Developing A Robust Stress Corrosion Cracking Management Plan For Safe Operation

By Brian Kerrigan, Roland Palmer-Jones, Ramon Loback and Bernardo Pessoa

Stress Corrosion Cracking (SCC) has been described as the pipeline threat that is the most difficult to deal with due to the uncertainties of location, identification, measurement, and growth rate prediction. Managing SCC is a challenge at the best of times. However, it is particularly challenging if cracking is present across multiple pipeline systems and if the cracking is both axially and circumferentially orientated. This paper describes the development of a robust plan combining in-line inspection, direct assessment, hydro testing, and risk assessment to manage both axial and circumferential stress corrosion cracking across an extensive gas pipeline network. Key considerations in the development of the SCC management plan are discussed, and an approach that could be used to put together similar plans is recommended based on the lessons learned.

Introduction

Cracking mechanisms are complex, not always well understood and often difficult to predict. The morphology of environmental cracking is highly variable, and there may be many other features present in the pipe body and longitudinal seam weld area which are not environmental assisted cracking, but which do create similar signals in inspection data. These challenges make it difficult to reliably discriminate different feature types based only on a single source of inspection data (probability of identification) and creates significant uncertainties in how to best manage the future integrity of a pipeline subject to environmental assisted cracking.

Since not all parts of the system, or even sections within a single pipeline system, will have the same susceptibility to SCC, it is crucial to understand the threat before proposing a solution or plan to manage this issue. Prior to defining a management strategy, operators must be able to answer the following questions:

1. What type or types of environmental assisted cracking am I dealing with?
2. What are the primary contributing factors and at what level do they prevail on each other?
3. Where is cracking most likely to occur along my pipeline system?
4. Can I quantify the risk along my entire system?

The paper describes how Nova Transportadora do Sudeste (NTS) have utilized the holistic, collaborative approach illustrated by ROSEN's crack management framework to develop a robust management plan combining in-line inspection, direct assessment, and risk assessment to manage both axial and circumferential stress corrosion cracking across an extensive gas pipeline network.

Abbreviations

A-SCC	Axial Stress Corrosion Cracking
C-SCC	Circumferential Stress Corrosion Cracking
EMAT	Electro Magnetic Acoustic Transducer
ILI	In-Line Inspection
IMU	Inertial Measurement Unit
MFL	Magnetic Flux Leakage
NTS	Nova Transportadora Sudeste
POD	Probability of Detection
POI	Probability of Identification
SCC	Stress Corrosion Cracking
SCC-DA	Stress Corrosion Cracking Direct Assessment
SCCMP	Stress Corrosion Cracking Management Plan

Copyright 2019, Brazilian Petroleum, Gas and Biofuels Institute – IBP

This Technical Paper was prepared for presentation at the Rio Pipeline Conference and Exhibition 2019, held between 03 and 05 of September, in Rio de Janeiro. This Technical Paper was selected for presentation by the Technical Committee of the event according to the information contained in the final paper submitted by the author(s). The organizers are not supposed to translate or correct the submitted papers. The material as it is presented, does not necessarily represent Brazilian Petroleum, Gas and Biofuels Institute' opinion, or that of its Members or Representatives. Authors consent to the publication of this Technical Paper in the Rio Pipeline Conference and Exhibition 2019.

