10 Industry Practice Regarding SCC

10.1 Scope Statement

“Develop a practicable procedure regarding how to assess SCC in operating pipelines within the context of integrity management.”

This work item is addressed first in Chapter 10 and concluded in Chapter 11. This first chapter addresses both the capabilities of current practice and through an operator survey and operator interviews, the current methods of implementation by the industry. Chapter 11 addresses the same issues, but from the viewpoint of how these practices fit within and address the regulatory requirements of an Integrity Management (IM) program.

10.2 Questionnaire Concerning Current Assessment Procedures

In order to understand and assess the practices employed by operators to address SCC, Baker prepared a survey document to assist in gathering information from pipeline operators on SCC occurrence history and operating company practices for SCC detection, management and mitigation. The survey was drafted by Baker and reviewed by a working committee of INGAA, headed by Dave Johnson of Cross Country Energy Services, LLC, which made suggestions for improvement. The comments aided in streamlining the survey in order to provide for the rapid gathering of relevant information. The survey and cover letter were sent to member companies by the trade associations themselves. A copy of the survey and cover letter is included as Attachment A.

In endorsing the completion of the survey, INGAA and API, in their cover memo to member companies, stressed the importance of industry input into the process. The American Gas Association (AGA) also distributed the survey to their member companies who operate a reasonable amount of transmission pipe that could be affected by SCC.

Forty-two survey forms were returned, with one additional response made via email only. These responses represent 34 distinct operating entities, representing 45 natural gas and liquid pipelines. Note that one form addressed multiple pipeline systems, while other forms covering separate pipelines were reported by the same person or group. Also, note that not all respondents answered every survey question. Because the trade associations distributed the survey forms, the percentage of respondents from the original distribution cannot be determined. In general, however, the level of response was considered good, and appreciation is given to INGAA, API and AGA for their support.

10.3 Summary of Questionnaire Responses

10.3.1 SCC Occurrence Information

Twenty-three of the responses indicated that SCC had been detected, with the earliest detection noted as 1965. The system age at the time of first detection ranges from 7 years to 70 years, with an average of 29 years. It is important to note that, typical of such responses with a relatively small data base, numerical averages are skewed by disproportionate numbers that may be attributed to a
relatively small number of pipeline systems. For example, one operator reported 46 SCC in-service failures. Five other operators reported over 30 hydrostatic test failures apiece, with the highest reported by two operators being, coincidentally, 61. Thus, the numerical average numbers developed from this operator survey, such as of SCC in-service and hydrostatic failures (six and fifteen, respectively) can be misleading, and should not be construed as representative of industry averages.

Based on the responses received, the number of main line valve sections where SCC has been detected ranged from 48 percent down to 0.1 percent of the total number of mainline valve sections comprising each pipeline system. Approximately 45 percent of the SCC occurrences found were during inspections specifically for SCC, another 35 percent of the SCC occurrences were noted as found during an inspection specifically for SCC or during an inspection for other reasons, while the remaining 20 percent were found during an inspection not specifically looking for SCC.

Of the pipelines where SCC was noted by the respondents as having been detected (23 pipelines), 65 percent (fifteen pipelines) are natural gas lines and 35 percent (eight pipelines) are liquids lines. Since mitigation, 20 pipelines of these pipeline segments were reported as not having experienced additional in-service or hydrostatic test failures.

10.3.2 SCC Detection Methods

There are several nondestructive examination (NDE) methods available for identifying SCC on a pipeline system. The most common include:

- **Visual** – The pipe is exposed and the pipe coating is examined for soundness and performance. The coating is then removed at locations where disbonding is suspected and a technician examines the pipe surface for evidence of cracking. Note that normally SCC colonies cannot be detected by the naked eye.
- **Magnetic Particle** – The pipe is examined visually with the assistance of magnetic particle imaging.
- **Liquid Dye Penetrant** – The use of dyes on the surface of the pipe to enhance the visualization of cracks.
- **Eddy Current** – The use of eddy currents to measure the occurrences of cracking.
- **ILI Tool** – MFL, TFI, EMAT, etc.

On the survey form, the respondents could make multiple selections as to the methods employed. The percentages of distinct operator entities utilizing each of the NDE methods for SCC detection described above are summarized in Table 10.1.
Table 10.1 NDE Methods Used for SCC Detection

<table>
<thead>
<tr>
<th>NDE Method</th>
<th>Number of Operators</th>
<th>Percent of Operators</th>
</tr>
</thead>
<tbody>
<tr>
<td>Visual</td>
<td>21 (of 34 operators)</td>
<td>62%</td>
</tr>
<tr>
<td>Magnetic Particle</td>
<td>18</td>
<td>53%</td>
</tr>
<tr>
<td>Liquid Dye Penetrant</td>
<td>5</td>
<td>15%</td>
</tr>
<tr>
<td>Eddy Current</td>
<td>1</td>
<td>3%</td>
</tr>
<tr>
<td>ILI</td>
<td>10</td>
<td>29%</td>
</tr>
<tr>
<td>Other</td>
<td>5</td>
<td>15%</td>
</tr>
</tbody>
</table>

For the “other” category, operators comments included: Destructive laboratory methods, metallurgical examination and optical microscopy; 100 mV Shift Close Interval Survey, DCVG; field ultrasonic techniques; and, metallography.

Of the operators that responded as to whether or not they had written procedures for NDE evaluation, physical field practices for SCC detection, and/or reassessment intervals if SCC is detected, 81 percent (26 of 32), 73 percent (24 of 33) and 50 percent (16 of 32) responded “yes,” respectively.

