

Managing Corrosion of Pipelines that Transport Crude Oils

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“A simplified analogy for pipe corrosion is tooth decay...If you brush regularly, you probably won’t have many problems with your teeth. Similarly, if you sweep your pipeline clean of potential corrodents, you won’t have many problems with corrosion.”

—Trevor Place

Oil and gas pipelines play a critical role in delivering the energy resources needed to power communities around the world. In the United States alone, according to the U.S. Department of Transportation (DOT), more than 2.5 million miles of pipelines—enough pipeline to circle the earth approximately 100 times—deliver oil and gas to homes and businesses. While pipelines are recognized by government agencies such as the DOT and the National Transportation Safety Board as being one of the safest and most efficient means of transporting these commodities, their use still poses an intrinsic risk due to failures and leaks. Although major pipeline failures occur infrequently, several pipeline incidents in recent years have put the issue

of pipeline safety into prominent view. In response, both the Canadian National Energy Board (NEB) and the DOT are implementing measures that promote pipeline safety and security.

To better understand how corrosion can impact the safety and reliability of transmission pipelines, *Materials Performance* asked several NACE International members in the oil and gas industry to comment on the challenges faced by the industry when managing corrosion of pipelines, in particular the pipelines that

The Trans Alaska Pipeline.





A cleaning pig appears clean in the receiving barrel with only a small amount of sand on the rubber. Photo courtesy of Jenny Been, TransCanada Pipelines.

transport crude oils. Panelists are Jenny Been with TransCanada Pipelines; Oliver Moghissi with DNV; Michael Mosher with Alberta Innovates-Technology Futures; Sankara Papavinasam, FNACE,⁽¹⁾ with CanmetMATERIALS; Trevor Place with Enbridge Pipelines; and Sonja Richter with Ohio University. (See their biographies in the sidebar, "Meet the Panelists," pp. 32-33.)

MP: *The oil industry is facing concerns by the general public that heavy crude oils, particularly diluted bitumen (dilbit), are corrosive and can lead to leaks and oil spills from transmission pipelines. What are the main challenges the industry faces when managing corrosion of pipelines that transport crude oils?*

Moghissi: Internal corrosion is one of many possible threats to a crude oil transmission pipeline that must be managed. It should be noted that crude oil by itself is not corrosive at pipeline conditions, but water can drop out of the crude oil and allow corrosion to occur where it accumulates. Water carried by heavy crude oils, including dilbit, does not significantly differ in corrosivity from water carried by other crudes. Corrosion in crude oil pipelines is addressed by conventional corrosion control practices

and is generally effective. However, pipelines travel over long distances, and what is considered unlikely at one location can become significant when summed over a pipeline infrastructure.

Place: Crude oils, including dilbit, are not corrosive in pipelines. The main technical challenge is that trace water and sediments—not the crude oil—cause corrosion. The presence of crude oil, including the dilbits we have tested, actually decreases the corrosiveness of the standard brine used in standard testing. Although we know that we have a minimally corrosive system, we think it may be possible to reduce corrosion even further—and this possibility is what drives our research and development efforts. It is challenging to accurately measure very small or very rare things, and the corrosion that occurs in transmission pipelines is typically isolated and progresses rather slowly; this makes it difficult to identify and assess the likelihood of internal corrosion, and also to evaluate the beneficial effects of mitigation activities.

Mosher: One of the main challenges facing the industry with respect to managing corrosion of crude oil transmission pipelines is the difficulty in predicting internal corrosion. Most internal corrosion in crude oil transmission pipelines is caused by the settling of solid particles that can carry water to the pipe surface. Transmission tariffs are set to limit basic sediment and water (BS&W) to <1% (often 0.5%). The solid particles tend to be encapsulated by a layer of water that may concentrate water on the pipe wall surface. This creates the potential for corrosion to occur if the flow conditions of the pipeline system allow for these solids to settle out. The water (an electrolyte) is a necessary component of the corrosion cell. Without it, corrosion will not occur at appreciable rates within the transmission pipeline. This type of corrosion is typically referred to as underdeposit corrosion and will often manifest as localized pitting. Moreover, pitting corrosion can proceed rapidly or lay dormant for extended periods of time, making this type of corrosion particularly difficult to predict.

