Report to the State of Michigan

Evaluation of technologies to assess the condition of pipe coating on Line 5

June 30, 2018

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Executive Summary

This report presents the findings of the Enbridge assessment of the technologies that may be suitable for detecting damage to the coating of the two 20-inch diameter pipelines (Dual Pipelines) that span the Straits of Mackinac (the Straits). This assessment was completed in response to Section D of the Agreement between the State of Michigan and Enbridge Energy, Limited Partnership and Enbridge Energy Company, Inc., dated November 27, 2017 (the Agreement).

A total of nine technologies have been evaluated:

1. Cathodic Protection Close Interval Survey.
2. Direct Current Voltage Gradient Survey.
3. Alternating Current Voltage Gradient Survey.
4. Alternating Current Attenuation Survey.
5. Electromagnetic Acoustic Transducer In-line Inspection.
6. Cathodic Protection Current Mapper In-line Inspection.
7. Metal Loss In-line Inspection.
8. Visual Examination.
9. High-voltage Holiday Detection.

All of these technologies (except #8) involve electrical, electromagnetic, and/or ultrasonic measurements that indirectly indicate the existence of coating damage. Although several of these technologies have experienced widespread industry utilization for onshore pipelines, their use on in-situ submarine/offshore pipe is limited or non-existent.

The results of this study have shown that only Cathodic Protection Close Interval Survey (CP CIS) has the maturity in application to be used on submarine/offshore pipelines for detection of coating damage. CP CIS, in conjunction with metal-loss in-line inspection (ILI)[1] is the most reliable combination of technologies for managing any potential external corrosion threat on the Dual Pipelines in the Straits. Enbridge will execute CP CIS on the Dual Pipelines in 2018.

1 To evaluate the interior and exterior of its pipelines, most of which are underground, Enbridge uses sophisticated ILI tools that incorporate leading imaging and sensor technology to provide us with a level of detail similar to that of MRIs, ultrasound and x-ray technology in the medical industry. By examining the interior walls of our pipes inch by inch, ILI tools alert us to potential problems and help us determine whether or not further investigation, or preventive maintenance work, is required.

Background

External coating and cathodic protection (CP) are used synergistically to prevent external corrosion and metal loss on Enbridge's Dual Pipelines across the Straits. The external coating system provides a primary barrier between the steel and the environment and substantially reduces the amount of metal requiring CP. CP is an electrochemical method of preventing corrosion where metal is exposed to aqueous environments.

Section D of the Agreement required Enbridge to assess technologies that would be capable of detecting damage to the external coating used on the Dual Pipelines across the Straits. Importantly, such technologies should be practicable and provide additional benefit to the objective of managing external corrosion on the Dual Pipelines—over and above Enbridge's existing suite of external corrosion management practices, which include:

- Use of an external coating system to reduce the amount of pipe wall that is exposed to lake water/bottom sediment;
- Use of CP to electrochemically alter the pipe wall at locations of coating damage;
- CP monitoring programs to ensure adequacy of the applied protective current;
- Regular in-line inspections of the pipe wall to locate and size any areas of metal loss caused by external corrosion; and
- Rigorous, industry-leading integrity management processes that include detailed quality assurance of ILI, long-term trending of data, use of forward-looking analysis, and direct pipe examination of pipe as required.

Previous investigation—including regular ILI performed as part of Enbridge's integrity management program, the Enbridge Line 5 Biota Investigation[i], the Enbridge Line 5 Screw Anchor Inspections[ii], and all associated third-party reporting—have demonstrated that measureable external corrosion on the Dual Pipelines is non-existent, that the environment in the Straits is minimally corrosive, that the biota is not creating uniquely corrosive conditions on the pipe surface, and that CP on the pipeline is protecting the pipe from corrosion by, in part, creating protective calcareous deposits at areas of coating damage.

This report uses input from a variety of data sources (see *Sources of Data*) to assess technologies capable of detecting coating damage, and provides recommendations about their potential to provide additive benefit to Enbridge's management of external corrosion on the Dual Pipelines in the Straits.

Sources of Data

Third-party Consultancy

Enbridge engaged an industry-leading engineering consulting firm, Mears Group Inc. (Mears)[1], to perform a detailed review of potential technologies for detecting coating damage on submarine/offshore pipelines.

Elements of this effort included:

1. Review literature on available technologies.
2. Determine applicability to the Straits of Mackinac Line 5.
3. Summarize the findings in a comprehensive report.

The Mears report is included in this document as *Appendix A*.

Enbridge Literature Search

Enbridge accessed additional industry research through its membership to Pipeline Research Council International (PRCI)[2] and other subscription reference libraries, including the ASM Corrosion Analysis Network[3]. Such technical resources (requiring membership or subscription) is often state-of-the-art or industry leading. In some cases, this information is not available to Mears or the general public.

Proprietary Vendor—Specific Data

In some cases, vendors of specific technologies were unable to share proprietary information directly with Mears due to competing commercial interests. In these cases, Enbridge leveraged its access to such proprietary information to evaluate the potential of these technologies to detect coating damage on submarine/offshore pipelines.