10.3.3 SCC Management

There are a number of management practices available for SCC. The following is a list of management practices specifically noted on the survey form:

- Failure History Characterization – Use information of past SCC failures as an indication of the specific conditions that may result in the future occurrence of SCC.
- Coating Type Characterization (Coal Tar, Tape, etc.) – Characterizes the condition and type of coating, and correlates the information with the occurrence of SCC.
- Pipe Material Characterization (API Grades, Pipe Mill, etc.) – Characterizes the type of pipe and correlates it to the occurrence of SCC.
- Operation Characterization (Pressure, Temperature, etc.) – Correlates the specific operating conditions of the pipeline with the occurrence of SCC.
- Location Characterization – Correlates the environmental conditions near the pipe with the occurrence of SCC.
- Age Characterization – Correlates the age of the facilities with the occurrence of SCC.
- Bell Hole Characterization – Results of buried pipe inspection reports are utilized to determine if there are common characteristics in pipe with SCC compared to pipe with no SCC utilizing trending analysis.
- Magnetic Flux Leakage ILI Characterization – Utilization of MFL ILI tools to detect SCC.
- Other ILI Characterization – Utilization of other ILI tools to detect SCC.
- Cathodic Protection Level Characterization (Voltage Levels) – Monitoring of CP voltage levels at locations with and without active SCC for use as a predictive tool.
- Hydrostatic Retest Program – Testing pipe to determine presence of SCC. If test pressure critical size cracks are present, a rupture of the line will likely occur.
- External Corrosion Direct Assessment
- Risk Assessment Ranking (Segment by Segment Comparison)

On the survey form, the respondents could make multiple selections as to the methods employed. The percentages of distinct operator entities utilizing each of the SCC management practices described above are summarized in Table 10.2.

<table>
<thead>
<tr>
<th>SCC Management</th>
<th>Number of Operators</th>
<th>Percent of Operators</th>
</tr>
</thead>
<tbody>
<tr>
<td>Failure History Characterization</td>
<td>20 (of 34 operators)</td>
<td>59%</td>
</tr>
<tr>
<td>Coating Type Characterization</td>
<td>20</td>
<td>59%</td>
</tr>
<tr>
<td>Pipe Material Characterization</td>
<td>9</td>
<td>26%</td>
</tr>
<tr>
<td>Operation Characterization</td>
<td>21</td>
<td>62%</td>
</tr>
<tr>
<td>Location Characterization</td>
<td>13</td>
<td>38%</td>
</tr>
<tr>
<td>Age Characterization</td>
<td>15</td>
<td>44%</td>
</tr>
<tr>
<td>Bell Hole Characterization</td>
<td>13</td>
<td>38%</td>
</tr>
<tr>
<td>Magnetic Flux Leakage ILI Characterization</td>
<td>13</td>
<td>38%</td>
</tr>
<tr>
<td>Other ILI Characterization</td>
<td>8</td>
<td>24%</td>
</tr>
<tr>
<td>Cathodic Protection Level Characterization</td>
<td>13</td>
<td>38%</td>
</tr>
<tr>
<td>Hydrostatic Retest Program</td>
<td>14</td>
<td>41%</td>
</tr>
<tr>
<td>External Corrosion Direct Assessment</td>
<td>9</td>
<td>26%</td>
</tr>
<tr>
<td>Risk Assessment Ranking</td>
<td>13</td>
<td>38%</td>
</tr>
</tbody>
</table>

Approximately 48 percent (16) of the operators who responded when asked whether or not they had written procedures for SCC management (33) answered “yes.” Of the 14 distinct operators who indicated how long these written procedures had been in place, four stated that they have had a written procedure for 30 or more years on at least one of their pipeline systems. Six operators indicated implementation of written procedures within only the last four years on at least one of their pipeline systems.

10.3.4 SCC Mitigation

SCC mitigation techniques identified in the survey include:
- Operating Condition Modification (Pressure or Temperature Reductions, etc.)
- Selective Sleeve Installation
- Clean Pipe and Recoat
- Grind Pipe and Recoat
• Soil Condition Modification (Drainage Pattern Change, Replacement or Chemical Treatment of Soil, etc.)

On the survey form, the respondents could make multiple selections as to the techniques employed. The percentages of distinct operator entities utilizing each of the SCC mitigation techniques described above are summarized in Table 10.3.

Table 10.3  SCC Mitigation Techniques

<table>
<thead>
<tr>
<th>SCC Mitigation</th>
<th>Number of Operators</th>
<th>Percent of Operators</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating Condition Modification</td>
<td>17 (of 34 operators)</td>
<td>50%</td>
</tr>
<tr>
<td>Selective Sleeve Installation</td>
<td>17</td>
<td>50%</td>
</tr>
<tr>
<td>Clean Pipe and Recoat</td>
<td>12</td>
<td>35%</td>
</tr>
<tr>
<td>Grind Pipe and Recoat</td>
<td>15</td>
<td>44%</td>
</tr>
<tr>
<td>Soil Condition Modification</td>
<td>2</td>
<td>6%</td>
</tr>
<tr>
<td>Other</td>
<td>15</td>
<td>44%</td>
</tr>
</tbody>
</table>

Of the 31 operators that responded as to whether or not they had written procedures for SCC mitigation, approximately 52 percent (16 operators) responded “yes.”

