Topic Paper #4-3

CORROSION MANAGEMENT TECHNOLOGIES AND METHODOLOGIES

Prepared for the

Technology Advancement and Deployment Task Group

On December 12, 2019 the National Petroleum Council (NPC) in approving its report, *Dynamic Delivery – America's Evolving Oil and Natural Gas Transportation Infrastructure*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Permitting, Siting, and Community Engagement for Infrastructure Development Task Group. These Topic Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of 26 such working documents used in the study analyses. Appendix C of the final NPC report provides a complete list of the 26 Topic Papers. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

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Topic Paper

(Prepared for the National Petroleum Council Study on Oil and Natural Gas Transportation Infrastructure)

4-3	**Corrosion Management Technologies and Methodologies**
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SUMMARY

This topic paper describes different aspects of corrosion integrity management and technology advancement. In-line inspection of corrosion uses relatively mature technologies for detecting and sizing metal loss defects. The uncertainties associated with in-line inspection for corrosion features (especially sizing accuracy) vary for different morphologies. While corrosion management is mature compared to other threats, the corrosion process is complex and additional research and development will help to better address complex corrosion cases and provide better data to support asset integrity decision making.

I. INTRODUCTION

Corrosion is among the most common threats to pipeline integrity. Despite effective preventative methods, pipeline steels will always be susceptible to corrosion when they come into contact with oxygen and water. The technologies associated with measurement and assessment of corrosion are the most mature of the common pipeline threats. This maturity refers to the availability and performance of inspection tools, accuracy of assessment methods, and availability of clear and effective regulatory requirements for asset management. The industry continues to pursue improvements that will support enhanced effectiveness and efficiency of corrosion programs.

This paper focuses primarily on asset integrity management through the measurement and assessment of corrosion features to support mitigation planning. Corrosion prevention (through cathodic protection and use of corrosion inhibitors) also supports asset integrity management. Typically considered part of operational integrity, corrosion prevention supports asset integrity through minimizing growth rates and providing useful monitoring information to support decision making.

II. CORROSION MEASUREMENT

Corrosion inspection technologies (both field and in-line inspections) are typically considered to be among the most mature and best developed technologies in the industry. Available tools are able to accurately identify and measure internal and external corrosion using a variety of techniques and technologies. While there remain challenges with performance related to certain morphologies, the need for significant technological innovation is relatively minor compared to other threats. The industry is committed to continuous improvement and two examples of current areas of research and development include pinhole corrosion and tool performance uncertainty.

While metal loss in-line inspection tools have good overall performance, detecting and sizing very small features (classified as pinholes) remains a challenge. Current in-line inspection tools do not have high sizing accuracy specifications for features smaller than approximately 5 mm (0.2 inches). Thus there can be significant uncertainty in the measurement of these features. As a result of this sizing limitation, pinhole corrosion (which is considered as a small leak threat) is usually managed through flow monitoring, right-of-way surveillance, and/or other leak detection technologies. These management strategies are reactive. Advances in in-line inspection technology related to these features will help operators to more effectively address pinhole corrosion features in a proactive manner.

Field inspection of corrosion features often use ultrasonic technologies (automatic and/or manual) to support detection, sizing, and classification of internal corrosion or manufacturing defects. While some studies have been conducted to understand the performance of these tools for crack features and external corrosion, minimal work has been done to quantify their performance for internal corrosion and manufacturing defects. Developing a better understanding of the performance of field inspections will improve confidence in the results and enhance direct assessments and validation/calibration of in-line inspection results.

While corrosion measurement technology is in a mature state, continuous improvement to its precision, accuracy, and repeatability will support enhancements to integrity decision making, helping to support improved effectiveness and efficiency of corrosion integrity programs.

III. CORROSION ASSESSMENT

Once identified by field or in-line inspection, the severity of corrosion features can be assessed to identify mitigation requirements. Typical integrity programs consider three primary areas when assessing a feature, including: the feature assessment based on as-measured properties; estimation of the feature growth rate; and consideration of measurement uncertainties.

a. Feature Assessment

Several methods are available for the assessment of corrosion features, which have been proven to be accurate through laboratory testing, numerical modelling, and field experience.

