Internal Corrosion Workshop
Atlanta, GA
March 26, 2009

PHMSA sponsored a workshop on issues related to internal corrosion (IC) of hazardous liquid pipelines on March 26, 2009, in Atlanta, GA. The workshop was held in conjunction with NACE Corrosion 2009. Presented below is a summary of the presentations made at the workshop, the questions posed by participants, and the responses to those questions. Copies of the presentations are available on the internet at https://primis.phmsa.dot.gov/meetings/Mtg57.mtg.

Opening Remarks by Jeff Wiese, Associate Administrator for Pipeline Safety

Recent events have caused questions to be raised concerning whether pipeline safety regulations adequately manage IC. Members of Congress are among those who have asked these questions. There have been a number of high-visibility spills over the last few years that resulted from IC, including the well-publicized spill on Alaska's North Slope.

Congress reauthorizes PHMSA's pipeline operations periodically, typically every four years. The last reauthorization occurred in 2006. During the later stages of Congress' work, there were 2 high-visibility spills in Alaska. That resulted in mandates being included in the reauthorization legislation on which PHMSA is still working. The Pipeline Inspection, Improvement, Enforcement and Safety Act of 2006 (PIPES Act, the reauthorization legislation) also required that PHMSA submit a report to Congress on this subject. That report has been submitted and is available via a link on PHMSA's web site. Congress will reauthorize PHMSA again in 2010, and could impose additional requirements if they conclude that the agency is not taking appropriate action to address this concern.

Among the commitments made in PHMSA's report to Congress were an Advisory Bulletin (issued as ADB-08-08), conduct of this workshop, evaluating opportunities to improve best practices and adopt consensus standards, and considering the need for new rulemaking. The Advisory Bulletin (available on PHMSA's web site) is a succinct description of currently-required actions; it is a clarification of existing rules. PHMSA also met with its Technical Hazardous Liquid Pipeline Safety Standards Committee on this subject in July 2007, and published the results of this meeting in the *Federal Register* August of that year for public comment.

From 1988 to the present, the trend for external corrosion accidents is downward. Over the same period, the trend for accidents caused by IC is upward. Congress and others are questioning why. One concern is the latitude operators have to determine whether a commodity is inherently corrosive. Another is the extent to which operators are taking actions to control internal corrosion, such as use of cleaning pigs.

Section 195.579 requires that operators must investigate the corrosive effect of the commodity transported and take adequate steps to mitigate internal corrosion. One concern now being expressed concerns the adequacy of those investigations. It is not enough to conclude that one does not have corrosion concerns because the pure product being transported is not corrosive. Products in transport are seldom pure. Contaminants can introduce internal corrosion problems even when the basic commodity would not be corrosive. PHMSA expects that operators will investigate thoroughly the potential for internal corrosion in their pipelines given the characteristics of the liquid actually being transported. PHMSA expects that operators will:

- Consider factors described in the Advisory Bulletin
- Conduct periodic product quality sampling
- Perform periodic review and evaluation of corrosivity
- Use cleaning pigs periodically
- Appropriately use and monitor inhibitors
- Analyze fluids from low-point drains and fluids removed by cleaning pigs to identify corrosion products
- Periodically inspect locations susceptible to IC
- Apply consensus industry standards
- Implement other suggestions found in report to Congress
- Look beyond the requirements of the pipeline safety regulations in Part 195

PHMSA is interested in feedback on the adequacy of existing standards and the need for more requirements. This is our opportunity, for PHMSA and for the industry, to assure that this important safety issue is being addressed appropriately. If we fail to take advantage of this opportunity, Congress could impose additional requirements.

This issue will be discussed again at the Research and Development Forum to be held June 24 and 25. Industry experts are encouraged to attend that meeting.

Questions and Answers

Has PHMSA found methods for corrosivity testing with which it is more comfortable? (Context was a comment that NACE could be more helpful and provide more options).

Response: The adequacy of testing is somewhat situation-dependent. This issue is likely to be among those discussed at the upcoming R&D Forum.