Richter: The main challenge is to manage the water that is transported along with the crude oil and is responsible for the cor-

rosion that occurs if it is in contact with the pipeline wall. Crude oils are not corrosive at temperatures encountered in pipelines. It is not until crude oils are heated in refineries that they can become corrosive. The industry severely limits the amount of water allowed into transmission lines to <0.5% by weight. While this small amount of water (which is heavier than the oil) can easily be kept off the pipeline wall and entrained in the crude oil, it is a challenge for the industry if production (and flow rates) decreases, making it more challenging to keep the water entrained and off the pipeline walls. However, heavier crude oils entrain the water more easily than lighter crude oils, which is beneficial for corrosion protection.

Papavinasam: The main challenge the industry currently faces is to establish public confidence that the risk due to internal corrosion of oil transmission pipelines is low and that the risk can continue to be managed at the lower level using established engineering practices. Under normal oil transmission pipeline operating conditions, corrosion occurs by an electrochemical mechanism. Crude oil (including dilbit), being a nonconducting electrolyte, does not support corrosion. However, if the crude oil contains water, then corrosion may take place in those locations where water drops out of crude oil and comes in contact with the metallic surface. The bulk crude oil may indirectly affect the corrosion by influencing the locations where water may accumulate and by influencing the corrosivity of water in those locations. The pipeline operators keep the risk of internal corrosion in oil transmission pipelines at a lower level by limiting the amount of water to <1% BS&W (typically to <0.5%). However, based on some non-scientific reports and extrapolation of corrosive conditions of refineries (operating above 200 °C) to the conditions of oil transmission pipelines (operating typically below 70 °C), some members of the public are concerned that crude oils are corrosive.

MP: *What are the characteristics of crude oils and the transportation process that could lead to transmission pipeline corrosion? Are some crude oil grades more corrosive than others?*

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Place: The primary factor that affects internal corrosion in transmission pipelines is flow rate. Transmission/refinery-ready crude oils (including dilbit) contain very little corrosion-causing water or sediment, but internal corrosion can occur if the flow conditions in the pipeline allow these materials to accumulate and persist on the pipe floor for extended periods of time. No crude oil grades have yet been proven to be more corrosive than others, but there are measurable variations in certain corrosion-related properties of crude oil. ASTM G205¹ is an industry guide for evaluating three important crude oil properties that can have an impact on internal corrosion: these are wettability, emulsion-forming tendency, and effect of crude oil on the corrosiveness of brine. Based on our investigation so far, there does not appear to be any correlation between the crude oil grade and these corrosion-related crude properties. Our tests have shown these properties to vary as much within a crude grade as they do between different crude grades.

Moghissi: Corrosion in crude oil pipelines is often attributed to microbiologically influenced corrosion (MIC). The most significant factor in evaluating the likelihood of MIC is whether water and solids suspended in the oil remain entrained or fall to the bottom of the pipe. The critical velocity for entrainment depends upon physical properties of the oil (e.g., heavy crudes have lower critical velocities) and throughput. With everything else being the same, pipelines with slow flow (below critical velocity) tend to be more susceptible to corrosion than those with high flow (above critical velocity).

Mosher: The primary method of crude oil corrosion within transmission lines is underdeposit corrosion. Particles settling at the bottom of the pipeline establish an environment that can promote a water-wetted surface. The chemical properties of the settled water and presence/absence of active bacteria could vary between crude oil sources, but (to my knowledge) there is no literature comparing the corrosiveness of waters from different crude oils. However, several papers have been published that show crude oils can inhibit the corrosiveness of water when mixed together. Settling

of solids during the transportation process is largely governed by elevation changes in the pipeline. In areas of overbends or underbends in the pipeline, the fluid dynamics can promote the settling of particles where they would otherwise be carried safely through the pipe. I have seen no evidence—scientific or statistical—indicating that one type of crude is noticeably more corrosive than another under standard pipeline operating conditions.