10.4 Operator Interviews

A series of operator interviews were conducted subsequent to receipt of the responses to the questionnaire. The operators were very cooperative in supplying information regarding their procedures and policies. Results from the interviews are summarized in Table 10.4 with additional details in the following sections.
Table 10.4 Summary of Operator Interviews

<table>
<thead>
<tr>
<th>Operator</th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
<th>F</th>
<th>G</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operates hazardous liquid (L) or gas (G) transmission pipelines.</td>
<td>G</td>
<td>G</td>
<td>L</td>
<td>G</td>
<td>G</td>
<td>G</td>
<td>L</td>
</tr>
<tr>
<td>Has operator experienced in-service failures (leaks or ruptures) attributed to SCC? Yes (Y) or No (N)</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
<td>N</td>
<td>Y</td>
<td>Y</td>
<td>Y</td>
</tr>
<tr>
<td>Has operator experienced hydrostatic testing failures (leaks or ruptures) attributed to SCC? Yes (Y) or No (N)</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
<td>Y</td>
<td>Y</td>
<td>Y</td>
<td>Y</td>
</tr>
<tr>
<td>Has operator discovered SCC using ILI (I) or MPI (M)?</td>
<td>I/M</td>
<td>I/M</td>
<td>I/M</td>
<td>M</td>
<td>I/M</td>
<td>M</td>
<td></td>
</tr>
<tr>
<td>Has operator attributed observed SCC to high-pH SCC? Primarily (P), Mixed (M), None (N)</td>
<td>P</td>
<td>M</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Has operator attributed observed SCC to near-neutral pH SCC? Primarily (P), Mixed (M), None (N)</td>
<td>P</td>
<td>P</td>
<td>N</td>
<td>P</td>
<td>N</td>
<td>N</td>
<td></td>
</tr>
<tr>
<td>Does operator consider ILI reliable for detection of SCC? Yes (Y) or No (N)</td>
<td>N</td>
<td>N</td>
<td>Y</td>
<td>N</td>
<td>N</td>
<td>N</td>
<td></td>
</tr>
<tr>
<td>Does operator rely primarily upon hydrostatic testing for detection of SCC? Yes (Y) or No (N)</td>
<td>N</td>
<td>N</td>
<td>Y</td>
<td>Y</td>
<td>Y</td>
<td>Y</td>
<td></td>
</tr>
</tbody>
</table>

10.4.1 Operator A

Operator A operates several major gas pipelines. A southern pipeline had 14 in service failures. All of these were at tape coating sections. Since they instituted a spike test, followed by normal hydrotest, they have experienced no further in-service failures in this line, although there have been some test failures. They established their re-inspection interval based on an early Life Prediction Model developed by Brian Leis/PRCI. Currently they are using a 7-year re-test interval.

One of their northern lines had instances of SCC detected by inspection of sites selected as potentially favorable for occurrence of SCC, based upon the experiences of TCPL. Crack depth in all instances was less than 10 percent of the wall, and the repair procedure was to grind out the SCC indications.

Generally, fusion-bonded epoxy (FBE) external coating has performed well and Operator A concludes that FBE should be viewed as a mature coating that consistently performs well given good application procedure. They specify 14-16 mils thickness for FBE.

Operator A has issued an internal safety advisory bulletin on SCC while a procedure for inspection of pipe under disbonded coating for SCC is being developed. Operator A performs wet fluorescent magnetic particle inspection (WFMT) whenever there is evidence of a disbonded coating. They are currently training in-house corrosion technicians/engineers to the latest draft of their SCC procedure.
and expect to adopt it as an operating procedure once their in-house resources are fully trained to the procedure. The instances and evaluation of these excavations will be added to their in-house database.

The idea of operators sharing their individual databases relating to occurrence of SCC with the pipeline industry was discussed. Operator A believes an industry-wide SCC database might be helpful, and would consider participation if individual corporate names associated with the data need not be attributed within the database. An industry organization such as PRCI might be a good “clearinghouse” for an SCC database.

Concerning ILI, Operator A has concluded that the ILI industry does not offer an effective tool for detecting SCC in gas pipelines. Operator A tried and abandoned use of the liquid coupled elastic wave tool, and mentioned that running tools in slugs is expensive and disruptive to operations, requiring drying the line in addition to the other considerations. The possibilities of EMAT were discussed, though no specifics were available.

Operator A recognizes that initiation of SCC, as well as reactivation of dormant SCC, is related to strain rates imposed by pressure cycles being within a critical range; however, they note that control of pressure cycles to avoid the critical range of strain rate is not feasible.

To summarize, Operator A asked that SCC be characterized in perspective to a number of operational considerations, including not only other more frequent failure modes, but also concerns over supply reliability. Pipelines that cannot be pigged must be shut down in order to perform an integrity assessment using hydrostatic testing. Interrupting operation of a single pipeline that supplies power plants or local distribution companies (LDC) may have significant economic impact upon a community and result in other public concerns and safety issues. Direct assessment for identification of SCC has not proven sufficiently reliable to substitute for hydrostatic testing.

Operator A identified a need for collaborative funding for improvement in ILI tools for detection of SCC, and for development and validation of direct assessment methods for SCC.

10.4.2 Operator B

Discussion with Operator B was limited to their interstate gas pipelines. The original pipeline was constructed in 1931 and was assembled by oxy-fuel welding and couplings, and has since been phased out of operation. The remaining looped pipeline segments date from the 1940s to 1970s and is predominately Nominal Pipe Size (NPS) 30 and 36.

This portion of Operator B’s system experienced two in-service failures identified as classic or high-pH SCC in 1973 and 1984. These two failures were classic in that they were located in the first valve section downstream from a compressor station. After these two SCC failures, Operator B initiated a program of hydrostatic testing for the first valve sections downstream from compressor stations. Initially these hydrostatic tests were at 105 percent of SMYS at the lowest elevation for 1 hour, but were later revised to spike-type tests at 100 to 110 percent of SMYS for 1 hour followed by 100 percent of SMYS for 7 hours.

