense or subject the pipeline to needless pressure fluctuations.

In principle, the maximum re-inspection interval could be determined from the crack growth rate, the size of the largest flaw that could exist in the pipeline and the size of a flaw that would cause a failure at the operating pressure. Several methods are available for calculating the critical flaw size, and the maximum size of a flaw that could be in the pipeline can be determined from the hydrostatic test pressure or estimated, in some cases, from in-line-inspection (ILI) data or direct assessment (DA). A few companies have been able to determine crack growth rates for their pipelines, but most companies do not have such information.

For companies that do not have specific information about possible crack growth rates on their pipelines, this document addresses the question as to the appropriate intervals for reassessing HCAs if SCC is discovered either because of an in-service failure or during one of the assessments.

If there is no evidence of SCC either from the failure history of that pipeline or from findings during previous assessments, the reassessment interval should be the maximum specified by the regulations, which, at present, is 7 years. However, if SCC is discovered, shorter intervals may be appropriate, as discussed below.

Industry experience with in-service failures following hydrostatic tests suggests that a reasonable and prudent first interval on a pipeline that is known to contain SCC would be 3 to 6 years, provided the test pressure was at least 100% SMYS. The shorter time would apply to test sections in which a recent failure has occurred either in service or at a relatively low pressure during the first hydrostatic test. The longer time would apply where no low-pressure failures occurred during the first test.

A model has recently been developed that provides a technical basis for establishing subsequent hydrostatic re-test intervals based upon the test pressure, the maximum allowable operating pressure (MAOP), the tensile properties of the steel and the length of previous intervals. The principal assumption upon which the model is based is that a crack that already exists in the pipeline has a greater chance of reaching critical size than a crack that might initiate some time in the future. On that basis, subsequent intervals can be calculated as

$$t_n = t_p(\alpha/\beta)$$

where

t_n = length of the next interval

t_p = sum of the lengths of the previous intervals

α = difference between the test pressure and MAOP

β = difference between the pressure corresponding to the flow stress and the test pressure.

The flow stress can be estimated in several nearly equivalent ways, typically as the average of the actual yield strength and ultimate tensile strength or as the actual yield strength plus 10 ksi.

One interesting feature of this method is that the lengths of subsequent intervals are particularly sensitive to the test pressure, because it affects both α and β, but in opposite ways. Thus, a relatively small increase in test pressure can justify significantly longer intervals. Another interesting feature is that, after the second interval, each subsequent interval gets longer than the previous one.

Predictions from the model have been tested against histories of 13 valve sections that have experienced either high-pH or near-neutral-pH SCC and have been subjected to multiple hydrostatic re-tests. Within those 13 valve sections, eight in-service failures occurred after the initial hydrostatic tests. Five or six of those eight probably would have been prevented if the intervals from this method had been used rather than the ones that were, but no more re-tests, in total, would have been required. The only two service failures that would have occurred with a 3-year first interval and subsequent intervals determined from this method occurred on a valve section that had been tested to only 90% SMYS.

According to a strict interpretation of the model, the lengths of subsequent intervals should not be affected whether or not failures occur during any of the re-tests. However, to provide a greater level of confidence in the safety of the pipeline, a modification to the method has been devised for shortening subsequent intervals by various amounts depending upon how close the test-failure pressure was to the operating pressure. If the test failure occurred very near MAOP, the next interval would be half of the previous interval; if the test failure occurred at or near the maximum test pressure, the next interval would be calculated based upon the original model. Failure at intermediate pressures between MAOP and the maximum test pressure would lead to proportionate intermediate amounts of shortening. To add still more conservatism, the origin point for calculating subsequent intervals would be moved from the first test to the most recent test in which a failure occurred.

Reassessment intervals for ILI can be established in two alternative ways. If accurate measurements of crack sizes are available from successive runs, crack growth rates can be calculated by comparing the sizes of specific cracks at the two different times. Based upon the distribution of growth rates, a conservative value can be used to schedule inspection and repair of joints that contain cracks. Another ILI assessment should be conducted in about 7 years to verify the assumptions about growth rates.

If sufficiently accurate data are not available to follow the growth of individual cracks, the maximum size crack that is left in the line can be used to calculate an equivalent hydrostatic test pressure, and then the hydrostatic re-test model can be used to establish subsequent intervals.

The appropriate action following SCC DA will depend upon the severity of cracks that are discovered.

If Category 4 cracks are found, an immediate pressure reduction should be implemented, followed as soon as possible by an assessment that covers 100% of the segment. Such an assessment could be a hydrostatic test, an ILI or, if the segment is very short, a 100% magnetic-particle inspection (MPI). Subsequent remediation will depend upon the severity of cracks that are found in the 100% assessment. It could involve replacement of one or more joints of pipe, sleeving of cracked portions of the pipe, grinding or buffing out the cracks or re-coating.

If Category 3 cracks are found, the possibility of Category 4 cracks existing elsewhere in the segment should not be ignored and, therefore, the procedure for Category 4 cracks should be followed.

If Category 2 cracks are found, the segment should be assessed with hydrostatic testing, ILI or a 100% MPI within 2 years, and a temporary pressure reduction should be considered until the full assessment has been completed.

If Category 1 cracks are found, more digs should be conducted until no larger flaws are found. If the largest flaw is Category 2, the next assessment, which may be DA, Hydrostatic testing or ILI, should be conducted in 3 years. If the largest flaw is Category 3 or 4, follow the procedure for Category 4.

If inconsequential cracks are found, more digs should be conducted until no larger flaws are found. If the largest flaw is Category 1, the next assessment, which may be DA, hydrostatic testing or ILI, should be conducted in 7 years. If the largest flaw is Category 2, 3 or 4, the procedure for the most severe category that is discovered should be followed.

If no cracks are found at the location that is expected to be most susceptible, no additional actions should be required before the next scheduled assessment.

2. Introduction

An appropriate reassessment interval is one that is short enough to provide a reasonable assurance that the pipeline will not fail before the next assessment but not so short that it would entail unnecessary interruption of service and expense. In principle, establishing a reassessment interval for a failure mechanism that involves time-dependent flaw growth requires determining or establishing the maximum size flaw that could exist in the pipeline, the critical size of flaw that could cause a failure at maximum allowable operating pressure (MAOP) and the flaw growth rate. The amount of tolerable flaw growth would then be the difference between the critical flaw size and the current flaw size. Dividing that amount of growth by the flaw growth rate would give the maximum safe reassessment interval.

In practice, there are several fairly straightforward ways to calculate critical and remaining flaw sizes, but estimating crack growth rate is much more difficult.

3. Calculating Flaw Sizes

A relationship between flaw size and failure pressure was developed by Battelle in the early 1970s.[1] It is known as the log-secant criterion or the NG-18 model. Input parameters include the diameter and wall thickness of the pipe, the Charpy V-notch toughness of the steel and the flow stress, which is an empirically derived value that is between the yield strength and the ultimate tensile strength of the steel. A number of definitions have been proposed for the flow stress including the yield strength plus 10 ksi, 1.1 times the yield strength, 1.15 times the yield strength, 0.9 times the ultimate tensile strength and the average of the yield and tensile strengths. For the present discussion, the latter definition has been used, although, for the line-pipe steels in which stress-corrosion cracking has been observed, all of the definitions give similar values for the flow stress. The log-secant criterion is somewhat conservative; it is available to the public and it is used by many pipeline companies.

More recently developed failure criteria incorporate elastic-plastic fracture mechanics, which makes them more accurate, but less conservative, and they require more information about the deformation properties of the steel. They include the Pipe Axial Flaw Failure Criterion (PAFFC) developed by Battelle [2], the CorLas™ model developed by CC Technologies [3], and failure assessment diagrams such as API 579.4.

Fortunately, inaccuracies from any of the methods, either from inaccurate material-property data or limitations of the basic model, tend to cancel out when calculating amount of additional crack growth to cause a failure. For example a conservative model will underestimate the size of flaw that would cause a failure at operating pressure, but it also will underestimate, to approximately the same extent, the size of a flaw that can survive a given hydrostatic test pressure.

Any of the above methods is considered acceptable. For the present discussion, the log-secant method will be used because it is readily available and in common use by the industry.

4. Estimating Crack Growth Rates

The growth rate of a stress-corrosion crack is critically dependent upon the composition and concentration of the chemical environment in contact with the steel and the micro-creep behavior of the steel, neither of which are known for cracks that exist in a pipeline. To use crack growth rates from laboratory experiments where the environmental conditions have been artificially maintained at the most severe level certainly would be overly conservative. Besides, laboratory studies have shown that crack growth rates tend to decrease rapidly with time, so using short-term laboratory tests to predict long-term behavior would be doubly conservative.

In addition, it should be recognized that conditions in the field vary considerably from one pipeline to another, from one location to another on a given pipeline, and from one time to another at a given location.

Several methods have been developed for estimating crack growth rates appropriate for buried pipelines. They include using the general industry experience with successful reassessment intervals, metallographic examination of cracks in pipe that had previously been hydrostatically tested, and using information from repeated assessments.

Some companies that have a significant problem with SCC may have specific information about their pipelines that indicates what an appropriate growth rate might be or at least what an appropriate reassessment interval might be. For companies that have little or no experience with SCC but cannot eliminate the possibility of SCC on their system, relying on the experiences of companies with a significant problem probably is a conservative approach. Statistics on industry experience with in-service failures following a hydrostatic test can be useful in this respect and are summarized later in this report.

Some companies have been able to determine crack growth rates from metallographic cross sections through cracks in pipe that was in service for several years after a high-pressure hydrostatic test. At the time of the hydrostatic test, some of the deeper cracks apparently were widened and blunted by plastic deformation at the crack tip. Subsequently the cracks continued to grow, but the new crack growth was much tighter than the previous, and the crack growth rate could be calculated by dividing the amount of new growth by the time since the hydrostatic test. For example, in a highly susceptible valve section that was hydrostatically re-tested 3 years after a previous hydrostatic test, a secondary near-neutral-pH stress-corrosion crack was found to have grown about 2 mm since the previous test. There have been a number of unconfirmed verbal reports of similar findings, but the reported crack growth rates typically have been even lower.

Other types of information from repeated assessments also can provide clues about crack growth rates. In principle, growth of individual cracks could be monitored with repeated ILI runs, but it is generally felt that, especially for gas pipelines, current ILI technology is not accurate enough to provide reliable measurements of crack growth rates. However, a method has recently been developed for establishing hydrostatic re-test intervals based upon the experience gained from previous hydrostatic tests.[6] That method is described in the following section.

5. Establishing Hydrostatic Re-Test Intervals

A method has been developed for determining re-test intervals based just upon things that are known about the pipeline: the hydrostatic-test history (pressures and dates) and the range of tensile properties of the steel, which can be obtained from mill records. The method addresses the intervals after the second hydrostatic test; it does not specifically treat the first interval. It also considers only ruptures; it does not consider leaks. The method is applicable to high-pH SCC and near-neutral-pH SCC. In fact, it is not necessary to know which type of SCC is on the pipeline. The assumptions upon which the method is based have been verified by comparing its predictions against the field experience of a number of pipeline companies that have conducted multiple hydrostatic tests on pipelines that contained stress-corrosion cracks.

5.1 Assumptions

The method is based upon the following assumptions:

- The pipeline in question contains stress-corrosion cracks. (If it does not, the choice of an interval is not critical to the safety of the pipeline.)
- The growth rate for a surviving crack will be less than the previous growth rate for a crack that already failed. This seems to be reasonable, because the combination of environmental conditions and steel susceptibility associated with the failed crack must have been more severe than those conditions associated with a crack that is smaller.
- A crack that initiates in the future will not fail before some existing crack does. Similar to the previous argument, the conditions where a crack has not yet started are expected to be less severe than those where a crack is already growing.
- Future operating conditions (pressure levels, pressure cycles, cathodic-protection levels and temperature) are no more severe than past operating conditions.
- Although the crack growth rate probably is not constant over time, it is acceptable to represent the growth rate as the average over time. This is illustrated schematically in Figure 2.

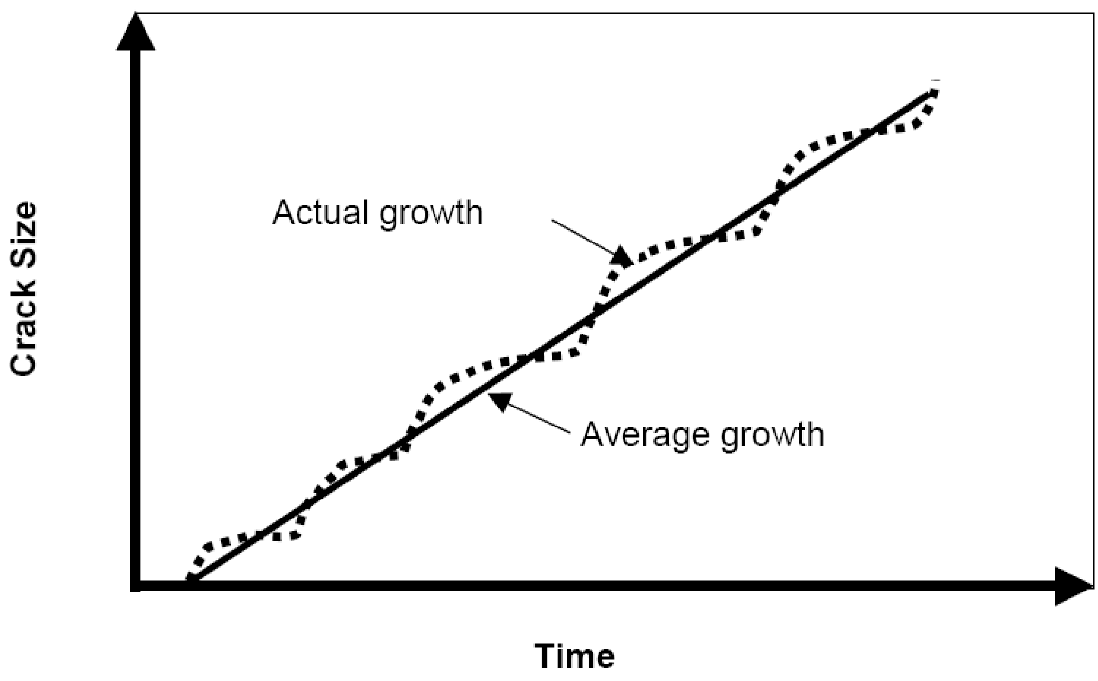

Figure 2 - Substituting the Average Crack Growth Rate for the Actual Variable Rate

Although the preceding assumptions appear to be reasonable, since they cannot be proved, predictions from the method have been tested against field experience to validate the assumptions.

5.2 Basis for the Method

Since there is a direct relation between the size of a defect and the pressure at which it would cause a rupture and because the pressures on a pipeline can be measured accurately, whereas the size of a defect usually is not known (unless good ILI data are available), it is convenient to use the failure pressure of a defect as an indirect measure of the size (see Figure 3). In fact, the primary reason for knowing the size is to be able to calculate the failure pressure.

Consider a pipeline that has been found to contain stress-corrosion cracks and has been subjected to two hydrostatic tests, the second one occurring t_1 years after the first. Referring to Figure 4, the maximum prior growth rate of a surviving crack can be determined from the test pressure (P_t) and the flow stress. The flow stress is the stress at which an infinitesimally small flaw would cause a failure. As stated previously, there are several, nearly equivalent, ways to define flow stress. For the present purposes, the average of the yield strength and the ultimate tensile strength is used.

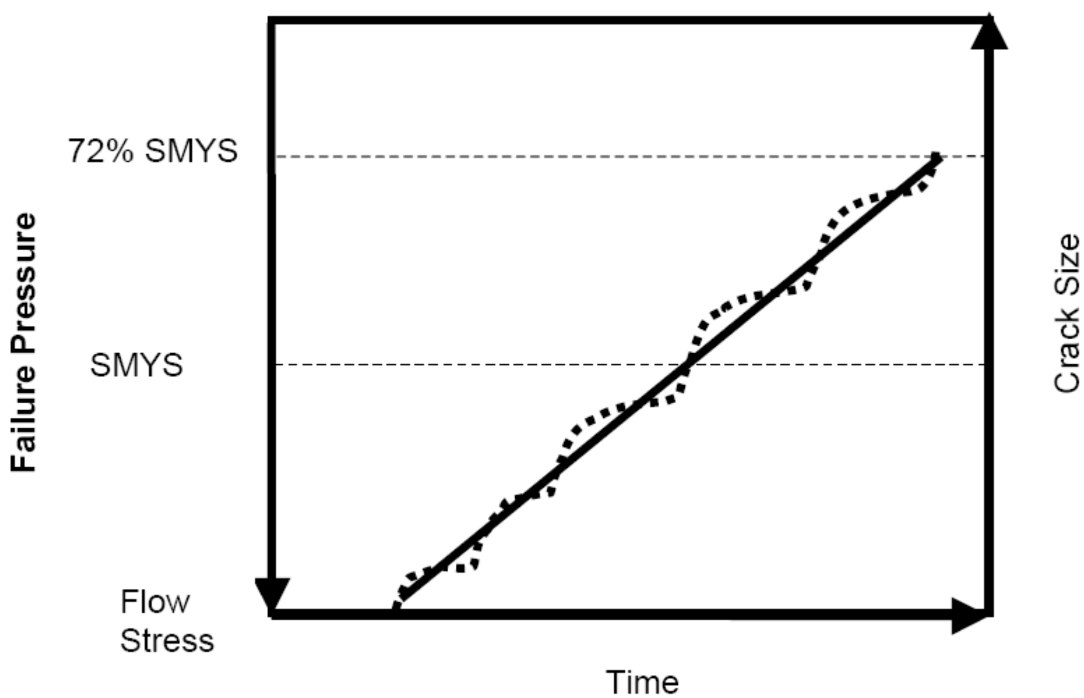

Figure 3 - Using Failure Pressure to Represent Flaw Size

Assuming that some sub-critical stress-corrosion cracks survived the first hydrostatic test, Point A in Figure 4 represents the smallest that it could have been at that time and Point B represents the largest size that could have survived the second hydrostatic test. The slope of Line AB therefore is the maximum average growth rate that could have occurred during time t_1. In reality, the initial size probably was somewhat greater, and the final size probably was somewhat smaller, which means that the actual highest growth rate was less than the calculated maximum. Thus, using the maximum possible prior growth rate as an estimate of future growth introduces considerable conservatism into the approach.

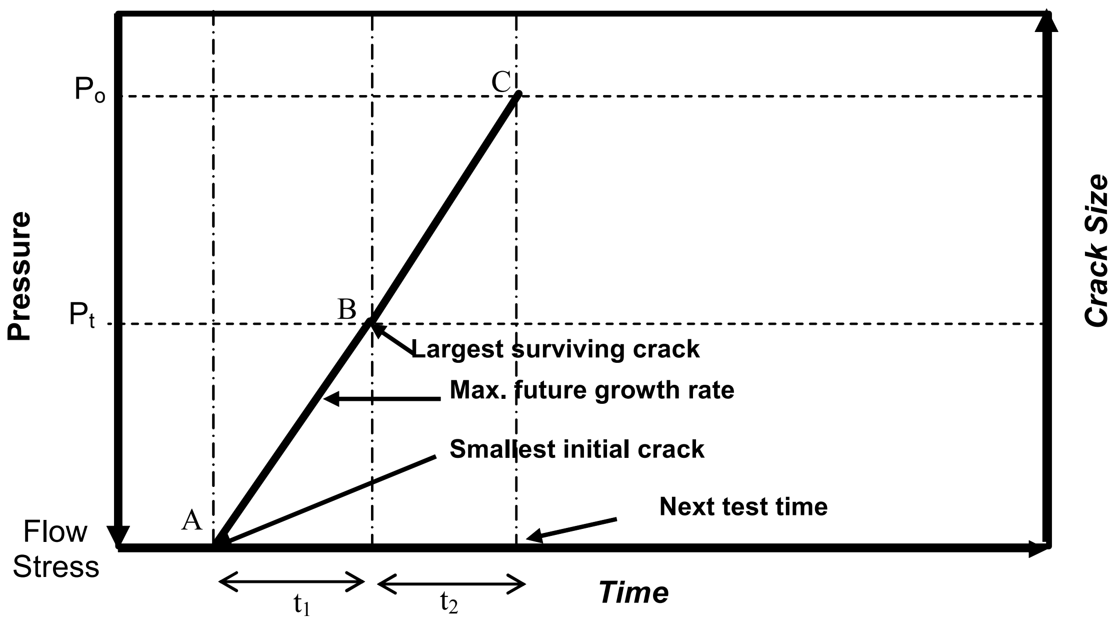

Figure 4 - Extrapolating the Maximum Prior Crack Growth Rate to Establish the Interval for the Next Re-Test

P_o is the maximum allowable operating pressure, and P_t is the hydrostatic test pressure.

According to the assumptions of the method, Line BC represents the maximum size of the largest flaw that could have survived the second hydrostatic test and continued to grow at the prior maximum rate. That hypothetical worst defect would be large enough to cause a failure at the maximum allowable operating pressure (MAOP) at Point C. Therefore time t_2 in Figure 4 represents a safe interval to wait before re-testing the pipeline again.

Figure 5 illustrates how each subsequent interval can be calculated based upon the total time since the first hydrostatic test following the discovery of SCC in the pipeline. Implicit in the structure of Figure 5 is the assumption that the pipeline still contains a few cracks that existed at the time of the first hydrostatic test. Using the principle of similar triangles, it can be shown that the ratio of the next interval (t_n) to the difference between the test pressure (P_t) and the operating pressure (P_o) is equal to the ratio of the sum of the previous intervals (t_p) to the difference between the pressure corresponding to the flow stress and the test pressure.

$$t_n/\alpha = t_p/\beta$$

$$t_n = t_p\,(\alpha/\beta)$$

where α equals P_t minus P_o, and β equals the pressure corresponding to the flow stress minus P_t. As is shown in Figure 6, both the test pressure and the flow stress have strong influences on the ratio of the future intervals to previous intervals.

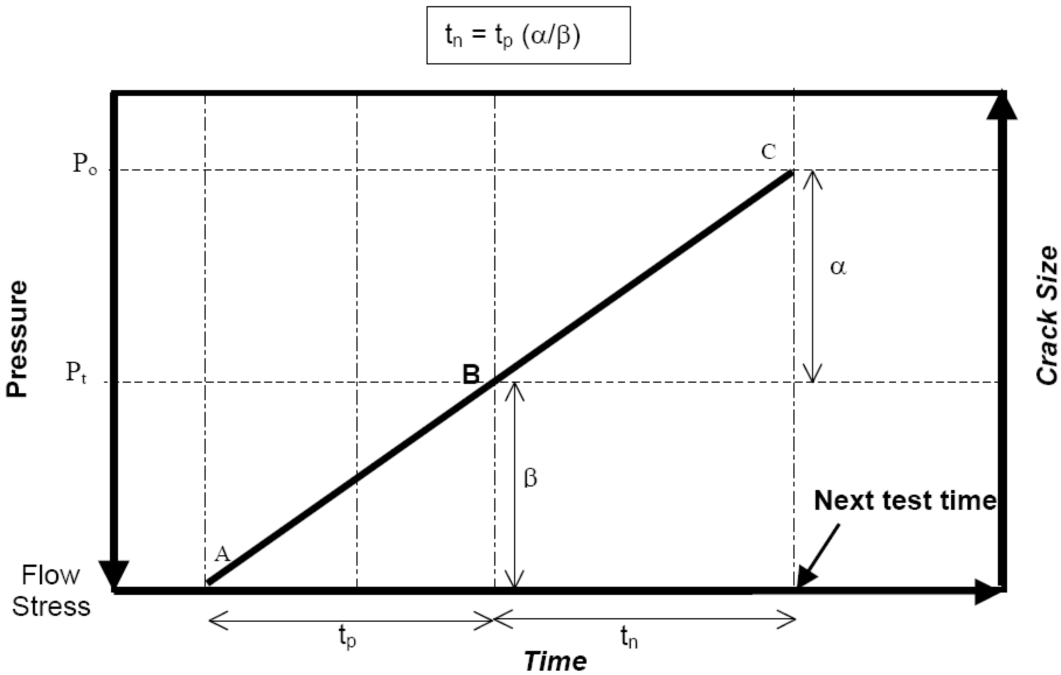

Figure 5 - Establishing Subsequent Intervals Based upon Previous Intervals

A key result of applying this method is that the duration of intervals after the second interval can be significantly longer than either of the first two. For example, if $\alpha = \beta$, the second interval would equal the first, the third would be twice as long as the first, the fourth would be four times as long as the first and the fifth could be eight times as long as the first.

According to this method, establishing subsequent intervals does not depend upon whether any failures occurred during any of the previous hydrostatic tests. It is only necessary to know the maximum growth rate for cracks that ultimately survive the prior tests, since all cracks with higher growth rates would have been removed during the prior test.

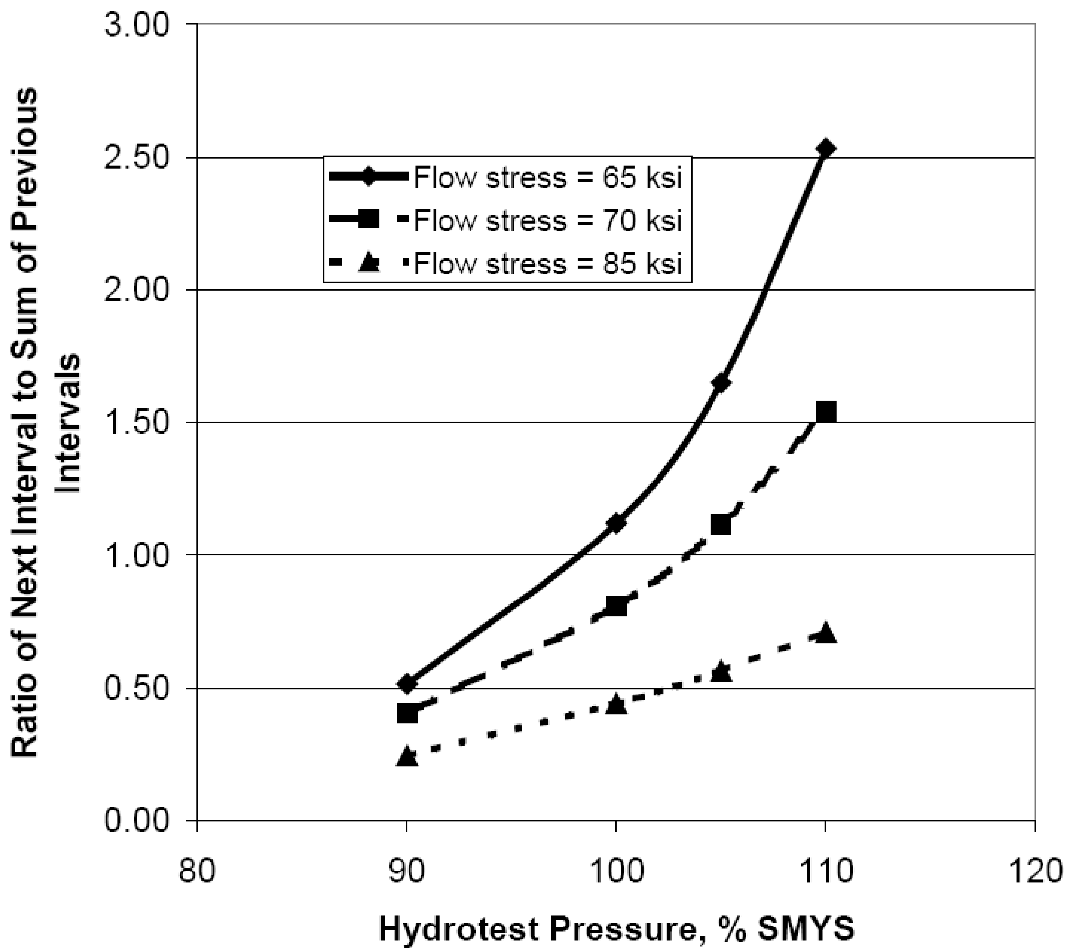

Figure 6 - Effects of Hydrostatic Test Pressure and Flow Stress on Length of Subsequent Intervals Between Re-Tests for an X52 Pipeline Operating at 72% SMYS

5.3 Case Studies

In order to check the predictions of the method against field experience, data were obtained for 13 valve sections that had experienced either high-pH SCC or near-neutral-pH SCC and had been subjected to multiple hydrostatic tests. The histories of those valve sections are summarized in Table 26. Data also were obtained for 132 additional valve sections from the same pipeline systems; those valve sections also had been subjected to multiple hydrostatic tests but had not failed during those tests.