Papavinasam: Industry has established that the BS&W of oil transmission pipelines is lower than 1% (typically lower than 0.5 %) volume to volume. The result of low amounts of water in oil transmission pipelines is a low probability of internal corrosion. However, locations where water accumulates may be susceptible to corrosion. ASTM G205 classifies the crude oils into four categories in terms of how they affect the corrosivity of the water phase and provides detailed and systematic procedures for determining the corrosivity of the water phase in the presence of crude oil. Tests carried out by various research and testing laboratories conclude that the corrosivity of various crude oils is low and that of dilbit is in the same range as that of other crude oils.

Richter: The density difference between oil and water causes the water to tend to separate at the bottom of the pipe. This is more prone to occur with light crude oil as compared to heavy crude oil, and increases the possibility of corrosion. In addition, heavy crude oils are more likely to contain beneficial compounds that can help protect the pipeline from corrosion. These beneficial compounds can contribute to high acid numbers and/or high sulfur content. Although beneficial at lower temperatures, such as in transmission pipelines, these compounds can become corrosive at high temperatures, such as in refineries. A water wetting model is included in the MULTICORP corrosion prediction software developed by Ohio University, which allows for prediction of the flow rate necessary to keep the water entrained.

Been: The presence of a small quantity of water in crude oil is inevitable. However, <0.5% of water is not considered to be a corrosion concern unless conditions exist

that enable the precipitation and accumulation of this water on the pipe wall. Water drop-out and accumulation can occur at low velocities and under stagnant conditions. A model described in NACE SP0208-2008² can be used to determine the velocities at which water could drop out of crude oil as a function of the crude oil density and viscosity; the effect of temperature is minimal. Water is less likely to drop out at lower velocities when entrained in heavier crude such as dilbit as compared to typical light crude. These velocities are well below our normal operating velocities on our transmission pipelines. Increasing flow velocity and turbulence after a period of low velocity or line stoppage will reintroduce the water back into the main oil stream. Suitable models to predict the deposition of solids are not available. However, it is well understood that the deposition of sediments is minimized in highly turbulent flow. Where conditions are amenable to deposition and underdeposit corrosion, laboratory underdeposit corrosion tests have indicated that relatively low corrosion rates are expected over a wide range of crude densities.

MP: How does the industry identify corrosion in a transmission pipeline or determine if a transmission pipeline is susceptible to corrosion?

Been: The occurrence of internal corrosion is initially considered during the pipeline design phase, when the line is designed to operate normally under turbulent flow conditions to prevent the deposition of water and sediments. Prior to and during operation, predictive models are used to identify potential susceptible locations, with continuous consideration of changes in operational parameters. Cleaning pigs and intelligent pigs are used to regularly assess the pipeline condition during operation.

Richter: Corrosion is identified with systematic inspections, which include measuring the wall thickness and the corrosion rate. The susceptibility to corrosion is determined in part by predictions based on the water chemistry, flow characteristics, temperature, and in part by corrosion measurements. Typically, corrosion in crude oil pipelines occurs due to dissolved acid gases and water, both of which have been mostly

separated out before the crude oil enters the transmission pipeline.

Moghissi: The most common way to predict susceptibility to corrosion is to determine water content (usually measured as BS&W) and compare pipeline throughput to the critical entrainment velocity. Consideration can be given for the water chemistry, presence of corrosion inhibitors (including both carryover or injected), any biocide treatments, and whether the pipeline is pigged. Ultimately, the existence of corrosion damage can be verified by methods such as inline inspection (ILI), pressure testing, and/or internal corrosion direct assessment (ICDA). Each of these methods has different strengths and weaknesses.

Papavinasam: The industry assesses the susceptibility of oil transmission pipelines to internal corrosion by two processes: direct assessment and ILI. NACE SP0208-

2008 documents the use of the direct assessment method and proposes a four-step process to identify the causes of corrosion in oil transmission pipelines: pre-assessment (collect and analyze pipeline operating data); indirect inspection (identify locations susceptible to corrosion based on operating data collected); direct inspection (inspect the locations predicted to be susceptible to internal corrosion); and post-assessment (establish the frequency of subsequent inspections). NACE SP0208-2008 also lists several models that can be used to predict the location of water accumulation in the indirect inspection step. Currently, NACE Task Group 477 is developing a standard report to provide guidelines for selecting the most appropriate model for this purpose. NACE SP0102-2010³ provides guidelines to perform ILI where instrumented tools (commonly known as intelligent pigs) are

sent through the pipeline for determining the remaining wall thickness of the pipeline.

