Stress-Corrosion Cracking On Gas-Transmission Pipelines: History, Causes, and Mitigation

B. N. Leis and R. J. Eiber

ABSTRACT

This paper reviews the historical data concerning external stress-corrosion cracking (SCC) of gas transmission pipelines as it has evolved since 1965 and the factors controlling such SCC (e.g., pipe environment, steel, and operation). Discussion of these factors leads to identification of ways in which this cracking can be controlled / mitigated -- in the practical setting of an operating pipeline that is expected to provide a reasonable return on equity.

INTRODUCTION

This paper addresses external stress-corrosion cracking (SCC) on gas transmission pipelines. SCC was first recognized during the course of analyzing a gas-transmission pipeline rupture that occurred in Louisiana in 1965. However, comparing the metallographic and fractographic features, that have since become synonymous with SCC with similar information archived in pipeline failure analysis reports at Battelle indicates that the first SCC failure probably occurred in 1957.

This paper begins with a detailed review of the incidence and character of SCC. That review is followed by topical sections titled Controlling Factors, Field Digs and Monitoring, and Management and Mitigation. While SCC has been a problem in transmission pipelines since the 1960's and much has been written on each of these topics, significant work remains to be done before the cause of SCC is determined and
practical mitigative schemes are developed. Thus, this paper discusses these topics briefly and in rather generic terms. How this discussion applies to any given pipeline is very case-specific because of the large number of factors that control the susceptibility to SCC and its kinetics. The paper closes with conclusions drawn from the discussion of these topics.

THE HISTORY OF PIPELINE SCC

SCC leading to reportable incidents has occurred primarily on gas-transmission pipelines, although it has also caused incidents on liquid-products transmission pipelines. To date, two different environments, which form under disbonds between the coating and the pipe, have been found to promote SCC on transmission pipelines (e.g., see [1]). One of these environments is termed high-pH, because it occurs at a pH of -9.3. This was the environment responsible for the first incident recognized as being due to SCC (circa 1965). The second environment is referred to as either near-neutral, because for that environment the pH is -6, or low-pH, because its pH is lower when compared to a pH of -9.3. This second environment was identified first in 1985 and has typically been associated with incidents in northern climates [1,2].

Location of SCC Incidents

SCC has occurred on pipelines located on several continents around the world. High-pH SCC has occurred in the United States, Australia, Iran, Iraq, Italy, Pakistan, and Saudi Arabia. Near-neutral pH SCC is known to have occurred in the northern part of the United States, in Canada, and in Russia.

Pipe and Coating Characteristics Associated with SCC Incidents

Table 1 summarizes the pipe and coating characteristics for SCC incidents where such data are available, including data for both axial and circumferential crack
orientations. The majority of the high pH SCC incidents have involved axial cracks. The very few cases where cracking occurred transverse to the pipeline’s axis involved secondary stresses due either to a dent, or local bending and/or axial loading due, for example, to ground movement. About two-thirds of the incidents that involved the near-neutral pH-cracking environment had axially oriented cracking, with the remainder being oriented transverse to the pipeline’s axis. As was the case for the high-pH incidents with transverse cracking, the transverse cracks in the near-neutral environment were in

<table>
<thead>
<tr>
<th>Diameter Range, mm (inch)</th>
<th>Wall Thickness, mm (inch)</th>
<th>Grade</th>
<th>Mfg. Process</th>
<th>Coating Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>High pH SCC — Primarily Axial Cracks</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>168-914 (6-36)</td>
<td>2-9.5 (0.18-0.375)</td>
<td>172-448 (Grd 25-X65)</td>
<td>Seamless, ERW, FW, DSAW, Lapweld</td>
<td>76% Coal Tar/Asphalt, 20.6% PE Tape, 3% Bare</td>
</tr>
<tr>
<td>Near-Neutral pH SCC -- Axial Cracks</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>114-1067 (4.5-42)</td>
<td>3.2-9.4 (0.125-0.370)</td>
<td>241-448 (35-X65)</td>
<td>DSAW and ERW</td>
<td>65 % PE Tape, 23.6% Coal Tar / asphalt, 11.8% Shrink sleeve</td>
</tr>
<tr>
<td>Near-Neutral pH SCC -- Transverse Cracks</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>168-914 (6.6-36)</td>
<td>3.6-8.7 (0.142-0.343)</td>
<td>290-448 (X42-X65)</td>
<td>DSAW and ERW</td>
<td>100% PE Tape</td>
</tr>
</tbody>
</table>
areas where secondary stresses were present, as for example mountainous regions. Thus, the relative difference in the incidence of transverse cracking for the near-neutral environment lies in the difference in the profiles of the pipelines that suffered SCC.

