Pipeline Integrity and Direct Assessment
A Layman’s Perspective

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November 18, 2004

This report is developed from information clearly in the public domain. All observations
and comments are derived from data supplied from these sources.
Executive Summary

This paper presents a brief summary of Direct Assessment (DA), a pipeline inspection method currently permitted in federal regulation for natural gas transmission pipeline integrity management in high consequence areas. Recently proposed Federal rulemaking would expand the use of DA for external and stress corrosion cracking (SCC) on liquid pipelines as well.\(^1\) This paper presents observations and comments on the application and proposed regulatory changes concerning DA, and suggests areas for further development and attention. This document is meant to serve as a first level quick read, or background primer, for those not familiar with DA and is not intended to encompass all aspects of DA. Further detailed information may be gained by reading the footnoted references.

We support the continued development of DA techniques as defined in current regulation as they relate specifically to addressing the limited corrosion risks associated with external (ECDA) and internal (ICDA) corrosion discussed in this report. For ECDA and ICDA, appropriate warnings and cautions are incorporated into current and proposed federal regulations, as well as the ECDA industry standard, to warrant its prudent use as defined.\(^2\) It should also be recognized that the use of ECDA and ICDA addresses only certain general corrosion threats to transmission pipeline that can cause failures. Sufficient DA regulations, practices, or industry guidelines for SCC, have yet to be published.\(^3\) For reasons discussed in this report, we believe that a DA structured process approach, in the near term, may prove very effective in addressing pipeline SCC risks of concern. In addition, the four-step structured process approach utilized in DA may serve as an appropriate template to deal with certain integrity issues for distribution pipelines which are not currently covered under federal regulations governing pipeline integrity management.

Why DA?

Current integrity management regulations for transmission pipelines permit three inspection methods for liquid pipelines: 1) pressure testing, such as hydrotesting, 2) internal inspection, also known as smart pigging, or 3) other technology. Four inspection methods for natural gas transmission pipelines are allowed: 1) pressure testing, 2) internal inspection, 3) direct assessment for external, internal or SCC corrosion, or 4) other technology. Other technology usually requires that the method provide an equivalent understanding of the condition of the pipe and approval from OPS. Each of the permitted pipeline inspection methods has its own strengths and weaknesses in addressing various pipeline risks of concern, or threats. A

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\(^2\) As of this writing, only one industry standard has been completed and issued for DA, RP0502-2002 addressing ECDA. It is our understanding that industry standards further defining ICDA and DA for SCC (SCCDA) are under development.

\(^3\) ASME B31.8S-2001, “Managing System Integrity of Gas Pipelines,” addresses some key principles concerning ICDA and high pH SCC, but does not incorporate sufficient detail required by proper regulation or industry recommended practices, especially for near-neutral SCC.
discussion of some of these issues is presented in an industry article.\textsuperscript{4} Federal pipeline regulations currently specify that DA can be utilized as a primary inspection method on natural gas transmission pipelines only for external and internal corrosion, or stress corrosion cracking.\textsuperscript{5} As mentioned previously, proposed changes to regulations would also permit DA for external corrosion and SCC on liquid pipelines.

What DA Is:

DA has been developed for natural gas transmission pipelines to deal with certain types of general external, internal corrosion, and a very specialized external corrosion called stress corrosion cracking. Hydrotecting, or current smart pigging technology, may not be suitable, or cost effective, on certain transmission systems. For example, some pipelines cannot be smart pigged, and removal from service for hydrotesting may not be a viable option for some critical pipelines. DA is essentially a structured process approach that doesn’t impede a pipeline operation. DA utilizes various above ground tools and experience to predict where trouble zones for these corrosion attacks will or may occur, and then field measures and monitors the condition of the pipe at these sites. Based on the field verifications, additional feedback is received to tune various assessment approaches on the pipeline, further predict where similar conditions may exist that are conducive to such corrosion, and perform additional field verification. For pipeline systems where general external or internal corrosion or SCC may be a risk of concern, DA may be a more cost effective and rational approach to hydrotesting or smart pigging.