Internal Corrosion Considerations – Alan Mayberry (PHMSA)

At least 29 percent of corrosion accidents since 1988 have been caused by IC. The true percentage is likely higher. The type of corrosion was not specified for 20 percent of the corrosion-caused accidents reported to PHMSA, and 18 percent were defined as “other.” Some portion of these 38 percent were also likely be caused by IC. Most, but not all, of these accidents involved crude oil. Over 217,000 barrels of commodity have been released as a result of IC accidents. The Prudhoe Bay leak in March 2006 released 4800 barrels and affected 2 acres of tundra.

Section 195.579 addresses IC. It requires that operators investigate the corrosive effect of the commodities they carry and take appropriate mitigative actions. It does not require the use of inhibitors, but does require the use of coupons or other techniques to monitor the effectiveness of inhibitors if they are used. The rule requires that any pipe removed from a pipeline be examined to determine if IC is present. It also specifies standards for tank bottoms. Section 195.585 requires that operators take action when corrosion is identified if the remaining strength of the pipe is determined not to be adequate for the maximum operating pressure or if pitting is likely to result in leakage.

The investigation of the potential for IC that is required by 195.579 is expected to consider all relevant risk factors. These include:

- Foreign material (water, sand/silt, other contaminants, microbes)
- Impurities (sulfur, salts, acids, H_2S, CO_2)
- Pipeline design (flow, topography, low points)
- Upstream environment
- Temperature
- Pipe configuration, design, and material specifications
- Operating conditions (steady state, slack line, upsets)
- Any other circumstance or condition that could cause, promote, or increase the likelihood of internal corrosion

Any significant change in risk factors should result in re-investigation. Investigations must be valid for the current state of pipeline IC risk factors. Investigations must be documented as required by 195.589(c), and that documentation must be available for inspection. PHMSA's inspections have identified lack of documentation, weak or nonexistent technical analysis, no consideration for relevant internal corrosion risk factors, and failure to consider ILI results that identify internal corrosion anomalies.

Questions and Answers

1. Has the accident trend data been evaluated for the period since modern integrity management regulations have been in effect? Have they had an impact?

   Response: There has been some impact. We know that operators have made repairs for IC anomalies. It is hard to separate the effect of integrity management from the effect of modern pipe and practices.

2. How much analysis of incidents/accidents does PHMSA do? How does that feed into the agency's understanding of its needs?

   Response: The issues in Alaska were management of change and cleaning pigs. We see the need for more rigor to consider the differences as a field/producing area changes. We are considering the need to change the regulations. That's part of the reason for this workshop.

3. How closely does PHMSA investigate incidents?

   Response: We spent considerable time in Alaska, reviewing records.

4. How about the other 25 events each year?

   Response: We investigate all IC incidents and take enforcement action when it is appropriate. Alaska was unusual, in terms of the large size of the lines that were unregulated. They are now under regulation. PHMSA has done a detailed root cause review. On the broader front, PHMSA has added a dedicated accident investigator in each region. We've also created a data analysis group (Performance Evaluation Group – PEG) whose whole purpose is to review data from incidents, annual reports, etc. It's hard to investigate all incidents, particularly the small ones, to the same degree, but we are looking at the significance and addressing them appropriately.

5. What are PHMSA's expectations for dealing with different products, particularly refined products and chemical lines?

   Response: Deferred to later panels.

<u>NACE Standards on Pipeline Internal Corrosion – Oliver Moghissi (DNV Columbus)</u>

Standards are documents established by consensus and approved by a recognized body to address situations in which they are used repeatedly. Standards provide guidelines intended to achieve an optimum degree of order and consistency. For pipeline operators, use of standards often results in reduced costs, greater consistency and interoperability, regulatory compliance, and reduced liability exposure. Use of standards by all pipeline operators makes it easier to integrate a newly-acquired pipeline into an existing operational structure. For pipeline vendors, compliance with standards provides market access, a competitive advantage, and a vehicle for establishing a common understanding with their clients. For government, reliance on standards provides access to technology, lower costs for regulatory development and enforcement, and a reduced adversarial relationship with the regulated community.