These assessment methods are well established in the industry and are clearly documented within existing regulations and thus are not described here in detail. Typical assessments determine the burst pressure of corrosion features based on the corrosion shape and size as determined by the in-line or field inspection. Appropriate safety factors (considering feature morphology and location) are pre-defined and used to evaluate mitigation requirements for each feature or group of features. However, the industry is currently working to further enhance these methods to better account for pinhole corrosion (due to limitations in existing in-line inspections), address the effects of pipe strain on corrosion behavior, and better understand temperature severity effects on corrosion growth.

Given the in-line inspection limitations related to pinhole corrosion (as described earlier), industry has worked towards development of methodologies to support their management. Preliminary work has aimed at creating a fault-tree based assessment method that can be used by operators or vendors to better identify the pinhole corrosion features that may have been undersized by the in-line inspection.[1] This will help operators identify potential features of concern and address them before they can become an integrity concern, thus decreasing overall risk.

Corrosion fitness-for-service assessments typically assume that internal pressure is the principal driver for burst failure. However, if high longitudinal strain (such as may be caused by ground movement) exists at an area of internal corrosion, the feature may be more susceptible to failure than would be expected by an assessment which neglects the strain. This is especially of concern when the metal loss has considerable circumferential extent and depth. Industry is currently developing tools to better evaluate the impact of longitudinal strain on the integrity of pipelines.

Temperature can have a significant impact on the rate of corrosion growth within a pipeline, with corrosion growth rate typically increasing with temperature. However, there is currently no known method to define the temperature severity for corrosion growth, making it difficult to quantify the impacts of operational changes to determining future pipeline integrity. Further industry study is needed to better understand the impacts of different parameters associated with high temperature operation (for example, determining the relative importance of the maximum, average, and most frequent temperatures; the duration of each temperature conditions; the rate of temperature fluctuations; and other factors). Better understanding of these temperature effects will help operators determine mitigation requirements and assess operational risks associated with product temperature changes within pipelines.

b. Corrosion Growth Rate

The corrosion growth rate provides beneficial information to help monitor the growth of metal loss features over time, evaluate the overall corrosion severity on the line, and determine

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[1] Desjardins Integrity Ltd. Development of a Methodology for Management of Pinhole Corrosion with ILI. *Draft report prepared for CEPA*, (2014), June.

the interval of time required before the next assessment.[2] There are three main analysis techniques to calculate a feature-specific growth rate: historical, feature matching, and signal matching. Historical methods typically assume a growth profile and estimate growth based on the age of the pipeline. Feature matching methods compare the results of two inspections, matching features based on their size and location and determining the rate of change over the time between the inspections. Signal matching methods are typically performed by in-line inspection vendors and use comparisons between inspection tool signals instead of matching the features directly.

Accurately determining the corrosion growth rate is challenging as these methods all have uncertainties. Historical methods may inaccurately account for changes to the corrosion prevention systems or operating conditions. Feature and signal matching methods rely on accurate feature measurements, which can be susceptible to measurement bias and random errors related to tool performance. This can result in features appearing to improve over time or other inaccuracies in the measurements. Thus, industry is working to enhance the precision of corrosion growth rate estimations through use of statistical validation, successive high-resolution in-line inspections, and field verification.

There are several recommended guidelines and best practices associated with corrosion growth rate and associated re-inspection intervals within the industry.[3] ASME B31.8[4] indicates a 10-year re-inspection interval, which can be based on growth rate of 0.06% wall thickness per year without considering the accelerating factors in corrosion. ASME B31.8S[5] recommends growth rates based on soil resistivity with a maximum corrosion growth rate of 0.31 mm/year (12 mils/year). The Gas Research Institute[6] provides some guidelines with the typical worst external corrosion growth rate of 0.56 mm/year (22 mils/year) for pitting and 0.3 mm/year (12 mils/year) for general corrosion. API 1160[7] recommends that the re-inspection interval is not

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[2] K. Spencer, S. Kariyawasam, C. Tereault, and J. Wharf, A Practical Application to Calculating Corrosion Growth Rates by Comparing Successive ILI Runs from Different ILI Vendors, *International Pipeline Conference,* (2010), IPC 2010-31306; T. Bubenik, W. Harper, P. Moreno, and S. Polasik, Determining Reassessment Intervals from Successive In-Line Inspections, *International Pipeline Conference,* (2014), IPC 2014-33025.