Operator B has not experienced hydrostatic test failures attributed to classic SCC, nor have they identified other classic SCC incidents as a result of inspection of exposed pipe.
Operator B has experienced multiple in-service failures attributed to low- or near neutral-pH SCC on NPS 26, 30 and 36 pipeline segments coated with asphalt enamel external coating. Subsequent hydrostatic testing and direct examination has revealed other instances of near neutral-pH SCC associated with disbonded asphalt enamel coating.

Operator B has observed the following characteristics of near neutral-pH SCC on their large-diameter system:

- Asphalt enamel coating that has disbonded, typically around the full circumference of the pipe, and for a significant distance along the length of the pipe, but remains intact as a shell around the pipe.
- A film of water between the disbonded external coating and the pipe surface.
- Adherent surface deposits containing:
  - rust-colored iron oxide,
  - powdery white calcium carbonate, and
  - pasty white iron carbonate.
- Shallow pitting corrosion.
- Families or colonies of parallel cracks aligned with the axis of the pipe (circumferential SCC has not been observed). Most cracks are relatively shallow, but linked cracks have been sufficiently deep to cause the in-service failures at normal operating pressures.

Operator B has prepared an SCC Comparator that is distributed to field personnel who may be present at excavation sites and have occasion to observe and report on the condition of the pipeline. The SCC Comparator is a laminated sheet printed front and back that includes color photographs of known instances of SCC that field personnel can reference during direct examination of excavated pipe. Field personnel who observe the characteristics in the above bullet list are instructed to request that a corrosion specialist inspect the pipe further for SCC.

After the second in-service failure attributed to near neutral-pH SCC, Operator B contracted with GE-PII to perform an ILI with their Elastic Wave Tool on the pipeline that experienced the failure. Subsequent direct examination revealed that while the Elastic Wave Tool can detect SCC, other surface conditions that are not injurious to integrity are also reported. The number of indications that are not SCC may exceed the number of SCC indications by three to ten.

Operator B has invested considerable effort to identify other information that can be integrated with the results from the Elastic Wave Tool to increase the probability of identifying near neutral-pH SCC at a dig site. Operator B reports that integration of results from:

- a high-resolution MFL tool, graded for external corrosion depths up to 10 percent pipe body wall penetration,
- the Marr Associates Soil Characterization/SCC predictive model, and
- close-interval CP survey,
combined with the results from the Elastic Wave Tool significantly increases the probability of correctly predicting the location of near neutral-pH SCC on their system.

The MFL tool results are graded to identify indications of pitting corrosion with up to 10 percent wall loss (different from grading for identification of significant wall loss) but with no deeper corrosion. Locations with relatively minor pitting corrosion are likely to be associated with disbonded, but intact external coating with corrosive water between the coating and pipe surface.

The Marr Soil Model identifies locations where near neutral pH SCC may occur if disbonded coating is present.

Acceptable results from close interval surveys are consistent with absence of extensive coating holidays, or disbonded coating that remains intact.

By application of all of the criteria, Operator B identifies locations with otherwise minor pitting corrosion that could occur under disbonded coating, soil conditions that may cause SCC and indications of surface conditions that may be SCC.

During excavation and direct examination of locations selected by the screening method, the pipe is evaluated by visual examination for deposits. The pipe surface is cleaned with a brush-off blast and examined for shallow pitting corrosion and with MPI, typically using the wet black powder on white background.

Operator B employs manual UT to evaluate depth of near neutral-pH SCC revealed by MPI.

Depending upon depth of identified SCC, Operator B may grind the cracks to sound metal and recoat, or replace the section with new pipe.

Operator B reports application of epoxy coating to all large diameter pipe exposed for direct examination and considers that to be a permanent solution to avoiding SCC at the recoated locations, even if minor surface cracks remain.

Operator B hydrostatically tests each valve section where near neutral pH SCC has been identified, examined and repaired. Operator B acknowledges that shallow near neutral pH SCC under disbonded coating that was not removed for direct examination may survive hydrostatic testing and may eventually grow deeper.

Operator B has a 3-year contact with GE-PII for ILI services and works closely with GE-PII to improve reliability of their tools for detection of SCC in gas transmission pipelines. Operator B has previously been an active member of the AGA-Pipeline Research Committee (now Pipeline Research Council International, Inc.) for decades and favors cooperative funding of the improvement of ILI technology for detection of SCC.

10.4.3 Operator C

Operator C operates thousands of miles of large diameter transmission and distribution lines throughout Canada and the US. These lines range in diameter from 10-inch to 48-inch NPS. The system transports liquids with roughly 50 different commodities from jet fuel to crude oil. Another group operates the gas transportation side of their business.
The dates of construction for the system range from the 1940s to the present. The coating type varies with somewhere between 30 and 40 percent being polyethylene tape wrap. The current coating of choice for new construction is fusion-bonded epoxy, though the use of a three-part powder polyethylene coating was mentioned. Nearly all of their system is designed to allow passage of ILI tools.

Operator C employs approximately 30 people within their integrity management group. The overall program is driven by the company’s main goal of NO leaks.

They approach SCC as just one portion of an overall defect management program, which attempts to prevent the occurrence of defects, locate defects that do occur and mitigate defects as appropriate. They use ILI as the primary source of data gathering. In particular, the use of high-resolution UT tools has been used effectively for detection of SCC. While they rely upon the ILI tool vendors for initial data processing, they apply in-house knowledge to validate and improve ILI data interpretation. This has resulted in reducing the number of false positive anomaly reports. They anticipate conducting nearly 6,000 miles of ILI this year.