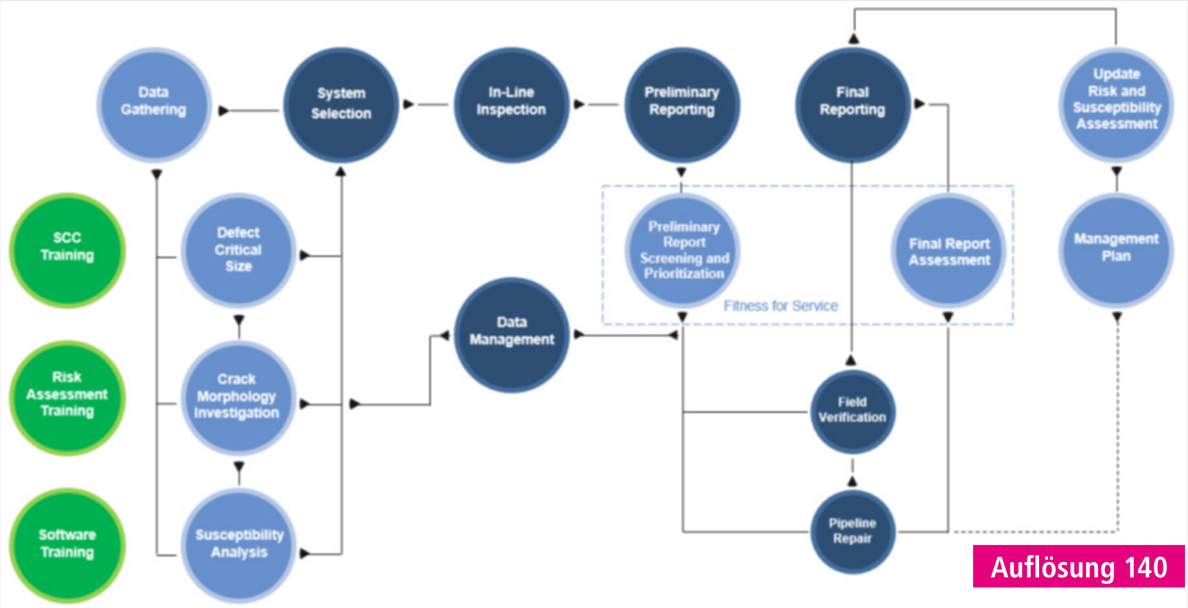

Figure 1: *Crack Management Framework*

The Project

NTS acquired a 2,050 km multi-diameter gas transmission pipeline network in Southern Brazil in 2016. Prior to the acquisition, one of the segments suffered an in-service failure due to environmental assisted cracking. ROSEN were contracted in 2016 to support using the approach given in the management framework to assist with understanding and quantifying the threat of SCC along the system. The end goal of this project was to provide a long-term management plan.

The value of an integrity management program is now well established (e.g. based on ASME B31.8S or API 1160). For specific threats, a more detailed process driven approach is recommended as a subsidiary of the overall program. The crack management framework illustrated in ***Figure 1*** has been developed based on our experience with numerous operators worldwide to communicate with the stakeholders, and includes the key elements of a program needed to understand, quantify and effectively manage the threat of cracking.

The work was completed in three phases as listed below:
Phase 1: Understand the Threat
Phase 2: Quantify the Threat
Phase 3: Define a Strategy to Manage the Threat

Phase 1: Understand the Threat

It is important to understand the complete situation following a failure, particularly if cracking is suspected as a primary failure mode. In this case, there was no historic evidence of cracking within the system and most of the pipelines had ever been inspected with crack detection technology. A number of key upfront tasks were executed in parallel to quickly understand the threat and identify gaps whilst the most appropriate technology was being selected and mobilized.

It is important to highlight that the crack management process does not start with running a crack detection inspection tool. The phase 1 tasks executed as part of this project are shown below in ***Figure 2***. It is important to note that

Figure 2: *Phase 1 Tasks Executed*

Figure 3*: EMAT Technology for Axial Crack Detection*

much of the work required for phase 1 had already been completed by TRANSPETRO, the operators of the system before the acquisition by NTS.

Data Collection and Gap Analysis

This is one of the most important tasks in the entire process. Initial data from the failure site concluded the following:

» Failure was on a 22 inch dimeter segment;
» The failure was due to an axial pipe body crack on a field bend;
» The failure occurred on the intrados of a side bend;
» Circumferential cracking was also observed on the extrados of the side bend;
» The coating type was asphalt enamel;
» The pipeline material grade was API 5L X65 and within specification;
» The pipeline was commissioned in 1988 (27 years old); and
» The pipeline was operating at approximately 60% SMYS at the time of failure.