Table 26 - Case Studies of Valve Sections with SCC and Multiple Hydrostatic Tests

Case	Time from 1st Hydrotest to Service Failure	Number of Hydrotests Following 1st	Number of Hydrotests with Failures	Comments
1	NA	3	2	
2	3, 27	10	8	90% SMYS hydrotest and high flow stress
3	7	3	0	
4	17	6	2	
5	NA	8	1	37 years to 1st hydrotest failure
6	4	8	0	
7	NA	6	0	
8	NA	2	1	
9	NA	1	1	Hydrotest failures above 98% SMYS after 38 years
10	22	2	1	
11	6	3	0	
12	8	2	0	
13	NA	2	2	

Representative examples of how the predictions from the method compared with field experience are illustrated in Figure 7 and Figure 8. Figure 7 represents a valve section that was hydrostatically tested to 110% of the specified minimum yield strength (SMYS) in 1968 during which four SCC ruptures occurred (open stars). Subsequently, a service failure due to SCC occurred in 1972 (filled star) after which eight hydrostatic re-tests were conducted, none of which produced failures (open circles). The dark slanted lines represent the maximum crack growth rates that would be predicted by the method for various times. If the first re-test had been conducted three years after the first test, the joint that actually failed in service in 1972 should have failed during the 1971 hydrostatic re-test at some pressure above 900 psig. Subsequently, three additional re-tests would have been conducted, none of which would have produced failures. In summary, using this method would have eliminated one service failure and demonstrated the integrity of the valve section with four fewer hydrostatic re-tests.

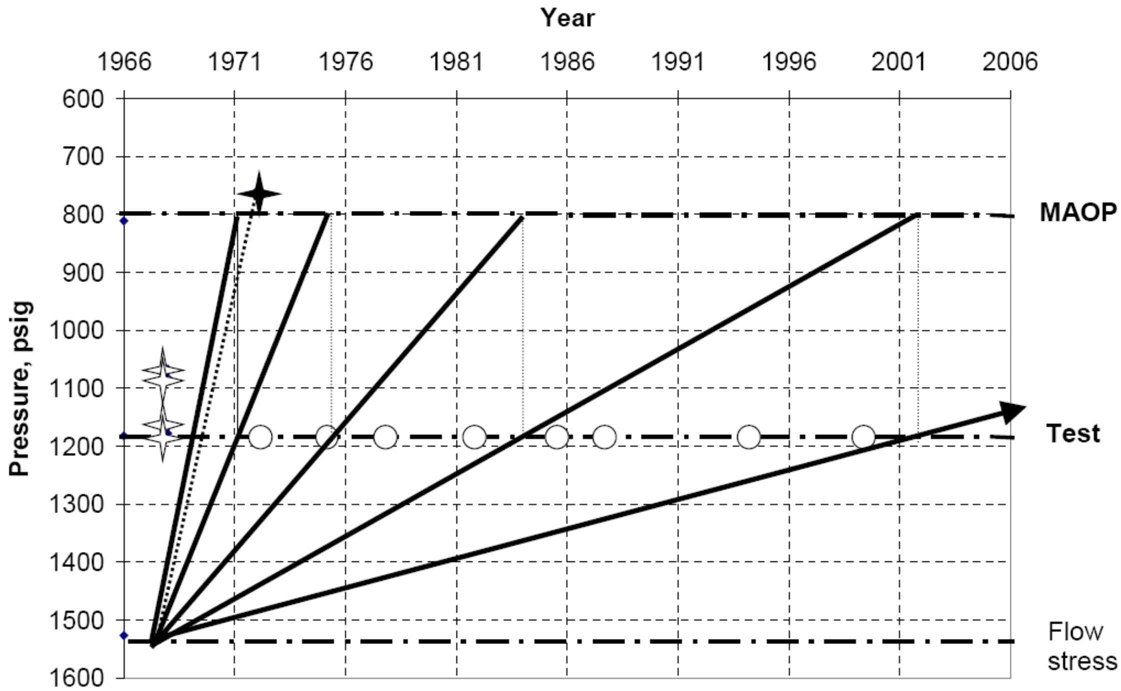

Figure 7 - Comparison of Service History with Predictions of this Method for Case 6

Open stars represent hydrostatic-test failures, closed star represents a service failure and open circles represent hydrostatic re-tests without failures. Dark slanted lines represent predictions for maximum crack growth rates at various times.

Figure 8 represents a valve section that experienced several hydrostatic-test failures in 1987 after which three hydrostatic re-tests were conducted, the latter two each producing a rupture due to SCC very near the maximum test pressure of 105% SMYS. In this case, this method would have predicted the same number of re-tests and test failures, but both failures would have occurred in the 2004 re-test at pressures above 1300 psig.

Comparable analyses that were completed for all 13 valve sections are summarized in Table 27. Comparisons were made for first intervals of three years and five years. Of the eight service failures that occurred after the initial hydrostatic tests, five or six probably would have been prevented if the intervals from the method had been used rather than the ones that were, but no more re-tests in total would have been required. The only two service failures that would have occurred with a 3-year first interval and subsequent intervals determined from this method occurred on a valve section that had been tested to only 90% SMYS. In addition, the pipe in that valve section had unusually high values of flow stress, which further reduces the effectiveness of a hydrostatic test. In terms of Figure 5, the relatively low test pressure and high flow stress produce a small value for α and a large value for β.

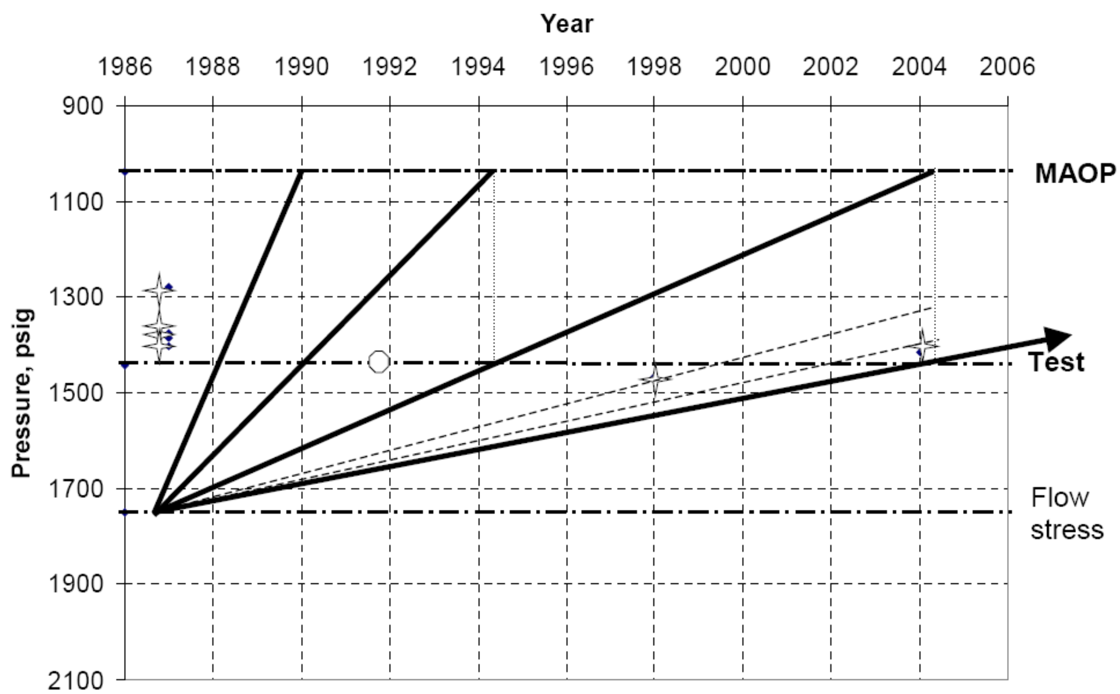

Figure 8 - Comparison of Service History with Predictions of this Method for Case 1 (Symbols are as described for Figure 7)

The additional 132 valve sections that had been tested without producing SCC failures had been subjected to 370 hydrostatic tests (238 in addition to the original 132). Had the predictions from this method been used to establish the intervals, about 236 additional re-tests would have been conducted. As with the original 13 case studies, using this method to establish re-test intervals would not have required any more re-tests than were actually conducted.

Table 27 - Summary of Comparisons of Prediction from this Method with Actual Service Experiences

Case	Events after First Hydrotest	Actual_Number	Predicted from Method			
			t1 = 3 years		t1 = 5 years	
			Number	Difference	Number	Difference
	Service failures	0	0	0	0	0
1	Hydrostatic re-test failures	2	2	0	0	-2
	Number of hydrostatic re-tests	3	3	0	2	-1
	Service failures	2	2	0	2	0
2	Hydrostatic re-test failures	31	23	-8	23	-8
	Number of hydrostatic re-tests	10	8	-2	5	-5
	Service failures	1	0	-1	0	-1
3	Hydrostatic re-test failures	0	1	1	1	1
	Number of hydrostatic re-tests	3	4	1	3	0

Case	Events after First Hydrotest	Actual_Number	Predicted from Method			
			t1 = 3 years		t1 = 5 years	
			Number	Difference	Number	Difference
4	Service failures	1	0	-1	0	-1
	Hydrostatic re-test failures	2	3	1	3	1
	Number of hydrostatic re-tests	6	5	-1	4	-2
5	Service failures	0	0	0	0	0
	Hydrostatic re-test failures	1	0	-1	0	-1
	Number of hydrostatic re-tests	8	4	-4	3	-5
6	Service failures	1	0	-1	1	0
	Hydrostatic re-test failures	0	1	1	0	0
	Number of hydrostatic re-tests	8	4	-4	4	-4
7	Service failures	0	0	0	0	0
	Hydrostatic re-test failures	0	0	0	0	0
	Number of hydrostatic re-tests	6	4	-2	4	-2
8	Service failures	0	0	0	0	0
	Hydrostatic re-test failures	3	3	0	3	0
	Number of hydrostatic re-tests	2	3	1	2	0
9	Service failures	0	0	0	0	0
	Hydrostatic re-test failures	4	3	-1	3	-1
	Number of hydrostatic re-tests	1	4	3	3	2
10	Service failures	1	0	-1	0	-1
	Hydrostatic re-test failures	2	3	1	3	1
	Number of hydrostatic re-tests	2	5	3	3	1
11	Service failures	1	0	-1	0	-1
	Hydrostatic re-test failures	0	1	1	1	1
	Number of hydrostatic re-tests	2	2	0	2	0
12	Service failures	1	0	-1	0	-1
	Hydrostatic re-test failures	0	1	1	1	0
	Number of hydrostatic re-tests	2	2	0	1	-1
13	Service failures	0	0	0	0	0
	Hydrostatic re-test failures	11	5	-6	4	-7
	Number of hydrostatic re-tests	3	2	-1	2	-1
TOTAL	Service failures	8	2	-6	3	-5
	Hydrostatic re-test failures	56	46	-20	42	-14
	Number of hydrostatic re-tests	56	50	-6	38	-18

5.4 Limitations of the Method

There are several circumstances that are not covered by this method but they are believed to be rare, and, if they do occur, would be difficult to prevent under any approach. One is the possibility that two or more nearly co-linear sub-critical cracks could coalesce to form a critical size flaw. That would cause a discontinuous step in the growth curve, which is not consistent with the method.

Another possibility is that a coating defect could develop after the first hydrostatic test and a severe chemical environment might develop under the defective coating, which might produce a relatively rapidly growing crack. However, initiation of a new crack in an otherwise crack-free pipe is always a possibility and is not predictable.

If either of those possibilities were not highly improbable, some cases of the method failing to match field experience would have been expected, but that is not the case. Therefore, although use of the method cannot guarantee prevention of all service failures, the assumptions upon which it was built appear to be reasonable representations of conditions on existing pipelines.

5.5 Time Dependence of Crack Growth Rate

Even under controlled laboratory conditions, growth rates for stress-corrosion cracks vary considerably over time. For stressing conditions typical of gas pipelines, the growth rates for both high-pH and near-neutral-pH SCC decrease rapidly with time in laboratory tests. Because conditions in the field are not constant, one would expect even larger variations, but reliable data are not available. In order to predict the time for a flaw to grow to critical size, some assumption about the time dependence of the growth rate must be made. In the past, many people, not having any specific data, have assumed a constant growth rate with time.

Implicit in the current method is that the growth rate is such that, on average, the failure pressure decreases linearly with time. This assumption would be equivalent to a constant depth-wise growth rate for very long flaws in very tough pipe, but it would be different for typical-size flaws in pipe with typical toughness.

To illustrate this point, Figure 9 shows a log-secant failure diagram for a 30-inch-diameter, 0.312-inch wall thickness X52 pipe with a flow stress of 71,240 psi and a 2/3-size Charpy toughness of 20 ft-lb. For that example, the ratio of the next interval to the sum of the previous intervals (α/β in Figure 5) would be 1.0 according to this method. However, different values would be obtained if one assumed a constant depth-wise growth rate. Consider, for example, a 10-inch-long flaw that just survived a hydrostatic re-test at 105% SMYS. The maximum depth of that surviving flaw would be about 21 percent of the wall thickness. For that flaw to grow to a critical size through depth-wise growth, it would have to grow to about 56 percent of the wall thickness, which would represent additional growth of 35 percent of the wall thickness. The time to grow to critical size would be 35/21 or 1.7 times the length of time that the crack had previously been growing.

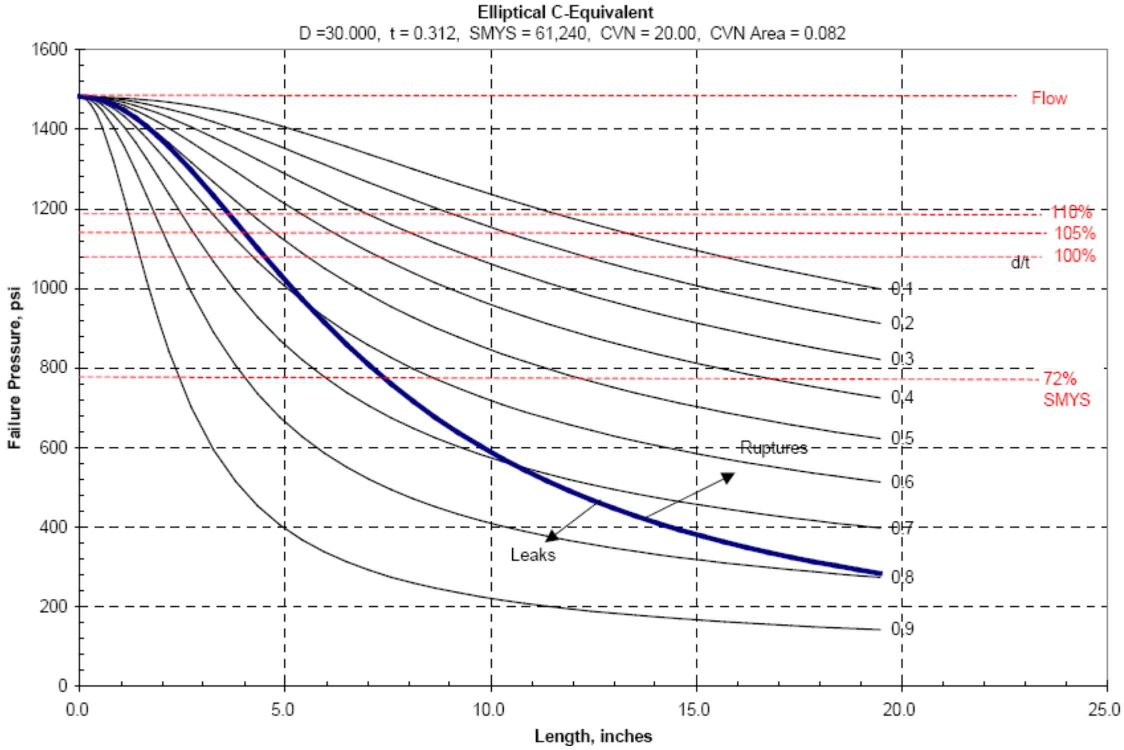

Figure 9 - Log-Secant Failure Diagram for 30-inch-diameter, 0.312-inch wall-thickness X52 Pipe with a Flow Stress of 71,240 psi and a 2/3-size Charpy Energy of 20 ft.-lb.

Figure 9 shows how assuming a linear crack growth rate would affect the interval ratio for a range of crack sizes undergoing depth-wise growth only. For crack lengths greater than 8 inches, the linear growth assumption would lead to longer intervals than would be derived from the present method; for shorter cracks, the opposite would be true, but the failures would be leaks rather than ruptures. Therefore, for any crack that would cause a rupture at the MAOP of 72% SMYS, intervals derived from the present method would be shorter than from an assumption of constant growth rate.

The results in Figure 10 are valid only for the specific pipe properties that were used in the example and for depth-wise growth only. If the crack became significantly longer while it grew deeper and the depth-wise growth rate was constant, shorter intervals would be predicted. However, lacking specific information about the nature of the crack growth, the assumption of the present method appears reasonable, especially in view of the fact that predictions from the method are consistent with service experience.

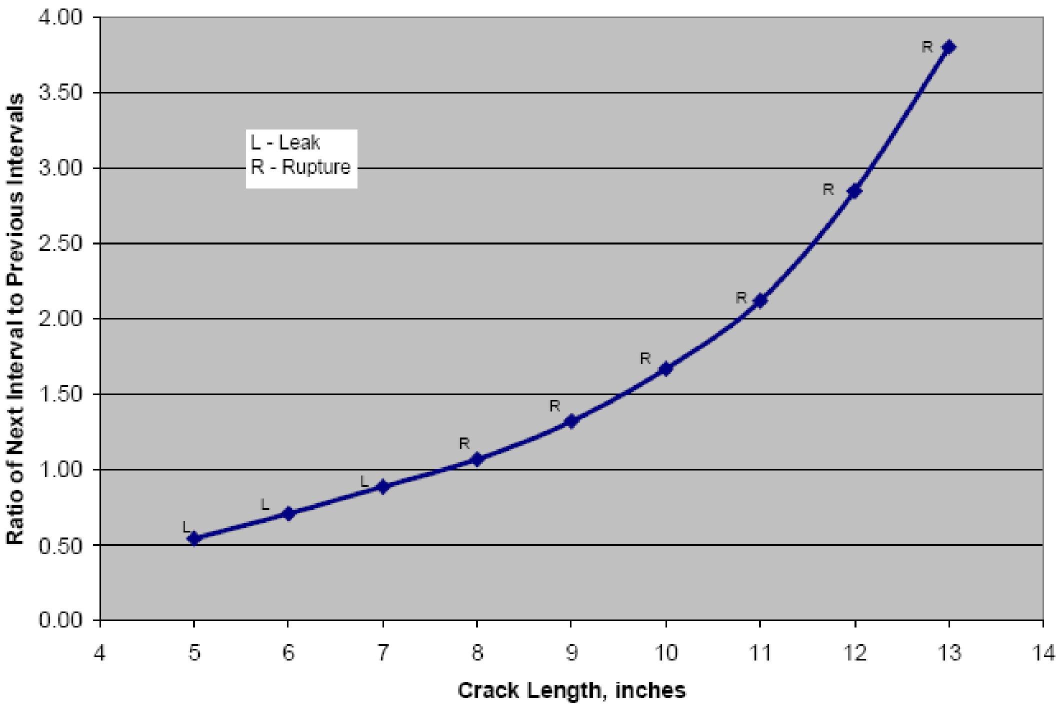

Figure 10 - Ratio of Next Interval to Sum of Previous Intervals for Pipe in Figure 9 and Depth-wise Crack Growth with Constant Growth Rate

5.6 Choice of Flow Stress

As was illustrated in Figure 6, the predicted intervals are sensitive to the flow-stress, which will be different for each joint of pipe. The flow stress is defined as the stress at which an infinitesimally small crack would cause failure. Various ways to calculate flow stress have been developed empirically to produce a good conservative fit to measured fracture behavior of pipe. Two of the most common are the average of the yield strength (YS) and ultimate tensile strength (UTS) and the YS plus 10ksi. Those two formulations usually give nearly the same value for X52, X60 and X65 line pipe, as is shown in Table 28 for representative data from pipe that has experienced SCC in the field. Most pipeline companies have records from the pipe manufacture from which a statistical distribution of yield strengths and tensile strengths can be obtained. Since higher values of flow stress result in shorter (more conservative) intervals, it is suggested that a value one standard deviation above the mean be used when statistical data are available.

Table 28 - Various Ways to Calculate Flow Stress

	X52	X60
Avg. Yield Strength, psi (real data)	56,900	69,000
Avg. UTS, psi (real data)	76,100	89,000
(YS+UTS)/2, psi	66,500	79,000
YS+10,000, psi	66,900	79,000
1.1*YS, psi	62,600	75,900
1.4*SMYS, psi	72,800	84,000
(TS+UTS)/2 + 1 Std. Deviation, psi	73,500	82,000

Typically, for pipes that have experienced SCC in the field, the flow stresses rarely have exceeded 1.4 times the SMYS. Therefore, that value could be used as a default value if the company has no record of the mechanical properties of the pipe.

5.7 Modifying Intervals Following Re-Test Failures

According to a strict interpretation of the method, the lengths of future intervals do not depend on whether or not failures have occurred during previous re-tests. Any joint of pipe that would have failed in service during the next interval would have been removed during the current re-test. Crack growth rates in the surviving joints would be so low that the pipe would survive until the next re-test. Even if a rupture occurred very near the MAOP during the re-test, it would not violate the assumptions of the method.

In view of the multiple levels of conservatism that are built into the method, it is highly unlikely that re-test failures would occur much below the test pressure, and industry experience bears that out. The vast majority of failures in re-tests following an initial test above 100% SMYS have been at or near the test pressure.

However, in the unlikely event that a re-test failure did occur near the MAOP, that would be an indication of a relatively small safety factor, and some modification to subsequent intervals would provide a higher level of confidence. Therefore, an approach has been devised to modify subsequent intervals if a failure occurs during any re-test, the amount of reduction in subsequent intervals being greater the farther the failure pressure is from the test pressure.

The approach is illustrated by the hypothetical example shown in Figure 11 and Figure 12. Figure 11 represents the hydrostatic re-test history of a pipeline that has had an SCC service failure that was followed immediately by a hydrostatic test at time T_0. There may have been a few test failures before the line successfully passed the test at σ_t. There were no failures during the next two re-tests at times T_1 and T_2, but a failure occurred at σ_{HF} during the re-test at time T_3. According to the strict interpretation of the model, the next re-test would be scheduled for time T_4, which is determined by extending a line from A through B until it intersects the MAOP stress.

However, because of the failure at σ_{HF}, subsequent intervals should be modified as illustrated in Figure 12, where a dashed line has been drawn from Point B to a point at σ_0 which represents ½ of the previous interval. Point C is defined as the intersection of the dashed line with σ_{HF}. The time for the next re-test, T_n, is then determined by extending a line from Point A through Point C to σ_0. The origin then would be moved to T_3, and subsequent intervals would be determined as before, assuming that no failures occur in the subsequent re-tests.

The reasoning behind this approach is as follows. If the failure pressure were nearly equal to the test pressure, that behavior would be only slightly different from leaving a crack that would fail just above σ_t, and the next re-test would be scheduled very close to T_4. However, if σ_{HF} were close to σ_0, the next interval would be half of the previous interval, consistent with assessment at the "half life" as is customary in other engineering applications. However, re-setting the origin to T_3 adds still more conservatism to the approach.