As is evident from Table 1, pipe covering a wide range of diameters, wall thicknesses, grades, manufacturing processes, and coatings have experienced SCC. Thus, it is unlikely that SCC is uniquely associated with a line pipe grade or manufacturing process. Spiral-welded pipe is the one pipe manufacturing process that is not evident in Table 1. Such pipe was mainly used in Canada in the 1980’s, primarily in conjunction with a fusion-bonded epoxy coating. Coatings based on fusion-bonded epoxy are also missing from Table 1, because no SCC incidents have occurred on pipe with this coating. It is quite likely that the absence from this table of incidents involving spiral-welded pipe is due to the use of this type of coating on the spiral-weld line pipe.

**Pipeline Age at SCC Occurrence**

Data on the age of pipelines at the first occurrence of SCC were published initially in 1974.[3] These data have been updated with the results for the intervening time, with the results being presented in Figure 1. This figure indicates the average age of the pipe at the time of the first high pH SCC incident is 22.9 years.

Figure 2 presents similar results for the near-neutral pH SCC incidents in Canada. Figure 2 indicates the average time to the first SCC incident is 21.3 years. It is important to note that the time to the first SCC incident as presented in Figures 1 and 2...
involves data biased somewhat by the fact that the high-pH cracking was first identified about 20 years before that for the near-neutral environment. Research into the mechanism(s) and factors that control high-pH cracking are much better understood than that for the near-neutral environment. For this reason, controls to limit high-pH SCC have been developed whose effect is to limit the extent of high pH incidents as compared to their initial frequency. This bias probably contributes significantly to the trend in Figure 1 as compared to that evident in Figure 2.

**Soil Conditions**

SCC has been found to occur in a range of soils, and, as is evident in Figure 3, SCC has been found at all clock positions around the circumference of the pipeline. SCC primarily seems to occur in soils that are alternately wet and dry. Clay soils where there is moisture draining across or along a pipeline are likely sites for SCC. Locations near the bottom of a hills are an area where a number of incidents have occurred. Areas that are continually wet, such as in rivers or lakes have not experienced SCC to the same extent as has occurred along the edges of streams or lakes.
FACTORs CONTROLLING SCC

Cracking Environments

The high-pH environment favors the presence of carbonaceous materials, which in conjunction with the imposed potential gives rise to a carbonate - bicarbonate aqueous solution.[5,6] (This high-pH cracking environment involves a carbonate - bicarbonate solution, with the cracking velocity increasing with concentration.) The near neutral (low-pH) environment favors soil conditions that produce carbonic acid and temperatures that favor a balance between the solubility of CO$_2$ and the ingress of hydrogen.[1,2] (The near-neutral pH cracking environment is usually a weak carbonic acid solution. There is also an indication that near-neutral SCC may require an anaerobic soil condition.[2]) The likelihood of finding either of the two cracking environments depends on the temperature around the pipeline, the potential acting at the pipe surface, the type of coating, and the type of soil [1].

The high-pH cracking mechanism is based on dissolution [3-5]. It is rate-limited by the same factors that control corrosion. It is also rate-limited by the need for bare pipe surface to be exposed by the rupture of an Fe$_3$O$_4$ passivating film. The formation of this film is favored at certain potentials, and because film rupture favors areas of locally high strain, such dissolution tends to be focused at grain boundaries. Thus, for the high-pH environment, the mode of cracking is generally intergranular. Rupture of this film and the continuous re-exposure of bare surface thus requires local inelastic straining, such that the pressure history experienced by the pipeline and the pipe steel grade are important factors.