The following information was collected for the entire system: design information, manufacturing records, construction records, geotechnical records, direct and indirect inspection records and operational history.

Failure Investigation

A detailed review of the failure was completed by a local technical experts and ROSEN added to this work as more information became available. The aim of the failure investigation was to review the morphology of the cracking, the failure mode and identify any contributing factors. The calculations concluded that the pipe had arrested through-wall cracks, which is expected for high toughness materials. The pipe ruptured due to crack growth in the longitudinal direction until it reached a critical value. Where gaps remained, further work was recommended, such as geotechnical evaluation and soil analysis. Stress corrosion cracking was confirmed as the cracking mechanism. Relevant stresses imposed during construction due to field bending were identified as possible contributing factors.
At this stage, it was clear that an in-line inspection campaign was required. Considering the lines transported natural gas and the failure was due to an axial crack, Electro Magnetic Acoustic Transducer (EMAT) tool was identified as the primary option (see ***Figure 3***).

Direct Assessment Planning / Susceptibility Screening

All pipelines in the system were assessed and ranked in terms of SCC susceptibility considering the findings of

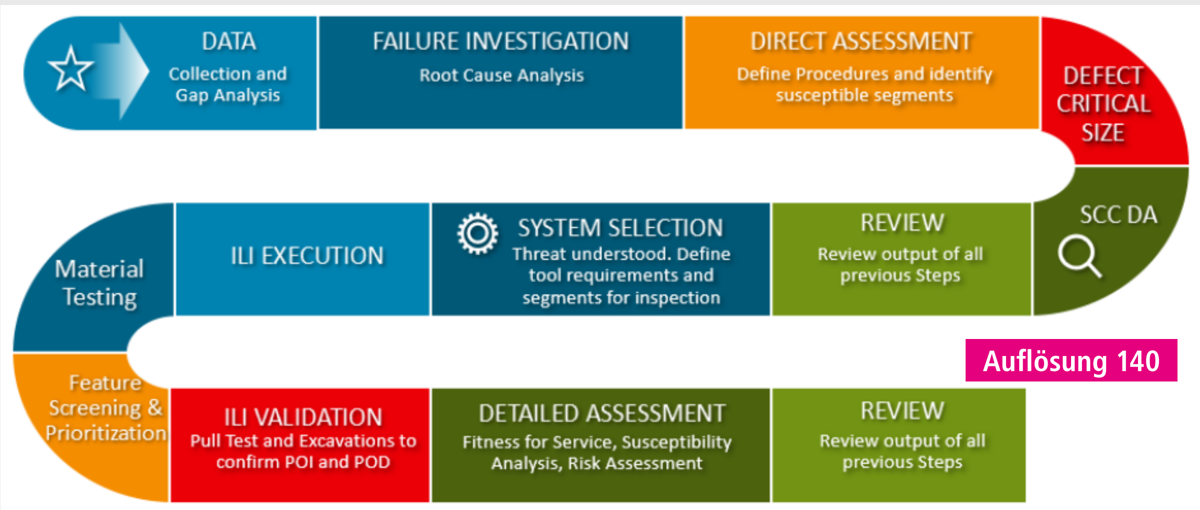

Figure 4*: Phase 1 and 2 Tasks Executed*

***Table 1**: Overview of Phase 2 Activities*

Phase 2 Activity	Description	Value Added
Material Testing	Some segments contained pipe from multiple manufacturers and it was identified during phase 1 that material certificates were limited for some sections. In the anticipation of a high feature count, material was sourced from the pipeline system, which suffered a failure, and mechanical testing was completed to quantify the material properties and fracture toughness.	Avoided the requirement to make assumptions on material quality, which typically result in a conservative assessment. This significantly improved confidence and reduced number of immediate digs.
Feature Screening and Prioritization	Once the preliminary ILI information was available, features for in-field investigation were assessed and prioritized. Consistent guidance on immediate response, in-field assessment criteria and remediation were provided.	Collaboration between ROSEN and NTS allowed for an efficient and safe dig campaign. Data was fed back instantly to the ILI evaluation team and incorporated into the analysis. This process resulted in increased understanding and refinement of feature classification and/or sizing ahead of the final ILI reporting.
ILI Validation	A pull through test was completed on a joint removed from service containing axial crack colonies. Over 30 excavations were completed, and the findings were shared.	Confirmation that the technology was able to reliably detect and size critical features caused by the primary cracking threat. Improved understanding of pipeline, feature morphology and allowed the review of tool performance, i.e. Probability of Identification (POI) and Probability of Detection (POD).