The principal US standards developing body is the American National Standards Institute (ANSI). Their principals of standardization include:

- Transparency–access to information; time and opportunity to comment
- Openness–Participation by anyone
- Impartiality and Consensus–No favoring of interests. Consideration of views and attempted reconciliation
- Effectiveness and Relevance–Address regulatory and market needs, scientific and technological developments
- Coherence–Avoid conflict with other international standards
- Development Dimension–Facilitate developing country participation

The Development Dimension also serves to facilitate participation by all domestic stakeholders, including operators and vendors.

Standards are developed in response to an identified need. For example, NACE SP0206, covering IC direct assessment for dry gas pipelines, was developed in response to the regulatory requirement for integrity management assessments. In-line inspection and pressure testing are often not practical. External corrosion direct assessment standards were developed first, because "dry gas" is not normally considered susceptible to IC. Then the accident at Carlsbad occurred, demonstrating that IC was a real concern in pipelines carrying nominally-dry gas. Standard development began as an attempt to quantify the "first sag" in which an inspection could be conducted and an operator could reasonably assume that the pipeline was free from corrosion downstream if the inspection was successful.

NACE has developed a number of standards relevant to IC (see the presentation for a listing of these standards).

NACE's strategic goal is to establish, promote, and maintain a comprehensive integrated corrosion management framework. SP0206 addresses this goal by providing guidance on how to apply the numerous subject-specific standards that now exist. SP0206 does not, however, provide detailed guidance that may be needed for some decisions. There is room for improvement, and additional development work is needed.

For the future, there is a need for operational and life cycle management guidance that considers economic risk and the management structure with which to make decisions. NACE has a task group working on this. Their goal is an overarching document. It may identify gaps that will require additional standard development work. This is a top-down vs. bottom-up effort, which is different from most standards work.

Questions and Answers

1. When/why did NACE change from RP (recommended practice) to SP (standard practice)?

   Response: It is related to the use of the standards internationally, where standard practice is the term used. Standards now being renewed are changing from RP to SP.

2. Aren't the task groups only open to NACE members? (Refers to statement during the presentation that process is open and transparent to all).

   Response: Anyone can participate in the process. Task groups are typically developed for appropriate size and mix of people, but everyone can comment. The ANSI process also requires a broader opportunity for public comment.

3. How do you address corrosivity for chemical pipelines that don't normally contain water?

   Response: They are treated like every other pipeline. You need to make engineering judgments on the likelihood of internal corrosion and its location. If you are dealing with IC by managing it, you need to inspect to verify.

4. Why are we welding access fittings on carbon-steel pipelines when we can analyze the problem away? How can we use RP 0277 to substantiate the case against access fittings?

   Response: This reflects a decision where the benefits are expected to be greater than the costs. A standard won't tell you whether to install access, but it will address the considerations that are appropriate to making that decision.

5. When is the next review of SP 0106?

   Response: Standards are reviewed every five years. The number indicates this was the first standard adopted in 2006. It will be due for review in 2011.

6. With regards to TM0172, there are 2 problems: reproducibility and excess conservatism (higher rates).

   Response: NACE is working on that now. They will make + 10 percent water optional. That's not appropriate for determining corrosion rates. It is more applicable to evaluating the effectiveness of inhibitors.

Panel #1

PHMSA Data and History – Joshua Johnson (PHMSA)

IC occurs in an environment that is more controlled than the environment external to a pipeline. Most corrosion engineers know, intuitively, how to control internal corrosion. Why, then, is the trend for accidents from this cause upward?

IC is often seen as a secondary threat, largely under control. (The exception is when an inherently corrosive commodity, e.g., sour crude, is transported). External corrosion and third-party damage are seen as more important (less under control) and receive more attention. There are many more services and suppliers to the pipeline industry that deal with external corrosion. Most of those working in the pipeline industry are more at home dealing with external corrosion. There are fewer tools available to address IC. As a result, corrosion practitioners in the pipeline industry tend to be more uncomfortable dealing with IC. The level of that discomfort increases when microbial-influenced corrosion (MIC) is involved.

There are a number of reasons for a history of somewhat-ineffective control of IC. Corrosion coupons are often ineffective. They are located where they are accessible rather than where IC would be expected to occur (e.g., low points where water would drop out). MIC creates a situation that is not familiar to most corrosion specialists. Operators have often made insufficient use of cleaning pigs. Dead legs and other areas of no or low flow create an environment in which IC is more likely to occur.