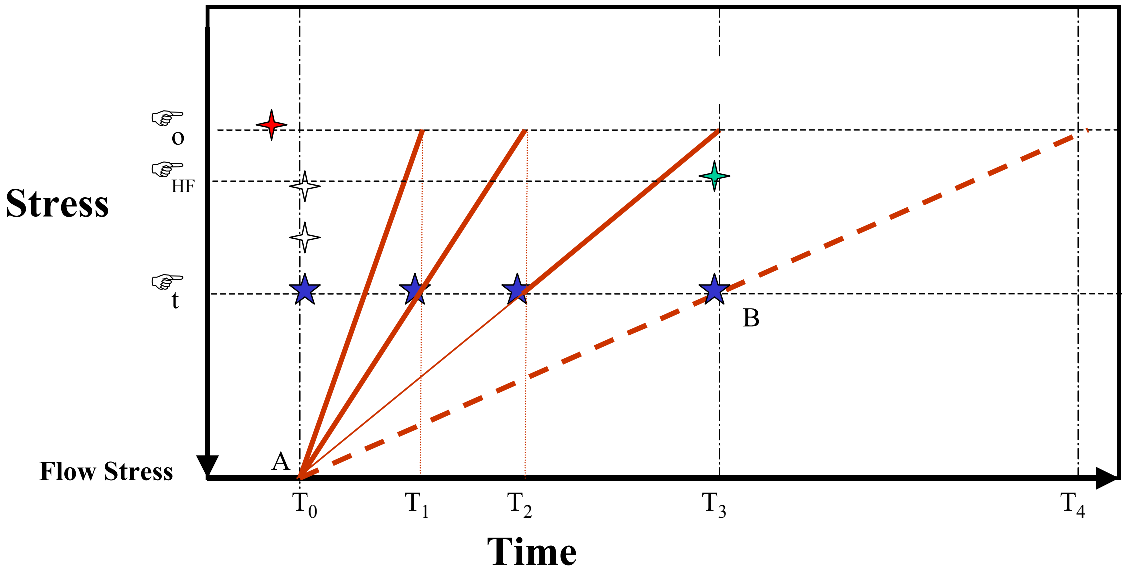

Figure 11 - Hypothetical Re-Test History to Illustrate Modification to Method Following a Re-Test Failure

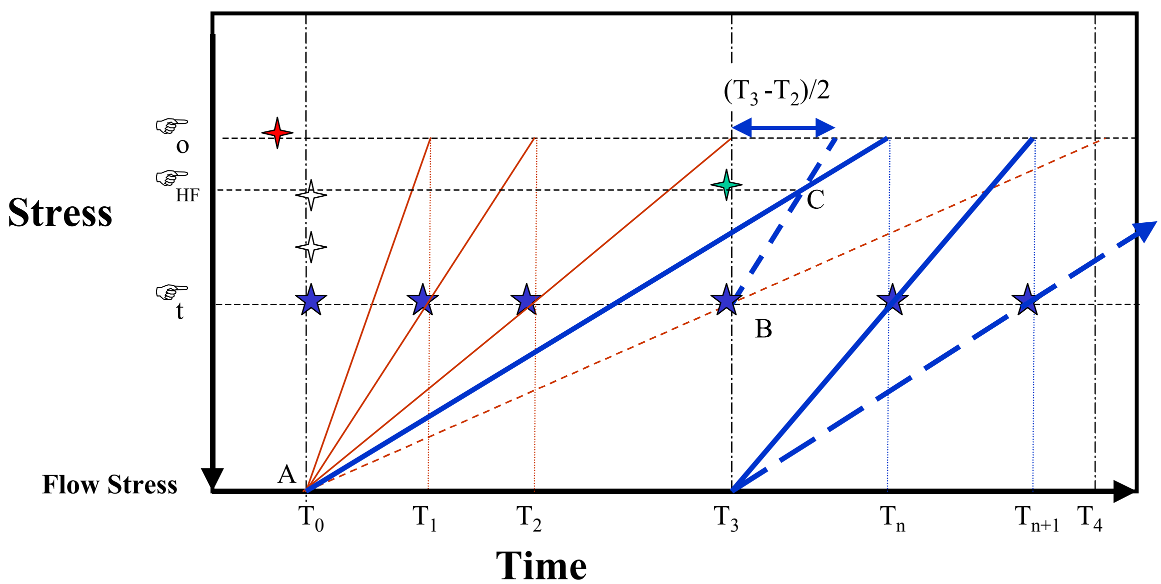

Figure 12 - Illustration of Modification to Re-Test Intervals Following a Re-Test Failure

In practice, it is not necessary to draw the diagram of Figure 12. By considering the various triangles in Figure 12, it can be shown that the length of the next interval, t_n is given by

$$t_n = (t_p+½t_{n-1}S_3/S_4)S_1/S_2-t_p$$

where

t_p = sum of all previous intervals

t_{n-1} = length of most recent interval

S_1 = flow stress – maximum operating stress

S_2 = flow stress – failure stress

S_3 = test stress – failure stress

S_4 = test stress – maximum operating stress.

6. The First Hydrostatic Re-Test Interval

The method described above can be used after two hydrostatic tests have been conducted, the first test being one that either produced a failure due to SCC or one that was conducted after an SCC service failure occurred. It cannot be used to establish the interval between the first two tests. Unless a company has specific information about crack growth rates on its system, its best option is to rely upon general industry experience. As part of the joint industry project, relevant data were obtained for 38 valve sections that had experienced high-pH SCC and 11 valve sections that had experienced near-neutral-pH SCC, all of those sections having been subjected to at least two hydrostatic tests following discovery of SCC.

The key piece of information is how long after a hydrostatic test that a valve section has remained in normal service without experiencing a service failure. As is shown in Table 28, that depends somewhat on the level of the first hydrostatic test; longer lives have been experienced for test pressures of 100% SMYS or higher compared with test pressures between 90 and 100% SMYS. For test pressures of 100% SMYS or higher, there were no service failures within the first 3 years and only one within 12 years. 90 percent of the valve sections that have been in service for more than 20 years beyond the first test have not experienced a service failure. Almost 90 percent of the valve sections survived at least 6 years without even experiencing a hydrostatic re-test failure.

As is shown in Table 29, a similar behavior pattern has been observed for 11 valve sections that had experienced near-neutral-pH SCC. All of those valve sections had been tested to at least 100% SMYS.

Based upon the above data, it appears that a reasonable and prudent choice for the length of the first interval would be 3 to 6 years, the shorter time being selected where SCC is thought to be more aggressive, either because of an in-service failure or multiple failures during the first hydrostatic test. The longer time would be appropriate if SCC were discovered at a very high pressure during a hydrostatic test.

A 3 to 6-year first interval also is consistent with crack growth rates that have been deduced from metallographic examinations of cracks that had survived a hydrostatic test several years earlier. The most aggressive of those rates have been on the order of 0.03 inch per year. Typically, a crack that survived a hydrostatic test at 105% SMYS would have to grow another 0.10 inch in depth to fail at 72% SMYS, which, at the aggressive growth rate of 0.03 inch per year, would take about 3 years and probably more than 6 years at typical growth rates.

Table 29 - Percent of Valve Sections Not Experiencing Failure Following First High-pH SCC Hydrotest (Based upon 38 valve sections)

	Hydrotest Pressure	Years Since First Hydrotest					
		3	6	7	9	12	>21
% of Valve Sections with No In-Service Rupture Within Time	>90% SMYS	97	94	90	84	83	80
	>100% SMYS	100	96	96	96	96	90
% of Valve Sections with No In-Service Rupture or Hydrotest Rupture Within Time	>90% SMYS	89	79	71	68	52	48
	>100% SMYS	97	89	88	84	67	50

Table 30 - Percent of Valve Sections Not Experiencing Failure Following First NN-pH SCC Hydrotest (Based upon 11 valve sections, all tested >100% SMYS)

	Years Since First Hydrotest				
	3	6	7	9	12
% of Valve Sections with No In-Service Rupture Within Time	100	91	90	78	75
% of Valve Sections with No In-Service Rupture or Hydrotest Rupture Within Time	73	64	60	44	38

7. Re-Inspection Intervals for In-Line Inspection

In-line inspection (ILI) is used by very few gas pipeline companies because of the difficulty of getting reliable defect-size data without using a liquid couplant. However, in a few special cases, ILI is the best alternative, and companies that use it need to establish appropriate re-inspection intervals.

An important part of an ILI is establishing the minimum size flaw that is detected and the uncertainty in the sizes of large and small flaws. This usually is accomplished with confirmatory excavations. Flaws that are judged to present an unacceptable risk are removed or sleeved. The maximum size of any remaining flaw is the critical parameter that determines the appropriate re-inspection interval. The company's policy for what size flaw should be removed or sleeved and the uncertainty in determining flaw size from the ILI data determine the largest flaw that might remain in the pipeline.

Depending upon the type of ILI data available to the pipeline company, there are at least two options for establishing appropriate reassessment intervals:

- If the growth of individual cracks can be followed with successive runs, the actual growth rates can be determined by dividing the change in size by the time between the two runs.
- If such data are not available, the maximum size of flaw that is left in the line can be used to establish an equivalent hydrostatic test pressure, and the hydrostatic re-test model can be used.

The use of crack-size data from successive runs to establish growth rates has recently been described by Katz, et. al.[7] The growth rates of 19 individual cracks were measured, and the value at the 95th percentile was used as a conservative estimate of the growth rate. Then, that growth rate was imposed on all of the cracks that were left in the line to calculate a minimum time to failure for each crack. Those results were used to schedule inspections to verify the flaw sizes and make necessary repairs. Although that procedure theoretically should prevent any future failure, it was recommended that another ILI run be conducted in about 7 years to validate the assumptions.

Alternatively, an equivalence with a hydrostatic test can be established by determining what hydrostatic-test pressure would be required to remove that largest remaining flaw. The hypothetical pipeline of Figure 9 can be used to illustrate this point. From the failure diagram in Figure 9, it is possible to construct a family of curves, as shown in Figure 13, that represent the ranges of flaw sizes that can survive a hydrostatic test of any given pressure.

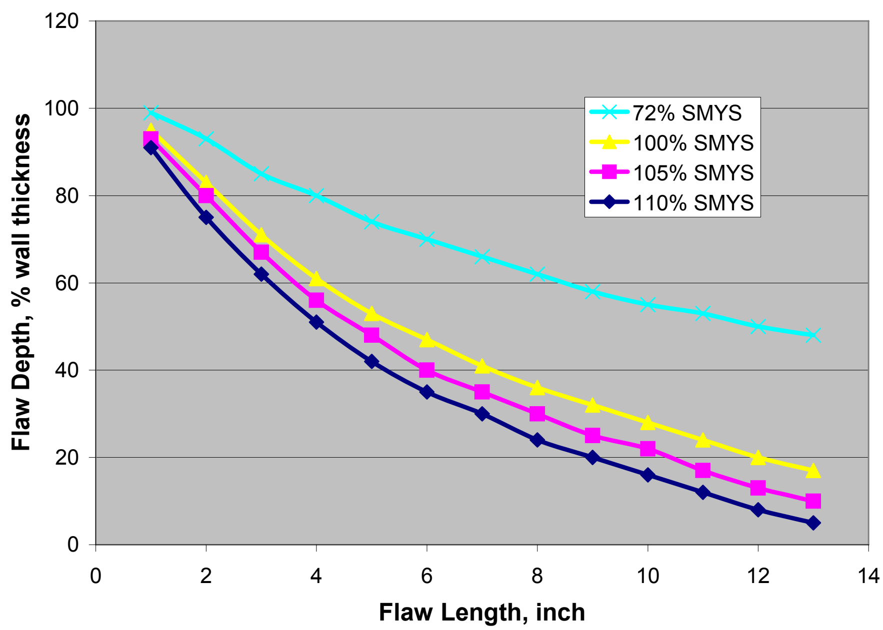

Figure 13 - Flaw Sizes that would be Critical at Various Pressures for Pipe from Figure 9

So long as the maximum flaw size that can remain in the pipeline is smaller than the largest flaw that could survive a hydrostatic test, the ILI run can be considered to be at least equivalent to such a hydrostatic test, and the guidelines for establishing hydrostatic re-test intervals can be used for the ILI re-inspection intervals.

8. Re-Inspection Intervals for SCC DA

Appropriate actions following the discovery of SCC during DA will depend upon the number and severity of the cracks that are found. In some cases, it may be advisable to conduct a hydrostatic test or an ILI rather than schedule another DA.

The following guidelines are based upon the condition that the first dig must be at the location in the segment where the probability of SCC is judged to be highest, thus increasing the chance of finding one of the most severe cracks.∗ However, because there is a distinct possibility of missing the largest crack, extra conservatism has been added for SCC DA compared to hydrostatic testing or ILI. That conservatism involves assuming the existence of larger cracks than are found.

If Category 4 cracks are found, there is a possibility of a service failure in the near future. Therefore, an immediate pressure reduction should be implemented, followed as soon as possible by an

∗ Categories of severity are defined in a companion document.

assessment that covers 100% of the segment. Such an assessment could be a hydrostatic test, an ILI, or, if the segment is very short, a 100% visual examination. Subsequent remediation will depend upon the severity of cracks that are found in the 100% assessment. It could involve replacement of one or more joints of pipe, sleeving of cracked portions of the pipe, grinding or buffing out the cracks or re-coating.

If Category 3 cracks are found, the possibility of Category 4 cracks existing elsewhere in the segment should not be ignored, and, therefore, the procedure for Category 4 cracks should be followed.

If Category 2 cracks are found, the possibility of Category 3 cracks existing elsewhere in the segment should not be ignored. Because Category 3 cracks might grow to critical size in 3 to 5 years, the segment should be assessed with hydrostatic testing, ILI, or a 100% visual inspection within 2 years, and a temporary pressure reduction should be considered until the full assessment has been completed.

If Category 1 cracks are found, the possibility of Category 2 cracks existing elsewhere in the segment should not be ignored. Because Category 2 cracks might grow to critical size in 5 to 10 years, more digs should be conducted until no larger flaws are found. If the largest flaw is Category 2, the next assessment, which may be DA, Hydrostatic testing or ILI, should be conducted in 3 years. If the largest flaw is Category 3 or 4, follow the procedure for Category 4.

If inconsequential cracks are found, the possibility of Category 1 cracks existing elsewhere in the segment should not be ignored. Although Category 1 cracks would not be expected to grow to critical size in less than 10 years, more digs should be conducted until no larger flaws are found. If the largest flaw is Category 1, the next assessment, which may be DA, hydrostatic testing or ILI, should be conducted in 7 years. If the largest flaw is Category 2, 3 or 4, the procedure for the most severe category that is discovered should be followed.

If no cracks are found at the location that is expected to be most susceptible, no additional actions should be required before the next scheduled assessment. Industry experience suggests that, for every joint of pipe that contains a colony of cracks that is severe enough to cause a service failure, there probably are thousands to tens of thousands of colonies with minor cracking. Furthermore, those minor colonies are not randomly distributed throughout the system; they tend to be preferentially located near the more severe cracks. Therefore, if any HCA or segment that is being assessed contains a colony of cracks that is severe enough to cause a service failure within 7 years and if a joint of pipe is chosen for DA based upon it having the highest probability in that segment of having SCC, then the probability of that joint of pipe not having any stress-corrosion cracks would be extremely low. In other words, if the joint of pipe with the highest probability of SCC contains no cracks, it is highly unlikely that another joint of pipe within that segment has cracks that are large enough to cause a service failure within 7 years, and, under those circumstances, excavating one entire joint per segment should be sufficient.

The above guidelines may be ignored if the company has performed an engineering critical assessment to suggest that some other course of action would be appropriate. Also, at any time during the DA process, the operator may consider switching to hydrostatic testing or ILI if it appears that the number of excavations may become impractical.

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APPENDIX E - HYDROSTATIC TEST PROCEDURE

Question 4. What is the appropriate procedure for hydrostatic testing?

1. Summary

Hydrostatic testing has proved to be a very effective way of managing stress-corrosion cracking (SCC) in buried gas transmission pipelines.

From a technical perspective, the optimum procedure for a hydrostatic test involves a short pressure spike at a relatively high pressure followed by a leak test. Foe managing SCC, the spike pressure should be as high as possible within the range of 100 to 110% SMYS but should not be so high as to cause bulging of the pipe or a large number of failures. The hold time should be only long enough to verify the pressure and not more than 1 hour.

The leak test can be performed either by maintaining a lower water pressure for a longer time or with flame ionization after the pipeline is re-pressured with gas. If a water-pressure test is used, the pressure should be at least 10% lower than the spike pressure and 10% higher than the maximum allowable operating pressure. Typically, 8 hours is sufficient to stabilize the pressure, but shorter times may be enough if the pressure remains constant.

Occasionally, multiple failures have occurred when testing a given valve section. Over 70% of the repeat failures due to SCC have occurred at pressures equal to or greater than the previous failure pressure. Of the remainder, none of the pressure reversals has exceeded 5% of the previous pressure.

2. Introduction

Hydrostatic testing typically is conducted for two purposes:

1. To demonstrate the structural integrity of a pipeline by removing near-critical flaws or, by surviving the test, showing that near-critical flaws do not exist in the pipeline.
2. To determine whether leaks exist in the pipeline.

It has proven to be a very valuable tool for managing stress-corrosion cracking (SCC) in pipelines. The most important parameters in a hydrostatic test are the pressures and the hold times. Considerable research has been conducted to provide guidance for selecting pressures and hold times.

3. Background

One of the key factors in determining optimum test parameters is the fact that some flaws may grow slowly during a test, and, if they survive, would have a lower failure pressure after the test than before the test. Research has shown that such growth occurs to a significant extent only if the failure pressure of the defect is above approximately 95% of the test pressure. [1] It also has been shown that, although some flaw growth may continue for many hours, the rate of growth decreases rapidly with time, and by far most of the growth occurs within the first few minutes at the test pressure. [2] Based upon that early research, it was concluded that

- "The hold time at maximum pressure should be minimized since it causes remaining subcritical cracks to grow." [1] A hold time of 1 hour was identified as an upper bound because it causes a very high percentage of near-critical cracks to fail and still minimizes growth of the remaining flaw population, but analysis showed that the hold time could be much shorter. [2]
- "While long hold times are required for a leak check, this can be performed at a lower pressure than the maximum test pressure such as approximately 90 percent of the maximum test pressure." [1]

4. The Spike Test

Based upon the above findings, the use of a "spike" hydrostatic test has become popular among the pipeline companies, where a short-time, high-pressure spike is followed by a longer hold time at a lower pressure to check for leaks.

Based upon a sophisticated probabilistic model for the growth of high-pH stress-corrosion cracks, Leis and Kurth developed guidelines for selecting the spike-pressure. [3] They concluded that the spike pressure should be at least 100% SMYS with something in the range between 105 and 110% SMYS being optimum. Pressure above 110% SMYS runs the risk of expanding the pipe or causing small, stable weld defects to fail. While 110% SMYS would be ideal, it may be impractical because of elevation differences in the pipeline, and 105% SMYS is nearly as good, and even 100% SMYS provides considerable benefit. Pressures of 90 to 95% SMYS provide little benefit.

Another important finding from the early research on hydrostatic testing is that "repeated cycles of proof testing are detrimental since they cause more flaw-growth than is caused by holding at constant pressure levels." [1] Therefore, if a company experiences repeated failures at or near a very high test pressure, it may be better technically (in addition to financially) to reduce the target pressure by a few percent.

5. The Leak Test

From a technical standpoint, the pressure for the leak test should be at least 10% lower than the spike pressure and at least 10% higher than the maximum allowable operating pressure (MAOP). The hold time should long enough to allow the pressure to stabilize if there are no leaks. That is, sufficient time should be allowed for the water temperature to equilibrate with the ground temperature and for residual gases to be absorbed by the water. Typically, 8 hours has been sufficient for those purposes.

A number of gas pipeline companies have found that a flame ionization test after the pipe is re-pressurized with gas is a more sensitive test for leaks than is a long hold time with water in the pipe. Therefore, flame ionization should be an acceptable alternative to a leak test with water pressure.

6. Industry Experience with Hydrostatic Testing for SCC

Within this joint industry project, data were examined from over 1000 hydrostatic tests, most of which were conducted specifically looking for SCC. Many of those tests were in first valve sections where the probability of SCC would be highest in general. About 30% of those tests produced failures, but at least half of the failures were in about 27 valve sections that experienced multiple failures in a sequence. It was unusual to have more than five repeat failures in a single test sequence, but there were two examples of 20 or more.

There was a general trend that each subsequent failure occurred at a higher pressure than the previous failure pressure, but there also were a number of exceptions to this. Figure 14 illustrates the kinds of pressure sequences that can be observed. In this joint industry project, data were obtained for 73 repeat failures in 11 test sequences, four of which were in the same valve section in different years. Of the 73 repeat failures, 51% occurred at pressures above the previous failure pressure, 22% occurred at essentially the same pressure, and 27% exhibited what is termed a pressure reversal. Pressure reversals of 1, 2, 3 and 5% were exhibited in 10, 8, 4 and 5% of the failures, respectively. In no case was a pressure reversal greater than 5% experienced. This is reasonably consistent with observations made in the early research on hydrostatic testing of pipe that contained flaws other than SCC, which showed that pressure reversals greater than 5%, although possible, were highly unlikely.[1] Those that did occur usually were associated with defects in brittle electric-resistance weld zones.

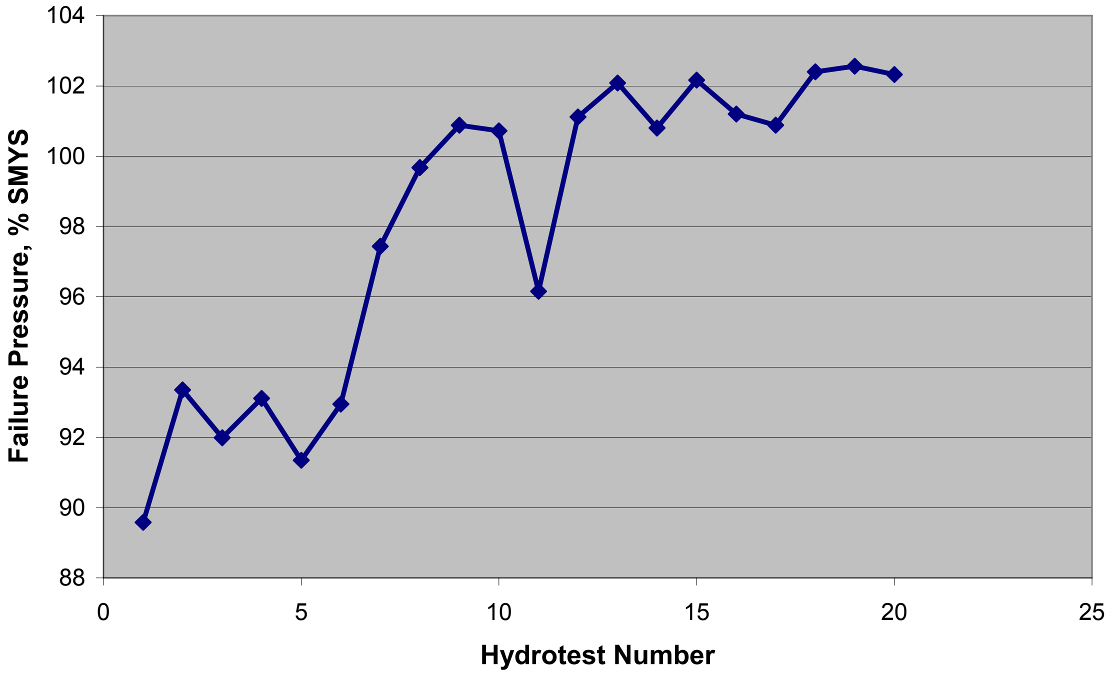

Figure 14 - Sequence of Failure Pressures in a Hydrostatic Test in which 20 Ruptures Initiated at Stress-Corrosion Cracks

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APPENDIX F - DIG LOCATIONS FOR SCC DA

Question 5a: When using SCC DA, where is the best place to dig?

1. Summary

The assessment of SCC-susceptible segments may utilize hydrostatic testing, ILI or excavations, either individually or in combination. When excavations are used, it is necessary to determine where the excavations should be located.

The amount of information available to select excavation sites varies considerably from situation to situation. For the first assessments, there may be little information other than basic pipeline attributes, although some operators may have access to data from CP monitoring, above-ground surveys or ILI runs as well as local knowledge about topography and drainage. For subsequent assessments, information from excavations of the HCA/segment of interest, together with excavation results from adjacent or similar segments, may enable better discrimination. Such information is particularly useful if it helps to build up an understanding of the type, extent and likely distribution of SCC in the segment being assessed, so that the implications of different site selection criteria can be considered.

Guidance on selection of excavation sites, based on the likelihood of finding SCC, has been developed to take these considerations into account. A three-tiered approach to site selection has been adopted, based upon the level of information available:

Tier 1: Site selection based on pipeline attributes and operating history, with no prior experience of SCC assessments and no information available from excavations or surveys

Tier 2: Site selection incorporating additional information available from local monitoring and surveys, ILI and excavations for other operational reasons

Tier 3: Site selection augmented by feedback from previous SCC assessments, leading eventually to a series of pipeline-specific, weighted risk factors incorporated in an overall ranking model; such a model could form the basis for quantitative risk analysis.

The individual factors are identified, based on collective industry knowledge and up-to-date operational experience, taking into account the independent risks from high pH and near-neutral pH SCC. Their integration into Tier 1 and Tier 2 Site Selection Protocols is illustrated, and the issues associated with incorporating new excavation data in Tier 3 are highlighted.

2. Introduction

The management of SCC risk commences with the identification and prioritization of SCC-susceptible segments for assessment (see Questions 1 and 2). When excavations are used in the assessment process for a segment, it is necessary to establish a site selection process in order to determine where the excavations should be located.

Site selection may be used either for identifying the locations of excavations conducted specifically for SCC DA, or for determining the SCC risk at the site of excavations conducted for other operational reasons (tie-ins, mechanical damage or corrosion remediation). Excavations specifically for SCC may typically be 40 feet long, incorporating one or two girth welds, whereas excavations conducted for other operational reasons may expose a shorter or longer pipe length.

The principal intent of site selection for SCC assessment is to identify the locations where the likelihood of finding SCC is highest. The selection process gathers as much relevant information as possible in order to provide the best possible discrimination along the length of the segment being assessed.

The amount of information available to assist site selection may vary considerably from one situation to another. For the first assessments, there may be little information other than basic pipeline attributes such as location, age, construction details and operating history. However, in some instances, operators may have access to information from CP system monitoring, site surveys, ILI and opportunistic excavations, not only for the segment of interest but also for adjacent and similar segments. For subsequent assessments, information from targeted excavations of the segment of interest, together with targeted excavation results from other segments, will enable improved discrimination and re-evaluation of the selection criteria.

The guidance on selecting segments has been developed to take these variations into account. A three-tiered approach has been adopted, based on the level of information available:

- Tier 1: Site selection based on pipeline attributes, operating history, with no information available from excavations or surveys
- Tier 2: Site selection incorporating additional information from any site surveys, ILI or excavations for other operational reasons particularly that concerning coating condition and evidence of environmentally assisted degradation
- Tier 3: Site selection augmented by feedback from previous SCC excavations on the same or nearby segments, leading eventually to the development of a series of pipeline-specific, weighted risk factors incorporated in an overall ranking model. Such a model could form the basis for quantitative risk analysis.

Each Tier incorporates a number of individual Relative Risk Factors addressing the parameters considered to influence the likelihood of SCC. Each tier takes into account the independent risks from high pH and near-neutral pH SCC.

The individual factors are discussed in the sections that follow, and are used to develop illustrative examples of the Tier 1 and Tier 2 Site Selection Protocols.

3. General Approach

The main guidance for site selection is derived from the NACE SCC DA Guidance [1], the CEPA SCC Guidance [2] and ASME B31.8S [3]. Other important reports that identify the factors correlating with the occurrence of SCC in gas transmission pipelines include the protocol for high pH SCC developed by Eiber and Leis [4], the Gap Analysis conducted for PRCI by Fessler [5], the Canadian NEB report [6], the review completed by NACE Task Group T-10E-7 [7] and the review for DOT by Michael Baker [8]. These are supplemented by the review of service experience completed as part of this Joint Industry Project [9].