They do not utilize a specific hydrostatic testing program for defect management as they feel that ILI is more accurate and cost effective.

Operator C performs approximately 1,000 digs per year based on ILI results. Whenever the pipe is exposed, magnetic particle inspection (black on white) and ultrasonic testing (shear wave) is conducted. The lack of a specific ASNT training manifest for pipeline inspectors was mentioned as an area of potential improvement.

They currently base SCC fitness-for-service (FFS) analysis on the AGA NG-18 ln-secant formula for critical flaw size, though they noted that this is not entirely appropriate since this formula is for analysis of a semi-elliptical flaw, which is somewhat different than what occurs within an SCC colony. They have been conducting burst tests on cut-out sections of pipe containing SCC with results being collected in an empirical database, which can then be used to refine the FFS analysis.

Operator C feels that the pressure cycle/profile or, in actuality, the strain rate associated with pressure fluctuations has a direct effect on the growth and dormancy of SCC. High strain rates equates to high occurrences of SCC.

The majority of SCC found has been the near neutral-pH type, which is consistent with the general findings that near neutral-pH SCC occurs more on pipelines that experience low soil temperatures. It was postulated that related to the higher solubility of CO2 at lower temperatures.

If SCC is found, the cracks are ground out if possible with pressure capacity checks being made using RSTENG. If necessary, full encirclement, pressure-containing sleeves are installed over the area, or if SCC is present over a large area, an entire section may be replaced. In any case, the repaired section is recoated with the recoating extending virtually the entire length of the excavation.

While Operator C has not had any failures related to SCC (they have experienced corrosion fatigue incidents), they indicated that post-incident response would initially be the same as any incident. They have procedures in place on accident investigation including transportation of failed sections and laboratory examination. If the forensic investigation concludes that the cause was SCC, then
their integrity management program is used to determine an appropriate long-term response. In the opinion of Operator C, a pressure reduction to 80 percent of the level at which the failure occurred, which is widely applied when responding to an SCC incident, is effective approximately 80 percent of the time; however, additional site-specific analysis is needed to determine the final long-term response.

Operator C cooperates with and supports both PRCI and CEPA in basic research, but also performs substantial in-house research on ILI, repair techniques and non-destructive evaluation.

10.4.4 Operator D

Operator D operates multiple pipeline systems that include thousands of miles of pipeline transporting gas from the Gulf Coast to the Northeast USA. One of these systems is nearly 100 percent piggable and has been entirely pigged. Another of the systems is approximately 75 percent piggable, and all of the piggable sections have been pigged. The systems include approximately 170 valve sections that are immediately downstream from compressor stations.

The Integrity Management Program for Operator D is organized under a Director of Pipeline Integrity & Operational Compliance who reports to the Vice President of Operations. Responsibility for mitigation of stress-corrosion cracking (SCC) is assigned across three groups headed by Managers reporting to the Director.

- Manager - Operational Compliance
- Manager - Pipeline Integrity
- Manager - Metallurgical Services

Operator D was proactive in initiating a hydrostatic testing program of the first valve sections downstream from compressor stations in 1986 without suffering an in-service failure. To date, Operator D has tested 63 valve sections containing approximately 1,343 miles of pipeline. Operator D employs a spike hydrostatic test program with the test pressure for the first hour producing a hoop stress greater than 100 percent of SMYS, and the remaining seven hours at a test pressure producing a stress greater than 90 percent to SMYS. Operator D routinely employs a flame-ionization leak survey immediately after return-to-service from hydrostatic testing, followed by one or two subsequent leak surveys after two or three month intervals. Operator D considers the post-test flame-ionization leak surveys technically superior for detection of small leaks compared to the seven-hour hold period of hydrostatic testing.

Operator D has experienced approximately 12 pipeline failures (leaks and ruptures) during hydrostatic testing that were attributed to SCC, but no in-service failures have been attributed to SCC. Operator D considers that the hydrostatic testing program has demonstrated success in avoiding in-service failures due to SCC.

When a hydrostatic testing failure attributed to SCC has occurred in a valve section, that valve section is characterized as SCC Susceptible Site for purposes of retesting. The next downstream valve section may also be included in the test program. Valve section characterized as SCC Susceptible Sites are scheduled for retesting, with the first interval being 3 years. If the re-test of a
valve section classified as an SCC Susceptible Site does not result in a failure attributed to SCC, the retesting interval is extended one year. Consequently, the re-testing intervals could increase from 3 years to 4, 5, etc. years as long as no other failures were attributed to SCC. The hydrostatic retest criteria have been effective, but will require some changes to accommodate the next integrity assessment criteria of the IMP regulations.

All SCC that Operator D has observed has been confined to approximately 6 valve sections and classified as classic or high-pH SCC. All observed SCC has been oriented longitudinally, or no circumferential SCC has been observed. Observed SCC has generally been on the lower portion of NPS 26 and 30 pipes, and associated with disbonded coal tar enamel (80 percent of incidents) or asphalt coating (20 percent).

Operator D has attempted ILI for SCC using both the elastic wave and EMAT tools, but the experience was unsatisfactory. Operator D’s experience with both types of ILI tools was that the tool provided false-positive indications of SCC that were not SCC, and SCC was not identified in some cases where colonies were known to exist. Consequently, Operator D will continue to rely upon hydrostatic testing for the near future as the most reliable method for determining if a valve section has suffered SCC that is a threat to pipeline integrity.

Operator D is currently revising their SCC management program for compliance with the gas integrity rule and considers the following five factors as the most significant for assessing the SCC threat on a pipeline segment:

1. High operating temperature.
2. High operating pressure.
3. Coating condition.
4. Location (i.e., downstream from compressor station as well as geographic location).
5. Cathodic protection effectiveness.