The mechanism of cracking in the low-pH environment is still the subject of research, but it is generally considered to involve hydrogen in concert with dissolution, leading to an essentially transgranular mode of cracking. So, as with SCC in the high-pH environment, the pressure history and the pipe steel grade are important factors in determining the incidence and kinetics of cracking in the near-neutral environment.
Role of Stress

Because film rupture and dissolution, as well as the diffusion of hydrogen, all are affected by stress (or strain), the loading imposed on the pipeline can be a significant factor. Likewise, factors that influence the formation of passivating films or other surface scales can be important aspects that influence both susceptibility and the rates of reaction that control cracking kinetics. But, even when such conditions lead to a susceptible pipe steel in either of these environments, the occurrence of cracking still requires the presence of a tensile stress.

Incidents have generally been observed at hoop stress levels above 60 percent of SMYS. However, for some incidents, such as a few of the low-pH SCC incidents in Canada, the hoop stress was as low as 46 percent of SMYS. But, in all such cases there was either a secondary loading or there was some stress concentration in the area of the SCC, which served to increase the local stress to a level equal to or greater than 60 percent of SMYS.

Conditions for SCC

Three conditions must be satisfied concurrently for SCC C there must be a tensile stress, a cracking environment, and a material that is susceptible to cracking in that environment. If any one of these three conditions is not satisfied, cracking either does not start, or it slows down, or stops.

In the case where cracking had started earlier at a time when these conditions were concurrently satisfied, the cracking kinetics will change, the extent to which depends on how fully each of these conditions was satisfied. For example, the kinetics of high-pH cracking depend strongly on the temperature, the potential, and the concentration of the environment. While interrelated, a change in these parameters can alter the cracking kinetics by orders of magnitude C all while the pH remains near - 9.3. Because the environment and the stressing conditions supporting cracking can change in a given
location over time, the resultant cracks can be expected to show a range of sizes and shapes that depend on the conditions when they initiated as well as over the period the cracks have been growing. Such differences are manifest in the spacing and depths of SCC, which can vary significantly under a common, small area of disbonded coating [7].

The presence of SCC should be judged on the basis of its potential to become critical in service C not the number of cracks or their superficial appearance. Indeed, in most cases very closely spaced, shallow cracks are less of a concern than are a few adjacent deeper cracks [7].

Because the three conditions for SCC can be concurrently satisfied at a limited number of sites, over a limited fraction of the time the pipeline is in service, only a small portion of a pipeline typically suffers SCC. This is one reason that the number of incidents due to SCC is small as compared, for example, to corrosion. Yet, because SCC forms in colonies, nearby axial cracks can grow together at their tips (Acoalesce@ to form flaws that can be very long compared to their depth. Such longer cracks typically fail as ruptures rather than leaks, which makes incidents due to SCC potentially catastrophic and underscores the concern for such cracking. A second reason also accounts for the limited number of reportable incidents due to SCC. The use of periodic high-pressure hydrostatic retesting of pipelines with a history of cracking exposes SCC that will become critical in subsequent service. Were retesting not carried out for pipelines with an established history of SCC, it has been estimated that the incidence of related failures would increase by a factor of ten or greater [9].