Susceptibility Analysis	An SCC model was created per segment considering the findings in the previous tasks and a probability of failure per joint was calculated. This model could also be overlaid with the ILI information to assist with prioritization of anomalies.	Industry experience tells us that most SCC colonies will remain shallow and dormant throughout their life. Therefore, some may not be deep enough to be accurately detected by EMAT technology. Alongside the ILI, susceptibility model will identify areas where SCC is most likely to occur to assist with long-term management.
Fitness for Service Assessment	All features reported by the inspection tools were assessed to confirm their immediate and future integrity, including the crack-like anomalies reported by EMAT.	Defined action list to provide immediate and future integrity assurance for all anomalies.
Risk Assessment	A risk assessment considering the threat of SCC was complete per pipeline. This considered the susceptibility analysis (probability of failure) combined with the consequence analysis (primarily considering the location class changes along their pipeline).	Threat of SCC can be quantified on a joint-by-joint basis and high-risk areas identified for immediate action.

the failure investigation and initial data review to identify segments for direct assessment and In-Line Inspection (ILI). Several segments were identified where cracking was credible. Within these segments, locations were identified for immediate direct assessment alongside the ILI planning phase.

Phase 1 Start

Critical Defect Sizes

In anticipation of planning an inspection and investigation campaign for cracks, it is important to consider the critical and acceptable crack sizes for the following reasons:

1. Confirm that the technology selected is able to identify the critical defect size;
2. The critical sizes can be incorporated into defining immediate call criteria during the ILI evaluation; and
3. Assessment and repair decisions for any cracks found in the field following SCC-DA or ILI.

SCC Direct Assessment

Alongside the planned ILI campaign, an SCC direct assessment campaign was carried out. Over 20 sites were exposed across multiple segments. More than 1,000 SCC colonies were verified, both axial and circumferential in orientation. As well as verifying the presence of cracking, information was collated for the following parameters in-line with NACE SP0204:

- » Pipe-to-soil potential;
- » Soil resistivity;
- » Soil samples;
- » Electrolyte analysis;
- » Deposit analysis;
- » Groundwater samples;
- » Coating evaluation;
- » Geometry measurements (bend angle, out-of-roundness); and
- » In-situ metallography.

System Selection

Considering the SCC-DA and failure investigation data, it was clear that the inspection technology needed to identify the following items as a priority:

1. Axial cracking;
2. Geometric anomalies (out-of-roundness, ripples, dents); and
3. Field bends.

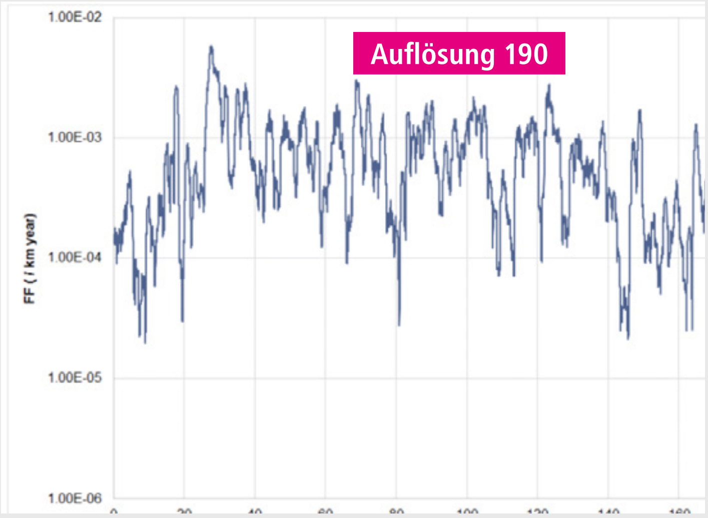

***Figure 5**: Example SCC Susceptibility Profile along a Route*

Given that there is limited technology to accurately detect and size tight circumferential cracks in gas systems, It was recommended the use of high-resolution geometry tools including inertial monitoring units for mapping which can identify load sources such as bending strain and pipe movement. Additional inspection technologies were suggested to complement the analysis and identify factors such as hard spots or changes in pipe grade, but these were not included in the initial inspection campaign.

The tool selection for the campaign was as follows:

» Axial Cracking: Electro Magnetic Acoustic Transducer (EMAT);
» Metal Loss: Magnetic Flux Leakage (MFL);
» Geometric Anomalies: Geometry Tool (RoGeo); and
» Bending Strain, pipe movement and XYZ: Inertial Measurement Unit (IMU).

Phase 2: Quantify the Threat

Once the results of the inspection are available, it is important to quantify the threat. The number, depth, length and location of ILI crack indications allow a quantification of the level of risk. There have been multiple locations where encroachment has occurred along the pipeline route and managing the threat of cracking in these areas is considered paramount for safety. To do this, a number of activities to validate and quantify the critical defect sizes, SCC susceptibility (probability of failure) and risk level. ***Figure 4*** illustrates the tasks involved. ***Table 1***

An example of a susceptibility profile is shown in ***Figure 5***. This data was then combined with the consequence analysis to predict the overall risk, per joint, per segment so further actions could be taken, if required.

Phase 3: Define a Strategy to Manage the Threat

Following the execution of phases 1 and 2, there was an increase in the knowledge of the threat and the quantification of the risk to the business for the key pipelines.
The main findings of phase 1 and 2 are outlined below and ***Figure 6*** illustrates the tasks executed:

***Figure 6**: Phase 1and 2 Tasks Executed*

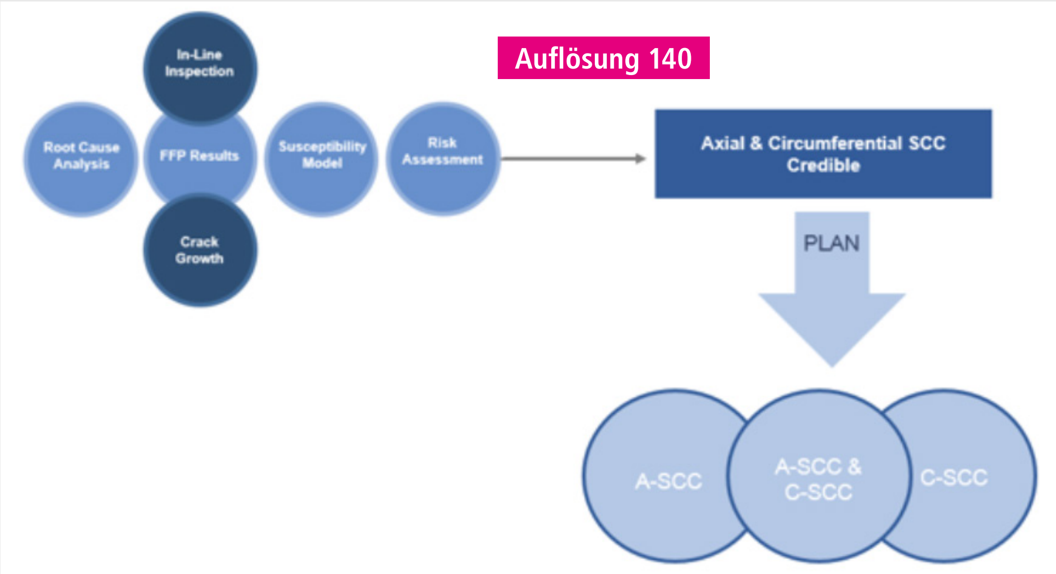

Figure 7: *SCC Management Overview*

- » Crack morphology: SCC (Axial and circumferentially orientated) focused in field bends;
- » ILI reporting: A significant number of crack-like indications reported along multiple pipelines. For other pipelines, no indications have been reported;
- » Confidence in ILI technology for critical features: High. A significant number of colonies verified following ILI;
- » Crack growth rate: Crack growth rates up to 0.3 mm per year were confirmed as credible considering the findings of the in-field campaign;
- » Fitness for service: A detailed analysis was completed and many crack-like indications features required immediate investigation;
- » SCC susceptibility: Probability of SCC varies across system. Modelling has identified the key areas; and
- » Risk assessment: High-risk areas identified.

As part of the overall integrity management system, the management plan for SCC (SCCMP) constitutes a high level, risk-based strategy for continuous monitoring and mitigation of any affected pipeline. A robust management plan was developed considering the following elements:

- » Data Gap Analysis;
- » SCC Susceptibility Results;
- » In-line Inspection Results;
- » Fitness-for-service Assessment Results;
- » Risk Assessment Results;
- » Coating Condition;
- » CP System Condition;
- » In-field Data; and
- » Current Pipeline Operation.

The SCC management plan developed considered guidance outlined in ASME B31.8S, CEPA 2015 and API 1176. ***Figure 7*** outlines with inputs used to drive an SCC management plan.

A pipeline may or may not be susceptible to stress corrosion cracking (SCC). If SCC is present on a pipeline, it is typically axially or circumferentially orientated. It is credible that a pipeline can contain both axial (A-SCC) and circumferentially orientated SCC (C-SCC), as in this case. For gas lines, typical management of axial cracking can be focused around repeat EMAT inspection as no liquid coupling is required during inspection. For circumferential cracking in gas lines, crack detection inspection has not been fully developed. To manage either or both types of cracking effectively, alternate strategies are required. However, it is likely to have a significant overlap.

There is a variety of options for managing either or both types of cracking effectively. The typical options to manage axial and/or circumferential cracking are illustrated in ***Figure 8*** and ***Figure 9***. The options can vary in cost and the selection of any option will be dependent on the severity of the cracking at the time of assessment. The options have been categorized on the following basis:

- » Category A: High CAPEX cost and/or significant production downtime anticipated;
- » Category B: Medium to high CAPEX cost, unlikely to include production downtime; and
- » Category C: Low to medium CAPEX/OPEX cost, unlikely to include production downtime.

A typical SCC management strategy is based on a multi-layer approach combining threat mitigation and monitoring activities with a performance review process; an example is outlined below:

- » Mitigation: Recoating of significant sections of pipeline to mitigate any future SCC growth.