Mosher: ILI tools, such as magnetic flux leakage (MFL), ultrasonic testing (UT), or a combination of both, give the pipeline operator a “snapshot in time” of the internal and external condition of their pipeline. Corrosion features over a certain threshold are measured by the instrument as it passes through the pipeline. In addition, the location of the pig is recorded using a global positioning system (GPS). The tool gives the location of any anomalies detected along the length of the pipeline inspected. Anomalies of significant size/depths will often be validated by an excavation of the pipe. Often operators will use sequential ILI runs to predict the corrosion rates of anomalies and schedule future ILI runs based on their calculations. Other methods of identification include the NACE protocol

Meet the Panelists



Jenny Been

Jenny Been is a corrosion specialist with Trans-Canada Pipelines (Calgary, Alberta, Canada) in the Pipeline Integrity Department, where she focuses

on crude oil corrosion, risk assessment, and stress corrosion cracking. Been has more than 20 years of experience in corrosion control. During her career, she established a pipeline corrosion management industry working group focused on monitoring and mitigation of pipeline corrosion, has provided technical support to the National Energy Board's Pipeline Integrity Management Program, and developed pipeline integrity management manuals for pipeline operators. She currently serves on the NACE Board of Directors and has held leadership roles for several NACE technical committees. She attended the University of British Columbia where she obtained degrees in chemical engineering and a doctorate in materials engineering.



Oliver Moghissi

Oliver Moghissi is director of the Det Norske Veritas (DNV) Materials & Corrosion Technology Center (Columbus, Ohio). His personal

experience is focused on developing and applying technology to optimize corrosion management programs, especially for oil and gas production and transportation facilities, and includes optimizing corrosion control programs, developing corrosion evaluation methods, and implementing corrosion technologies for life extension and regulatory compliance. He has chaired a range of NACE technical and administrative committees and received the NACE Presidential Achievement Award in 2003. He served as president of NACE for the 2011-2012 term. Moghissi received a Ph.D. in chemical engineering from the University of Florida and M.S. and B.A. degrees from the University of Virginia.



Michael Mosher

Michael Mosher is a professional engineer at Alberta Innovates-Technology Futures (Devon, Alberta, Canada) in the Advanced

Materials Portfolio. Mosher has extensive expertise in pipeline corrosion and the majority of his work has focused on internal corrosion of crude oil transmission pipelines. Currently, Mosher leads an industry working group on pipeline integrity and corrosion management that is focusing on pipeline corrosion control systems for monitoring internal corrosion and developing mitigation strategies to reduce operating risks associated with pipelines as well as provide operational best practices and guidelines to the industry. He received a master's of applied science degree in materials engineering from Dalhousie University.

for ICDA of liquid petroleum pipelines (NACE SP0208-2008) and hydrotesting.

Place: Corrosion typically takes time to occur on a transmission pipeline, and pipelines could easily operate for more than 20 years before sufficient evidence of corrosion would demonstrate susceptibility. In the past, such identification was usually afforded through inline pipeline integrity inspection tools (smart pigging) used to identify areas of internal corrosion metal loss. This was a purely “reactive” evaluation of corrosion susceptibility. Enbridge now uses proactive operational analysis. An in-house susceptibility model based on theoretical analysis, in conjunction with our extensive pipeline operational history of more than 60 years, is used to assess the likelihood that water could accumulate in a pipeline. The primary driver in this analysis, as discussed previously, is flow conditions. The ability of

flowing oil to harmlessly transport trace corrodents like water and sediment is related to velocity, density, and viscosity of the oil. I believe most pipeline operators use either a theoretical model; an empirical experience-based model; or, like Enbridge, both.

MP: *How does the industry typically control corrosion that may be caused by transporting crude oils?*

Richter: There are two main ways in which corrosion of crude oil pipelines is controlled—by design and by mitigation. When new pipelines are designed, the material selection and the wall thickness allowance are determined based on a prediction of corrosion using models that take the water chemistry, type of flow, temperature, etc. into consideration. Once the pipeline is built, corrosion is monitored with corrosion measurements, and corrosion inhibitors are used to manage it. On top of

that, companies employ pipeline integrity strategies by using inspection and preventive maintenance to assure the integrity of the pipeline.