[3] Y. Li, L. Krissa, M. Abdolrazaghi, and G. Fredine, Validation of Corrosion Growth Rate Models, *NACE International Corrosion Conference*, (2016), Paper No. 9504.

[4] American Society of Mechanical Engineers. Gas Transmission and Distribution Piping Systems. *Standard*, (2018), ASME B31.8.

[5] American Society of Mechanical Engineers. Managing System Integrity of Gas Pipelines. *Standard*, (2018), ASME B31.8S.

[6] Leis, B. N., and Bubenik, T. A. Periodic Re-Verification Intervals for High-Consequence Areas. *Gas Research Institute Technical Report,* (2001), GRI-00/0230.

[7] American Petroleum Institute. Managing System Integrity for Hazardous Liquid Pipelines. *Recommended Practice,* (2019), API 1160.

more than half the remaining life of the deepest (un-remediated) corrosion feature. API 579[8] states that the corrosion growth rate can be calculated using the environmental and operating conditions but recommends no particular value. Title 49 CFR 195[9] discusses the consideration of corrosion growth rate with no guideline on particular rate; however, it recommends a maximum assessment interval of five years, unless an engineering analysis supports extension. API 1163[10] states that the comparisons between two successive in-line inspections can be used for data verification but does not provide direction on the corrosion growth rate calculation. NACE[11] provides a standard practice for assessing pipeline external corrosion using the external corrosion direct assessment methodology. In this practice, re-inspection of the pipeline is based on a corrosion defect growth rate of 0.4 mm/year (16 mils per year). Furthermore, it is recommended that for pipelines with adequate cathodic protection, the threshold of pitting growth rate can be reduced by up to 24%. DNV proposes[12] a methodology that uses the statistically active corrosion approach to estimate the corrosion growth over the pipeline and determine the next re-inspection interval. This methodology includes data preparation, statistical screening, raw data review, cathodic protection and coating assessment, and establishing reassessment interval. Keifner[13] proposed a method to determine growth rate by estimating the time that corrosion in the pit is initiated and uses probability density functions of the feature depth to determine growth rate through Monte-Carlo simulation.

The Pipeline Research Council International has been actively investigating corrosion growth rates and developing methodologies to help support industry advancement in this area. In one project,[14] a methodology was developed which helps to address in-line inspection measurement uncertainties to estimate growth error. Another project[15] determined the corrosion growth rate considering time-related uncertainties and incorporated them into a probabilistic reliability-based approach. This probabilistic approach uses multiple successive in-line inspection runs and applies a Bayesian hierarchical framework using aspects of a stochastic process to increase flexi-

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[8] American Petroleum Institute. Fitness for Service. *Standard,* (2007), API 579.

[9] CFR 195.452.j (3), (4), *Code of Federal Regulations*, October 1, 2013.

[10] American Petroleum Institute. In-line Inspection Systems Qualification. *Standard*, (2013), API 1163.

[11] American National Standards Institute. Pipeline External Corrosion Direct Assessment Methodology, *Standard Practice,* ANSI/NACE SP0502-2008 (formerly RP 0502) Item No. 21097,

[12] T. Bubenik, W. Harper, P. Moreno, and S. Polasik, Determining Reassessment Intervals from Successive In-Line Inspections, *International Pipeline Conference,* (2014), IPC 2014-33025.