The NACE SCC DA document is concerned principally with identifying the information to be gathered before, during, and after the DA process; Table 38 (taken from the NACE document) describes the data considered to be essential and useful for segment prioritisation and site selection. The NACE, CEPA and ASME guidance documents all leave decisions about how to make use of the information to the discretion of the operator.

Industry experience suggests that, while there will be many ways in which the issues can be addressed, one appropriate approach is to define a series of Relative Risk Factors (RRFs) that address each of the criteria known to influence the likelihood of high pH or near-neutral pH SCC occurring. The primary aim of the RRFs is to identify locations within the segments where excavation may be most likely to find SCC, and, to the extent that the knowledge base is sufficient, where the most severe SCC is located. This approach is consistent with that developed for segment prioritization

(Question 2) and many of the criteria are similar, although for site selection they are being applied at a localized (joint-by-joint) level of discrimination.

In line with the guidance in ASME B31.8S, it is appropriate to focus the RRFs on pipeline attributes and operating history, together with the four general topics that are expected to determine the most likely sites for SCC to occur: terrain, drainage, loading conditions and cathodic protection. The weighting given to these general topics in the site selection process will depend on individual operator experience; in the absence of prior knowledge, it is probably appropriate to give approximately equal weight to each of five topics as follows:

Table 31 – RRF Topic Weights

Pipeline attributes (including coating type)	20%
Operational history, loading and temperatures	20%
Terrain (topography, soil texture, drainage)	20%
Coating condition	20%
CP system design and performance	20%

Clearly these weightings will be reviewed and modified by the operator as additional information becomes available.

4. Development of Relative Risk Factors

The rationale for the individual Relative Risk Factors is presented below and summarized in Table 36 and Table 37 (see also Section 3.2).

4.1 Attribute and Operational Factors

<u>Distance from the compressor station</u> incorporates the influences of operating temperature and fluctuating stress in the region immediately downstream from compressor discharges [4], [5], [6], [7] and [9].

Typically, <u>operating temperature</u> is highest near the discharge of the compressor station and decreases as the distance from the discharge increases [5]. Higher operating temperatures contribute to external coating degradation, particularly for coal tar coatings [4], and may result in higher crack growth rates for high-pH SCC [7].

The growth of both high-pH and near-neutral-pH SCC to a size causing in-service or hydrostatic test failures may also be promoted by <u>stress fluctuations</u>, particularly within the first few miles downstream of the compressor [6], [7].

Within the 20-mile region downstream from compressors, the frequency of in-service and hydrostatic test failures (and the frequency of excavated/ILI cracks more than 10% deep) diminishes as distance increases [4], [5], [9] The locations for near-neutral pH SCC are more uniformly spread over the downstream region, particularly for asphalt coatings. A graded scale of RRF, incorporating the effects of both operating temperature and stress fluctuations, can be included for both types of SCC, but with a more gradual cut-off for near-neutral-pH SCC to reflect the operational experience [9].

Table 32 – Graded Scale of RRF

Distance	RRF			
	High pH	Near-neutral pH		
	All coatings	Tape	Asphalt	Others
<2 miles	H	H	M	L
2-5 miles	H	H	M	L
5-10 miles	M	H	M	L
10-20 miles	M	M	M	L
20-40 miles	L	M	M	L
>40 miles	-	L	M	-

Coating type is included to provide discrimination for site selection in the (unlikely) event that more than one coating type is present in an individual pipeline segment. Service experience [1], [6], [8] and [9] indicates that SCC has not occurred in joints with fusion bonded epoxy coatings (RRF Score VG) but has occurred in association with other types of coating or bare pipe. Detailed studies of the relationship between coating type and the propensity for SCC formation [7], [10], combined with the review of operator experience [9], form the basis for a series of RRFs for different coating types and ages, for both high-pH and near-neutral-pH SCC.

Service experience from the U.S., Canada and Europe [3], [6], [10] has indicated that field-applied coatings and girth weld sleeves are more prone to SCC than other locations. Similarly, attachments, weights, anchors and casings can give rise to potential shielded crevices that are more at risk than the uniform pipeline [1]. An RRF Score can be added if any of these features is present.

A prior history of SCC within a particular segment is a clear indication that the conditions for SCC may be present in a nearby segment [6], [8], [9]. A RRF Score can be added to focus initial attention close to locations that have a prior history of SCC (A risk-reducing factor applies if prior excavations have revealed no cracking in the vicinity).

A prior history of other features that might promote SCC, such as hard spots or mechanical damage [1], [6], [8] would also merit a RRF score to focus attention on such locations. Axial residual stresses can be higher at bends, especially field bends. In many instances, features such as hard spots and mechanical damage may already have been addressed via other integrity management activities; their inclusion here is to make doubly sure they are not overlooked.

During the course of excavations and ILI investigations, some operators have found correlations between near-neutral pH SCC occurrences and pipe manufacturer [11], [12]. There is a possibility of inherent differences between the SCC susceptibilities of different steels, but this is currently an unproven aspect of ongoing research. It is more likely that differences in the pipe forming, welding and surface treatment processes give rise to differences in residual stresses and oxide coating, and that these influence the propensity to SCC formation. Also, the seam weld can be both a stress concentrating feature and a promoter of "tenting," and it has frequently been associated with near-neutral pH SCC under tape-wrapped coating. If correlations between pipe manufacturer or weld type and SCC occurrence are found for particular pipelines, they can be incorporated via a RRF score based on the judgment of experts.

Pipe properties can also influence the severity of cracking; critical defect depths are smaller in pipes with low toughness and hence there is less time before SCC grows to the critical depth. An additional RRF may be appropriate if pipe toughness is known to be low; in practice, this can probably be linked to the pipe manufacturer.

4.2 Terrain

Undulating terrain, slope inclination and the potential for subsidence all contribute to the possibility of generating secondary stresses (axial or bending) that have been associated with SCC failures [5]-[7]. Pipe-soil movement has also caused disbondment, wrinkling and cracking of the coating [6], [8], [10], allowing accelerated SCC. Secondary stresses are most likely to be generated where the slope change occurs, particularly at the bottom of the slope but also at the top or at slope changes in between [1]. A graded scale for secondary stress, based on slope intensity, can be included as follows.

Table 33 – Graded Scale for Secondary Stress

Average slope over 500 feet):	RRF
Steep (e.g. >20%)	H
Intermediate (e.g. >5%)	L
Flat (e.g. <5%)	-

Secondary stresses may also be generated, for example, where the surrounding support (e.g., a rock cradle) begins and ends, or at a point of minimum elevation. A low RRF Score can be added to promote site selection at these positions.

If there is a known history of ground/pipe movement, then the problems of secondary stresses and coating degradation are more likely to be present, particularly for smaller diameter pipelines [6], [8]; again, a low RRF Score can be added to promote site selection at these positions.

Considerable research has been directed towards correlation of SCC likelihood with soil texture [1], [2], [4]-[7]. There is substantial evidence from service failures that silt and clay soils, which adhere to the coating and hold more moisture, are more likely to be associated with high-pH SCC than are sand and gravel soils. For high-pH SCC, RRF scores can be added to reflect these findings.

There is also evidence that soil texture is a discriminating parameter for near-neutral-pH SCC [1], [2] [5], [6], [7], but the situation is less clear and there are no generalized rules. For tape coatings, disbondment and the conditions for SCC are more likely to occur in textures containing clay and silt, whereas, for asphalt coatings, the drier sand and rock textures are more prone to the conditions for SCC (see also the interacting effects of CP, below). The RRF scores for near-neutral-pH SCC distinguish between tape and asphalt coatings (there is very little evidence of near-neutral-pH SCC under coal tar coatings).

There is a considerable amount of evidence from service failures that the local drainage conditions have a substantial influence on the likelihood of SCC formation [1], [4]-[6], [7]. Alternating wet/dry or variable soil moisture conditions promote the formation of high-pH SCC in coal tar coated lines and near-neutral-pH SCC in asphalt coated lines. Alternating wet/dry conditions may be due to seasonal changes in the water table or be associated with run-off after rainfall. In most instances near-neutral pH SCC, and also in some instances high pH SCC, is associated with continuously wet conditions [1], [4], [7]. These conditions can develop in areas of poor or inadequate drainage, at the bottom of slopes, at river crossings and at other depressions in the landscape, and in irrigated areas. An RRF can be included to reflect these issues, based on subjective judgment and local experience.

There have been occasions where near-neutral-pH SCC occurred in sandy or well-drained soil with high resistively, under asphalt coatings [7]. The RRFs can be extended to reflect this experience.

The resulting RRFs for drainage are as follows.

Table 34 – RRFs for Drainage

	High-pH	Near-neutral-pH	
		Tape	Asphalt
Drainage condition			
Well-drained, predominantly dry	L	L	H
Poorly or seasonally drained	M	H	M
Never drained	M	H	M
Location of river crossing, depression	M	H	L
If no such feature present	-	-	-

4.3 Coating Condition

There is considerable evidence that poor coating condition–porosity, wrinkles, disbondment and cracking–are associated with both high-pH and near-neutral-pH SCC, particularly for field-applied coatings [4]-[10]. There have been numerous occurrences of near-neutral-pH SCC under field-applied spirally wrapped PE tape coatings, at locations where tenting and local disbondment occurs, giving rise to local environments that are shielded and are not reached by the cathodic protection currents. Good initial coating quality and prolonged good coating condition are associated with mill-applied coatings, mainly because of good surface preparation prior to coating. It will be necessary for the RRF to be based on the judgment of experts with local knowledge.

If direct examination of coating quality is possible, coating quality may be established as good; however, if coating quality has to be inferred from attribute information or CP test point data, good quality cannot be guaranteed and the RRF can be adjusted accordingly.

Direct examination of the pipe surface condition provides several indicators of the likelihood of SCC, both at the excavated site and nearby. These include the presence of oxide scale, corrosion and old or new shiny metal, as well as old or new iron carbonate and calcareous deposits. The pH of the under-coating liquid helps to identify any SCC found.

Indirect evidence of coating conditions that promote near-neutral pH SCC, even when the exposed coating appears to be sound, can sometimes be obtained from Magnetic Flux Leakage ILI. Shallow pitting corrosion under an intact but disbonded CP-shielding coating is often found in association with near-neutral pH SCC [6], [11] and an RRF score can be used to focus excavations on such areas if they are present.

SCC can be promoted if there is coating and pipe damage due to mechanical impact [6]. A RRF score can be added if there is a history or risk of mechanical damage in the locality. Also, a score can be added if there has been an in-service coating repair in the vicinity; this can either enhance or reduce the risk of SCC, depending on an expert assessment of coating quality and the susceptibility of the boundary region between the new and existing coating.

4.4 CP System Design and Performance

CP system design is a primary indicator of the likelihood that SCC-preventing conditions have been applied. Well-designed systems ensure operation at around –950 to –850 mV Off, whereas in some areas –100 mV shift has been applied. The history of CP is as important as the present situation; many pipelines were originally constructed with inadequate or no CP and upgraded at a later date.

CP system reliability and reproducibility are measures of the likelihood that correct CP conditions (better than -850 mV Off) have always been maintained and that periods of local inadequate CP have been avoided. If protection is marginal, and voltages are generally –850 to –780 mV Off, or if the –100 mV differential criterion has been applied, there is an increased risk of high-pH SCC [1], [4]. If there are problems sustaining the level of protection and the potential is worse than –780 mV OFF, the risk of near-neutral-pH SCC is higher [1], [7]. The RRF addressing these issues will need to be based on the judgment of experts with local knowledge.

Other possible problem areas for CP system reliability are at rail and cable crossings. Similar risks exist in the proximity of industrial and commercial sites, particularly those with highly rated buried power cables. To reflect these concerns, additional RRF scores can be included if any of these features are present, and particularly if there is a prior history of such occurrences.

The availability of above-ground survey data can give important information to corroborate the quality of both coatings and the CP system, and correlate with SCC occurrences found during the early stages of an excavation program (although it requires careful interpretation for CP-shielding coatings). Close interval survey (CIS), direct current voltage gradient (DCVG) and C-Scan survey data can all locate potential faults [1], [7], [10], but they may not detect intact but disbonded coatings. An RRF score can be used to direct future excavations to such locations, based on the judgment of experts with local knowledge.

The CP system effectiveness depends upon the extent to which the system meets the specified requirements, both at the present time and over the previous operating life. Effective maintenance of the protection levels at all times is the optimum performance; however, systems may be only partially effective in meeting these criteria, or the current may be partially shielded by the coating. In some instances, CP-shielding coatings may negate the effects of CP entirely. The RRF score, based on the judgment of experts with local knowledge and supported by information from excavations, will need to reflect these issues.

5. Development of Site Selection Protocols

5.1 Allocation of Tier 1 and Tier 2 Relative Risk Factors

The Tier 1 approach is applicable when no prior SCC knowledge is available and when there is no information available from in-ground surveys or other relevant excavations. The Tier 2 approach makes use of all available information from surveys, opportunistic excavations, ILI and other sources relevant to the segment being assessed, enabling better discrimination and site selection.

The assignment of Relative Risk Factors to Tier 1 and Tier 2 in accordance with this approach is illustrated below:

Table 35 – RRFs for Tier 1 and Tier 2

Tier 1	Tier 2
Attribute and operational information	
Distance from compressor	Confirmation of pipe, joint coating type
Coating type	Type
History of SCC nearby	Possible CP shielding due to attachments, casings
Pipe manufacturer	
Pipe toughness	Hard spots, mechanical damage
Weld type, bends, casings	Cracking found by excavations
Terrain	
Slope of land	Soil texture
Points of minimum elevation	Soil resistivity
History of ground movement	Soil moisture content
Well, poorly or seasonally drained	Groundwater chemistry
Location of creeks or river crossings	pH of liquid beneath coating
Coating condition	
	Adhesion, porosity, disbonding
	Repair coating condition
	Mechanical damage to coating
	Surface deposits, corrosion
CP system design and performance	
System design (e.g., -850 mV, 100 mV shift)	Good, marginal or poor protection
History of CP installation, upgrades	"Problem" locations revealed by surveys
	Proximity to sources of electrical interference

It can be seen from this table that, while the Relative Risk Factors in Tier 1 will provide a useful level of discrimination, at least for initial screening, the ability to define excavation sites is considerably enhanced by the factors in Tier 2. Consequently, the use of such information at the earliest opportunity in the SCC assessment process is encouraged even if only one or two of the Tier 2 factors can be utilized.

5.2 Tier 3

The fundamental difference between Tier 3 and Tier 2 stems primarily from the availability of information from excavations already conducted on the segment being assessed, or on other segments with the same attributes and SCC experience, as part of the ongoing SCC assessment process. The NACE SCC DA document [1] lists a large number of measurements and observations that form part of the assessment, including the following:

<u>Pipeline attributes and operational features</u>

Presence of stress-promoting features – dents, wrinkles, rock ledges, road crossings
Presence of hard spots
Presence of weights, anchors, supports

<u>Coating condition</u>

Confirmation of the coating type
Pipe surface condition (oxide scale, corrosion, carbonate or calcareous deposits, pH of under-coating liquid, etc.)

Evidence of disbondment (poor application, in-service degradation)
Faults and holidays, creep, wrinkles and cracking
Correlation with survey results prior to excavation
Confirmation of field joint type
Repair coating condition, bond to original coating

Cathodic protection

Evidence of inadequate protection and/or shielding (now or previously)
Correlation with survey results prior to excavation
Presence of local CP shielding (e.g., from rocks)
Presence of weights, anchors, supports
Presence of local sources of electrical interference

Terrain

Soil type and texture
Drainage, soil moisture and resistivity
Confirmation of land use
Presence of river crossings, other local undulations
Groundwater conductivity, presence of agro-chemicals

History –update

Has SCC been found?
If so, what type, what extent and distribution; no of colonies, depths

This new information does not require additional Relative Risk Factors; instead it necessitates a complete review and update of the Tier 2 factors, based on expert analysis and interpretation of the new data. In some instances, this process will allow sub-division of some of the factors identified in Tier 2 and clarification of the discriminatory features needed for the expert interpretations. In order for this to be sound and successful, it is necessary to acquire a considerable number of fully documented records (as described by NACE, [1]) relevant to the segment being assessed.

6. Implementation and Application

6.1 Tier 1 and Tier 2 Protocols

The preceding sections identified a series of individual factors to be considered when developing a site selection protocol for SCC-susceptible segments. Table 36 and Table 37 illustrate how they might be combined into Tier 1 and Tier 2 Protocols respectively, incorporating a simple High-Medium-Low ranking for each factor.

The Tier 1 Protocol is based on the key factors that will provide joint-by-joint discrimination in the absence of any further local knowledge of pipeline condition. The Tier 2 Protocol includes additional information obtained indirectly from standard system monitoring above-ground surveys and ILI, or obtained directly from examination of the exposed pipe and coating; in either case, this additional information requires interpretation by technical experts with local knowledge. Either Tier 1 or Tier 2 can be used at the outset of the SCC assessment process, before any specific knowledge about SCC occurrence has been obtained for the segment being assessed.

If only partial Tier 2 information is available, it should still be used wherever possible. However, the selective used of additional information must not be allowed to penalize particular sites.

When a particular pipeline segment is examined, not all the RRFs will necessarily be discriminatory. This will particularly be the case for short segments. For example, the entire segment may be subject to the same drainage conditions or the same CP system quality, although there will usually be local low points that can be selected for excavation. Nevertheless, it is confidently expected that there will always be sufficient variation in some RRFs to enable discrimination and selection of sites for excavation.

The Tier 1 and Tier 2 Protocols are structured to select different sites for high pH and near-neutral pH SCC. In most instances, only one type of SCC is likely to be present, and the appropriate scale of RRFs will be used. In the absence of any prior knowledge, an operator should excavate sites selected according to both RRF scales.

In the first instance, and in the absence of any other information, an overall ranking can be obtained by replacing High-Medium-Low with 5-3-1 (and –2 for Good). Based on the overall operational experience of many operators, this may be a satisfactory starting point. However, such an approach arbitrarily allocates equal weight to each factor; as new information is obtained from excavations, operators will select and apply weight to the individual factors for the Tier 1 and Tier 2 Protocols according to the attributes, operational history and service experience of their own pipeline systems.

6.2 Site Selection for HCAs

The application and outcome of the site selection process may be determined by the juxtaposition of segments and HCAs in a pipeline. A segment is defined as a continuous length of a pipeline with nominally common attributes such as installation age, operating pressure and pressure history. In some instances, operators may elect to separate segments on the basis of pipe wall thickness, grade and coating type, whereas in other instances, operators may elect to consider an entire compressor-to-compressor length as one segment. It follows from this that the relationship between segments and HCAs also varies from situation to situation. An HCA may contain several segments or may be an entire segment; in some instances several HCAs may be within a single segment.

The key principle is that the ranking of selected sites for excavation should be applicable to a known length of pipeline with nominally common attributes (i.e., a segment). Hence, if several HCAs fall within a segment, it follows that an excavation site outside the boundary of an HCA will be used for its assessment if the site selection ranking shows a higher likelihood of finding SCC at this location.

6.3 Implementation of Tier 3

The Tier 3 approach is primarily used for reassessments rather than first assessments. It provides the route for incorporating the results from the ongoing SCC assessments: modifying the weightings, sub-dividing the definitions of each factor in the Tier 1 and Tier 2 Protocols and developing statistically sound predictive models. The manner in which this is undertaken will be determined by each individual operator. Several operators have initiated an ongoing process for reviewing and updating their Site Selection Protocols as excavation results become available, as described above. Some operators have been undertaking extensive excavation programs for many years and have already obtained a sufficiently large database of SCC records to enable the development of quantitative risk assessment models based on this type of approach; for most operators, however, this is still a long way off.

7. Next Steps

The application of the Site Selection Protocols will lead to the identification of one or more sites in a segment where SCC is most likely to occur or is likely to be most severe. This will give guidance for the first excavations; the need for further excavations on the same segment will depend on the SCC findings. The issues to be considered in determining how many excavations are necessary to complete an assessment, and how long the interval should be before the next assessment, are discussed in the JIP Report "Question 3: Methods for establishing reassessment intervals" and the JIP Report "Question 5b: Determining how many excavations should be conducted."

8. REFERENCES[12]

[1] Standard Recommended Practice, Stress Corrosion Cracking (SCC) Direct Assessment Methodology, NACE Standard RP0204-2004 Item No. 21104, 2004.

[2] "SCC Recommended Practices," Canadian Energy Pipeline Association (CEPA), 1997.

[3] "Managing System Integrity of Gas Pipelines," ASME Code for Pressure Piping, B31.8S-2001 (Supplement to ASME B31.8).

[4] R. J. Eiber and B. N. Leis, "Protocol to identify potential areas of high pH stress corrosion cracking," paper presented at 11th PRCI/EPRG Joint Technical Meeting on Pipeline Research, Arlington, VA, May 1997.

[5] R. R. Fessler, "Stress corrosion cracking gap analysis," PRCI Report L52038, September 2002.

[6] "Stress corrosion cracking on Canadian oil and gas pipelines," NEB Report MH-2-95, November 1996.

[7] "State-of-the art report – external stress corrosion cracking of underground pipelines," NACE Task Group T-10E-7 Stress corrosion cracking study.

[8] M. J. Baker, Report TTO No. 8, prepared for DOT RSPA, January 2005.

[9] "Field experience of SCC in gas transmission pipelines – operator survey," JIP Report (draft), August 2006.

[10] J. P. Jansen, W. Sloterdijk, M. Meyer, D. Norman and C. J. Argent, "Coating degradation mechanisms and their impact on long term performance of external pipeline coatings," paper presented at 15th PRCI/EPRG Joint Technical Meeting on Pipeline Research, Orlando, May 2005.

[11] J. D. Davis, J. E. Marr and D. Venance, "SCC integrity management case study – Kinder Morgan Natural Gas Pipeline of America," paper 0586 presented at ASME International Pipeline Conference, Calgary, October 2004.

[12] J. A. Beavers and W. V. Harper, "Stress corrosion cracking prediction model," paper 04189 presented at NACE Corrosion 2004, New Orleans, March 2004.

12 Some of the referenced PRCI reports may not be available to non-members.

Table 36 - Summarized Illustration of Relative Risk Factors for Site Selection – Tier 1

Factor	High pH SCC	Near-Neutral pH SCC		
Attribute and Operational Information				
Distance From Compressor	All coatings	Tape	Asphalt	Others*
<2 miles	H	H	M	L
2-5 miles	H	H	M	L
5-10 miles	M	H	M	L
10-20 miles	M	M	M	L
20-40 miles	L	M	M	L
>40 miles	-	L	M	-
Coating Type (individual pipe joints)				
FBE or liquid epoxy	G	G		
Coal tar	H	L		
Asphalt	L	H		
Tape	H	H		
Wax	L	M		
Bare	L	L		
If coatings are field-applied	M	M		
If coatings are plant-applied	-	-		
Pipe manufacture and properties		Tape		Others
Manufacturer linked to other instances of SCC	H	H		H
Pronounced seam weld cap (DSAW)	-	H		-
ERW pipe more than 30 years old	-	M		M
Pipe toughness below 20 ft lbs (2/3 Charpy)	M	M		M
History of SCC (e.g., within 500 feet)				
In-service, hydrotest failure	H	H		
Cracking >10% deep	M	M		
Cracking <10% deep	L	L		
Excavations have found no cracking	G	G		
History/presence of other SCC-promoting features				
Hard spots	L	M		
Mechanical damage	L	M		
Bends, attachments, weights etc	-	L		
Terrain				
Secondary loading - slope inclination (e.g., average slope over 500 feet)		Tape	Asphalt	
Steep (>20%) or undulating	H	L	H	
Intermediate (5-20%)	M	L	M	
Flat (<5%)	-	-	-	
Location of top of slope	L	L	M	
Location of bottom of slope	M	M	L	
Location of >10% slope change	L	L	L	
Local point of minimum elevation	L	M	L	
History of ground movement	M	M	M	
Drainage: Location of creek, river crossing	M	H	L	
Coating Condition				
History or risk of mechanical damage; proximity to road crossings, industrial/commercial sites etc	L	M		
Previous coating repairs within 100 feet	L	L		
CP System Design				
CP system criterion is –850 mV OFF	-	-		
CP system criterion is 100 mV shift	M	L		
CP system criterion is less than –780 mV OFF	M	M		
History or risk of electrical interference with CP; proximity to cables, transport systems, industrial/commercial sites	L	L		

*The term "Other" refers to wax, coal tar, bare pipe, etc. that are not identified in the preceding columns and are not exempted from assessment (e.g., fusion bonded epoxy).

Table 37 - Summarized Illustration of Relative Risk Factors for Site Selection – Tier 2

Only the additional Tier 2 Relative Risk Factors are included below.

Factor	High pH SCC	Near Neutral pH SCC	
Attribute and operational information			
Terrain			
Soil texture at pipe crown depth		Tape	Asphalt
Organic	M	H	-
Clay	M	H	-
Silt	M	M	-
Mixed sand/ coarse clay	M	M	-
Mixed sand/ coarse silt	M	M	M
Sand	L	-	H
Coarse Rock	L	-	M
Bedrock (limestone, sandstone and shale)	L	-	M
Drainage		Tape	Asphalt
Well-drained, predominantly dry	L	L	H
Poorly or seasonally drained	M	H	M
Never drained	M	H	M
Soil resistivity			
High resistivity	L	H	
Low resistivity	-	-	
pH of liquid beneath coating			
High pH	H	-	
Near-neutral pH	-	H	
Groundwater chemistry (e.g., from local agricultural/industrial practices) could promote SCC	L	L	
Coating Condition			
Good adhesion, little porosity & disbonding (as-new)	-	-	
Some damage/porosity, limited disbonding	M	M	
Wrinkles, cracks, disbonding with deposits under	H	H	
Evidence of shallow corrosion below an intact but disbonded coating (addit score)	-	H	
Previous coating repairs within 100 feet	L	L	
CP System Performance			
Evidence of good protection at all times	-	-	
Marginal protection, history of variability	M	L	
Sustaining protection levels is/has been a problem	M	M	
CP is shielded by coating, or by attachments, weights, casings	M	H	
"Problem location" identified by CIS, DCVG, C-Scan survey, etc.	M	M	

Table 38 - Factors to Consider in Prioritization of Segments and in Site Selection for SCC DA (from NACE RP0204-2004)

The relative importance of each data element (indicated in last column) is

A. Usually important for prioritizing sites.
B. May be important for prioritizing sites in some cases.
C. Not relevant to prioritizing, but may be useful for record keeping.