What DA Is Not:

ECDA
ECDA addresses general external corrosion caused by lack of coating, usually from certain types of holes in the external coating of pipelines. These holes are normally associated with coating penetrations from rocks, poor pipe installation, coating deterioration with time, and from many types of third party damage, such as cuts. As clearly documented in the regulation and industry recommended practice, ECDA is inappropriate for use where external pipeline coating has disbonded from the pipeline.\textsuperscript{6} Disbonded coating is any loss of adhesion between the external protective coating and the outer pipe wall surface for various reasons. Coating disbonding creates gaps where reactants may accumulate and foster corrosion. The cathodic protective current cannot reach the pipe surface under the gap because the outer coating, which is usually nonconductive, prevents the protective current from getting to the metal. Shielding also prevents ECDA from clearly identifying selective external corrosion which can occur such as weld seam corrosion, fatigue cracking, or in casing areas, that can result in pipeline failure.

\textsuperscript{5} 49CFR 192.923 “How is direct assessment used and for what threats?”
ICDA
ICDA, as currently defined in regulations and ASME B31.8S, attempts to address internal corrosion on gas transmission pipelines that normally operate in dry gas service and assumes the presence of an electrolyte (i.e. water) serves as the driving mechanism for this general internal corrosion. ICDA rests on the principle that electrolyte settles out, or drains, on the inner lower surface of a pipe whenever a certain critical angle of inclination is exceeded for a specific gas flow velocity. In determining the critical angle of inclination, the model defined in GRI 02-0057, “Internal Corrosion Direct Assessment of Gas Transmission Pipelines—Methodology,” or a demonstrated equivalent model must be utilized. Dry gas service usually applies to pipelines where quality tariffs limit the presence of water in the pipeline to sporadic upset operations from the various gas streams entering a pipeline segment. The use of ICDA, however, does not exclude wet gas operations that can generate higher risks of failure from internal corrosion (especially for pipelines that don’t utilize an effective cleaning pig/analysis program). Responsibility to demonstrate effective internal corrosion monitoring in wet gas service falls to the pipeline operator, and notification to OPS is required under present regulations. Additional efforts to address the complications associated with wet gas service are under development, but a final industry recommended practice for ICDA that will also address wet gas operation has not been issued as of this writing.

SCCDA
SCC is a selective external corrosion attack resulting from a combination of disbonded coating, tensile stress, and certain environmental factors. There are two types of SCC that transmission pipelines have experienced, “high pH” and “near-neutral.” Industry recommended practices for SCCDA are under development as the current B31.8S largely focuses on high pH SCC factors and recommends hydrotesting if SCC has gone to failure. Development of an inspection method other than hydrotesting or smart pigging is warranted, as time to failure after a hydrotest or pig evaluation can be highly unpredictable for both gas and liquid transmission pipelines for various reasons unique to SCC. As clearly demonstrated by recent SCC failures in Arizona, Washington, and Minnesota, while SCC can fail as leaks, most SCC failures result in pipeline rupture. Ironically, though ECDA is inappropriate for corrosion associated with disbonded coatings, some of these indirect (above ground) tools or techniques may prove appropriate for identifying areas of coating disbondment that might assist in identifying possible SCC sites for further consideration. While not all disbonded coating sites are areas of concern for SCC, SCC occurs under

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7 49CFR192.927(c)(2) ICDA region identification.
8 Cleaning pigs are spheres or small bullet shaped devices that scrape the inside of a pipeline. Many pipelines that cannot pass smart pigs can, however, permit cleaning pigs though some pipelines cannot handle any pigs.
disbonded coating. Research in the application of indirect field determination of SCC sites via DA is warranted and should be supported. This effort is especially important given the possible long lead time that may be associated with smart pig development in identifying SCC in natural gas transmission pipelines.

**DA Pipeline Regulations Translated**

**The DA Process**
The DA methods for external and internal corrosion are defined in detailed federal pipeline regulations and follow a similar four-step structured process of: 1) a preassessment stage incorporating various data gathering, database integration, and analysis, 2) an identification phase using either above ground tools or calculations to flag possible corrosion sites, or calls, based on the evaluation or extrapolation of the database(s), 3) field examinations via excavation and direct assessment to confirm corrosion at the identified sites, and remediation as defined in regulation, and 4) post-assessment evaluation to determine if dig calls are representative on a pipeline segment. The specific federal regulations address in more detail these steps for ECDA and ICDA, but the same fundamental processes are involved. SCCDA requirements are addressed but they are yet to be defined in detail (just a two-step process of: 1) data gathering and integration, and 2) assessment method).