[13] J.F. Kiefner and K. M. Kolvich. Calculation of a Corrosion Rate Using Monte Carlo Simulation. *NACE Corrosion* (2007), Paper No. 07120

[14] S.J. Dawson, J. Wharf, and M. Nessim. Development of Detailed Procedures for Comparing Successive ILI Runs to Establish Corrosion Growth Rates, *Pipeline Research Council International Project EC 1-2,* (2009).

[15] M. Maes. Corrosion Growth Rate Models and ILI-Based Estimation Procedures for Reliability-Based and Deterministic Pipeline Integrity Assessments, *Pipeline Research Council International Project EC 1-10,* (2013).

bility while including the uncertainty of multiple in-line inspection measurements. Corrosion growth rate can also be calculated using multiple data sources such as back-to-back in-line inspections using machine learning approaches.[16]

Thus, there is significant industry guidance regarding corrosion growth rate measurement and many techniques available in the industry. Operators are responsible for determining the most appropriate methodology when managing their integrity programs and can use a combination of assessment methods and inspection results to maximize accuracy. Industry research is helping to further enhance these models and use the available inspection data to the best possible degree.

c. Measurement Uncertainties

In-line and field inspection measurements are both susceptible to different types of measurement errors, caused by inherent tool limitations, measurement techniques, and/or human factors. Prescriptive safety factors are typically used to help account for these measurement errors but may lead to overly conservative decision making and inefficient integrity programs. Operators and inspection companies typically rely on multiple measurement sources to help validate measurements and can reassess their sizing algorithms to help minimize measurement errors. Others use probabilistic analysis to quantitatively assess uncertainties to support integrity decision making and risk estimation.

There are several advanced statistical methodologies that can be used to improve the accuracy and precision of in-line inspection data given field inspection results. One example that has been proposed in the industry[17] uses a statistical approach based on linear regression and maximum likelihood to account for the uncertainty of both in-line and field measurements. The principle of this method is to quantify the uncertainty of in-line and field measurements by reducing their relative error and then calibrating the in-line inspection data relative to the field. The uncertainty quantification is performed by using the estimated tool errors, variance and covariance of the measurements, and the total number of compared measurements. After quantifying the uncertainty of in-line inspection and field measurements, this uncertainty can be included in adjusting the in-line inspection results, calibrating them to better estimate the true depth of the features. An example of tool performance is provided in Figure 1 and the resulting calibration of measurements provided in Figure 2, which shows the calibrated data fitting much better to the unity line. In this example case, the in-line inspection tool was under-calling the features, mean-

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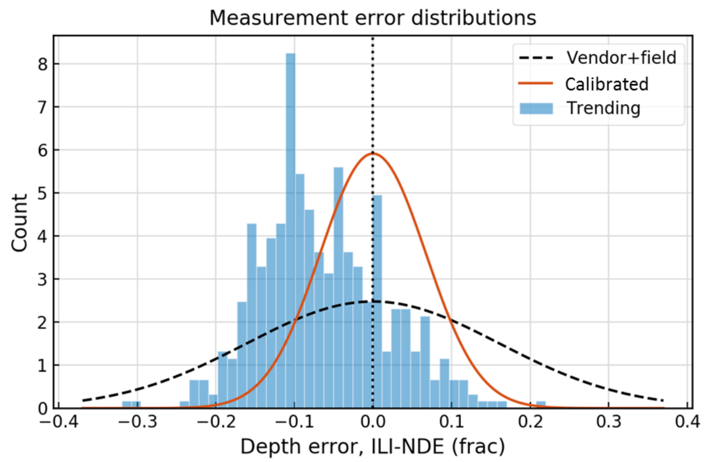
[16] J. Mazzella, L. Krissa, T. Hayedan, and H. Tsaprailis, Estimating Corrosion Growth Rate for Underground Pipelines: A Machine Learning Based Approach. *NACE International Corrosion Conference* (2019) Paper No. 13456.