Factor	Relevance to SCC	Use and Interpretation of Results	Ranking
PIPE-RELATED			
Grade	No known correlation with SCC susceptibility.	Background data needed to calculate stress as percent of SMYS.	C
Diameter	No known correlation with SCC susceptibility.	Background data needed to calculate stress from internal pressure.	C
Wall thickness	No known correlation with SCC susceptibility.	Impacts critical defect size and remaining life predictions. Needed to calculate stress from internal pressure.	C
Year manufactured	No known correlation with SCC susceptibility.	Older pipe materials typically have lower toughness levels, reducing critical defect size and remaining life predictions.	C
Pipe manufacturer	Near-neutral-pH SCC has been found preferentially in the HAZ of ERW pipe that was manufactured by Youngstown Sheet and Tube in the 1950s. Reported to be statistically significant predictor for near-neutral-pH SCC in system model for one pipeline system.	Important factor to consider for near-neutral-pH SCC.	A
Seam type	Near-neutral-pH SCC has been found preferentially under tented tape coatings along DSA welds and in HAZs along some electric-resistance welds. No known correlation with high-pH SCC.	May be important factor to consider for near-neutral-pH SCC.	B
Surface preparation	Shot peening or grit blasting can be beneficial by introducing compressive residual stresses at the surface, inhibiting crack initiation, and by removing mill scale, making it difficult to hold the potential in the critical range for high-pH SCC.6	Important factor to consider for both high-pH and near-neutral-pH SCC.	A
Shop coating type	To date, SCC has not been reported for pipe with undamaged fusion-bonded epoxy (FBE) coating or with extruded polyethylene coating.	Important factor to consider for both high-pH and near-neutral-pH SCC.	A
Bare pipe	SCC has been observed on bare pipe in high-resistivity soils.	May be important factor.	B
Hard spots	There have been instances in which near-neutral-pH SCC has occurred preferentially in hard spots, which can be located by III that measures residual magnetism.	May be important factor.	B

Factor	Relevance to SCC	Use and Interpretation of Results	Ranking
CONSTRUCTION-RELATED			
Year installed	Impacts time over which coating degradation may occur and cracks may have been growing.	Age of pipeline used in criteria for selection of susceptible segments in Part A3 of ASME B31.8S.1	A
Route changes/modifications		May be important for accurately locating each site.	C
Route maps/aerial photos		May be important for accurately locating each site.	C
Construction practices	Backfill practices influence probability of coating damage during construction. Also, time between burying of pipe and installation of CP might be important.	Early levels of CP might be important.	B
Surface preparation for field coating	Mill scale promotes potential in critical range for high-pH SCC.	May be discriminating factor.	A
Field coating type	High-pH SCC found under coal tar, asphalt, and tape. Near-neutral-pH SCC most prevalent under tape but also found under asphalt. Weather conditions during construction also may be important in affecting coating condition.	Important factor to consider for near-neutral-pH SCC.	A
Location of weights and anchors	Near-neutral-pH SCC has been found under buoyancy-control weights.	Might be important, especially for near-neutral-pH SCC.	B
Locations of valves, clamps, supports, taps, mechanical couplings, expansion joints, cast iron components, tie-ins, and isolating joints	No known relation to SCC. Just applicable to locating and characterizing sites.	May be important for accurately locating and characterizing each site.	C
Locations of casings	CP shielding and coating damage more likely within casings.	May be important for accurately locating and characterizing each site.	B
Locations of bends, including miter bends and wrinkle bends	Might indicate unusual residual stresses.	Residual stress may be an important factor.	B
Location of dents	Might indicate unusual residual stresses.	Residual stress may be an important factor.	B

Factor	Relevance to SCC	Use and Interpretation of Results	Ranking
SOILS/ENVIRONMENTAL			
Soil characteristics/ types (Refer to Appendix A.)	No known correlation between soil type and high-pH SCC, except for some evidence that high sodium or potassium levels might promote development of concentrated carbonate/bicarbonate solutions under disbonded coatings. Some success has been experienced in correlating near-neutral-pH SCC with specific soil types.	Might be important, especially for near-neutral-pH SCC.	B
Drainage	Has been correlated with both high-pH and near-neutral-pH SCC.	Might be important parameter.	B
Topography	Has been correlated with both high-pH and near-neutral-pH SCC, possibly related to effect on drainage. Also, circumferential near-neutral-pH SCC has been observed on slopes where soil movement has occurred.	Might be important parameter.	B
Land use (current/past)	No obvious correlations have been found, but use of fertilizer might affect soil chemistry as related to trapped water under disbonded coatings.	Might be important parameter.	B
Groundwater	Groundwater conductivity affects the throwing power of CP systems.	Might be important parameter.	B
Location of river crossings	Affects soil moisture/drainage.	Might be important	B
CORROSION CONTROL			
CP system type (anodes, rectifiers, and locations)	Adequate CP can prevent SCC if it reaches under disbonded coatings.	Important parameter.	B
CP evaluation criteria	Adequate CP can prevent SCC if it reaches under disbonded coatings.	Background information.	C
CP maintenance history	Adequate CP can prevent SCC if it reaches under disbonded coatings.	Background information.	C
Years without CP applied	For high-pH SCC, absence of CP might allow harmful oxides to form on pipe surface. For near-neutral-pH SCC occurring at or near the open-circuit potential, absence of CP could allow SCC to proceed.	Important parameter.	B
CIS and test station information	Although high-pH SCC occurs in a narrow range of potentials (typically between -575 and –825 mV vs. copper/copper sulfate [Cu/CuSO4] depending on temperature and solution composition), it has been observed on pipe that appeared to be adequately cathodically protected, because the actual potential at the pipe surface can be less negative than the aboveground measurements because of shielding by disbonded coatings. Nevertheless, locations of cracks might correlate with CP history, especially if problems had been encountered in the past.	Important factor to consider for both high-pH and near-neutral-pH SCC.	B
Coating-fault survey information	Because SCC requires coating faults, indications of coating condition might help locate probable areas.	Important background information.	B

Factor	Relevance to SCC	Use and Interpretation of Results	Ranking
Coating system and condition	The coating system (coating type, surface condition, etc.) is an important factor in determining SCC susceptibility and the type of SCC that occurs. Because SCC requires coating faults, indications of coating condition might help locate probable areas.	Important background information.	A
OPERATIONAL DATA			
Pipe operating temperature	Elevated temperatures have strong accelerating effect on high-pH SCC. For near-neutral-pH SCC, temperature probably has little effect on crack growth rate, but elevated temperatures can contribute to coating deterioration.	Important, especially for high-pH SCC.	A
Operating stress levels and fluctuations	Stress must be above a certain threshold for SCC to occur. Fluctuating stresses can significantly reduce the threshold stress.	Impacts SCC initiation, critical flaw size, and remaining life predictions.	A
Leak/rupture history (SCC)	There is a high probability of finding more SCC in the vicinity of previously discovered SCC.	Important.	A
Direct inspection and repair history	There is a high probability of finding more SCC in the vicinity of previously discovered SCC.	Important.	A
Hydrostatic re-test history	There is a high probability of finding more SCC in the vicinity of previously discovered SCC.	Important.	A
ILI data from crack-detecting pig	There is a high probability of finding more SCC in the vicinity of previously discovered SCC.	Important.	A
ILI data from metal-loss pig	If a metal-loss pig indicates corrosion on a tape-coated pipe where there is no apparent indication of a holiday, the coating is probably disbonded and shielding the pipe from CP, a condition in which SCC — especially near-neutral-pH SCC — has been observed.	May be important.	B

APPENDIX G - NUMBER OF DIGS FOR SCC DA

Question 5b: How many digs per segment are appropriate for SCC DA?

A key question regarding stress-corrosion-cracking direct assessment (SCC DA) is how many digs should be conducted in a pipeline segment. The answer to that question needs to be considered within the broader context of what kinds of actions are appropriate after discovering stress-corrosion cracks in a pipeline. In some cases, actions other than more digging, such as hydrostatic testing or in-line inspection (ILI) may be more appropriate. Severity rankings as defined in a separate document may be used to guide the choice of the next action.

To address this question, it is important to carefully define and recognize the purpose of SCC DA. The purpose of any assessment for SCC is to provide assurance that a service failure will not occur before the segment is re-assessed. It is not to find or remove every stress-corrosion crack in the segment; none of the assessment approaches can do that.

The following guidelines are based upon the condition that the first dig must be at the location in the segment where the probability of SCC is judged to be highest, thus increasing the chance of finding one of the most severe cracks. However, because there is a distinct possibility of missing the largest crack, extra conservatism has been added for SCC DA compared to hydrostatic testing or ILI. That conservatism involves assuming the existence of larger cracks than are found.

If Category 4 cracks are found, there is a possibility of a service failure in the near future. Therefore, an immediate pressure reduction should be implemented, followed as soon as possible by an assessment that covers 100% of the segment. Such an assessment could be a hydrostatic test, an ILI, or, if the segment is very short, a 100% visual examination with MPI. Subsequent remediation will depend upon the severity of cracks that are found in the 100% assessment. It could involve replacement of one or more joints of pipe, sleeving of cracked portions of the pipe, grinding or buffing out the cracks or re-coating.

If Category 1 cracks are found, the possibility of Category 2 cracks existing elsewhere in the segment should not be ignored. Because Category 2 cracks might grow to critical size in 5 to 10 years, more digs should be conducted until no larger flaws are found. If no flaw larger than Category 1 is found, the next assessment, which may be DA, Hydrostatic testing or ILI, should be conducted in 3 years. If the largest flaw is Category 2, the next assessment should be conducted in 2 years. If the largest flaw is Category 3 or 4, follow the procedure for Category 4.

If inconsequential cracks are found, the possibility of Category 1 cracks existing elsewhere in the segment should not be ignored. Although Category 1 cracks would not be expected to grow to critical size in less than 10 years, more digs should be conducted until no larger flaws are found. If no flaws larger than inconsequential are found, the next assessment, which may be DA, hydrostatic testing or ILI, should be conducted in 7 years. If the largest flaw is Category 1, 2, 3 or 4, the procedure for the most severe category that is discovered should be followed.

If no cracks are found at the location that is expected to be most susceptible, no additional actions should be required before the next scheduled assessment. Industry experience suggests that, for every joint of pipe that contains a colony of cracks that is severe enough to cause a service failure, there probably are thousands to tens of thousands of colonies with minor cracking. Furthermore, those minor colonies are not randomly distributed throughout the system; they tend to be preferentially located near the more severe cracks. Therefore, if any HCA or segment that is being assessed contains a colony of cracks that is severe enough to cause a service failure within 7 years and if a joint of pipe is chosen for DA based upon it having the highest probability in that segment of having SCC, then the probability of that joint of pipe not having any stress-corrosion cracks would be extremely low. In other words, if the joint of pipe with the highest probability of SCC contains no cracks, it is highly unlikely that another joint of pipe within that segment has cracks that are large enough to cause a service failure within 7 years, and, under those circumstances, excavating one entire joint per segment should be sufficient.

The above guidelines may be ignored if the company has performed an engineering critical assessment to suggest that some other course of action would be appropriate. Also, at any time during the DA process, the operator may consider switching to hydrostatic testing or ILI if it appears that the number of excavations may become impractical.

APPENDIX H - CRACK SEVERITY

Question 6: How should crack severity be defined and how should severity determine what kinds of remedial actions are appropriate?

1. Introduction

When cracks are found during excavation or ILI, it important to establish their severity in order to determine what the mitigating actions should be and how urgently they should be undertaken. A measure of crack severity also is essential for determining the reassessment interval for any smaller cracks that may remain after the first assessment or for considering whether any additional monitoring should be performed during the intervening period.

To facilitate decision-making, it is appropriate to develop a hierarchy of crack severity categories and response categories, thereby ensuring a coherent overall process for timely, effective and safe mitigation whenever cracking is discovered.

2. Crack Severity Categories

2.1 Definition

In line with other guidance for SCC (e.g., CEPA, [1]), it is appropriate to identify threshold depths and lengths below which cracks are not considered to present any immediate threat to integrity. To avoid confusion with other schemes, the term "Noteworthy" has been applied to cracks that exceed these thresholds and is defined as follows:

> *An SCC crack or colony is of Noteworthy size if the maximum crack depth is greater than 10% of the wall thickness and if the maximum interacting crack length (defined below) is more than the critical length of a 50% through-wall crack at a stress level of 110% SMYS.*

For Noteworthy cracks, categories of crack severity can be based upon critical cracks at other stress levels, using the actual interacting length and maximum depth. For example, taking 125% and 110% of MAOP in addition to 110% SMYS would give rise to a hierarchy of crack severity based on Predicted Failure Pressure (PFP) as follows:

Category 1: Predicted Failure Pressure is above110% SMYS
Category 2: Predicted Failure pressure is above 125% MAOP and below 110% SMYS
Category 3: Predicted Failure Pressure is above 110% MAOP and below 125% MAOP
Category 4: Predicted Failure Pressure is below 110% MAOP

110% SMYS is used to delineate Category 1 because it corresponds to the pressure commonly prescribed for hydrostatic testing.

Category Zero is used to describe those cracks that are below the threshold for Noteworthy cracks. They fall into two groups:

i. those that are shallow, i.e., less than 10% through-wall depth
ii. those that are so short that, even if they were 50% through-wall depth, they would not result in a hydrostatic test failure

Finally, cracks of any length that are greater than 30% through-wall depth, for which grinding is often not allowed by regulations, are grouped separately (These Deep Cracks also are categorized as Noteworthy).

The relationships between severity category and crack length and depth are illustrated schematically in Figure 15.

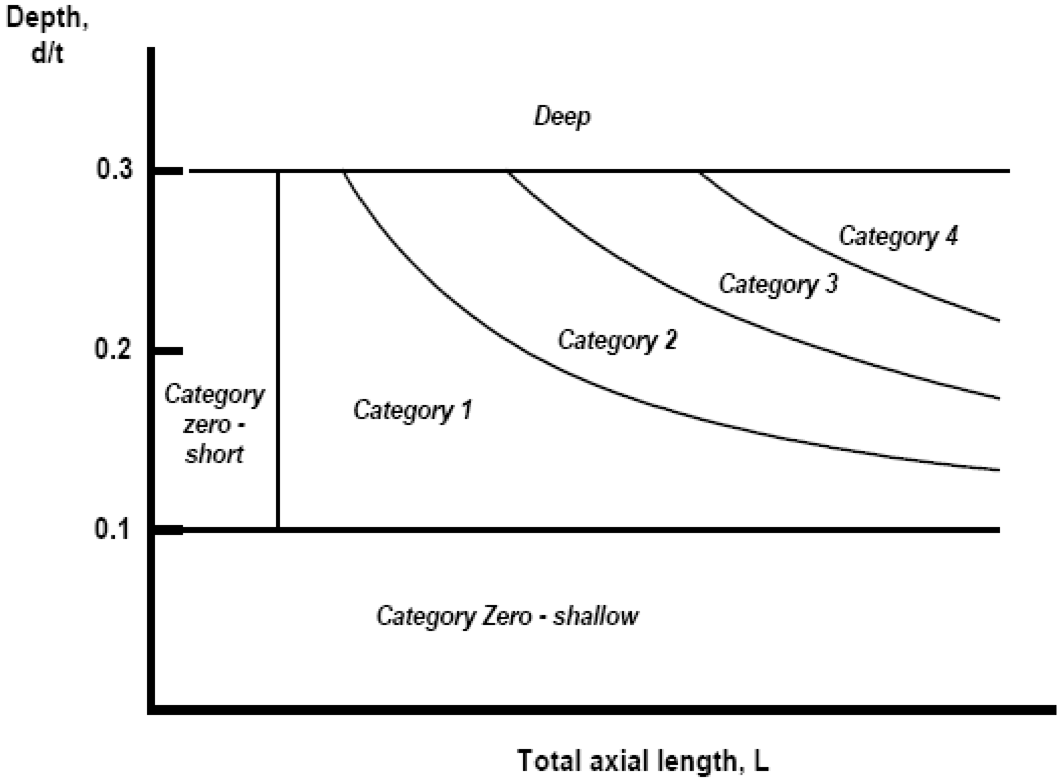

Figure 15 - Relation of Severity Categories to Crack Lengths and Depths (Schematic)

2.2 Measurement and Calculation

The use of these definitions of crack severity necessitates measurement of the crack length using, for example, magnetic particle inspection or in-line inspection (ILI), and confirmation of the crack depth measurement by controlled local grinding/buffing or by non-destructive testing.

For closely spaced cracks, it is necessary to take into account the possibility of time-dependent crack coalescence, particularly in the axial direction, during the period of operation following discovery. For this, the definition derived by CEPA [1] and adopted by NACE [2] is appropriate:

If the circumferential separation of two adjacent cracks is less than 14% of their average length and the axial separation is less than 25% of their average length, then they should be considered as a single crack with length equal to the total cumulative length.

The application of these crack severity categories also requires knowledge of the pipe size and operating pressure, together with pipe strength and toughness, to enable the calculations of crack criticality using the Pipeline Axial Flaw Failure Criterion (PAFFC) [3], CorLas [4], the log-secant method [5] or an equivalent method. PAFFC and CorLas are more accurate, especially for cracks less than 50% deep; the log-secant method, which is readily available and commonly used, is more conservative.

The CEPA/NACE guidance has been shown to accommodate interactions between adjacent coplanar or non-coplanar cracks when failure pressures are calculated.

The critical axial length defining the boundary between short Category Zero and Noteworthy cracks is dependent on pipe geometry, material properties and operating pressure. A calculation is necessary for each situation. However, as the illustrative examples in Table 39 show, the critical crack length typically is greater than 2 inches except for a few cases of smaller-diameter (less than 20-inch) pipe.

Table 39 - Examples of Maximum Lengths of Category Zero Cracks

Diameter, inches	Wall Thickness, inches	Pipe Grade	Pipe Toughness, ft lbs	Critical Length, inches
42	0.371	X65	30	2.3
36	0.39	X60	30	2.1
30	0.375	X52	20	2.4
24	0.312	X52	20	1.9
20	0.25	X52	20	1.6
20	0.312	X35	20	2.7
16	0.25	X42	20	2.2
12.75	0.25	X42	25	1.6

3. Response Time

The formulation of these severity categories enables an estimate to be made of the minimum remaining life at operating pressure for each severity category. Estimates are based on the time taken for the crack depth to increase to the critical depth to cause failure at the operating pressure.

Predicted failure lives are not totally precise since they depend upon the assumptions made about the crack aspect ratio and how it changes during the life of the crack; however, the degree of sensitivity to aspect ratio is not great, and it is possible to use a "worst case" aspect ratio for each severity category.

Failure lives are more significantly influenced by the assumptions made about the prevailing crack growth rate. Some operators with experience of SCC are able to use a relevant, realistic growth rate, whereas others may be required to use an upper bound rate derived from published data. For example, for a typical 30-inch-diameter pipeline with 0.375-inch wall thickness operating at 72% SMYS, using a growth rate of 0.012 inch/year (0.3 mm/year) gives rise to the following estimated minimum lives for each severity category:

Category Zero: failure life exceeds 15 (short) to 25 (shallow) years
Category 1: failure life exceeds 10 years
Category 2: failure life exceeds 5 years
Category 3; failure life exceeds 2 years
Category 4: failure may be imminent

4. Mitigation Actions

Cracking revealed by excavation will normally be ground or buffed out in accordance with established procedures, although, in some instances, shallow Category Zero cracking may be recoated and returned to service without grinding/buffing.

The metal-loss defect resulting from grinding/buffing will typically be assessed using B31G, RSTRENG6 or equivalent and repaired in accordance with standard procedures for metal-loss defects (including reinforcement sleeve repair if necessary). For deeper and more extensive areas of cracking, the option to replace a length of pipe will probably be considered.

Ongoing mitigating actions concerning the full length of the pipeline segment should constitute a measured response to the severity of the crack discovered, reflecting the Predicted Failure Pressure and the estimated life at the operating pressure. For example, Category Zero cracks may warrant no more than ongoing SCC Condition Monitoring and reassessment after a period of 7 years (the maximum currently permitted by U.S. regulations).

Category 1 cracks may benefit from an occasional exploratory excavation, or information from "opportunistic" excavations conducted for other operational reasons, in addition to Condition Monitoring.

Category 2 cracks may require more extensive investigation using SCC DA or ILI, and reassessment after an interval of around 3 years.

Category 3 cracks may be best addressed by hydrostatic testing or immediate ILI rather than SCC DA, which could become very extensive. It is probably also prudent to reduce the operating pressure until hydrostatic testing or ILI has been completed. Defect-specific engineering critical assessments would be beneficial in determining the appropriate pressure reduction and immediacy of response. Discrete mitigation of any other Category 3 cracking found will probably also be necessary.

Category 4 cracks would necessitate an immediate pressure reduction, and urgent hydrostatic testing or ILI, followed by appropriate discrete or general mitigation of any other Category 3-4 cracking found. Again, defect-specific engineering critical assessments would be beneficial in determining the appropriate pressure reduction and immediacy of response.

Deep Cracks will require immediate engineering critical assessment to determine the appropriate pressure reduction and immediacy of response. Deep Cracks will most probably require cut-out of the affected region (hot tap or full ring), although grinding followed by sleeve reinforcement may be possible in some circumstances.

The defect severity categories and corresponding mitigating actions are summarized in Table 40.

Table 40 - Summary of Crack Severity Categories and Mitigation

	Category Zero: shallow cracks	Category Zero: short cracks	Category 1	Category 2	Category 3	Category 4	Deep cracks
Description	Depth less than 10% of wall thickness. Est. life* at MAOP >15-25 yrs	Length less than around 2 inches (critical length). Est. life* at MAOP >15 yrs	PFP>110% SMYS. Will not fail hydrotest. Est. life* at MAOP >10 yrs	PFP>125% MAOP. Est. life* at MAOP >5 yrs	PFP>110% MAOP. Est. life* at MAOP >2 yrs	PFP<110% MAOP Failure imminent	Depth exceeds 30% wall thickness
Mitigation of discovered defects	Remove by grinding or buffing (optional). Recoat and reinstate	Remove by grinding, confirm by MPI. Assess using RSTRENG or equiv. Recoat and reinstate	Remove by grinding, confirm by MPI. Assess using RSTRENG or equiv. Recoat and reinstate	Remove by grinding, confirm by MPI. Assess using RSTRENG or equiv. Recoat and reinstate	Consider engineering critical assessment to determine options. Consider reducing pressure to 80% of recent highest operating pressure. Cut out or remove by grinding, confirm by MPI, assess using RSTRENG or equiv. Recoat and reinstate (at reduced pressure)	Reduce pressure to 80% of recent highest operating pressure. Considering engineering critical assessment to determine options. Cut out, or remove by grinding, confirm by MPI, assess using RSTRENG, or equiv. Recoat and reinstate at reduced pressure	Undertake engineering critical assessment to determine urgency of response and repair options. Cut out, or remove by grinding, confirm by MPI, assess using RSTRENG or equiv. Treat as Category 3 or 4
Ongoing mitigation and reassessment of segment/HCA	SCC Condition Monitoring until next Re-assessment	SCC Condition Monitoring until next Re-assessment	SCC Condition Monitoring until next Re-assessment. Consider additional excavations	Consider SCC DA or ILI. Bring forward next Re-assessment to 3 yrs	Consider hydrotesting, ILI, follow-up discrete mitigation (Meanwhile, consider operating at reduced pressure)	Urgent hydrotest, ILI, consider general mitigation. Operate at reduced pressure	Treat as Category 3 or 4

* Lives are estimated for a 30 inch diameter, 0.375 inch wall thickness pipe at 72% SMYS, using an SCC growth rate of 0.012 inch/year. Lives are increased or reduced in inverse proportion to SCC growth rate, and in proportion to wall thickness

5. Comments

The above approach is illustrative, and its application will require calculations specific to each pipeline segment. Detailed discussions of many of the issues related to calculating predicted failure pressures to establish crack severity categories and calculating estimated times to failure to establish schedules for mitigative actions are contained in other appendices.

With respect to calculating predicted failure pressures, it has been shown that PAFFC, CorLAS and SURFFLAW (NG-18) all give somewhat different predictions of SCC failure pressures, NG-18 being the most conservative, especially as defect depth reduces below 50%. The CEPA/NACE interaction criteria can be used when calculating the failure pressure of closely spaced cracks. The CEPA/NACE interaction criteria accommodate the effects of interactions for adjacent cracks around 50% deep, but the API 579 interaction criteria could be used to give an extra margin of safety for shallower cracks with higher failure pressures. The implications of time-dependent coalescence of adjacent cracks within colonies also can be addressed using the CEPA/NACE interaction criteria. There is no need to make provision for fatigue crack extension from shallow SCC that remains in re-coated gas pipelines, unless a specific fatigue issue has been identified for the pipeline in question.

Clearly, the exact numbers for response times will be inversely proportional to the crack growth rate and will depend upon many other factors including pipe grade, actual yield strength, diameter, wall thickness, toughness, operating pressure and the specific fracture-mechanics approach to calculate critical crack sizes at various pressures.

A sensitivity study described in another appendix showed that the expected failure times for Category 1 and Category 2 flaws are remarkably insensitive to pipe geometry and steel properties. However, the following factors tend to decrease the times slightly:

- Higher actual strength within grade
- Higher toughness
- Smaller diameter pipe (with lighter wall thickness)

The following factors tend to increase the expected failure times:

- Lower toughness
- Heavier wall thickness
- Larger diameter (with heavier wall thickness)
- Higher operating pressure

Overall, it appears that, for most cases, ten years seems appropriate for Category 1, five years for Category 2, and two years for Category 3.

When predicting remaining lifetimes for each severity category, the results from SURFFLAW and CorLas were generally good agreement. However, the results from SURFFLAW and PAFFC were considerably different, the predictions from PAFFC typically being on the order of half of those from SURFFLAW. The reason for the discrepancy is that PAFFC is less conservative in predicting failure pressures for a given flaw. That is, PAFFC will predict a higher failure pressure for a given flaw than will SURFFLAW or CorLas. That means that, according to PAFFC, a larger flaw will survive a given pressure, such as 110% SMYS or 125% MAOP. Since the severity categories have been defined in terms of failure pressure, a Category 1 crack according to PAFFC will be much larger than a Category 1 crack according to SURFFLAW or CorLas. At the same growth rate, a larger crack would reach critical size before a smaller one would. It is important to note that, for most cracks of equal size (but different predicted failure pressures), PAFFC and SURFFLAW predict virtually identical failure times. On average, for a given defect size, PAFFC predicts slightly longer failure times but places the cracks in a severity category 1 less than that from SURFFLAW. Therefore, if

PAFFC is used, the severity categories should be increased by 1 or the failure times should be divided by 2 to fit the pattern in Section 3.1 and 3.3.

The operator will also need to adopt a severity categorization scheme that is consistent with other operational and regulatory requirements, and may choose to adjust the category-defining pressures accordingly. For example, in some circumstances 100% SMYS or 100% MAOP may provide better alignment with other operational requirements or may enable useful sub-divisions of particular severity categories. If this is done, then it is essential to revise the definitions of severity category and their estimated failure lives, and the type and timeliness of response.