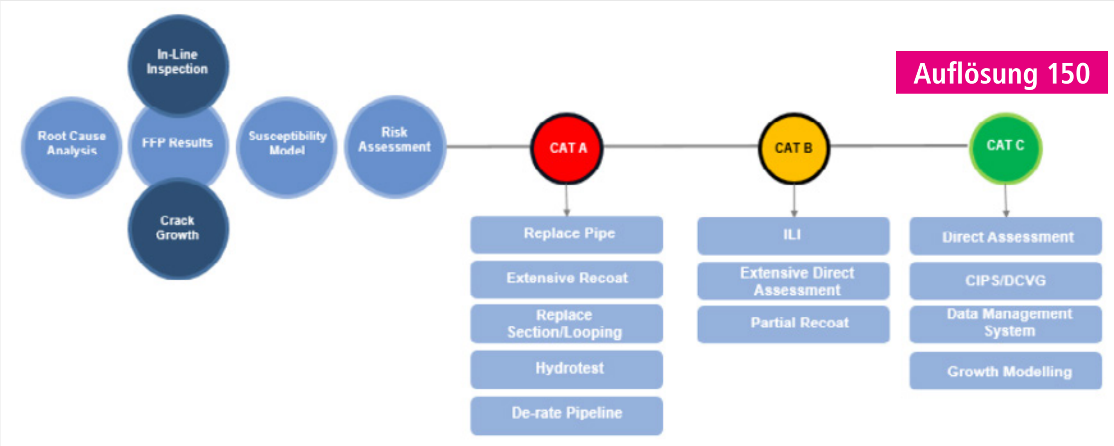

***Figure 8**: Typical Options to Manage AXIAL SCC*

- » Monitoring: Regular internal crack detection inspection to confirm the effectiveness of the mitigation and identify any locations where SCC remains active. Inspection frequency based on conservative estimates of crack development and growth rates.
- » Monitoring: A direct assessment is generally considered the best approach for C-SCC in gas lines. Ultrasonic in-line inspection tools are available but require a liquid slug. MFL technology can also detect significant (i.e. deep or open) circumferential cracking but is not recommended to be used for stand-alone circumferential crack detection in API 1163.
- » Review and audit: Backup survey, data management, susceptibility modelling, annual review and performance reporting.

Due to the significant number of digs recommended for some segments (which did not include new colony formation), the following alternative options were considered when defining a suitable long-term SCC management plan:

1. Replace the pipeline;
2. De-rate the pipeline operation;
3. Commit to an extensive recoating campaign targeting most susceptible field bends;
4. Hydrotest the entire pipeline at regular intervals; and
5. Inspect with axial and circumferential ultrasonic crack detection technology (liquid coupling required).

It was concluded that none of the options listed above was required. The long-term management plan adopted is outlined in ***Table 2***.

Conclusions

Cracking in gas pipelines is considered by many operators as the most challenging threat to manage effectively. Failures can often be catastrophic and it is essential that every operator anticipates this threat and quantify the level of risk being carried by the business.

NTS are in the process of managing both axial and circumferential environmental cracking which is focused in field bends. As we know, Brazil has a challenging terrain and unfortunately, approximately 30 to 40% of their system has been subject to field bending. In addition, as Brazil's population has increased