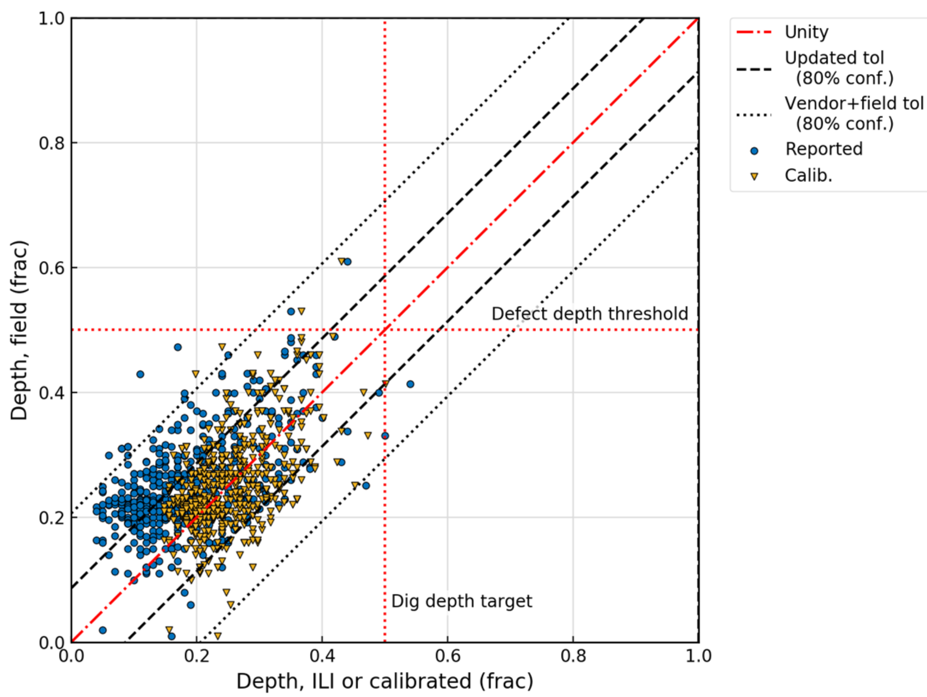
[17] M. Abdolrazaghi, S. Hassanien, and K. Cheng. Relative Statistical Calibration of ILI Measurements. *International Pipeline Conference*, (2016), IPC2016-64126; M. Abdolrazaghi, S. Hassanien, and J. Woo. Applications of Relative Calibration of Crack and Corrosion ILI Data. *Pipeline & Gas Journal,* (2017), March; M. Abdolrazaghi, S. Hassanien, and K. Cheng. Effect of Calibration of Measurements on Integrity Reliability Analysis. *International Pipeline Conference* (2016), IPC2016-64430.

ing that assessment using the as-issued data may have under-estimated the severity of the features.



Source: Enbridge

Figure 1: Example of Corrosion Depth Measurement Error



Source: Enbridge

Figure 2: Example of Corrosion Depth Unity Plot

Calibration of inspection data can help to correct for tool biases once enough field measurements are available. In order to implement any calibration methodology, the model assumptions must be verified and validated likely with support from the tool vendor. This includes validating the in-line inspection program using the API 1163[18] guidelines and ensuring that a sufficient number of trended sample data points are available to represent the feature population, considering linearity, normality, and constancy of variation of residual error. A major benefit of using calibration is that it allows operators to address both in-line inspection and field measurement errors within the integrity analysis. However, calibration should be used with caution to ensure that all appropriate related assumptions are considered, no errors are introduced into the assessment, and all regulatory requirements are met.

IV. CORROSION PREVENTION

While the prevention of pipeline corrosion typically falls outside of asset integrity programs (more closely aligning with operational integrity), its management is often performed in parallel with asset integrity programs. Two key areas of corrosion prevention, cathodic protection and performance chemistry, are discussed here to help address this important aspect of corrosion management within pipelines.