The effectiveness of DA largely rests on the ability of assessment “calls” to locate or predict past or currently active corrosion locations on a specific pipeline or pipeline segment and predict future problem sites. Call decisions are driven by various tools, technologies, or engineering evaluations, but are highly dependent on the level of experience and expertise utilized in this very critical step.

**ECDA - A quick summary**
ECDA requires a plan incorporating two different but complementary indirect (above ground) assessment tools and sets minimum conditions in assessing each ECDA region including: 1) more restrictive requirements for conducting ECDA on a segment for the first time, 2) criteria for identifying and documenting those above ground tool indications for direct examination (field dig), 3) criteria for defining the urgency of field verification, and 4) criteria for scheduling excavation of each urgency level. Certain minimum examination, scheduling and root cause analyses are also defined for field examinations.

**ICDA – Another quick perspective**
As defined in the natural gas transmission pipeline regulations, “An ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed.” The regulations require that ICDA Regions be identified (for covered segments). At least two field inspections are required for each ICDA Region. One location must be at a low point at the beginning of the covered segment, and the second location further downstream from this site near the end of the covered segment. Inspection measurements are

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12 49CFR192.926 (External), 49CFR192.927 (Internal), and 49CFR192.929(SCC).
13 49CFR192.927(c) The ICDA Plan.
performed using accepted industry techniques for pipe thickness measurement. In addition, ICDA effectiveness is defined via monitoring and remediation requirements (i.e. addressing first time situations) similar to that briefly described in the above ECDA section. ICDA regulation clearly warns about pipeline segments where cleaning pigs cannot be used and the need to draw off liquids and perform chemical analysis.\textsuperscript{14} A key section of this regulation is the requirement that if internal corrosion is discovered, the operator must evaluate the potential in all pipeline segments (both covered and non-covered) where similar characteristics to the ICDA Region covered segment were found.

**Confirmatory Direct Assessment (CDA) – A subset of ECDA or ICDA**

In addition to ECDA and ICDA another approach has appeared called CDA that can be considered a subset of ECDA and ICDA. Under current regulation, CDA can only be utilized for external or internal corrosion, and operators using CDA must have full ECDA or ICDA plans. CDA for external corrosion is the same as the ECDA process except that CDA: 1) reduces the number of types of inspection tools (requiring only one inspection tool instead of a minimum two types), and 2) changes the arrangement or order and number of minimum required field digs. CDA for external corrosion requires all “immediate action” indications and at least one high risk indication of scheduled action be excavated in each ECDA region. ECDA requires the operator to classify indirect examination criteria into immediate, scheduled, or monitored when scheduling, and addresses in more detail prioritizing, or reprioritizing after field analysis, possible calls for excavation. CDA for internal corrosion is the same process as ICDA except that CDA only requires the operator to dig one high-risk location in each ICDA region. Since the CDA efforts for either external or internal corrosion are not based on multiple independent levels of determination, regulations require shorter maximum reassessment intervals when using CDA (7 years versus 10 or 15 year maximum reassessment intervals for ECDA or ICDA depending on the operating pressure). The use of CDA permits certain natural gas pipeline operators to comply with the reassessment requirements defined in the Pipeline Safety Improvement Act of 2002.

**SCCDA – An even quicker perspective**

The regulatory requirements for SCCDA are defined in a short section of 49CFR192.929 that requires an operator to screen, evaluate and assess for conditions that might cause SCC in a covered segment and currently relies heavily on ASME B31.8S that is more focused on high ph SCC.\textsuperscript{15} Current regulations governing SCC are incomplete and we support ongoing efforts to bring this risk of concern in focus, both on gas and liquid transmission pipelines. Given the high likelihood that SCC failure will go to rupture, and the increasing risk demonstrated from coating disbondment associated with older coating applications on transmission pipelines across much of the U.S., more specific regulations and guidelines on SCC are needed.

\textsuperscript{14} 49CFR192.927(c)(4)(ii).