While other factors may be useful for threat assessment, Operator D considers them secondary to these five factors.

A corrosion technician is typically present at an excavation for visual examination of pipeline condition. Operator D has employed magnetic particle testing (MT) of exposed pipe surfaces in the past, but not as a routine practice for all exposed with disbonded coating. The revised SCC management program will include use of wet, black MT on white contrast for examination of pipe under disbonded coating. Contract inspectors will perform the MT in the near term, but Operator D anticipates training and equipping in-house employees, such as the corrosion technicians, for MT.

When SCC has been discovered, Operator D has employed grinding to remove the cracking and determine depth. Operator D has not found manual UT useful for determining depth of SCC colonies.

Operator D is an active member of PRCI. Operator D has investigated soils and site characterization for prediction of the location of classic or high-pH SCC, but has not found either useful.

New construction and replacements are installed with line pipe that is externally coated with FBE.
Multiple possibilities for industry initiatives were discussed:

- **Improved ILI of Gas Transmission Pipelines for SCC**
  
  Resources should be committed to development of reliable ILI for detection of SCC in gas pipelines (without use of liquid slug trains to facilitate use of UT pigs).

- **Database of SSC-related Information**
  
  The potential for developing an industry-wide database of information related to the SCC threat in gas pipelines was discussed in some detail. Challenges to development of such a database include development of an industry standard for collection of data associated with (1) in-service and hydrostatic testing SCC failures, and (2) excavations for direct examination. An industry standard for data collection would need to be developed under the direction of an industry group (INGA, PRCI, etc.) with funding.

  The perceived benefit of an industry-wide database could be more cost-effective assessment of the SCC threat of each pipeline system where trends from the database were applied. Given the cost of hydrostatic testing and excavation for direct examination, more cost-effective assessment of the SCC threat could conserve significant resources for addressing other threats that are more significant to public safety.

- **Post-Failure Response**
  
  An industry standard for Incident Response and Return-to-Service after an in-service failure attributed to SCC is desirable.

### 10.4.5 Operator E

Operator E operates thousands of miles of natural gas pipelines in Canada and the US. The coating systems on their pipelines, which vary widely in diameter, are approximately equally divided between tape, asphalt, FBE, and yellow jacket.

Operator E has been very involved in all issues relating to SCC, especially near neutral-pH SCC. They noted that they view SCC as a series of factors; i.e. as a continuum of events, rather than a single isolated event. The series includes:

- Incubation
- Disbondment
- Initiation
- Growth
- Coalescence
- Mechanical drivers, possibly including fatigue

They initially used soils models to provide estimates of SCC possible locations. They now view such models as a tool to correlate with potential coating disbondment segments. Drainage, local topography, soil disposition and similar aspects of soil models, tied with time in service, are seen as
predictors of potential coating failures, though not necessarily SCC areas. Further pipeline operating information such as temperature and/or pressure information are used to aid the assessment.

They have performed thousands of digs since 1986. All excavations are checked for the existence of SCC. Contractors trained in SCC assessment and associated data gathering perform these digs. Operator E has never seen SCC under FBE disbondment and note that FBE does not shield CP. They have not seen any cracking at the girth welds for FBE coated pipe, where shrink sleeves are employed.

While Operator E cooperates with and supports organizations such as PRCI in basic research, they also perform additional in-house research relating to operational issues.

They extensively use risk-based models, with calibration against field data. With its extensive system of pipelines, they are able to develop and maintain reliable in-house statistics for these models. The calibration with actual field experience was underlined as a requirement for meaningful model development and predictions. The models include not only a stochastic estimate of failure, but also of potential consequences such as injury, societal risk, financial cost, and regulatory/perception impact. Digs are prioritized based on this model. Locations are often re-inspected to determine growth rates, if any.

Especially for gas lines, Operator E does not view any ILI tool as effective for SCC detection. Hydrostatic testing is their tool of choice, although they see promise in emerging ILI technology. They have used a UT tool in a liquid slug, but note the laborious process and costs as well as difficulty in speed control. Initial hydrostatic testing is a 1-hour strength test at 100-110 percent SMYS, followed by a 2-hour leak test of 90 to 100 percent SMYS. They noted that they are concerned with crack growth during a long duration spike test, so any spike test is limited to a 5-minute hold. They use their risk management procedures to establish retest intervals. The distribution of crack sizes and rates are developed stochastically (i.e. in distributions rather than single deterministic estimates). The risk decision is based on the outcome of this model. They have found that the use of a Paris crack-growth model under-predicts the amount of damage.

They have correlated near neutral-pH SCC with distance from the stations with most instances occurring in the first third, very few in the middle third, and maybe one in the last third.

Operator E performs wet fluorescent MPI whenever there is evidence of a disbonded coating. They will blunt the cracks if required and practicable, and assess the remaining strength using standard procedures (e.g. RSTRENG or similar). As required, they may employ a pressure containment sleeve with no standoff. They do not employ composite wraps, noting that it is not cost effective in their experience.

If an incident occurs, they will evaluate the situation to employ the correct pressure reduction before final implementation of their return-to-service plan. A rule-of-thumb is to examine the operating records and reduce to 90 percent of the 60-day high pressure or 80 percent of the failure pressure. Additional information, such as the presence of swamp weights, may cause further reductions. This reduction will be re-evaluated if the interval to return of service is prolonged. They work closely with regulatory groups in that time. They also noted that they meet twice a year with interested regulatory groups in any case to discuss upcoming plans.
Operator E cautioned that a central database may not produce much benefit and instead stressed that regular communication between interested groups is of greater value. They support and sometimes participate in the development of ILI tools but recognize this is a lengthy process.