a. Cathodic Protection

Coating, soil conditions (e.g., resistivity), and effectiveness of cathodic protection systems are the main factors in determining external corrosion behavior. Computational approaches based on soil properties, mapping of any foreign cathodic protection systems and overhead power lines, and detailed mapping of the pipe-to-soil corrosion model can be used to estimate external corrosion growth rates. These models can be used to help identify areas susceptible to corrosion, estimate the corrosion rate, and forecast corrosion growth. These models typically include a large quantity of soil data (which can be provided using coupons, electronic resistance probes, and ultrasonic probes in the area of interest), pipe and coating information, and cathodic protection monitoring data, requiring big data solutions for effective modelling. Results of computational models can be used to complete a corrosion susceptibility assessment and improve management of the corrosion cathodic protection system.[19]

Cathodic protection management for pipelines sharing the same right of ways is one of the challenges for pipeline operators to ensure the adequacy of cathodic protection on their lines.[20] The ability to measure the pipeline potentials and minimize corrosion with cathodic protection is limited with available technologies. New approaches such as using cathodic protection

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[18] American Petroleum Institute. In-line Inspection Systems Qualification. *Standard*, (2013), API 1163.

[19] L. Krissa, and C. Baeté. Evolving CP Practices. *World Pipelines Journal,* (2016), February; L. Krissa, and C. Baeté. Responding to a Flood of CP Big Data. *World Pipelines Journal*, (2016), September.

[20] L. Krissa, C. Baeté, and J. DeWitt. CP Management of Multiple Pipeline Right-of-ways. *NACE International Corrosion Conference*, (2019), Paper No.5795.

coupons with stationary reference cells, remote monitoring rectifiers, and soil resistivity measurements have been implemented by some operators to maximize the effectiveness of their cathodic protection systems. Some analytical solutions and 3-D modeling based on cathodic protection ground bed data have also been developed to support analysis in this area.[21] Recent studies have shown that electrical interference and the presence of overhead powerlines can be used to support modelling of the corrosion growth rates in some areas[22] and can help to locate areas of higher corrosion susceptibility.[23]

Vapor corrosion inhibitors are being promoted as an alternative corrosion control measure. Operators have found success with introducing corrosion inhibiting gel solution into the casing annular space to control corrosion and monitor the inhibitor effectiveness. There has also been an industry sponsored project to evaluate the effectiveness of these inhibitors as an alternative method in mitigating the corrosion at tank bottoms.[24]

Thus, continued research and development in cathodic protection will help to inhibit corrosion along the pipeline (limiting required asset integrity mitigation programs) and cathodic protection models can provide valuable information regarding corrosion rates and locations. This information can help to support the planning and implementation of asset integrity programs and act as a supplementary data source to support in-line inspection results.

b. Performance Additives

The transportation of different product phases is strongly dependent on viscosity and flow conditions, and pipeline operators often inject multiple chemicals in the product stream to enhance performance and maximize throughput. For example, adding viscosity modifiers or drag reducing agents can improve the flow capacity in a pipeline asset by approximately 5% and can be even greater when multi-phase flow effects are considered. While each individual additive helps to improve the performance and the safety associated with the product, the combination of

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[21] R. de las Cases. Modeling of Multi-Pipeline Corridor Potential Profile with Common Cathodic Protection System. *NACE International Corrosion Conference*, (2019), Paper No.8910.

[22] L. Krissa, J. DeWitt, and P. K. Shukla. Experimental Studies to Determine Effects of Vapor Corrosion Inhibitors for Mitigating Corrosion in Casing. *NACE International Corrosion Conference*, (2016), Paper No. 7801.

[23] A. Garcia, L. Krissa, and J. DeWitt. Effect of Transmission Pipeline Properties on Alternated Induced Voltage. *NACE International Corrosion Conference*, (2017), Paper No. 9786.

[24] A. Garcia, L. Krissa, and J. DeWitt. Repair Prioritization Analysis for Cased Pipeline Crossings. *NACE International Corrosion Conference*, (2016), Paper No. 7587; P. Shukla, L. Krissa, and J. DeWitt. Overall Effect of Vapor Corrosion Inhibitors on Casing Corrosion Mitigation. *NACE International Corrosion Conference,* (2018), Paper No. 10901; P. Shukla, L. Krissa, J. DeWitt, and T. Whited. Monitoring Effectiveness of Vapour Corrosion Inhibitors for Tank Bottom Corrosion Using Electrical Resistance Probes and Coupons. *NACE International Corrosion Conference*, (2019), Paper No.13100.

multiple additives is rarely considered holistically. To date the corrosion prediction tools used to establish susceptibility to internal corrosion are not sufficiently robust to consider the effects of these multiple additives working together.