**The Incidence of SCC C Summary of Controlling Factors**

The advantage that accrues from the limited incidence of SCC because the three conditions for SCC are satisfied quite selectively has an equally significant disadvantage C it complicates and occasionally confounds prioritizing maintenance and mitigation activities. Part of the reason for this is evident in Table 2, which summarizes the factors that control the incidence and severity of SCC. Reference 8 provides a
<table>
<thead>
<tr>
<th><strong>PIPE STEEL MILL ASPECTS</strong></th>
<th><strong>PRESSURE SERVICE ASPECTS</strong></th>
<th><strong>ENVIRONMENT SOIL &amp; WATER</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>- Grade (actual YS, not SMYS)</td>
<td>- Ambient temperature</td>
<td>- Classification (species)</td>
</tr>
<tr>
<td>- Microstructure</td>
<td>- Gas temperature</td>
<td>- Water table (concentration)</td>
</tr>
<tr>
<td>- Coating preparation</td>
<td>- Depth of cover and packing</td>
<td>- profile</td>
</tr>
<tr>
<td>- surface</td>
<td>- MOP and its variation</td>
<td>- seasonal</td>
</tr>
<tr>
<td>- thermal</td>
<td>- Stress raisers</td>
<td>- drainage</td>
</tr>
<tr>
<td>- Forming</td>
<td>* Influences susceptibility</td>
<td>- Interaction with CP</td>
</tr>
<tr>
<td>- Welding</td>
<td></td>
<td>* Controls the species and their concentration which control type of cracking</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>FIELD TIES</strong></th>
<th><strong>HYDROTEST ASPECTS</strong></th>
<th><strong>TEMPERATURE</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>- Coating type</td>
<td>- Peak test pressure and hold time</td>
<td>- Interplay with soil and water</td>
</tr>
<tr>
<td>- Coating condition</td>
<td>- Hold pressure and duration</td>
<td>- Ambient (mean + seasonal)</td>
</tr>
<tr>
<td>- Age</td>
<td>- Depth of cover</td>
<td>- Interplay with local gas temperature</td>
</tr>
<tr>
<td>- Test frequency</td>
<td>- Time since last test</td>
<td>* Controls CO₂ solubility, hydrogen diffusion, and type of SCC</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th></th>
<th><strong>CP and COATING AND PRIMER</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>- Type of control, primer and coating</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Interplay with soil and moisture</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Condition of coating (age and temperature)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Level and variation (mean+seasonal)</td>
</tr>
<tr>
<td></td>
<td>* Influences potential at pipe’s surface and local reactions, and type of SCC</td>
<td></td>
</tr>
</tbody>
</table>
protocol to judge the relative significance of these many factors. In Reference 8, an index is provided that can be used to prioritize these factors along a right-of-way for a given pipeline. The index also can be used to rank the likelihood of SCC between two pipelines or between sections of a given pipeline. This protocol has been designed for use in making decisions regarding mitigation and rehabilitation in the absence of data from field digs and monitoring.

FIELD DIGS AND MONITORING

High-pH SCC Protocol and Field Monitoring

The protocol that has been developed for high-pH SCC provides insight into the relative likelihood that SCC could be encountered based on topical evidence along the right-of-way and operational information that can vary along the length of the pipeline. Application of this protocol provides information to help assess the likelihood that SCC is or has been active along a valve section or a pipeline where there is no prior experience with SCC. Areas along the right-of-way that are indicated to have high index values based upon application of the protocol should then be looked at more closely. For example, variables, such as the ground water, ground temperature, soil resistivity, and pipe-to-soil potential at various depths can be monitored to create a monthly or seasonal profile.

There are four important criteria in implementing the high-pH protocol. These criteria include:

- Type of coating
- Maximum stress and stress range
- Pipe wall temperature
- Moisture content

These same four criteria can also be important in applications involving near-neutral pH SCC, but, as yet, a protocol like that for the high-pH SCC has not been formulated.
Field Digs

ATopical@ data from a monitoring effort should be augmented by data from Aexploratory@ field digs. Unless warranted by an unusually high index rating, such digs should be scheduled as part of otherwise routine work to avoid the significant cost of a dig dedicated to SCC. For example, a dig being done to confirm or react to results from a metal-loss pig run can be expanded to address concerns unique to SCC. Such digs should provide data on, for example, the type of soil, the condition of the coating, and the incidence of disbonds. When disbonds are found, the liquids they contain should be analyzed to determine the pH, the gas content, etc. Disbonds close to areas to be rehabilitated should be opened and the disbonded area inspected for SCC using techniques like dry magnetic particle inspection, or the possibly more sensitive liquid fluorescent magnetic particle inspection. Environments from below disbonds where the pipeline shows evidence of active cracking or evidence of prior cracking should be culled out and identified as candidates to determine the Acracking environment@. Differences between these areas and those where no cracking was found should be identified, and their significance determined.