Integrity management reviews have found IC, from reviewing pig logs, for instances in which the operator had concluded there was no IC threat. This has not always been pursued to the extent it should be.

Liquid Pipeline IC Examples – Dennis Johnston (Kiefner Associates)

Areas susceptible to IC are those with low or no flow that allow water to collect. These include:

- Portions of pump stations that rarely operate
- Drain lines
- Relief lines
- Valve bodies
- Sumps
- Tank bottoms

Typically, IC failures occur as small leaks from low-pressure pipelines due to localized metal loss. These leaks are hard to find.

Pipelines that operate infrequently are particularly susceptible to IC. Water and debris can drop out when the line is slack. Water may accumulate, move to low areas, and initiate corrosion. An operator cannot rely on turbulent flow to keep contaminants suspended if the line doesn't operate continuously.

Above-ground storage tanks also involve situations susceptible to IC. Water and debris may, again, drop out. Tank bottom corrosion can occur. Tank environments often concentrate water and incubate bacteria. If the water is not drained, it can be transported with product and cause problems in downstream piping.

Options to reduce the potential for IC include:

- Monitor and restrict the amount of water transported along with the product
- Drain water from above ground storage tanks prior to pumping
- Purge drain lines, relief lines, and portions that do not normally operate to displace the accumulated water
- Inspect with NDT to detect potential corrosion areas

MIC and IC – Brenda Little (Naval Research Laboratory)

A standard technique for dealing with MIC is liquid culture tests. There are problems with this tool, though. Only about 1 percent of naturally occurring bacteria can be cultured. Bacteria can go dormant, in which case they would not grow in a culture medium. There is no firm relationship between the numbers of bacteria and whether MIC has or will occur. In addition, not all sulfide-producing organisms are bacteria; sulfide-producing prokaryotes (SPP) are also a concern.

Archaeabacteria are not detected by standard culture kits and are very different from other bacteria. Archaea must be detected by molecular techniques. Hot samples from crude oil fields are rich in Archaea.

Pit morphology is often cited as a means of identifying MIC. Morphology can be deceiving. It should not be relied on to identify that corrosion is microbially caused in the absence of other data.

An accurate diagnosis of MIC requires:

- A sample of the corrosion product or affected surface that has not been altered by collection or storage
- Identification of a corrosion mechanism
- Identification of microorganisms capable of growth and maintenance of the corrosion mechanism in the particular environment
- Demonstration of an association of the microorganisms with the observed corrosion

Questions and Answers

1. How long can you rely on MIC samples for analysis?

   Response: You should take culture tests with you. If you are going to test for DNA, you should fix for that analysis. You can also fix for scanning electron examination. You need to take fixative media when drawing samples.

   You can see tunneling from acid attack as well as from bacteria. There are non-biological mechanisms to produce acids.

2. Can you comment on looking for acetate and manganese in corrosion that is MIC enhanced?

   Response: Measuring acetate can be very important. Manganese is important in some circumstances but it is not clear that it warrants routine monitoring.

3. We were told manganese was important to monitor if you have accurate corrosion – that it would come from the steel.

   Response: Doctor Little disagrees.

4. We are hearing that test kits might not be accurate. If you find bacteria, how do you address it?

   Response: Test kits can be useful if you really understand your system. If you know your system and know your problem you can grow bacteria. They are not useful if you don't know anything about your system. You can refer to GTI work. Molecular testing found other problems much more prevalent than sulfate-reducing bacteria – the test kit's target. You can have sulfate-reducing bacteria that will do something else if there are no sulfates in the system.

5. Can PHMSA provide guidance re: how operators can/should adjust testing techniques?

   Response: The regulations don't tend to require anything except not having IC. You need to recognize that negative test results, alone, do not necessarily prove there is no problem. More sophisticated techniques are probably not useful in a pipeline environment until you know there is a problem.

Panel #2

<u>Integrity Management and IC – Bruce Hansen (PHMSA)</u>

Section 195.452 requires integrity management for pipeline segments where a release could affect a high consequence area (HCA). Nearly 73,000 miles, or 45 percent of all hazardous liquid pipelines, have been determined able to affect an HCA. Operators must consider all threats, including IC. They must identify locations of greatest risk and implement mitigative actions for threats of concern. They must also assess the condition of their pipelines periodically.