Corrosion related to sulfide stress cracking can be caused by the presence of H_2S in the transported product and can have a detrimental effect on pipeline integrity.[25] H_2S scavenger additives can be introduced into the product stream to help reduce the volatile chemicals, limiting corrosion and minimizing health and safety concerns related to handling of the transported product. However, these additives may have adverse effects on the refinery processes and could impact the usability of the delivered product. Additional research is required to better understand the effects of H_2S and its mitigating chemicals on pipeline integrity and refinery processes.

Microbial influenced corrosion is a type of corrosion that is caused by bacteria present on the pipeline that can cause material removal and pipe degradation. This can be managed through the use of corrosion inhibitors that kill the bacteria. However, microbial influenced corrosion can be investigated further given the recent advancement in available technologies. In the past, the knowledge around microbial induced corrosion was limited to a few known organisms; however, its management should start with an understanding of the community as opposed to the activities of end-stage corrosion processes.[26] This research may help to minimize the additives required by targeting specific bacteria types, saving cost and improving efficiency of the corrosion prevention process.

The potential interaction of different pipeline additives requires further investigation, especially when considering the combination of multiple chemicals that may interact to have more severe corrosion effects than originally predicted. The Canadian Crude Quality Technical Association led a discussion on additive testing in 2003, which suggested the industry should do more testing to gain a better understanding of these effects.[27] Research groups such as the Pipeline Research Council International are actively pursuing research in this area.

V. CONCLUSION

Pipelines are complex environments with continuously changing internal and external conditions, which lead to multifaceted corrosion processes with many variables. Industry has

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[25] D. Mansouri, M. Zafari, and A. Araghi. Sulfide Stress Cracking of Pipeline-Case History. *NACE International Corrosion Conference*, (2008), Paper No. 08480.

[26] L. Gieg, K. Wolodko, and F. Khan. 2015 Large-scale Applied Research Project Competition-Natural Resources and Environment Sector Challenges-Genomic Solutions. Genome Atlantic Center, 2016-2017; A. Garcia, T. Place, M. Holm, J. Sargent, and A. Oliver. Pipeline Sludge Sampling for Assessing Internal Corrosion Threat. International Pipeline Conference, (2014), IPC2014-33113.

[27] The Canadian Crude Quality Technical Association (CCQTA). Additive Screening Project. *Summary Report*, (2003), April.

performed a great deal of laboratory testing to better understand these processes, but these tests cannot fully simulate the true pipeline environment. In these real-world environments, multiple factors—such as long path corrosion processes, interference effects, shielding, galvanic differences, and unpredictable environmental variations—can have concurrent influences on corrosion rates and locations. These combined effects are typically not known or studied in detail due to the large number of possible permutations and combinations leading to nearly impossible test matrices. In pipeline systems, the attributing factors for corrosion vary along the length of the pipeline, which can affect both internal and external corrosion development and prediction. For example, spatial and temporal changes in soil moisture can affect the soil resistivity and thus can severely impact local corrosivity. Therefore, while corrosion is the oldest and most mature threat to the pipeline, continuous research and development is still important to better understand the complexities of the process.

Corrosion inspection and monitoring technology is a well-established field with proven technological background and strong industry best practices. Current research efforts focus on enhancing the technology to address particular problem areas (morphologies and operating conditions) in terms of measurement and assessment. Corrosion prevention technologies are important to asset integrity programs, as they prevent mitigation from being required and can provide valuable information regarding corrosion growth rates and locations. Continuous improvement of corrosion integrity technologies will help to ensure that all types of corrosion can continue to be addressed through preventative means, further limiting potential loss of containment events while enhancing the efficiency of integrity programs.