\textsuperscript{15} Ibid, B31.8S, Appendix A3.4 “Integrity Assessment.”
Applications and Key Issues Driving DA

DA can be thought of as a process approach that can be utilized to deal with some corrosion risks of concern that may cause a pipeline to fail. B31.8S codifies the Pipeline Research Committee International’s (PRCI) work defining 3 of the 22 root causes that can be considered threats to pipeline integrity as corrosion related. It should be noted that while we are in accord with the identified 22 root causes, this author does not concur with the stated distribution of these root causes into the three major categories of “Time-Dependent, Stable, and Time-Independent.” It is our experience that the distribution of the root causes into these three categories is pipeline specific, and that this determination can be very crucial in selecting an integrity management method and re-inspection interval for a specific pipeline. For example, for many and various reasons, certain manufacturing related defects and third party damage can go quickly “Time-Dependent” after years of “Stable” operation. In addition, some active “Time Dependent” corrosion can be passivated, essentially going “Time-Independent” for the life of the pipeline. Prudent risk management understands that over reliance on historical data to predict future pipeline system failures can lead to serious surprises given the ability for root causes to shift categories as operations change.

No single pipeline integrity inspection method is currently capable of identifying or addressing all risks of concern that can result in pipeline failure. This is especially true for the limited corrosion risks identifiable by DA. It is worth mentioning, that not all pipelines experience the 22 root causes as each threat risk (we normally refer to them as risk of concern) will vary among pipelines. There are many issues that can make the risks of concern different for each pipeline or pipeline segment (even within the same company or operation overseeing multiple pipelines). This is especially important as the distribution of the 22 root cases can be sufficiently different for liquid pipeline as compared to gas transmission pipelines (i.e. pressure cycling), and should be seriously evaluated when considering DA on certain gas and especially liquid pipelines. One of the main objectives of risk management is to insure that the decision makers are matching the right inspection method or tools to the risks of concern unique to a specific pipeline, or integrity threats, in order to prudently manage their system and avoid releases.

We see little problem expanding the use of DA onto liquid pipelines for external corrosion and SCC provided that the operator has chosen this method to address the very limited types of corrosion or other root causes that can lead to pipeline failure. We believe there is considerable opportunity for SCCDA, if properly developed as an appropriate standard, to quickly improve efforts to efficiently and effectively address SCC threats for both liquid and gas transmission pipelines. OPS and all parties are strongly encouraged to push continued development of SCCDA standards quickly.

Advances in smart pigging tools should be encouraged as once technology has developed and field validated unique pig technologies, such tools demonstrate superior ability to clearly identify many of the 22 root cause anomalies that can be of further concern. OPS should monitor and report the use of DA as compared to smart pigging, to gauge whether pipeline

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16 Ibid, B31.8S, Section 2.2 “Integrity Threat Classification.”
efforts are unwisely substituting DA at the expense of other more appropriate inspection methods. For pipelines that cannot be pigged, pipeline operators need to clearly understand the limitations of DA as even this effort may be seriously deficient in addressing many threats that unpigable pipelines may experience.

Caution should be exercised in the use of ICDA on gas lines operating in wet gas service as the risk for operating failure are substantially different for wet gas versus dry gas pipeline service. There is a fine but critically important line between a pipeline operation experiencing infrequent upsets carrying electrolyte into a “dry” pipeline and intentional mis-operation of producers/suppliers driving gas production and a pipeline into wet service at the expense of the transmission pipeline infrastructure.\textsuperscript{17} The use of ICDA on pipelines receiving gas from large-scale LNG receiving facilities needs proper review and detailed public discussion. The interactions and quality specification changes that may be associated with these unique gas supply facilities are currently undergoing considerable debate within the industry and are not yet resolved. LNG gas introduction could have a serious detrimental impact on natural gas transmission pipeline internal corrosion risks and the application of DA inspection techniques may not be appropriate on such systems. We concur with OPS’ s effort to exclude ICDA in liquid pipeline operations as the reaction mechanics for such systems is different for liquid pipelines as compared to gas pipelines.

Lastly, the DA structured approach process should be considered a possible role model for addressing risks of concern associated with distribution gas pipelines. With over one million miles of small diameter low pressure distribution gas pipelines in this country, it is reasonable to assume that some sort of structured process approach template, similar to the DA process, may be highly efficient and effective in dealing with gas distribution infrastructure. Current methods of transmission pipeline inspection, hydrotesting and smart pigging, are inappropriate for this entirely different operation with its own unique exposures.