Assessments are a key element of integrity management. Most hazardous liquid pipeline operators use in-line inspection (ILI) for most of their assessments. ILI detects metal loss, whether from the internal or external surface of the pipe. High-resolution magnetic flux leakage (MFL) tools are capable of differentiating internal from external metal loss. Most assessments are done using high-resolution MFL tools.

IM experience to date has identified weaknesses in IC control programs. These include poor or no integration of IC corrosion data in risk analyses and failure to consider factors important to the onset of IC.

At this point, PHMSA considers that the Alaska experience is somewhat anomalous. Such large low-pressure, low-flow crude oil pipelines are not prevalent in other locations. PHMSA does not now see indications of similar problems elsewhere.

Current Practices in Mitigating IC – Jeff Whitworth (Shell Pipeline)

Shell's IC management program establishes a philosophy of continual process improvement that involves a systematic approach to managing corrosion risks through consideration of data across a number of disciplines. The program is a closed cycle in which demonstrated performance is taken into account to adjust program approaches. Information developed by the program is available to all personnel via the company's intranet.

Elements used to prevent corrosion include maintenance pigging, control of oxygen entry, separation/dehydration, flow analysis, threat modeling, and risk assessment meetings. IC monitoring is accomplished via coupons and probes, direct assessment, sampling, and ILI. Corrective actions include inhibition, brush cleaning and biocides. Failures are subjected to root cause analysis.

Pipeline Stream Quality Management (PSQM) – Kyle Costlow (EPCO, Inc.)

PSQM is a program designed to identify, manage, and document potentially corrosive product streams entering a pipeline system. System evaluation and mapping analyzes the pipeline system configuration considering system characteristics and operating parameters. All incoming product streams are considered. Data sources (existing and required) pertaining to all incoming product streams are identified, and product limits are established. Data considered includes:

- Presence of Water
- Acid gas concentration
- Oxygen concentration
- Presence of Microbes
- System Pressure
- System Temperature
- Corrosion rate

System analyses help determine where turbulent flow exists, helping to focus attention on areas more likely to be subject to IC.

Product streams are sampled routinely, following upsets, at points where custody is transferred and by on-line monitoring. Unannounced spot testing is also conducted. Unannounced testing controls for suppliers who may adjust their supplies to assure that routine, scheduled, samples will be found acceptable.

A Pipeline Operator's Process Management Approach in Managing IC – Tim Blair (Marathon)

Marathon's internal corrosion process is designed to incorporate preventive and mitigative measures that are monitored and assessed to assure the structural integrity of its assets. Preventive and mitigative measures include:

- Internal coatings and linings
- A robust cleaning pig schedule
- Corrosion inhibitor
- Corrosive property standards
- Routine line movement/flushing
- Construction design/modification

Performance is monitored and assessed using ILI, risk assessment, corrosivity testing, coupon/probe analysis, MIC sampling, visual examinations, and internal corrosion direct assessment (ICDA).

The program has had a positive effect on internal corrosion experience. Considering five-year periods before and after program initiation, it has reduced IC-related releases by 100 percent on mainline pipe (2 in the prior five years and none in the subsequent), reduced IC-related releases on facility piping by 50 percent (14 to 7), and increased communication and understanding between pipeline integrity personnel and field operations (through process training).

Facility piping presents additional difficulties. Most cannot be pigged, eliminating the most effective monitoring tool. Marathon uses hydraulic flow monitoring, slip line installations, tethered pigs, supplemental corrosion inhibitor, and ICDA to control IC in facility piping.

Marathon has found that a robust cleaning schedule to remove deposits and water is a very effective tool in controlling IC.

Questions and Answers

1. Is there any reason not to require cleaning?

   Response: It's hard to think of a reason why an operator would not, but it begs the question of how often. We can't address making it mandatory at this time.