Data Analysis and Decisions

Depending on what is learned during the course of these exploratory digs, additional sites for further digs may be identified. Where cracking is found, the protocol should be used to identify other similar areas, or areas with an index just below that used to identify the exploratory sites. In cases where evidence of SCC is found the sizes of the colonies and the crack spacing within them should be quantified. Colonies with Asignificant cracking@which is cracks deeper than 10 percent of the wall thickness, should be culled from the data and the sites that produced them analyzed with respect to the major factors identified in Table 2. Other sites that share these trends should be given a high priority for evaluation in future field digs. Particular care should be taken to identify areas that contain cracking that is continuous for more than a length of 1.5 inch (38 mm). If cracking is found, the information related to SCC management and
mitigation set forth in References 2, 7, and 8 should be reviewed in detail. These references elaborate on the general thoughts that follow.

**MANAGEMENT AND MITIGATION**

Methods for the mitigation of SCC in transmission pipelines have been developed and applied since the 70's. Each of the three conditions that must be concurrently satisfied offers some avenue to mitigation, although none has been very effective in stopping SCC. Obviously, one could reduce the wall stress -- but all this does is slow the process to some unknown extent and at a significant price in terms of throughput. One could also reduce the pressure cycles. However, the common practice of line packing pipelines in the evening or on weekends has led to even larger pressure cycles at a frequency that has increased compared to past operation. It is difficult to view reducing pressure cycles as being practical in that setting.

Another alternative is to make the steels less susceptible to the incidence of cracking or to make changes that reduce the SCC growth rate. For new construction there are some possibilities related to the use of controlled-rolled, high-strength low-alloy steels. But this is not a panacea. For existing lines it is conceivable that designed pressure tests could reduce the extent of microplastic strain, to limit the extent of film rupture and thereby reduce cracking. But, like the approach for new pipelines, there has been little done to evaluate the potential of such schemes. Accordingly, the best means of mitigation seems to be by control of the environment. Chillers have been effectively used by several companies whose pipelines operate in conditions that produce a high-pH environment. Such chillers reduce the kinetics by reducing the gas temperature. This does not stop the cracking but it does slow it down significantly.

In regard to management, the most common method involves hydrostatic retesting at an interval typically from 2 to 6 years although some companies use intervals as long as 12 years. This is the ultimate act in a management plan that in general involves
several steps prior to implementing the hydrostatic retest regimen. Steps before hydrostatic retesting can include Acondition monitoring@Afield digs@Acrack criticality assessment@ and Aconsequence analysis@. Depending on the outcomes of each of these, there are several layers of remedial measures and related field monitoring activities [2,8].

Important issues include: (1) whether the line in question has experienced SCC previously, (2) whether stress corrosion cracks are present in field digs, and (3) whether the cracking is significant. Cracking can be considered significant if the depth is greater than 10 percent of the wall thickness, with a length greater than 75 percent of that for the critical flaw at the maximum allowable operating pressure. Here the critical length is determined using a critical flaw prediction program such as PAFFC [10]. Another important issue related to consequences and remedial action is Class Location and the proximity of human activities in otherwise remote areas. It is suggested in this context that proximity be defined as the distance from the pipeline where a rupture and release of gas could be harmful.

Some plausible remedial measures follow:

! **Improve CP, Temperature, or P Conditions:**

This remedial measure is directed at slowing the SCC growth rate. These factors can be difficult to alter in a practical context.

For high-pH SCC, actions suggested are to increase the negative pipe-to-soil potential if the potential in the area is above (more positive) the level that controls corrosion. For near-neutral pH SCC, the environment will only form in the absence of cathodic potential and thus attempting to control with cathodic potential will not be beneficial.

For high-pH SCC, if the pipe temperature is high (e.g., because of proximity to the discharge of a compressor station), then reducing the discharge temperature could slow SCC growth. For example, a 15 to 25 F (10 to 15 C) reduction in gas temperature can significantly reduce the rate of high-pH SCC growth in many

\[ A \text{ depth of 10 percent is used because cracks deeper than this either have to be repaired or removed from the pipeline.} \]
applications. For near-neutral pH SCC, the temperature is usually not high as this contributes to the ground water being able to hold large concentrations of CO₂ producing the environment.

If the pipeline segment is subjected to pressure fluctuations that are above those typically encountered on a gas pipeline (i.e., R values of 0.85 and less), then it may be possible to reduce the pressure fluctuations through pressure control schemes.