Moghissi: Corrosion is typically controlled by minimizing water contact with the pipe wall (i.e., low BS&W, flow rates above the critical entrainment velocity, avoidance of no-flow designs such as dead-legs, and pigging), chemical treatment (i.e., corrosion inhibitors and, rarely, biocides), and cleaning (i.e., pigging) to disrupt microorganisms attached to the pipe wall.

Place: There are a number of common internal corrosion mitigation strategies, the selection of which is dependent on the commodity being shipped, the flow conditions in the pipe, and the expected corrosion mechanism. A simplified analogy for pipe corrosion is tooth decay. Tooth decay can occur if there is a build-up of food and



Sankara Papavinasam

Sankara Papavinasam, FNACE, FASTM, is a senior research scientist and acting pipeline program manager at CanmetMATERIALS

(Hamilton, Ontario, Canada). He has been involved in pipeline corrosion control issues since joining Canmet in 1994, and has developed three software packages for prediction and control of internal and external corrosion of oil and gas pipelines. Papavinasam is a member of many NACE technical committees and is chair of Task Groups 070 and 447 and vice chair of Specific Technology Group 31 and Technology Exchange Group 282X. He received awards from Natural Resources Canada, ASTM International, and the NACE Northern Area for developing methods and techniques to control corrosion, and was named a NACE Fellow in 2008 and an ASTM Fellow in 2011. His academic degrees include a M.Sc. (1984), M. Phil (1985), and Ph.D. (1990).



Trevor Place

Trevor Place is an engineering specialist in the Corporate Pipeline Integrity Department at Enbridge Pipelines (Edmonton, Alberta, Canada),

where he has focused on internal corrosion management and prevention since 2005. Place has more than 23 years of experience in pipeline integrity and corrosion control, and has authored or co-authored papers on pipeline internal corrosion that discuss sedimentation of pipeline solids and underdeposit corrosion and its mitigation, as well as papers on cathodic protection, AC-influenced corrosion, and corrosion testing. He co-chaired the NACE task group that produced the liquid petroleum ICDA standard practice (SP0208-2008), and was a keynote speaker at the NACE 2012 Northern Area Eastern Conference on crude oil corrosivity. Place is a Professional Engineer and a NACE-certified Cathodic Protection Specialist and Senior Internal Corrosion Technologist.



Sonja Richter

Sonja Richter is a senior research scientist at the Institute for Corrosion and Multiphase Technology (ICMT) at Ohio University (Athens, Ohio),

where she leads a joint industry project (JIP), the Water Wetting JIP. The project is aimed at investigating the effect of crude oil on acid corrosion in multiphase flow and is sponsored by a consortium of oil and gas companies. Richter joined the ICMT in 2007 as a post-graduate researcher after having graduated with a Ph.D. in mechanical engineering from the University of Iceland in 2006. A NACE member since 2008, she is a member of several NACE technical committees that focus on corrosion in oil and gas production.

bacteria in the nooks and crannies of your teeth. The foremost method of preventing tooth decay is routine dental care. If you brush regularly, you probably won't have many problems with your teeth. Similarly, if you sweep your pipeline clean of potential corrosidents, you won't have many problems with corrosion. Such sweeping can be purely hydraulic—by the flow of the product—or facilitated by pipeline pigs. Some people continue to have tooth decay even when they brush regularly, and those people might find that a mouthwash provides incremental protection by killing cavity-causing bacteria. Similarly, a pipeline operator can use a batch corrosion inhibitor to reduce problematic bacteria or to provide a protective film along the pipe wall (just like fluoride strengthens tooth enamel). I must credit both Tom Jack and Joe Boivin for this analogy.

Been: Internal corrosion is managed through the use of preventive measures and monitoring tools. Normal pipeline operating conditions include turbulent flow to prevent water drop-out and solids deposition. Preventive measures include the use of cleaning pigs to remove deposits. These tools are run at a frequency that is established based on operating history and an understanding of the deposition mechanism and corrosion rates. It is continuously reassessed based on the volume and nature of sludge observed to be present. Other integrity assessments such as ILI are also leveraged in terms of adjustments to the cleaning program.