10.4.6 Operator F

Operator F is a part of a larger pipeline group. The interview was limited to the still extensive gas transmission pipeline experience, encompassing most of the common pipe sizes that transport gas from the Gulf Coast to the Northeast U.S. and points in between.

Operator F has experienced in-service and hydrostatic testing failures attributed to classic or high-pH SCC oriented in the longitudinal direction. Longitudinal near neutral-pH SCC has not been observed in the Operator F system. The classic SCC has been associated with disbonded coal tar enamel coating. Operator F was an early adopter of fusion-bonded epoxy (FBE) coating and has over 30 years of experience with FBE, and has observed no SCC of pipe coated with FBE.

SCC has been observed in line pipe of multiple diameters, wall thicknesses and grades, supplied by multiple manufacturers and installed in multiple years with multiple maximum allowable operating pressures (MAOPs). Operator F has observed SCC in multiple states and in multiple types of soils and moisture conditions.

Operator F relies upon hydrostatic pressure testing and magnetic particle testing (MT) for detection of SCC. Operator F has concluded that current ILI technology for detection of SCC in gas pipelines is not reliable and that use of liquid slugs to permit UT inspection is not cost effective.

Operator F uses spike hydrostatic testing in which the aim stress is 105 percent of SMYS, the minimum stress at the high point of a segment is 100 percent SMYS and the maximum stress at the low point is no more than 110 percent SMYS. The initial test period is 1 hour followed by 7 hours at a stress of 90 percent of SMYS or greater. Operator F may follow hydrostatic testing with a flame-ionization leak survey on a case-by-case basis. For example, detection of a leak during a spike hydrostatic test could be cause to follow up with a flame-ionization leak survey.

Operator F employs MT of all bare pipe surfaces exposed for direct examination. Operator F uses MT with multiple types of magnetic particles (dry, wet visible, wet fluorescent, black on white, etc.), but concludes that MT with dry powder is sufficient to detect SCC on dry pipe surfaces when operators are properly trained. Wet visible magnetic particles are the preferred method for wet pipe surfaces. Application of dry powder to the bottom of the pipe is recognized to require more training and skill than the top of the pipe or other types of magnetic particles, but has proven satisfactory.

Operator F developed and presents weeklong workshops that address all types of direct examination of exposed pipeline segments as a part of the operator qualification program. Typical topics include assessment of external and internal corrosion, mechanical damage, SCC, etc. The weeklong workshops include both lecture and hands-on sessions focused upon detection of SCC as well as distinguishing SCC from other types of surface anomalies. The workshops include repair methods, including hands-on training for the grinding of pipe imperfections.
Operator F is an active member of PRCI. Operator F does not consider soils characterization models applicable to assessing the likelihood of classic SCC.

Operator F observes that visual appearance of SCC colonies is generally related to depth of penetration. For example, a colony of relatively short, unlinked cracks is likely to be relatively shallow. On the other hand, a colony that contains linked cracks with significant linear extent is likely to penetrate a significant portion of the pipe wall. Advanced NDE techniques such as focused UT, eddy current, etc. have been employed to estimate maximum depth of SCC, but have proven unreliable, apparently due to interference of nearby cracks. Consequently, Operator F considers grinding as the most reliable method to estimate depth of SCC.

If grinding is sufficient to remove shallow SCC detected by MPI, Operator F re-coats the exposed pipe and returns to service. If SCC is too deep to repair by grinding, Operator F either installs a Type B (pressure containing) sleeve or replaces the section containing the SCC.

If a pipeline segment experiences an in-service leak or rupture attributed to SCC, adjacent pipe joints are subjected to MT until pipe joints free of SCC are located on either side of the failure. All observed SCC is repaired and the segment returned to service. A risk assessment is performed and an Integrity Assurance Plan is developed to remediate the possibility of SCC in the area. Operator F applies the criteria in ASME B31.8S Appendix A3 for assessing the threat of SCC.

Operator F is in the process of developing a procedure for direct assessment of pipelines for SCC based on the existing draft version of the NACE SCCDA recommended practice.

Operator F would not be inclined to contribute to, or draw from an industry-wide SCC database. Beyond the difficulty of implementing an industry-wide database, Operator F has a significant internal database that is directly related to their system. An industry-wide database would likely have more potential value for an operator with less experience in dealing with SCC.

10.4.7 Operator G

Operator G operates approximately 7,700 miles of pipeline in 360 testable segments to transport a variety of products. The product mix is approximately one-third crude oil, one-third refined products and one-third highly volatile liquids and chemicals. Pipe sizes ranges from NPS 2 through 40.

Operator G has observed SCC in two testable pipe sections located in southern Louisiana. One of the pipe sections is NPS 8 and the other is NPS 16, both were installed in 1954 and coated with coal tar.

The first observed SCC was a hydrostatic test rupture in the NPS 8 section in 1985. No further SCC has been observed in the NPS 8 segment. The NPS 16 section suffered an in-service failure in 1993 and six hydrostatic testing failures attributed to SCC in 1994. Another hydrostatic testing failure occurred during a retest in 1999, potentially indicating that SCC remained active at least a portion of the time between the 1994 and 1999 tests.
All these SCC incidents were attributed to high-pH or classical SCC. These SCC incidents were generally associated with disbondment of the coal tar coating possibly attributed to soil stresses or possibly due to the quality of coating installation during initial construction. The operating temperature of these pipeline segments rarely, if ever, exceeds 100°F, which leads Operator G to believe that disbondment is not attributed to elevated temperature of transported fluids. No records have been located relating to soil and water samples collected at the time of the SCC failures for detailed characterization of the soil associated with the SCC.