Notwithstanding these issues, however, the crack severity categorization scheme outlined above provides a valuable basis for determining a safe, measured and proportionate response in the event that SCC is discovered.

Each severity category encompasses a wide range of defects and estimated failure lives. If Category 3 or Category 4 cracks are found, it is often valuable to conduct a specific engineering assessment to determine criticality more accurately and clarify the best course of timely action. The extent to which this course of action is useful will depend on the number and density of such defects, compared to the option of immediate general mitigation (including pipe replacement).

The severity categories and responses outlined above are applicable to SCC found in the pipe body regions. If the SCC is associated with other features such as welds or external attachments, or has occurred in a region of mechanical damage, then the severity categories are not applicable and a defect-specific engineering critical assessment or discrete mitigation will be required. For similar reasons, if the SCC is localized or associated with other features such as welds or attachments, then ILI is unlikely to be as useful for monitoring and assessing cracking as other approaches.

The implications of the severity categories are dependent upon the context within which they are being applied. For example, if they are being applied in conjunction with an excavation or SCC DA program, then it is necessary to consider the implications of any findings for the adjacent unexposed pipe, and also when establishing a safe interval before re-examination. These issues depend upon the extent and severity of cracking found and on the number of excavations undertaken; they are discussed in depth in the JIP Documents on “How many digs should be conducted” and “What are the appropriate re-test intervals.” If they are applied in conjunction with an ILI program, then it is necessary to consider the depth measurement accuracy and the reliability (probability of a missed call) of the ILI findings; these issues have not yet been addressed.

Information from excavation programs [7] indicates that the ratio of Noteworthy to Category Zero cracks is often in the region of 1:10. Hence the numbers of Category Zero cracks found during excavation provide a valuable guide to the likelihood of more severe cracking being present in a segment, especially in situations where only a small proportion of the total segment length is excavated. However, reliable information concerning the extent of cracking is only possible if cracks and colonies are correctly diagnosed and their numbers are recorded in a consistent manner.

This becomes a concern for very small crack-like indications, of which there may be a large number. Very small crack-like indications may be approaching the threshold of detection, depending on the technique used and the skill of the operator. Also, if they are found, small stress-corrosion cracks may be very difficult to distinguish from other surface blemishes that give rise to crack-like indications; again, this is operator-dependent. For these reasons, it is suggested that very small crack-like indications should be disregarded during SCC DA (they are already below the detection threshold for ILI), unless they form part of a larger colony. This will avoid the time and effort spent collecting information that is of doubtful reliability and could even be misleading.

While the discovery and recording of Category Zero cracks is clearly of great benefit to operators for monitoring the “SCC health” of a pipeline, they do not constitute a concern for pipeline safety and hence it should not be necessary for such cracks to be included in the regulatory reporting process. It is suggested that only Noteworthy cracks should be included in the regulatory process (along with in-service failures and hydrostatic test failures); this level of reporting is consistent with the principles of ASME B31.8S and CFR 192.

6. REFERENCES

[1] "SCC Recommended Practices," Canadian Energy Pipeline Association (CEPA), 1997.

[2] Standard Recommended Practice, Stress Corrosion Cracking (SCC) Direct Assessment Methodology, NACE Standard RP0204-2004 Item No. 21104, 2004.

[3] B. N. Leis and N. D. Ghadiali, "Pipeline Axial Flaw Failure Criteria – PAFFC," PRCI Report L51720, May 1994.

[4] C. E. Jaske, J. A. Beavers and B. A. Harle, "Effect of stress corrosion cracking on integrity and remaining life of natural gas pipelines," paper 255 presented at NACE Corrosion 96, March 1996.

[5] J. F. Kiefner, W. A. Maxey, R. J. Eiber and A. R. Duffy, "Failure stress levels of flaws in pressurized cylinders," Progress in Flaw Growth and Fracture Toughness Testing, ASTM STP 536, pp 461-481, 1973.

[6] J. F. Kiefner and P. H. Vieth, "A modified criterion for evaluating the remaining strength of corroded pipe," PRCI Report L51609, December 1989.

[7] See Appendix A

APPENDIX I - ISSUES RELATED TO PREDICTING FAILURE PRESSURE

Issues Related To Predicting Failure Pressure – Supplement To Question 6 on Defining Crack Severity and Determining Appropriate Remedial Actions

1. Background

The JIP approach to assessing crack severity is based on predictions of the failure pressure of cracked pipe and its remaining life at the operating pressure. Severity categories for Noteworthy cracks are linked to failure pressures ranging from 110% SMYS to 110% MAOP. Cracks less than 10% deep, and cracks so short that, even if they were 50% deep, they would not fail a hydrostatic test at 110% SMYS, are not considered to be Noteworthy. Finally, any cracks exceeding 30% deep, regardless of length, are also categorized as Noteworthy.

The underlying basis for these categories and the responses made when such cracks are discovered are dependent upon an understanding of the nature, time-dependence and failure behavior of SCC. This note summarizes some of the background understanding relating to three main issues:

- How to account for time-dependent crack coalescence during intervals between re-inspection
- How to account for the interactions between adjacent cracks when predicting the failure pressure
- How to select the most appropriate method for calculating failure pressure.

2. Crack Coalescence, Clusters and Colonies

Considerable effort over many years has been directed toward understanding the nature of crack development and coalescence. Much of this has been undertaken for PRCI by Leis and co-workers [1]-[8]. Figure 16 and Figure 17 illustrate the range of aspect ratios found in field studies and testing, both for small cracks and for those associated with hydrostatic test or in-service failure. This information shows that, while cracks initially form with aspect ratios (length: depth) as low as 2:1, they tend to grow and coalesce in the axial direction such that, by the time they are 5-10% deep, the aspect ratios may be 5:1 or more. These observations are similar for both high pH and near-neutral pH SCC.

Information obtained by the JIP participants confirms this general picture concerning the depths and lengths of cracks large enough to be discovered during excavations and ILI. The aspect ratios range from a minimum of around 5:1 to 100:1 or more, and they can be even greater if the cracks are adjacent to seam weld toes. Again, the observations are similar for both high pH and near-neutral pH SCC.

For typical pipe grades and geometries, the threshold conditions for Noteworthy cracks equate to a minimum aspect ratio of around 8:1. Hence the observations above confirm that, for both high pH and near-neutral pH SCC, cracks with aspect ratios less than 5:1 do not need to be considered further in the analysis and interpretation of crack severity categories.

Leis and co-workers have also reviewed field studies of crack colonies and clusters, both for high pH and near-neutral pH SCC. They identified a distinction between "dense" and "sparse" colonies, depending on whether the circumferential spacing of cracks was greater or less than 20% of the wall thickness. In dense colonies the cracking tended to develop axially but not radially (depth), such that many colonies appeared to become dormant when crack depths reached around 10% deep. However, in sparse colonies the individual cracks appeared to continue growing both axially (length) and radially (depth).

Leis and co-workers have attempted to develop models [1]- [8] addressing both axial crack coalescence and dormancy in dense colonies, taking into account the competing effects of crack tip stress field enhancement and compliance reduction due to closely-spaced adjacent cracks. The coalescence and dormancy effects are a complex function of the crack sizes and configurations, the applied stress and the material properties.

These models and the field observations were taken into account by CEPA [9] when they developed criteria for incorporating the effect of axial coalescence:

- If the circumferential separation of two adjacent cracks is less than 14% of their average length and the axial separation is less than 25% of their average length, then they should be considered as a single crack with length equal to the total cumulative length.

These criteria were incorporated into the CEPA guidance [9] and have subsequently been adopted by NACE [10].

3. Crack Growth due to Fatigue

Time-dependent growth can also occur due to fatigue, both in the presence of the environment and in its absence (i.e., after remediation and recoating).

The overlapping regimes of SCC and corrosion fatigue have been explored by Beavers, Fessler and others [11]-[13]. Regions of time-dependent growth, cycle-dependent growth and dormancy have been identified, and growth rates have been compared with field experience. In general, it seems that a field-derived average growth rate, taking into account the specific pipeline conditions, is the best way to address the impact of crack growth during intervals between re-inspections, irrespective of whether the growth is primarily due to static or cyclic loading.

If a pipeline is recoated and re-commissioned without removing shallow SCC, the cracks might still grow due to fatigue. Previous analysis [14] has indicated that the extent of fatigue crack extension from seam weld defects due to pressure cycling is insignificant for most gas pipeline operating conditions and can be neglected. This conclusion has recently been substantiated both analytically and experimentally for SCC growth during intervals between re-inspection [15].

4. Effect of Adjacent Cracks on Predicted Failure Pressure

The fitness-for-purpose code API 579 [16] includes a series of interaction rules for assessing coplanar and non-coplanar cracks, as shown in Figure 18. These rules were developed for all types of cracks, not just SCC, and indicate that two adjacent cracks should be treated as interacting if the axial and circumferential separation distances are less than 100% of the average crack length. Other codes such as BS 7910 [17] are less explicit in their treatment of interacting defects.

Kariyawasam, et. al. [18] have recently published a detailed study of the applicability of the API 579 and BS 7910 assessment codes and the different interaction rules to clusters of SCC. For the samples tested, predictions based on the single deepest defect in the interacting group gave the lowest errors, but not always conservatively. Predictions based on the CEPA interaction rules gave the most accurate, consistently conservative predictions; those obtained using API 579 were around 10-20% higher. In general, the results were not unduly sensitive to the crack length or to the assessment method used, but were dominated by the depth of the deepest individual crack in the interacting group.

On the basis of these results and observations, it appears that application of the API 579 interaction rules may introduce an unnecessary level of conservatism into predictions of failure pressures, and that the CEPA interaction rules are sufficient to accommodate both time-dependent coalescence and interaction effects as the failure pressure is approached. However, it should be noted that the experimental work has been on crack colonies around 50% deep; for shallower crack colonies with higher failure pressures it may become necessary to use the API 579 interaction rules to avoid non-conservative predictions.

5. Methods for Predicting Failure Pressures

Calculations and predictions of the failure pressures of axial cracks have historically used the log-secant method (NG-18), PAFFC or CorLAS [19]-[21], with occasional use of API 579 or BS 7910 [16], [17].

During the course of the Canadian NEB Inquiry [22] a comparative study of the applicability of NG-18, PAFFC and CorLAS to SCC was undertaken. Figure 19 shows that, for the range of samples tested, CorLAS and PAFFC gave better predictions than NG-18. Figure 20 shows that PAFFC gives reasonable predictions for a wide range of SCC test results, while the work by Kariyawasam, et. al. [18] shows reasonably similar predictions using CorLAS, API 579 and BS 7910, albeit for very few tests.

These test results have all been obtained for cracks and colonies around 50-70% deep. Figure 21 shows that, as the defect depth reduces, the NG-18 and PAFFC predictions deviate significantly; for example, NG-18 predicts that cracks 10% deep and over around 10 inches long will fail at 110% SMYS, whereas PAFFC predicts that infinitely long 10% deep cracks will not fail at this stress. Unfortunately, there are no test results to compare with the predictions; however, it is noteworthy that no 10% deep defects, however long, have ever caused a service pipeline to fail a hydrostatic test.

Predictions of failure pressure are also subject to any inaccuracies and assumptions made about the crack lengths and depths, and about the pipe material properties. These uncertainties must be incorporated in the overall calculations in a satisfactorily conservative manner.

6. Implications for Defect Severity Categorization

The experimental and analytical work summarized above has been used to form the basis for categorizing defect severity. In particular, it has led to the following judgments:

- The implications of time-dependent coalescence of adjacent cracks within colonies are addressed using the CEPA/NECA interaction criteria.
- The effect of cyclic loading on SCC development is best addressed by using pipeline-specific crack growth rate data to determine the remaining life at operating pressure.
- The threshold of 10% depth, below which cracking is not considered to be Noteworthy, is justified by analyses and field observations.
- The referral of all cracks exceeding 30% depth for cut-out or (possibly) sleeve repair is justifiable and is consistent with other operational practice (grinding limits, etc).
- Noteworthy cracks have aspect ratios (axial length: depth) of 5:1 or greater for both high pH and near-neutral pH SCC.
- There is no need to make provision for fatigue crack extension from shallow SCC that remains in recoated pipe unless a specific fatigue issue has been identified for the pipeline in question.
- The CEPA/NACE interaction criteria can be used when calculating the failure pressure of closely spaced cracks. The CEPA/NACE interaction criteria accommodate the effects of interactions for adjacent cracks around 50% deep, but the API 579 interaction criteria could be used to give an extra margin of safety for shallower cracks with higher failure pressures.
- PAFFC and CorLAS give good predictions of SCC failure pressures and are the preferred methods for categorizing defect severity. NG-18 is satisfactory for deeper defects but appears to become significantly conservative as defect depth reduces below 50%.

7. REFERENCES[13]

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[5] B. N. Leis and R. E. Kurth, "Hydrotest parameters to control high pH SCC on gas transmission pipelines," PRCI Project PR-3-9404 (Catalog No. L51865), September 1999.

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13 Some PRCI Reports may not be available to non-members.

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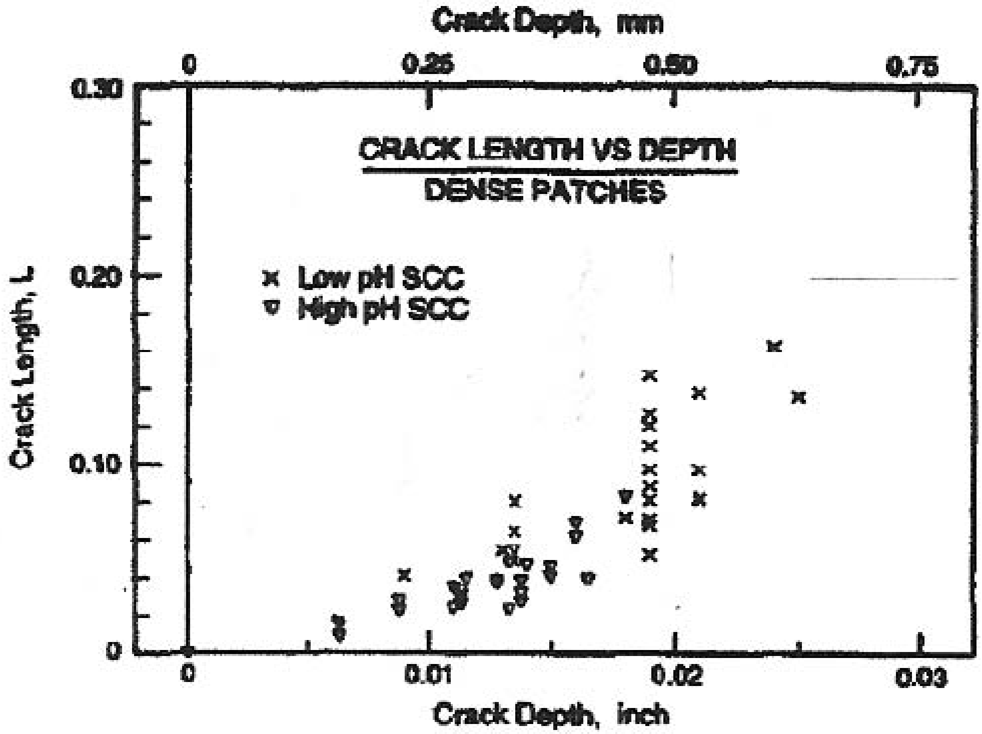


Figure 16 - Aspect Ratios of Small, Shallow Cracks [2]

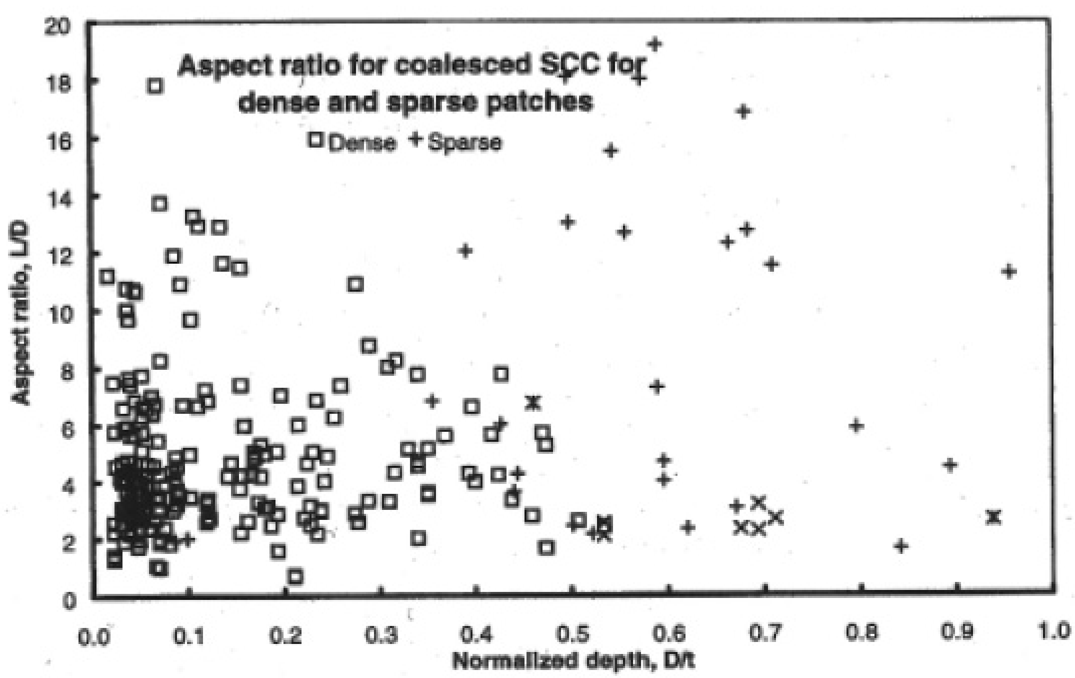


Figure 17 - Aspect Ratios of Coalesced Cracks Adjacent to In-Service and Hydrotest Failures [4]

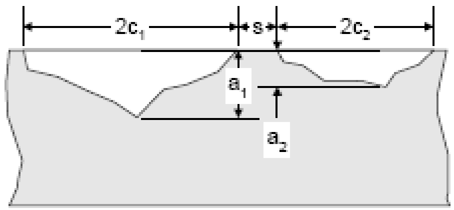
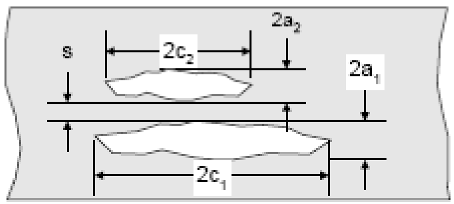
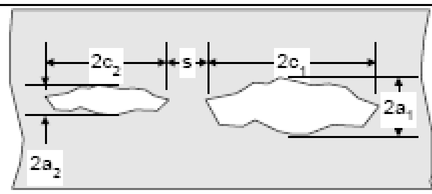
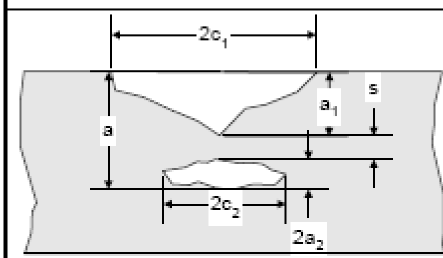
Multiple Crack-Like Flaw Configuration	Criterion For Interaction	Effective Dimensions After Interaction
	$c_1 + c_2 \geq s$	$2c = 2c_1 + 2c_2 + s$ $a = \max\left[a_1,\ a_2\right]$
	$a_1 + a_2 \geq s$	$2a = 2a_1 + 2a_2 + s$ $2c = \max\left[2c_1,\ 2c_2\right]$
	$c_1 + c_2 \geq s$	$2c = 2c_1 + 2c_2 + s$ $2a = \max\left[2a_1,\ 2a_2\right]$
	$a_1 + a_2 \geq s$	$a = a_1 + 2a_2 + s$ $2c = \max\left[2c_1,\ 2c_2\right]$

Figure 18 - API 579/ASME FFS-1 Guidance for Assessing the Interaction of Coplanar and Non-Coplanar Cracks [16]

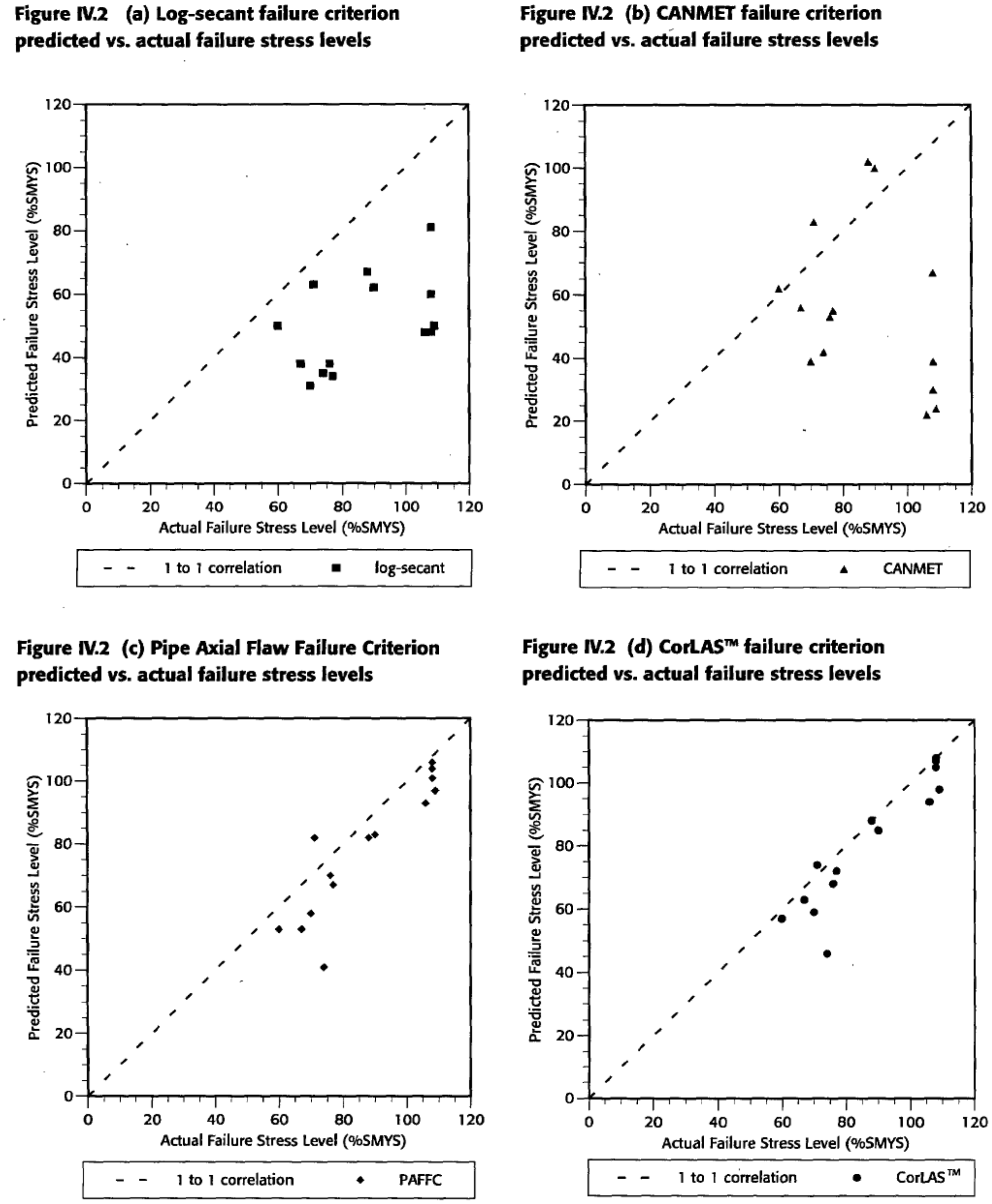


Figure 19 - Comparisons of Predicted and Actual Failure Pressures for SCC-Containing Pipes using Different Prediction Methods [22]