Mosher: The industry controls internal corrosion by three main mitigation methods. In the first method, crude oil pipeline operators maintain a turbulent flow regime to prevent the settling of solid particles and water droplets to the bottom of the pipe. In the second method, cleaning pigs remove any solids and/or water from the pipe surface and force them downstream. By taking away the solids and water from the pipe surface, the corrosive environment is removed. The third method is a chemical corrosion inhibitor package, applied following a cleaning pig run to suppress corrosion in a location where water collects. The inhibitor accomplishes this by suppressing either the cathodic or anodic reactions. In some cases, a biocide may be added to the

inhibitor package when MIC is believed to be a factor.

Papavinasam: The internal corrosion of production pipelines is primarily controlled by cleaning their surface using pigs and adding corrosion inhibitors and biocides. Crude oil transmission pipelines, on the other hand, are less susceptible to internal corrosion because they predominantly transport oil (more than 99%) and, by industry standard, their BS&W is limited to <1% (typically to <0.5%) volume to volume. All other corrosive substances are removed in the oil separators upstream of the crude oil transmission pipelines. However, the oil transmission pipelines may suffer internal corrosion in locations where water might accumulate. The operators control the internal corrosion by adjusting the flow rate so that water does not drop out and accumulate; using cleaning pigs to sweep off the accumulated water and sediment particles; and treating the surface with corrosion inhibitors and biocides.

MP: *Are enough technologies available to effectively identify and control transmission pipeline corrosion or is more research and development work necessary to address the issue?*

Papavinasam: Several advanced and reliable technologies are available and used in the industry. But there is always room for innovation and further improvements, and there are some specific areas where additional research and development (R&D) is needed. For example, computer simulation and industry experience indicate that the locations where water may accumulate in oil transmission pipelines are different for light and heavy oil; yet the boundary where the transition occurs is not well established. Further R&D is required to develop and validate reliable models to accurately predict the locations of water accumulation based on crude oil types. Also, laboratory methodologies to determine how the crude oils may influence the corrosivity of the water phase are established (ASTM G205); however, determining these properties requires withdrawing crude oil samples from the pipeline and carrying them to the laboratory for analysis. Advancements in techniques for online measurement of these properties would not only lessen the time lag between the sample collection and

analysis, but also would alleviate errors due to possible contamination of the samples. Additionally, ILI to directly measure the size and shape of the corrosion features is fairly established, but advancements in the algorithms and techniques to easily and quickly match the corrosion features from consecutive runs are required.

Been: The currently available tools and processes are sufficient to manage the internal corrosion threat for transmission pipelines; however, improvements and optimizations could be achieved with better predictive models regarding solids deposition and sludge corrosivity. We are actively involved in joint industry projects and R&D initiatives on internal corrosion monitoring and mitigation, including participation in public forums and conferences on crude oil corrosivity. During these events, we share our operating experiences and relevant integrity management practices. One industry effort employs a pilot-scale crude oil flow loop for the evaluation of cleaning pig designs and chemical inhibitor treatments and the assessment of corrosion monitoring equipment for underdeposit corrosion.

Moghissi: Improving our technical understanding of transmission pipeline internal corrosion would be helpful, especially with respect to predicting where extreme-value corrosion rates might occur. In addition, improving systems and processes for managing corrosion risk would also have an impact. This includes methods to incorporate corrosion in risk management systems. If corrosion risks were better tied to overall risk, operators could make more effective and efficient decisions.

Mosher: Technologies used in the detection and mitigation of internal corrosion for crude oil pipelines have progressed significantly in recent years but there is still a need for improvement and advancement. As long as there are corrosion failures occurring, it is imperative that better technologies be explored through R&D and field implementation. If we are to ever meet the industry target of zero incidents, detection and mitigation technologies will need to improve, either by refining the current tools or developing new and novel technologies.