The procedure for returning a pipeline to service after an in-service failure is determined on a case-by-case basis, depending upon the cause of the failure. If the cause of a failure were not apparent i.e. associated with mechanical damage, external corrosion, etc., the pipe would be sent to a laboratory for analysis in an attempt to determine the cause of the failure.

Should SCC be detected by magnetic particle examination, a typical repair plan would involve lowering the operating pressure to 80 percent of the highest operating pressure experienced during a 4-hour period in the two months prior to the time of discovery of the SCC per DOT guidance. If the SCC can be removed by grinding without reducing the pressure carrying capacity of the segment, the location would be recoated and returned to service following grinding. If the SCC can be removed by grinding, but the depth of grinding reduces the pressure carrying capacity of the pipe, a composite sleeve, a steel welded sleeve, or a fabricated mechanical device may be applied to restore the desired pressure rating. If the SCC depth is such the SCC cannot be removed by grinding, a temporary repair will be installed until the line can be taken out of service for a permanent pipe replacement. (Operator G's repair criterion does not currently allow permanent repair of a longitudinally oriented crack defect except with replacement pipe.)

Operator G has employed several ILI tools, including caliper for deformation conditions, UT and MFL for wall loss and TFI for seam imperfections, but has not used the UT tools designed to detect SCC yet. Application of special UT crack detection tools (or hydrostatic pressure testing) in pipeline segments susceptible to SCC is planned.

Operator G has screened approximately 360 testable pipeline segments for potential susceptibility to high-pH or classical SCC using the five SCC screening criteria in ASME B31.8S Appendix A3.3 with minor modification to adapt the criteria from gas to liquid pipelines, specifically converting distance downstream from compressor station to distance from pump station.

Operator G also has access to the draft version of the NACE SCCDA recommended practice, which recommends that screening for potential susceptibility to near neutral-pH SCC not consider operating temperatures above 100°F as a criterion. Therefore, Operator G has screened for potential high-pH SCC using the five SCC screening criteria identified in ASME B31.8S, but has also screened for potential near neutral-pH SCC using four of the five criteria identified in ASME B31.8S (without the 100°F temperature criterion). The screening process identified 24 segments at this time as potentially having susceptibility to near neutral-pH SCC, including the two segments that had suffered high-pH SCC. Segments where either high or near neutral-pH SCC has been detected will be assessed using specialized ILI technology or hydrotesting. Segments that are
identified as potentially susceptible to either type of SCC will be subjected to additional NDT including Magnetic Particle Inspection during routine maintenance or integrity management activities where pipe coating is being removed in an attempt to locate any other SCC occurring on these pipeline segments.

Operator G has identified a need for and is planning for additional training of company personnel in SCC awareness and magnetic particle inspection for detection of SCC.

Operator G is also considering the application of External Corrosion Direct Assessment to approximately 28 pipeline segments (not the 24 segments identified as potentially susceptible to SCC) that are not amenable to either hydrostatic testing or ILI. They are employing a consultant to perform black on white magnetic particle examination for cracks when a pipeline segment is excavated for direct examination. Although the magnetic particle examination is not employed solely to detect SCC, any SCC present in the locations examined directly should be revealed. If SCC is detected in any of these ECDA segments, they will be moved into the "susceptible to SCC" category and will be assessed by either hydrotesting or ILI. Operator G is considering the application of SCCDA in the future, but is currently awaiting completion of the NACE SCCDA document.

New construction and replacements are installed with line pipe that is externally coated with FBE at a coating plant and FBE joint systems are applied to girth joints during construction. Operator G also has specifications in place for pipe procurement, hot bends manufactured from line pipe, pipeline construction, CP design and operation, as well as the FBE coating specifications mentioned to also help eliminate the cause of the SCC phenomena in new pipeline construction.

Operator G is an active member of PRCI and reviews the results of research into pipeline integrity management for possible inclusion in its IMP. Operator G also has representatives on multiple API committees and NACE International committees developing other integrity-related technology.

The potential value of an industry database for collection of SCC related information was discussed. Operator G observed that the API Pipeline Performance Tracking System (PPTS) sponsored by the API Operators Technical Committee already contains integrity-related information that is useful to operators of hazardous liquid pipelines. The data fields collected in PPTS track accidents on hazardous liquid, carbon dioxide, and anhydrous ammonia pipelines attributed to approximately 40 possible pipe failure causes, including SCC.

Operator G supports the API initiative requesting a revision of § 195.452 to align the repair criteria and other issues for hazardous liquid pipelines with those applicable to gas transmission pipelines. Operator G also supports a possible revision of API Standard 1160: Managing System Integrity for Hazardous Liquid Pipelines to incorporate revisions to the IMP Regulations and possible inclusion of the concepts in ASME B31.8S.

Operator G also encourages pipeline regulators to consider a more performance-based rather than a prescriptive- and procedural-based perspective when reviewing integrity management programs. Operator G feels this approach will provide pipeline operators with greater flexibility to produce
more efficient and effective integrity management programs and demonstrate that the performance of the programs meets the desired objectives.

Operator G desires from this SCC research project

1. Confirmation that ASME B31.8S and NACE SCCDA are accurate for SCC screening applicability (or development of better tools if they are not accurate).

2. Identification of better ILI technology for more accurate SCC sizing and locating.

3. Knowledge of accurate mathematical models with easy to use analysis to determine fitness for purpose of pipe with SCC.

10.5 References

Internally developed material and operator interview responses.
This page intentionally left blank.