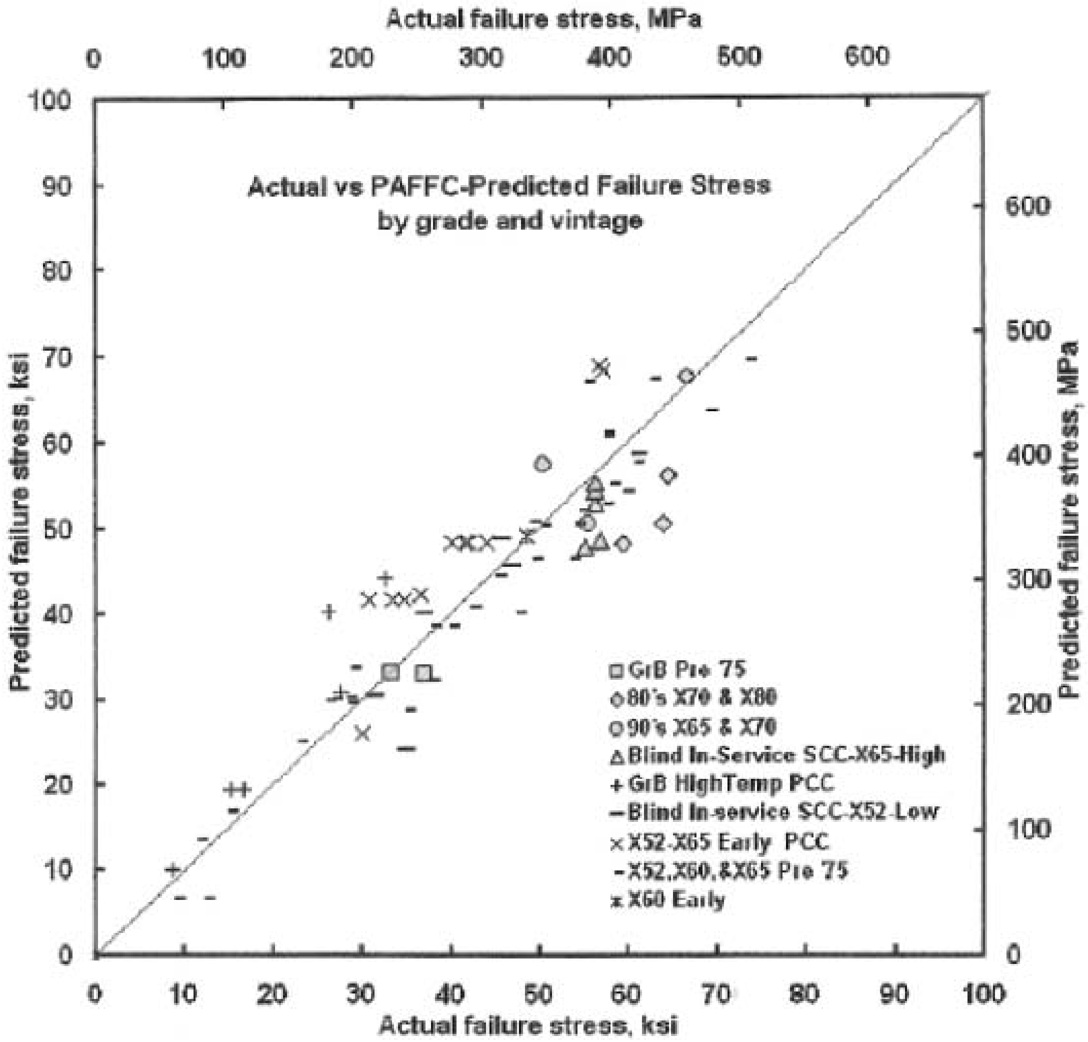
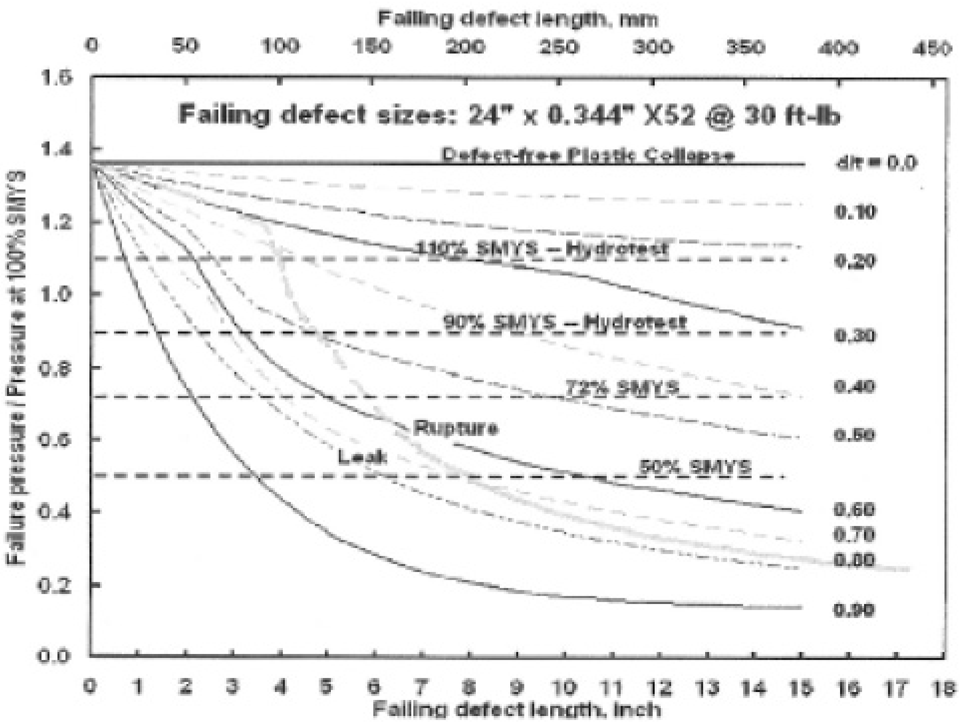
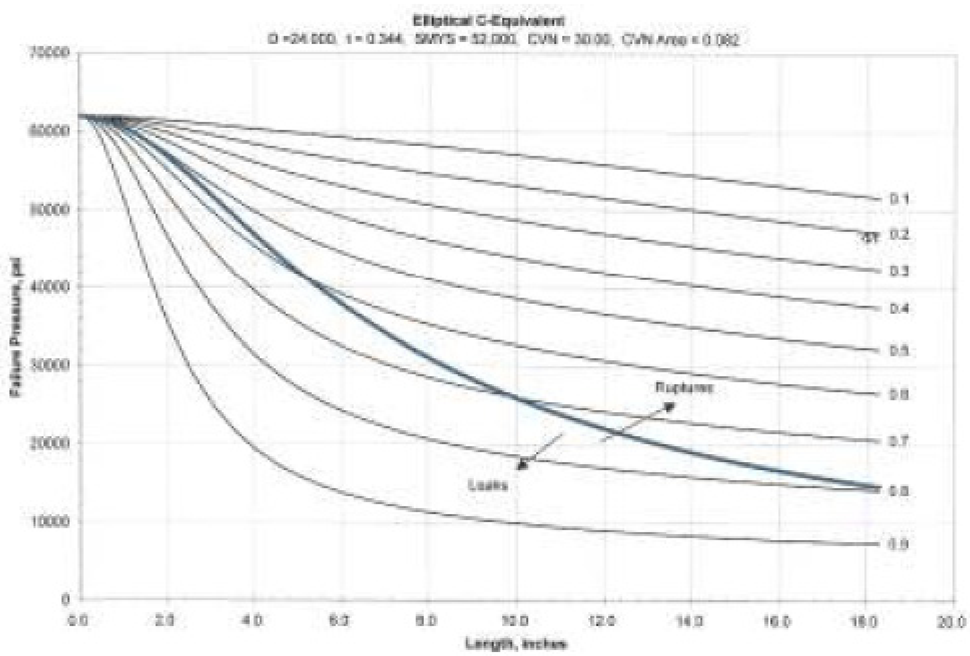


Figure 20 - PAFFC Full-Scale Validation Data for SCC [6]



(a) Failure Predictions using PAFFC



(b) Failure Predictions using NG-18 (SURFFLAW)

Figure 21 - Comparisons of Failure Predictions using PAFFC and NG-18, for a 24 in. x 0.344 in. x X52 Pipe with 30 ft.-lb. Toughness

APPENDIX J - ISSUES RELATED TO ESTIMATING REMAINING LIFE

Issues Related to Predicting Remaining Life – Supplement to Question 6 on Defining Crack Severity and Determining Appropriate Remedial Actions

The response to Question 6 defined severity categories for stress-corrosion cracks and indicated appropriate responses to the discovery of cracks in each category. The responses were described both in terms of their nature and their timing. This paper discusses various factors that can influence those times.

One of the most important factors is the crack growth rate. The appropriate response time simply is inversely proportional to the growth rate. In the answer to Question 6, a crack growth rate of 0.012 inch per year was assumed as a reasonable estimate based upon general industry experience. If an operator has a reason to assume a different rate, the response time should be adjusted accordingly.

The response times also will depend upon many other factors including pipe grade, actual yield strength, diameter, wall thickness, toughness, operating pressure and the specific fracture-mechanics approach to calculate critical crack sizes at various pressures.

1. Sensitivity of Lifetime Predictions to Method of Calculation

A sensitivity study was initiated using the log-secant method (SURFFLAW), CorLas and PAFFC to determine how important those factors are. The eleven cases described in Table 41 were examined initially for Category 1 (depth greater than 10% wall thickness and failure pressure above 110% SMYS) and Category 2 (depth greater than 10% wall thickness and failure pressure between 110% SMYS and 125% MAOP). Only depth-wise growth was considered. Also, only crack lengths that would lead to ruptures (not leaks) at MAOP and that were less than those that would push the severity category to the next level were considered. The growth rate for SCC was assumed to be 0.012 inch/year.

The deepest short crack and long crack for each category were used to represent the range of minimum times that would be predicted. The short crack length was taken as the length of the shortest crack that would fail by rupture (rather than leak) at MAOP. Those lengths differed somewhat for the different calculation methods. The lengths of the long cracks also differed for each method but usually were around 15 inches. Table 42 lists the results of the calculations.

The results from SURFFLAW and CorLas are compared in Figure 22, where it can be seen that there is generally good agreement between the two sets of predictions. Exact agreement would not be expected, partly because each method used slightly different lengths and depths for each comparable calculation.

Table 41 - Cases for Sensitivity Study

Case	MAOP, %SMYS	SMYS, ksi	Charpy Energy (.0824 sq. in.),ft-lb	Actual YS, Ksi	Actual UTS, Ksi	Diam., inches	W.T., inch	Comments
1	72	52	20	52	72	30	0.312	Baseline
2	72	52	20	**62**	**82**	30	0.312	High actual YS
3	72	52	**5**	52	72	30	0.312	Very low toughness
4	72	52	**80**	52	72	30	0.312	High toughness
5	72	52	20	52	72	30	**0.5**	Heavy wall
6	72	52	20	52	72	**48**	**0.5**	Large diameter
7	72	52	20	52	72	**24**	**0.25**	Smaller diameter
8	**80**	52	20	52	72	30	0.312	Higher MAOP
9	72	52	**10**	52	72	30	0.312	Low toughness
10	72	52	**160**	52	72	30	0.312	Very high toughness
11	72	**65**	**80**	**65**	**85**	30	0.312	Higher grade (X65)

Principal variables are highlighted in **bold**.

By contrast, Figure 23 shows that the results from SURFFLAW and PAFFC are considerably different, the predictions from PAFFC typically being on the order of half of those from SURFFLAW. The reason for the discrepancy is that PAFFC is less conservative in predicting failure pressures for a given flaw. That is, PAFFC will predict a higher failure pressure for a given flaw than will SURFFLAW or CorLas. That means that, according to PAFFC, a larger flaw will survive a given pressure, such as 110% SMYS or 125% MAOP. Since the severity categories have been defined in terms of failure pressure, a Category 1 crack according to PAFFC will be much larger than a Category 1 crack according to SURFFLAW or CorLas. At the same growth rate, a larger crack would reach critical size before a smaller one would.

It is important to note that, for most cracks of equal size (but different predicted failure pressures), PAFFC and SURFFLAW predict virtually identical failure times. This is illustrated in Figure 24, which compares predicted failure times for 6-inch, 10-inch and 14-inch-long cracks with depths between 10% and 50% of the wall thickness for 24- and 30-inch-diameter, X52 pipe with $^{2}/_{3}$-size Charpy toughness of 20 and 80 ft.-lb. However, there are some exceptions to this close agreement, particularly for very-low-toughness pipe and higher grades. For example, a comparison for X65 pipe is shown in Figure 24**.**

Table 42 - Predicted Failure Times for Category 1 and Category 2 Cracks, Using SURFFLAW, CorLas and PAFFC

Category 1: Predicted Failure Pressure Above 110% SMYS							
Case	Comments	Calculated Time to Failure, years					
		SURFFLAW		CorLas		PAFFC	
		Short Flaw	Long Flaw	Short Flaw	Long Flaw	Short Flaw	Long Flaw
1	Baseline	12.7	12.7	12.2	11.1	5.5	4.9
2	High actual YS	9.1	9.1	8.8	8.2	5.3	5.2
3	Very low toughness	13.3	13.3	11.9	9.6	4.9	3.4
4	High toughness	11.7	9.6	14.5	13	8.2	7.3
5	Heavy wall	21.3	21.3	20.5	17	10.6	9.2
6	Large diameter	21.7	21.7	22	17.7	9.4	8.8
7	Smaller diameter	9.6	9.6	9.9	9	5	3.8
8	Higher MAOP	10.7	10.4	10	9	4.4	3.6
9	Low toughness	15.6	12.7	10.9	9.8	5.7	4.2
10	Very high toughness	11.2	9.6	14.9	13	8.3	7.5
11	Higher grade (X65)	13	9.6	16	13.8	8.6	8.6
Category 2: Predicted Failure Pressure Above 125% MAOP							
Case	Comments	Calculated Time to Failure, years					
		SURFFLAW		CorLas		PAFFC	
		Short Flaw	Long Flaw	Short Flaw	Long Flaw	Short Flaw	Long Flaw
1	Baseline	4.9	6	5.2	4.7	2.3	2.6
2	High actual YS	3.6	5.7	3.8	3.9	3	3.1
3	Very low toughness	9.4	9.4	6.2	5.2	3	2.1
4	High toughness	4.9	4.4	5.3	5.7	3.3	3.4
5	Heavy wall	8.3	10.4	9.2	8.1	6.7	4.6
6	Large diameter	8.3	10.8	9.3	8.5	5.2	4.6
7	Smaller diameter	4	4.6	3.9	3.6	2.7	2.1
8	Higher MAOP	6.5	6.5	6.1	5.2	1.8	2.6
9	Low toughness	5.7	7.3	5.8	5	3.1	2.3
10	Very high toughness	4.7	4.4	5.8	5.7	3.3	3.6
11	Higher grade (X65)	6.2	7	5.8	5.9	4.2	4.2

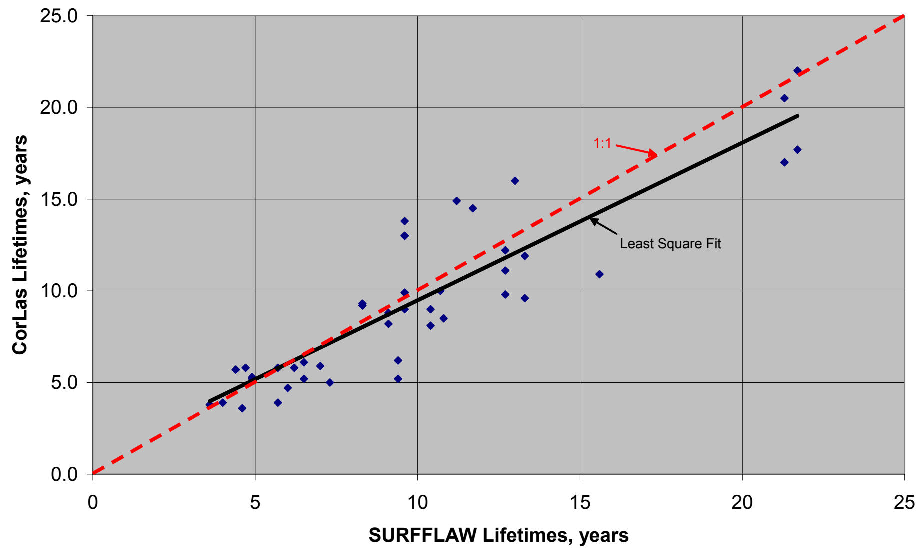


Figure 22 - Comparison of Predicted Lifetimes from CorLas and SURFFLAW for Category 1 and Category 2 Cracks

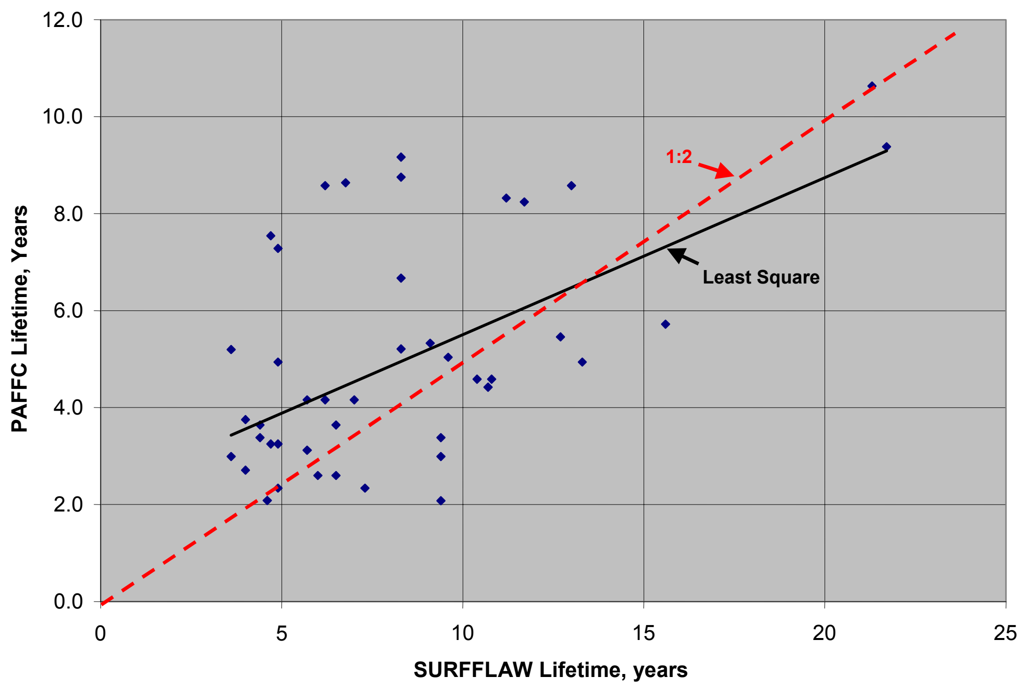


Figure 23 - Comparison of Predicted Lifetimes from PAFFC and SURFFLAW for Category 1 and Category 2 Cracks

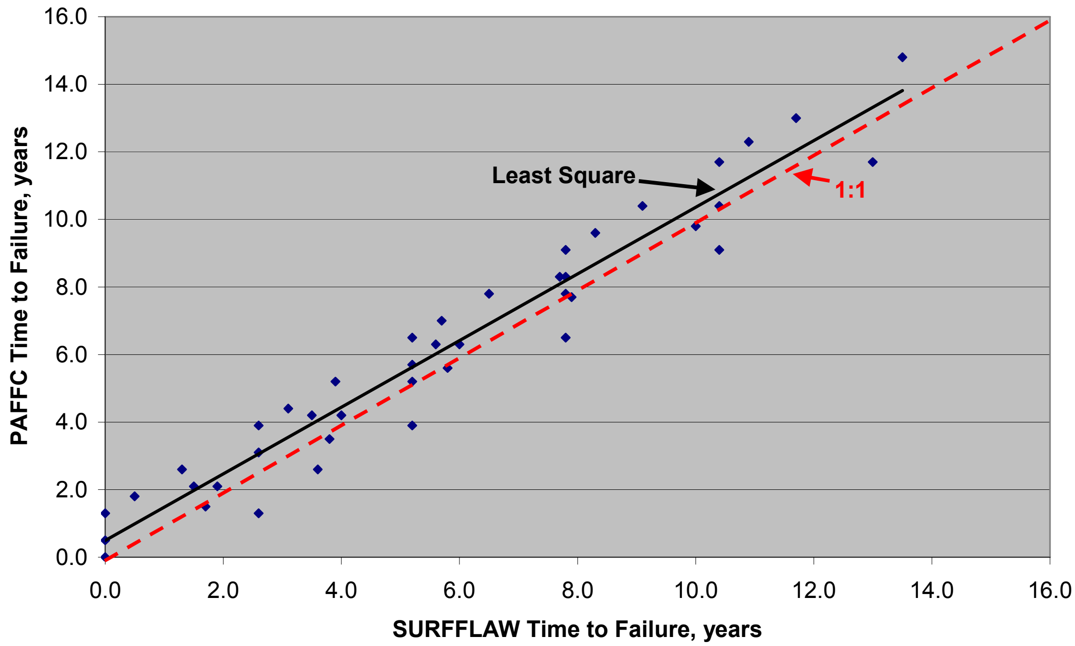


Figure 24 - Comparison of Predicted Failure Times for Various Size Cracks in X52 Pipe of Typical Toughness

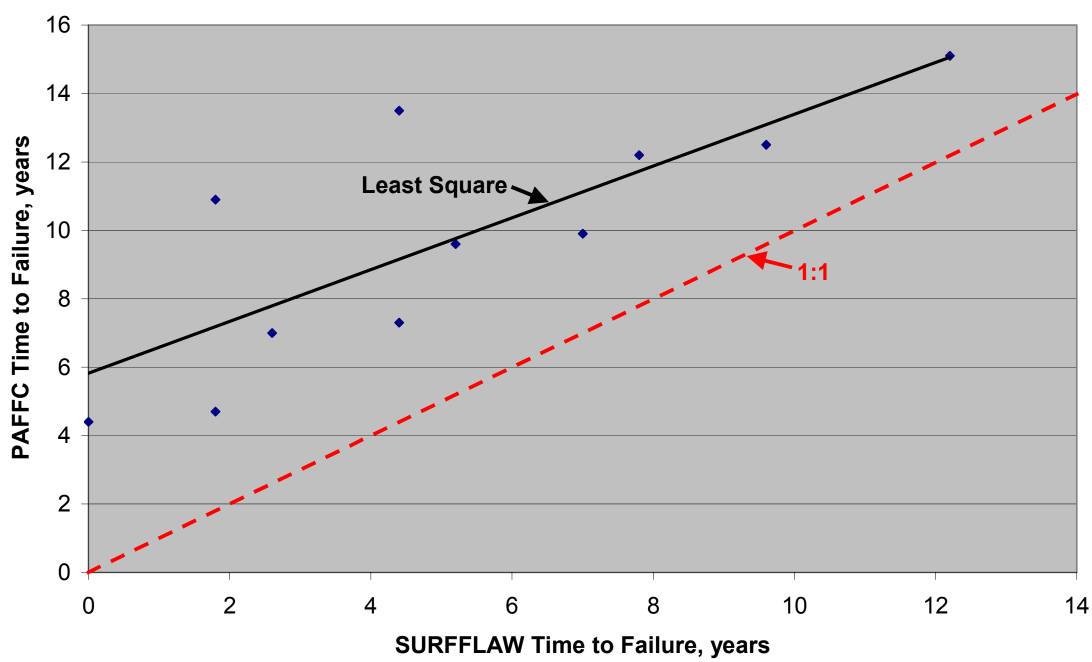


Figure 25 - Comparison of Predicted Failure Times for Various Size Cracks in X65 Pipe of Typical Toughness

To illustrate the comparison between PAFFC and SURFFLAW, consider a 10-inch-long crack that is 20% through the wall thickness in 24-inch-diameter, 0.25-inch wall thickness, X52 pipe.

SURFFLAW would predict a failure pressure of 96% SMYS (133% of an MAOP of 72% SMYS), which would make it a Category 2 crack (failure time > 5 years). PAFFC would predict a failure pressure of 118% SMYS, which would make it a Category 1 crack (failure time > 10 years). The actual predicted failure times would be 5.6 years from SURFFLAW and 6.3 years from PAFFC. Thus, SURFFLAW would be slightly conservative while PAFFC would be very non-conservative.

On average, for a given defect size, PAFFC predicts slightly longer failure times but places the cracks in a severity category 1 less than that from SURFFLAW. Therefore, if PAFFC is used, the severity categories should be increased by 1 or the failure times should be divided by 2 to fit the pattern in Section 3.1 and 3.3.

2. Sensitivity of Life Predictions to Input Variables

Baseline Condition

The baseline condition in Table 42 was a 30-inch-diameter, 0.312-inch-wall-thickness, X52 pipe with a toughness of 20 ft-lb, operating at 72% SMYS. The actual yield strength was assumed to be 52,000 psi and the flow stress 62,000 psi. As is shown in Table 42, under the baseline conditions, the expected remaining life for a Category 1 flaw would be about 13 years and for a Category 2 flaw about 5 to 6 years.

Higher Strength within Grade

A comparison shows that higher strength steels within a grade have a somewhat shorter expected life, especially for the shorter flaws.

Low Toughness

Surprisingly, the lower toughness pipes have longer expected lives. This is due to the fact that the sizes of the cracks that can survive a certain pressure are extremely small, so the amount of additional growth to cause failure at MAOP is still significant.

High Toughness

Conversely, for a similar reason, the higher-toughness pipes have a slightly shorter expected life. As is shown in Table 43, toughness values above 80 ft-lb do not have much additional effect.

Heavier Wall Thickness

Not surprisingly, the expected remaining life increases with increasing wall thickness.

Large-Diameter Pipe

The expected failure times for larger-diameter pipe (which would usually have heavier walls) are greater.

Smaller-Diameter Pipe

Because smaller-diameter pipe usually has a lighter wall thickness, the expected failure time is less.

Higher Operating Pressure

Table 43 shows that the expected failure times for Category 2 cracks are greater with higher operating pressures. This probably is due to the fact that the surviving flaws at the higher pressure are smaller, in similar fashion to the case for low-toughness pipe.

Higher Grade

Table 43 shows that higher grades also are expected to have longer failure times.

3. Predictions for Category 3 Cracks

Predictions for remaining lives of Category 3 cracks were made based upon the SURFFLAW method. As is shown in Table 43 below, 2 years appears to be a reasonable prediction for Category 3 cracks, based upon the assumptions previously used for Categories 1 and 2.

Table 43 - Life Predictions for Category 3 Cracks (Using SURFFLAW)

		Calculated time to failure, years	
Case	Comments	Short Flaw	Long Flaw
1	Baseline	2.1	2.6
2	High actual YS	1.8	2.1
3	Very low toughness	3.1	4.9
4	High toughness	2.1	1.8
5	Heavy wall	3.8	4.6
6	Large diameter	2.9	5
7	Smaller diameter	1.9	1.9
8	Higher MAOP	2.3	3.1
9	Low toughness	2.1	3.1
10	Very high toughness	2.1	1.6
11	Higher grade (X65)	2.3	3.1

4. Further Illustrations of Life-Prediction Sensitivities

The analyses above indicate that predicted lifetimes decreased slightly with higher toughness, higher actual strength within grade, and smaller-diameter pipe with lighter wall thickness. In order to illustrate the magnitude of those effects, additional calculations were performed using X52 pipe operating at 72% SMYS as an example. In the calculations to illustrate the effect of wall thickness, the diameter-to-thickness ratio was kept constant. The specific pipe sizes, in inches, were 18 x 0.188, 22 x 0.250, 30 x 0.312, 36 x 0.375 and 48 x 0.500.

Figure 25 illustrates the effect of wall thickness on projected lifetime for X52 pipe with an actual yield strength of 52,000 psi, an ultimate tensile strength of 72,000 psi and a Charpy toughness of 20 ft.-lb. Similar curves were determined for other combinations of actual yield strengths and toughness values.

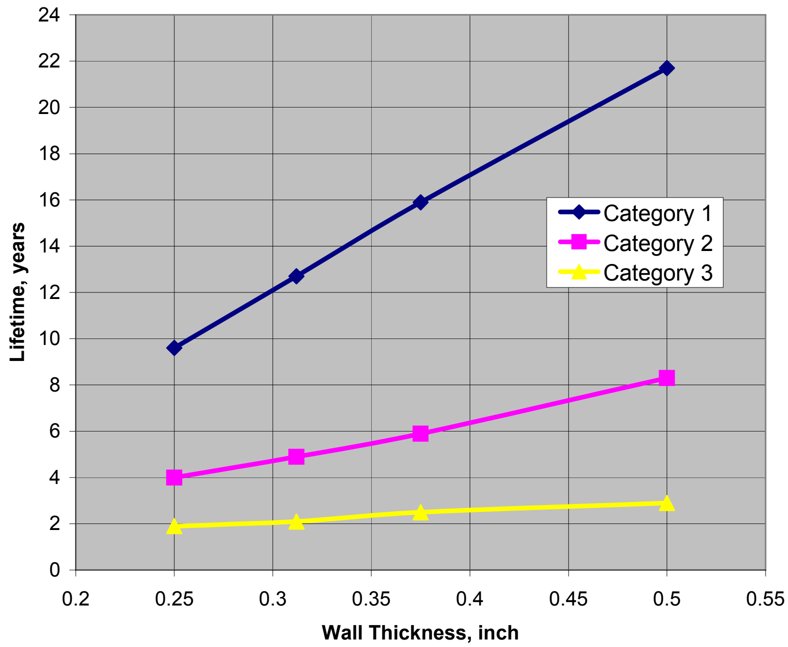


Figure 26 - Effect of Wall Thickness on Predicted Lifetimes for Surviving Cracks in X52 Pipe with a Charpy Toughness of 20 ft.-lb. Assuming a Crack Growth Rate of 0.012 inch per year

Figure 26 summarizes the results of those calculations by showing the minimum wall thickness that would satisfy the projected lifetimes of 10, 5 and 2 years for Category 1, 2 and 3 defect severities, respectively. There is a significant effect of toughness for Charpy values below about 30 ft.-lb. but almost no effect for values above 60 ft.-lb. Also, pipe with wall thickness greater than 0.325 inch would meet the projected lifetimes regardless of toughness.