Richter: There is already considerable technology and know-how that goes

into controlling transmission pipeline corrosion. However, new issues can surface, such as corrosion due to bacteria, which can occur under conditions that would not be very susceptible to acid corrosion. Furthermore, increased understanding of the fundamentals of the corrosion process and the mitigative methods needed to control it are an important aspect of keeping the state-of-the-art up to date.

Place: There is already a great deal of relevant technology available, but I don't think any engineer or scientist would ever say that there is enough technology. We are steadily increasing our understanding of the flow conditions that could promote the accumulation of potential corrodents, and there are new test methods being developed to determine the corrosion-related properties of crude oils. We have excellent pipeline inspection tools that rival medical imaging techniques, and we are developing new and improved processes to quantify pipeline reliability. However, integrity management is all about putting another zero between the decimal point and a failure incident—in true reliability terms, these probabilities are already very low, but they are not yet zero. I am confident that the industry at large will continue to undertake more research and development in the pursuit of perfect system reliability.

MP: *How would you rate the industry's track record in terms of managing transmission pipeline corrosion and preventing oil leaks and spills caused by pipeline degradation? Are current practices adequate or does more need to be done?*

Mosher: I believe the industry's track record for managing pipeline corrosion has been generally improving over the past couple of decades, despite facing an aging infrastructure. The industry has taken great steps to improve its integrity management systems; and this, in combination with ever-enhancing technologies for both corrosion detection and mitigation, will ensure an increasingly safer pipeline. Although the industry's record is quite respectable, neither industry nor the public should remain content with maintaining the status quo. Current practices cannot be deemed adequate while spills

and leaks are still occurring. It is certain that more work must be done to improve the integrity of our vital transmission pipeline network. To this effect, many of the larger pipeline companies actively support research and development efforts to improve their pipeline integrity.

Place: The statistics indicate that transmission pipeline performance is very good on its own merit, and extremely good as compared to other forms of hazardous materials transportation. With that being said, our industry has experienced some significant releases in recent history, so there is an ongoing need to improve and ultimately achieve our goal of zero releases on an annual basis. With the application of new technologies and continued growth in the application of reliability engineering principles, our industry performance continues to improve. There is significant investment by our industry through our research and development partner, Pipeline Research Council International (PRCI), as well as efforts led by the American Petroleum Institute (API), Association of Oil Pipe Lines (AOPL), and Canadian Energy Pipeline Association (CEPA). Through these efforts our industry is well-positioned for continuous improvement. The world's pipeline infrastructure is increasing in scope and capacity in direct response to our society's ever-increasing requirement for transportation of these important cargoes. So while current practices are excellent, our industry's perpetual desire for better and safer results lends itself to continuous learning and, therefore, changes and improvements in all of our integrity management practices.

Papavinasam: The oil transmission pipeline operation is mature and has a good track record. The industry has been successfully and reliably transporting oil in pipelines for more than 100 years now. Studies have indicated that the amount of oil spilled from oil transmission pipelines as a consequence of failure is <0.0001% of the total amount of oil being transported by the pipelines. The industry strives hard to improve the overall management system and to ensure that all tools and information available are effectively and consistently used. These efforts will further enhance the track record of the industry. The industry

currently undergoes tremendous change in terms of workforce. It is important to properly and systematically educate the next generation so that vast experience gained over the years is not lost and past mistakes do not reoccur.

Richter: As the infrastructure ages, the importance of corrosion management is increasingly being recognized within the industry and is taken very seriously. Current practices are adequate as they make use of state-of-the-art technology; however, it is advisable to continue to develop the technology and to increase the knowledge so we don't fall behind. This is especially true when it comes to corrosion mechanisms that are rather poorly understood, such as underdeposit corrosion and microbially induced corrosion.

Been: In our short term of operation, we have successfully managed transmission pipeline internal corrosion. The combination of the 0.5% BS&W limit and typically turbulent flow predisposes internal corrosion on crude oil transmission lines to be a low risk. However, the application of cleaning runs, ILI, and thoughtful design to minimize dead legs further mitigates the already low risk.

Moghissi: Although current corrosion management practices are generally good, the occurrence of leaks indicates that more can be done. It is my opinion that improving our understanding of how corrosion affects total risk, especially from unlikely events, can reduce the number of future leaks and spills.

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