**Repair and Recoat:**
Cracks that are less than 10 percent of the wall thickness can be ground out and then recoated. Also, non-welded steel sleeves can be used to repair either significant or insignificant SCC. Other repair methods such as rewelding or other types of sleeves can also be effective. But, Clock-spring or other such sleeves are not recommended for the repair of sharp defects like that due to SCC in that the sleeve does not reinforce the pipe adequately for sharp defects. When the extent of the SCC-affected pipe is unknown, a hydrotest can be conducted to identify the sections that need to be rehabilitated.

**Selective Replacement:**
It is unlikely that insignificant cracks would cause an operator to replace affected sections of pipe where public access is minimal. But, replacement is a viable remedial action where the pipeline passes close to an occupied building. When a section is replaced, consideration should be given to select a new coating that is resistant to the formation of SCC.

**Retest and Recoat:**
This option is similar to repair and recoat. The essential difference is apparent when significant cracks have been detected in a pipeline segment, because it may be difficult to locate all of the affected regions. A hydrostatic retest will accomplish this.

If a retest is conducted, it is recommended that the test pressure be 110 percent of SMYS to ensure that near-critical defects or SCC colonies are removed. A retest will also raise the proportional limit of the steel, which helps to reduce future localized micro-plasticity on the pipe surface that is a precursor to SCC initiation and growth.
In-Line Inspection and Selective Replacement:
This action is similar to the selective replacement option except that the replacement sites are identified by in-line inspection (ILI) to locate the SCC-affected pipe. Currently, such ILI inspections cannot accurately detect stress corrosion cracks of the size considered significant herein, although this status could change quickly. Where ILI is effective, its use will focus the replacement process, meaning fewer sections would need to be replaced. Hydrostatic testing is an alternative to ILI. At present, the hydrostatic retest is the only certain means of locating SCC affected pipe, but it only identifies sections with SCC that would be near-critical under operating conditions.

Replace or Loop Affected Sections:
This is the least favored option as it is the most expensive and time consuming but also the most certain approach to avoid concern today. And, if the line pipe steel and coating system are chosen to limit SCC, it is the most certain way to avoid concern for SCC in the future. Where local looping is selected continued monitoring for SCC is appropriate.

CONCLUSIONS

This paper has reviewed the problem of SCC as it has evolved since 1965 and identified the factors controlling it (e.g., environmental, pipe steel, and pipeline operation). Eight major factors were identified along with the important variables. For SCC to occur, three conditions must be concurrently satisfied. There must be a tensile stress, an environment that supports SCC, and a line-pipe steel that is susceptible in that environment. These three conditions serve as the headings in Table 2. Discussion of these factors led to identification of ways in which the process can be controlled / mitigated in the practical setting of an operating pipeline that is expected to provide a reasonable return on equity.

Six actions were identified and discussed:

! Improve CP², Temperature,² or ) P Conditions

² Effective for high pH SCC.
Repair and Recoat
Selective Replacement
Retest and Recoat
In-Line Inspection and Selective Replacement
Replace or Loop Affected Sections.

A protocol to identify areas susceptible to SCC was introduced and discussed in terms ranking related maintenance actions and other aspects involved in managing SCC.

ACKNOWLEDGMENT

The authors are indebted to Prof. Redvers Parkins whose comments helped forge the protocol that is part of Reference 8. Mr. Robert Sutherby of Nova and Mr. Burke Delanty of TransCanada also offered many excellent suggestions to improve the index. Their suggestions derive in large part from their role in the Canadian Energy Pipeline Association response to MH-2-95, as evident in the management plan embedded in Reference 6 of this paper. Finally, thanks are also due to Mr. Jim Marr of JEMARR and Associates for his contributions during the course of preparing Reference 8.

REFERENCES

1. Parkins, R. N., Environment Sensitive Cracking (Low pH Stress-Corrosion Cracking) of High-Pressure Pipelines@ AGA NG-18 Report No. 191, AGA Catalog No. 51623, 1990: see also Environment Sensitive Cracking of High-Pressure Pipelines in Contact With Carbon Dioxide-Containing Solutions@AGA NG-18 Report No. 205, AGA Catalog No. L51683, 1992