Similar curves illustrating the effect of higher actual strength of X52 pipe are shown in Figure 27.

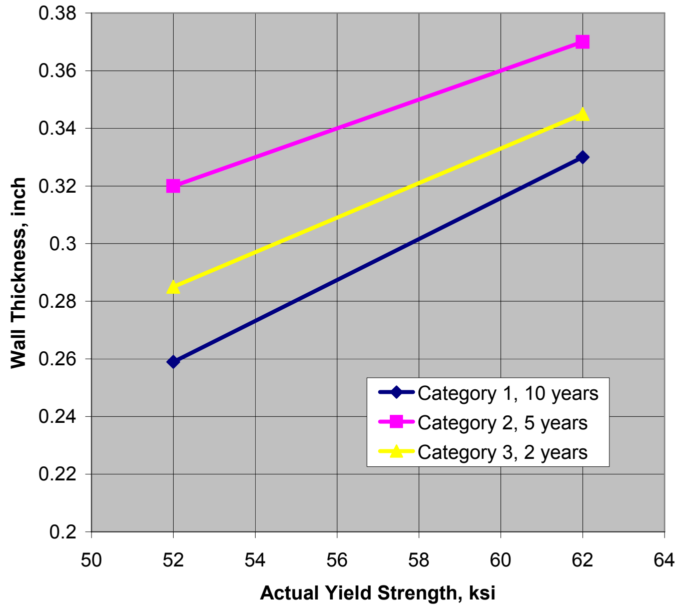


Figure 27 - Effect of Toughness on Minimum Wall Thickness Consistent with the Projected Lifetimes for X52 Pipe Assuming a Crack Growth Rate of 0.012 inch per year

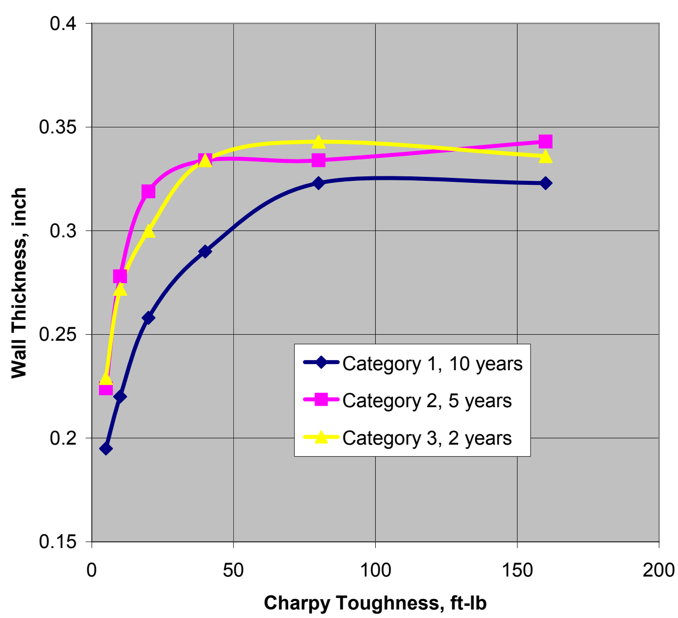


Figure 28 - Effect of Actual YS on Minimum Wall Thickness Consistent with the Projected Lifetimes for X52 Pipe Assuming a Crack Growth Rate of 0.012 inch per year

The 5-year projected lifetime for Category 2 cracks has more exceptions compared with the lifetimes for Categories 1 and 3. As is shown in Figure 28, reducing the projected lifetime from 5 years to 4 years would significantly reduce the minimum wall thickness that would be consistent with the projection, but this may not be necessary in practice.

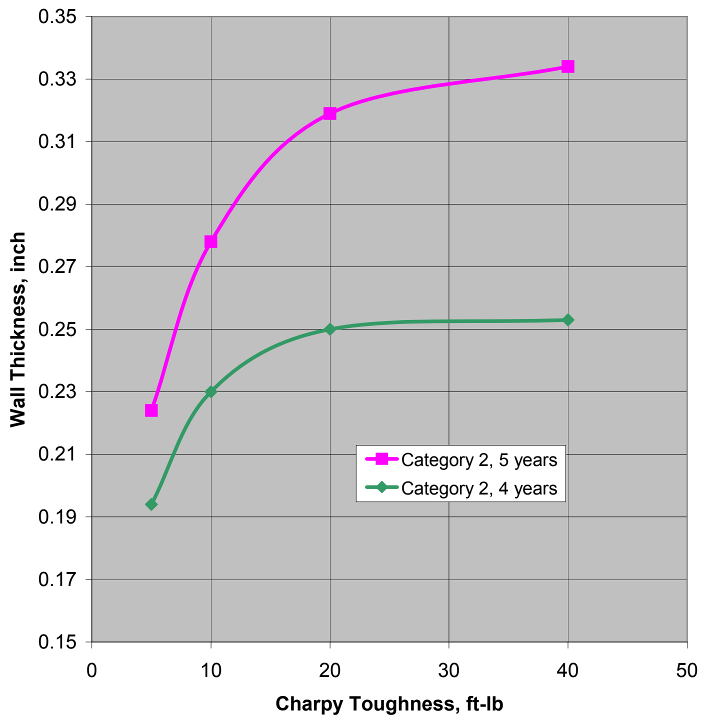


Figure 29 - Minimum Wall Thickness to Meet Two Projected Lifetimes for Category 2 Cracks

5. Summary of Predicted Failure Times

Overall, it appears that the expected failure times for Category 1 and Category 2 flaws are remarkably insensitive to pipe geometry and steel properties.

The following factors tend to decrease the times slightly:

- Higher actual strength within grade
- Higher toughness
- Smaller diameter pipe (with lighter wall thickness)

The following factors tend to increase the expected failure times:

- Lower toughness
- Heavier wall thickness
- Larger diameter (with heavier wall thickness)
- Higher operating pressure

For most cases, ten years seems appropriate for Category 1, five years for Category 2 and two years for Category 3.

Consideration of these estimates provides an initial indication of the urgency of response and a basis for determining what mitigation is appropriate. While the above guidelines are generally valid, individual companies may choose to do their own analysis and are encouraged to do so if they have specific data on crack growth rates or unusual circumstances such as very thin-wall pipe.

APPENDIX K - CONDITION MONITORING

Question 7. What additional preventative and mitigative measures are appropriate for SCC Condition Monitoring and how can they be used to enhance confidence in the management of SCC?

1. Summary

The aim of SCC Condition Monitoring is to identify any evidence that the SCC risk is changing over time. It is principally directed towards those segments that have been identified as SCC-susceptible but which, when examined, are found to contain little or no cracking. It is also applicable as a complementary tool for the management of segments that have more serious SCC and are subject to DA, ILI or hydrostatic test programs, especially during the intervals between assessments.

SCC Condition Monitoring is a structured process for collecting, regularly reviewing, interpreting and responding to all the SCC-relevant information obtained during ongoing operational and integrity management activities.

The main information sources for SCC Condition Monitoring are

- Site surveys and ILI results
- Excavations undertaken for reasons other than SCC
- Operational records
- Terrain, drainage and land usage reviews
- Other operator experience
- Research and development outcomes

The SCC Condition Monitoring process leads to an auditable overall procedure for recording and reporting the results and outcomes. The process either validates or drives changes to the operator's Integrity Management Plan and enhances confidence in the management of SCC threats. It is amenable to integration with modern computer-based information management systems.

It is recommended that SCC Condition Monitoring should be considered as an "Equivalent Technology" for those pipeline segments that require ongoing SCC threat management, but which on first assessment reveal little or no SCC, for as long as the risk of SCC is demonstrated not to increase.

2. Introduction

If SCC is discovered during pipeline operation or during an assessment of an SCC-susceptible segment or HCA, there are several courses of action depending on the severity of cracking; these include SCC DA, ILI, hydrostatic testing or, in the extreme, replacing the affected pipe section. However, if less severe cracking is found (e.g., defined as Category Zero or Category 1) or no cracking is discovered, it is appropriate to adopt other courses of action that are proportionate to the lesser severity. These courses of action are termed "SCC Condition Monitoring."

The SCC Condition Monitoring process collects all the ongoing integrity management activities from which information relevant to the occurrence or development of SCC can be obtained. In many instances, the information will have been gathered for other operational or integrity management reasons; nevertheless, it is also relevant to SCC and needs to be reviewed in this context. The purpose of collecting and regularly reviewing this information is to identify any evidence that the SCC risk is changing. The regular reviews also provide the basis for updating and refining the segment prioritization and excavation site-selection protocols, as well as triggering any other preventative or mitigative actions should the need arise.

While SCC Condition Monitoring is applicable as a stand-alone process for managing low-level threats of SCC, it is also a valuable complementary process for monitoring segments that contain more severe SCC and are subject to targeted excavations, ILI or hydrostatic testing. SCC Condition Monitoring provides the mechanism for continuous surveillance, learning and improvement as part of the overall SCC management program, especially during the intervals between assessments.

SCC Condition Monitoring is also applicable to segments for which there may be no formal requirement to address the threat of SCC, and for building confidence in the accuracy of segment prioritization and excavation site-selection models.

The following sections describe the information sources, data collation, interpretation and responses that form the structured SCC Condition Monitoring process.

3. Sources and Types of Information

SCC Condition Monitoring captures any evidence that the SCC risk is changing, either for the whole segment or for local regions within the segment. Much of the information is the same as that identified in the NACE [1] and CEPA [2] guidance on SCC management, and is described in more detail in the accompanying JIP reports on Segment Prioritization and Excavation Site Selection.

Information relevant to the identification of changes in SCC risk can be grouped into four main categories; these are summarized in Table 44 and described below.

Table 44 - Information Sources and their Relevance to Changes in SCC Risk

Information source	SCC relevance
Site-derived information	
CIS, DCVG surveys	Coating condition, disbondment, holidays
CP system monitoring	CP system effectiveness
Metal-loss ILI	Shallow corrosion, coating condition
Opportunistic excavations	Coating condition, corrosion activity
	Soil texture resistivity, moisture content
	Groundwater chemistry, pH
Geometry ILI	Mechanical damage, residual stress, stress concentrations
Leakage surveys and excavations	Evidence of SCC activity: confirmation of segment prioritization and site selection models
Operational information	
Pressure loading, pressure cycling	Stress, stress fluctuations
Discharge temperature	Coating degradation
Modifications and attachments	Local CP shielding, secondary loading
Repairs and recoating	Weak interface between original and new coatings; different types/ages
Age	Time-dependent coating degradation
In-service or hydrotest failure nearby	SCC problem clustering
Geophysical information	
Ground movement, settlement	Secondary (axial, bending) loading
Water table, drainage	Soil water content
	Groundwater chemistry, pH
Changed land use, encroachment	Mechanical damage
New road, rail and cable crossings	Secondary loading, mechanical damage, electrical interference
Intelligence-gathering, literature surveillance	
Other operator problems and responses	
New research information/results	Change in relative importance of individual risk factors
Information from own-company pipelines	

Site-derived information such as would be obtained from close-interval or DCVG surveys completed in the course of coating integrity, CP monitoring or corrosion surveys provide valuable information on coating condition and the effectiveness of CP in preventing local areas of corrosion. Leakage surveys may also provide valuable information on overall SCC activity, particularly for pipelines operating at 50% SMYS or below. Relevant information may also be available from ILI (MFL or geometry) runs and are relevant in identifying areas of corrosion activity (relevant to near-neutral pH SCC), coating damage and disbondment or regions of stress concentration or possible high residual stress.

Opportunistic excavations (those undertaken for other operational reasons such as pipeline modifications or repairs) can also provide valuable in-ground information on coating condition, the surrounding environmental conditions and the presence of SCC. Many operators are now routinely gathering SCC-related information every time the pipe is exposed. Information from opportunistic excavations is also extremely useful for building confidence in SCC segment prioritization and excavation site selection models.

Operational information includes changes to the pipeline operating conditions (operating pressure and pressure fluctuations, compressor discharge temperature) and any modifications such as tie-ins and external attachments, recoating or repairs. Changes to pressure, temperature and coating type may cause the segment to be no longer considered as SCC-susceptible. Also included in this group is any updated information on the occurrence of SCC elsewhere on the line or on adjacent lines. Finally, as the pipeline ages, the risk rankings are increased.

Geophysical information. Ground movement, landslip or settlement may introduce secondary loading or wrinkling/buckling, and may cause disbondment of the coating. Secondary loading may also result from the construction of new road or cable crossings, while building encroachment may enhance the risk of mechanical damage. All of these issues may result in localized residual stresses that promote SCC. Building encroachment may also enhance the risk of electrical interference with the CP system.

Changes to the drainage patterns and water table can have a significant impact on soil texture, soil resistivity and moisture content, all of which influence the conditions for SCC formation and growth. Changing land use may also influence the groundwater chemistry and the likelihood of SCC-promoting conditions developing at the pipe surface.

Intelligence-gathering and literature surveillance. The experiences of other pipeline operators are a valuable source of information concerning the likelihood and extent of SCC. Specific information can sometimes be obtained directly or via information-sharing workshops, while general information is available from Joint Industry Projects or from organizations such as INGAA, CEPA, NEB and DOT. Of particular relevance is information from other operators with pipelines having similar attributes and located in the same geographic region.

Another important source of information stems from the research programs by PRCI, CEPA and others addressing the factors that influence SCC formation and growth. New research results help to substantiate and interpret the trends observed in field experience. Much of the information is published at conferences or in the open literature.

All the information from intelligence-gathering and literature surveillance is used to review and, if necessary, change, the relative impact of the individual risk factors for segment prioritization and the identification of high-risk sites within the segment. For example, areas of particular current research interest include the influence of coating type, coating condition and pipe manufacturer on SCC formation, and the environmental/electrochemical factors determining SCC growth rate. Areas where new operational experience is of particular current interest include how the extent and location of low-severity SCC relates to the location and likelihood of serious cracks forming.

4. Assessment and Response

The impact of each of the SCC-related issues listed above has been discussed in depth in the accompanying JIP reports on Segment Prioritization and Excavation Site Selection, and is not repeated here.

The SCC Condition Monitoring process is centered on regular reviews at which all the SCC-related information is gathered and considered by experts with local knowledge. It is envisaged that such reviews will be undertaken annually. For each segment under consideration, the review takes into account the previous history of SCC and the previous assessments of SCC risk, and assesses whether the changed circumstances warrant a change to the previous risk ranking, either of the entire segment or of the highest-risk sites within the segment.

The annual SCC Condition Monitoring review does not preclude the need for review and response to information that becomes available during the year, for example, from site surveys or ILI runs. Whenever changes to SCC risk are identified, appropriate action should be taken.

In most instances the annual review will not identify any changes to the segment condition and the Condition Monitoring will continue as before, with further regular reviews until the next full SCC assessment becomes due. Full SCC assessments for segments with little or no cracking will probably be held at the maximum time intervals permitted by the regulations, currently seven years.

If changes in SCC risk are noted, the SCC Condition Monitoring process may trigger responses to be enacted before the next regular review. In the first instance, these may include additional or more frequent surveys and excavations. In the event of major or sudden changes in condition level, it may be appropriate to advance the next full assessment, or to undertake ILI or hydrostatic testing in accordance with the responses for more severe SCC (see the JIP report on Crack Severity and Response).

A flow chart depicting the overall process is shown in Figure 30.

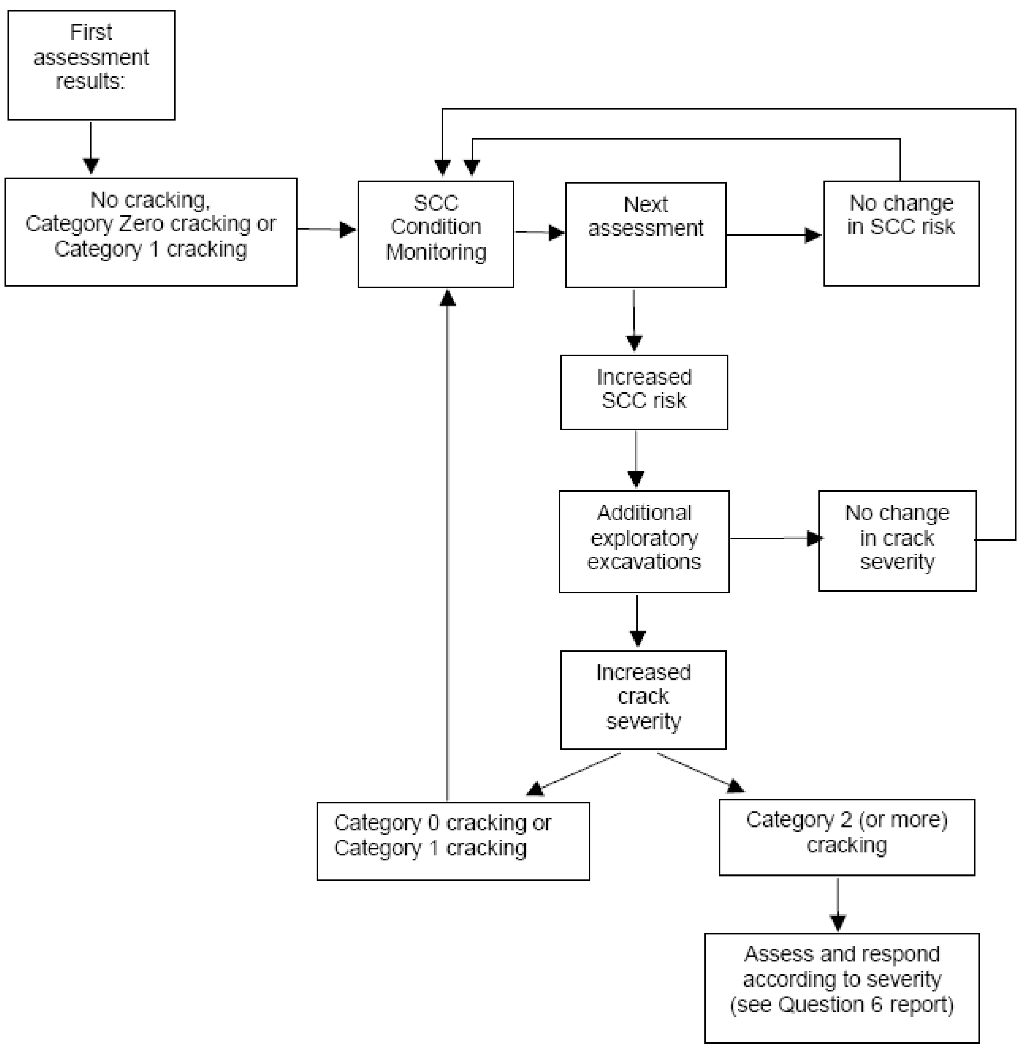


Figure 30 - Overall Flowchart for SCC Condition Monitoring

Information Collation and Management

The Condition Monitoring process requires the collation and review of information from a wide range of sources. Substantial advances have taken place in recent years in computer-based information management systems, enabling the collation and overlay of information to aid interpretation [3]-[5]. So far as information relevant to SCC Condition Monitoring is concerned, for example, the collation of data from above-ground surveys, ILI and geophysical surveys allow the exploration of possible connections between coating condition and environmental conditions. Such connections allow, for example, the identification of localities where apparently sound coatings (according to above-ground surveys) are accompanied by shallow corrosion (according to ILI); this combination of conditions has been correlated with near-neutral pH SCC [6].

It is also important that the SCC Condition Monitoring process should include provision for recording the results of the annual Condition Monitoring reviews and the actions taken, in addition to being the vehicle for collating and overlaying the different datasets. Links to the databases of in-service failures, hydrostatic test results, excavation records and SCC assessment results will add to the capability of the system and enhance its overall value as a management tool.

5. Regular Review and Reporting

It is envisaged that the SCC Condition Monitoring process and annual reviews will be overseen by an experienced integrity management engineer, in line with the operator's overall Integrity Management Plan. Some of the information identified above will require interpretation by subject experts with local knowledge; however, much of the information can be addressed by engineers with general experience of risk assessment. Moreover, not all the information identified above will be available, and some will not be applicable, for example to segments operated at low stress. The Condition Monitoring process has the flexibility to accommodate and utilize as much or as little information as is available.

It is important that the Condition Monitoring reviews and their outcomes are integrated with the other processes for recording and reporting SCC occurrences, in line with the requirements of CFR 192 and ASME B31.8S (Some of the high-level information must be reported on a semi-annual basis). As was indicated above, an integrated information management system may be the most effective means of recording all the necessary information and reporting the overall outcomes in an appropriate, auditable format.

It is also necessary to establish measurable criteria to indicate that the Condition Monitoring process has been implemented effectively and is fulfilling its required function. In the first instance, it will be sufficient to record the number of reviews and the types of datasets available to support decisions (e.g., number of surveys, ILI runs, excavations, etc.). Subsequently, the number of instances of increased risk, and the reasons for them, will be a measure of the ongoing "health" of the segment, alongside the numbers of in-service and hydrostatic test failures reported to DOT. As industry-wide experience with SCC Condition Monitoring develops, it may also be possible to identify a small number of appropriate key performance measures.

6. SCC Condition Monitoring As an "Equivalent Technology"

The SCC Condition Monitoring process described above incorporates all the elements necessary for monitoring and controlling SCC in pipeline segments that are subject to low levels of SCC risk, and in which little or no SCC has been found. The formal, regular recording of the findings, the assessment of SCC risk and the response are in line with the requirements of CFR 192 and ASME B31.8S and lead to an auditable process consistent with other integrity management activities. Safeguards are inbuilt such that, in the event that the occurrence or risk of SCC is found to have increased, the segment will require assessment using DA, ILI or hydrostatic testing.

It is recommended that consideration be given to adopting SCC Condition Monitoring as an "Equivalent Technology" for Integrity Management, alongside DA, ILI and hydrostatic testing, in situations where the occurrence of SCC has been shown to low (Category 1, Category Zero or no cracking found) and the SCC risk does not increase.

7. Benefits of Condition Monitoring – An Example

Many operators are already undertaking many of the SCC Condition Monitoring activities identified above, but the information has not generally been collated and reviewed in a manner that demonstrates the benefit to integrity management. The following example illustrates how the process can be used.

Operator X had a known SCC threat of concern on Pipeline A, which failed in service in 2002. The upstream and downstream valve sections were hydrostatically tested in 2003 without failures; the original in-service failure looked unique, and a condition monitoring program was initiated. A large number of SCC direct examinations were undertaken in 2003 and 2004.

The results of the SCC direct examinations, combined with knowledge of the pipeline system, led to a hydrostatic test on an adjacent line (Pipeline B) in 2005; this failed. More investigative excavations were then undertaken on a further adjacent line (Pipeline C), and Category 3 cracking was found in 2005. The pipeline was de-rated and hydrostatically tested and it failed twice. An R&D project was then initiated to provide assistance in prioritizing hydrostatic tests and selecting more investigative excavation sites. This, in turn, led to the initiation of a large hydrostatic test program; the majority of tests passed, but one leak occurred on a further adjacent pipeline (Pipeline D).

This experience demonstrates very clearly the benefit of collecting and reviewing all the available information as part of a SCC Condition Monitoring process, enabling identification of areas of high risk in other, adjacent pipelines and pre-emptive action (excavations, hydrostatic testing) to minimize the risk of in-service failures.

8. Comments

The preceding sections set out the requirements to be considered and illustrate concepts and approaches to address them when a formalized Condition Monitoring process is developed as part of SCC threat management. However, this is not the only approach, and it will be the responsibility of each operator to determine how best to interface the requirements of SCC Condition Monitoring with other in-company operational and organizational requirements.

SCC Condition Monitoring is principally intended for those SCC-susceptible segments with little or no SCC, for which it is proposed as an Equivalent Technology. However, it is also a useful complementary tool for segments with more serious cracking and subject to DA, ILI or hydrostatic testing. This is particularly so during the intervals between reassessment, which may be as long as seven years according to current regulations. The processes described above are amenable to all segments, providing a vehicle for collecting relevant information and monitoring for any change in SCC risk.

The preceding sections describe a substantial number of information sources that can provide indications of changing SCC risk. For many pipelines, not all this information will be available; however, this should not preclude the implementation of an effective SCC Condition Monitoring process. As experience is gained though the application of the process, it will be possible to identify the key pipeline-specific parameters; it may even be possible to target or modify the information-gathering activities in order to enhance the SCC-related data, as has been done recently by those operators who have included SCC examinations whenever operational excavations are conducted.

The concept of Condition Monitoring as an Equivalent Technology for managing low-level integrity threats is not specific to SCC. Similar approaches can be envisaged for other threats such as external and internal corrosion, weather and outside force damage. In many respects, Condition Monitoring can be considered as providing the continuous ongoing framework for integrity management, within which discrete activities such as regular assessments (Hydrostatic testing, ILI, DA) are coordinated.

9. REFERENCES

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[2] "SCC Recommended Practices," Canadian Energy Pipeline Association (CEPA), 1997

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ABBREVIATIONS AND ACRONYMS

ASME	American Society of Mechanical Engineers
ASME ST-LLC	ASME Standards Technology, LLC
CEPA	Canadian Energy Pipeline Association
CIS	Close Interval Survey
DA	Direct Assessment
DCVG	Direct Current Voltage Gradient
DOT	Department of Transportation
FBE	Fusion Bonded Epoxy
HCA	High Consequence Area
ILI	In-Line Inspection
JIP	Joint Industry Project
MAOP	Maximum Allowable Operating Pressure
MFL	Magnetic Flux Leakage
NACE	National Association of Corrosion Engineers
NEB	National Energy Board
OPS	Office of Pipeline Safety
PAFFC	Pipe Axial Flaw Failure Criterion
PFP	Predicted Failure Pressure
PHMSA	Pipeline and Hazardous Material Safety Administration
PPIC	Process Performance Improvement Consultants
RRF	Relative Risk Factor
SCC	Stress Corrosion Cracking
SMYS	Specified Minimum Yield Strength
UTS	Ultimate Tensile Strength
YS	Yield Strength

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