2. How many people does it take to support the corrosion control programs of the presenters?

   Response: Marathon – about 20 corrosion techs, about 8 corrosion specialists. About double that within the pipeline integrity department to which they report.
   Shell – with 4500 miles of pipelines and 36 terminals: 12 corrosion techs, 2 supervisors and a corrosion tech assistant. There are about 5 people dedicated to the IM program in the Asset Integrity Group. We also leverage other resources.
   EPCO: with 50-55,000 miles of pipe, there are about 52 people in the corrosion prevention group. 5 are supervisors, 2 are in the stream quality program. The majority are corrosion techs.

3. What is the baseline minimum for maintenance pigging on low-risk crude lines?

   Response: Marathon – quarterly (some are bi-weekly)
   Shell – quarterly (some are every 3 days)
   EPCO – highest frequency is monthly. Some are annual.

4. To Shell – what is your cleaning schedule and program for tank bottoms?

   Response: per 653. Crude tanks are generally lined. Most product tanks are not lined.

5. What is the test method for corrosivity?

   Response: 0172. EPCO also uses different kinds of tests.

6. How confident are you that you are catching incoming upsets?

   Response: Marathon – Hard to say better than average. Upsets do occur.
   Shell – we mostly transfer our own stuff so have high confidence.
   EPCO – it's foolish to think that you can catch 100%. We are trying to do what we can.

Panel #3

<u>PHMSA Pipeline Safety Research: Internal Corrosion 2002-2009 – Joe Mataich (PHMSA)</u>

PHMSA's pipeline safety R&D mission is to sponsor research and development projects focused on providing near-term solutions that will improve the safety, reduce environmental impact, and enhance the reliability of the nation's pipeline transportation system. Over the past seven years, PHMSA has co-funded 16 projects related to IC. These have addressed new technologies, standards, IC control risks and risk detection, prevention, and mitigation practices. One project has resulted in a NACE Standard, for liquid petroleum internal corrosion direct assessment. Several projects have investigated alternative in-line inspection vehicles.

Current projects are described in the presentation available at the meeting web site. Information on all projects can be obtained from the PHMSA web site: http://primis.phmsa.dot.gov/rd/.

Using side stream Using side stream monitoring and pipeline flow monitoring and pipeline flow modeling to better modeling to better understand internal understand internal corrosion threats – Benne Mumme (Koch)

Koch has used side stream monitors, including permanent installations and trailer-mounted, to monitor for internal corrosion. Typical equipment includes coupons, electrical resistance monitoring, linear polarization resistance, galvanic probes, and sessile bacteria monitoring. The presentation includes several photographs and plots of data acquired through side-stream monitoring.

Flow modeling can be used as part of a program to assure that water is kept entrained. Using elevations, pipeline specs, and crude types, models can illustrate necessary flow rates to keep water necessary flow rates to keep water entrained. Models can also identify areas where low flow rates suggest that water may accumulate and help in design of mitigation activities.

Evaluating Corrosion Mechanisms with Extended Coupon Analysis – Bruce Cookingham (BP Alaska)

The work described originated in research on MIC conducted by GRI (1988). It was initiated as a result of experience of offshore pipelines experiencing leaks from MIC despite use of biocides and inhibitors from early in their service period. Pipeline steel coupons were exposed in a model system containing multiple bacterial species. After various exposure periods, the coupons were examined using multiple techniques.

Targeted analyses identified problems involving selected chemicals that worked or didn't work to inhibit corrosion. As a result, BP was able to reduce its inhibition costs while increasing effectiveness.

Questions and Answers

1. Is the technique described by Bruce Cookingham commercially available?

   Response: Yes. CC Technologies (now DNV) and one other lab.

2. For Koch, has the galvanic probe helped measure liquid upsets and oxygen? How much does it cost?

   Response: We don't use the galvanic probe to measure oxygen. It is an indicator. You can do oxygen analysis in a sampling environment. The described unit cost 40-60 thousand dollars.

3. Are the tools for non-piggable lines described by Joe Mataich commercially available?

   Response: Two systems are in field demo for gas pipelines. None are yet commercial. See the PHMSA web site for more info.

4. Who should develop requirements for cleaning periodicity, the regulator or a standards organization?

   Response: Generally, regulators should follow the standards groups. It is a complicated problem. In Enbridge's experience, there is a significant relationship to the flow velocity.

5. Would sediment treatment work on sediments other than sands?

   Response: Sediments probably need to be treated individually, based on own merits.