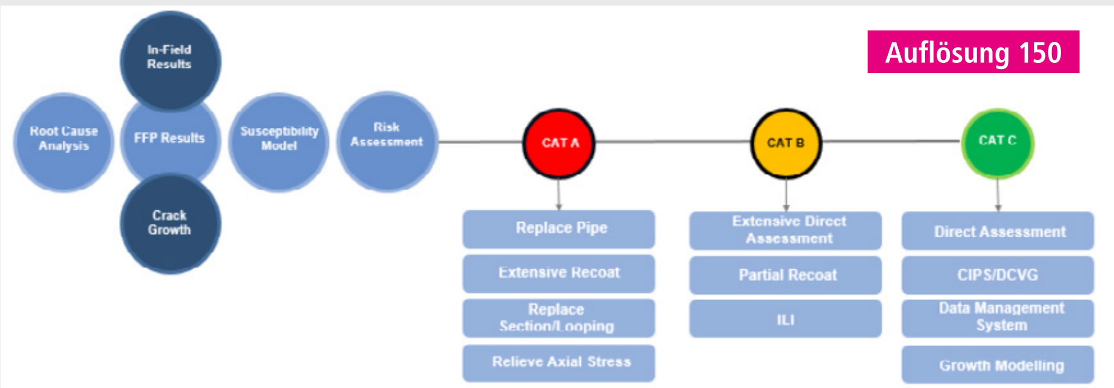

***Figure 9**: Typical Options to Manage CIRCUMFERENTIAL SCC*

***Table 2**: Overview of SCC Management Strategy*

	Description
Management of Both Circumferential and Axial SCC	• Investigation of the sites identified in the risk assessment as 'HIGH RISK' and mitigate if required. • Complete additional mechanical testing (fracture toughness testing and/or burst testing) to fill any data gaps and refine predictive models. • Revised in-field coating systems and procedures. • Indirect inspections recommended (CIPs and DCVG). • Maintenance improvements recommended (CP system). • Data management improvements recommended (Management system). • Review in-field findings regularly and update susceptibility, risk and management plans.
Management of Axial SCC Only	• Investigation of the reported crack-like indications as per the schedule outlined in the remnant life assessment. • Routine inspection using EMAT technology to detect and size axially orientated cracking.
Management of Circumferential SCC Only	• Investigation of the most susceptible joints to evaluate the severity of the circumferential cracking. • Investigation of areas where significant strains have been reported by the inspection tool. • Routine inspection using MFL-A to identify any 'wide' or 'open' circumferential cracking. This requires detailed analysis, i.e. combined with bending strain information. • Routine inspection to monitor bending strain and pipe movement.

over recent years, encroachment has occurred along their pipeline system right of way resulting in location class changes. A classic linear approach to treat management of inspection, assessment and repair does not work well with SCC. The uncertainties related mean it can result in excessive excavation activity, or significant defects not being identified. This was recognized and a significant amount of time and effort was invested to understand the system and quantify the threat utilizing the crack management framework as a platform.
This paper has described how NTS have developed their long-term management plan alongside ROSEN. The plan is not carved in stone but is a baseline of activities to move forward safely whilst collecting further data and improving understanding. It is focused around routinely integrating data sets and susceptibility models to enhance long-term crack management.

This case study presented here provides the following key conclusions:

1. Managing axial and circumferential cracking is a challenge, but it can be done effectively;
2. Adopting a framework approach ensures that all key elements are addressed and the risk is quantified;
3. A detailed understanding of the threat is required for effective implementation of integrity management activities;
4. There is a substantial long term cost saving if a detailed understanding is gained upfront; and
5. Management plans are not set in stone. Plans can be refined or edited as more data is collected and the understanding is improved.

Bibliography

[1] ASME, Managing System Integrity of Gas Pipelines, ASME B31.8S, 2016.
[2] API, Recommended Practice for Assessment and Management of Cracking in Pipelines, API 1176, 1st Edition, 2016.
[3] CEPA, 'Recommended Practices for Managing Near Neutral pH Stress Corrosion Cracking, 3rd Edition, May 2015.
[4] API, In-Line Inspection Systems Qualification, API 1163, 2nd Edition, 2013.
[5] NACE, Stress Corrosion Cracking Direct Assessment Methodology, NACE SP0204, 2004.
[6] FESSLER et al, Characteristics, Causes and Management of Circumferential Stress Corrosion Cracking, IPC2014-33059, 2014.

AUTHORS

BRIAN KERRIGAN MSc
Principal Integrity Engineer
ROSEN Group
(Town/Country)
(Phone)
(Mail)

ROLAND PALMER-JONES
Head of Integrity Services
ROSEN Group
(Town/Country)
(Phone)
(Mail)

RAMON LOBACK
Pipeline Integrity Specialist
NTS - Nova Transportadora Sudeste, Rio de Janeiro, Brazil
(Phone)
(Mail)

BERNARDO PESSOA
Pipeline Integrity Engineer
NTS - Nova Transportadora Sudeste, Rio de Janeiro, Brazil
(Phone)
(Mail)