Enbridge Experience and In-house Specialists

Enbridge has in-house experience with eight of the nine technologies that are part of this assessment. Enbridge has leveraged the experience of its staff to provide additional commentary about these technologies for detecting coating damage on submarine/offshore pipelines.

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1 Mears Group, Inc. is an international engineering and construction company encompassing pipeline-related services, including pipeline integrity engineering, testing and construction services. Corrosion prevention and control are at the core of their specialty technical and engineering services.
2 PRCI is a not-for-profit corporation comprised primarily of energy pipeline companies whose mission is to collaboratively deliver relevant and innovative applied research to continually improve global energy pipeline systems.
3 ASM International is the world's largest and most established materials-information society. The Corrosion Analysis Network is a single source for comprehensive and authoritative online information for researching, understanding, preventing and solving corrosion-related problems.

Evaluation Methodology

Technologies potentially applicable to detect damage to the coating on Line 5 across the Straits were evaluated in consideration of several capability elements, as discussed in the following subsections.

In order to maintain simplicity in the assessment, each element is qualitatively assigned a traffic light color:

- Green means the technology satisfactorily meets the objectives of that element and is ready for use with minimal development on the Dual Pipelines in the Straits.
- Yellow indicates that the technology has some limitations and may not meet the objectives of that element directly in its present form, and that some development may be required for application to the Straits.
- Red indicates that there are major limitations, that the technology does not meet the elements objectives, or that the technology is not at present adaptable for use in the Straits.

Defect Detection Capability

Small-defect[1] Detection

This element considers the ability of the technology to detect isolated areas of coating damage and/or external corrosion smaller than 1 square inch (<600mm^2). Technologies that meet this objective are graded green. Technologies that could detect clusters of a few closely spaced areas of coating damage are graded yellow. Red is assigned to technologies that cannot detect a few closely spaced areas of coating damage.

Large-defect[2] Detection

This element considers the ability of the technology to detect areas of coating damage and/or external corrosion as small as 1 square inch (>600mm^2). Technologies that meet this objective are graded green. Technologies that might only be expected to detect areas of coating damage larger than 16 square inches (12,900 mm^2) are graded yellow. Technologies unable to detect areas of coating damage smaller than 160 square inches (103,200 mm^2), i.e. one order of magnitude less sensitive, are graded red.

1 Enbridge uses the term 'Small Defect' according to guidance provided by ANSI/NACE SP0502-2010, in which "small coating holidays" are described as "...isolated and typically <600mm^2 (1 in^2)". NB: The term "holiday" is an industry standard term defined as "a discontinuity in a protective coating that exposes unprotected surface to the environment." The terms "holiday", "defect", "area of coating damage", "coating damage", and "damage to the coating" are used interchangeably throughout this document.

2 Enbridge uses the term 'Large Defect' to describe an area of coating damage that does not meet the previous definition of 'Small'. This is consistent with ANSI/NACE SP0502-2010, which only defines a "small coating holiday" (see previous footnote); and NACE SP0207-2007, which describes 'medium to large defects' as "...typically >600 mm^2 (1 in^2)".

Submarine/ Offshore Readiness

This element considers the maturity of the technology with respect to industry use with submarine/offshore pipelines. Green is assigned to technologies that are in widespread use for submarine/offshore pipelines and this is reflected in the commercial availability of the technology for that purpose from several vendors. Yellow is assigned to technologies that have extremely limited use (pilot or feasibility projects) but are not yet commonly available for submarine/offshore use. Red is assigned to technologies that are considered at present to be not feasible for submarine/offshore use.

Applicability to the Dual Pipelines

This element considers the known technical limitations specific to conditions of the Straits. Green is assigned to technologies that are expected to provide satisfactory detection capability under the specific circumstances of the Dual Pipelines. Yellow indicates that the specific circumstances of the Dual Pipelines would have a significant impact on that technology's ability to detect areas of coating damage. Red indicates that there are parameters/circumstances of the Dual Pipelines that would render the technology ineffective.

Evaluation

Cathodic Protection Close Interval Survey

Small-defect Detection	Large-defect Detection	Submarine/ Offshore Readiness	Applicability to the Dual Pipelines

Cathodic Protection Close Interval Survey (CP CIS) is performed on a buried or submerged metallic pipeline in order to obtain valid direct current (DC) structure-to-electrolyte potential measurements at a regular interval that is sufficiently small enough to permit a detailed assessment of cathodic protection levels.

In its simplest form, this survey requires an electrical connection from the protected pipeline structure to a voltmeter or datalogger, which is connected in turn to a reference electrode placed near the pipeline (typically directly above the pipeline). Voltage measurements are taken every few feet (i.e. at 'close intervals') by moving the reference electrode along the length of the pipeline. There are several methodologies to conduct CP CIS surveys, as presented in *Appendix A*. The methodology that would be most applicable to the Straits crossing would be an interrupted ON/OFF potential survey.

CP CIS is intended to provide comprehensive measurement of cathodic protection levels on a pipeline (status of protection with respect to industry and regulatory standards) as opposed to detecting areas of coating damage, yet the technology has been recognized as a coating-assessment technique[iii].

Isolated areas of coating damage smaller than 1 square inch (<600 mm^2) are unlikely to be detected by this method; but clusters of closely spaced coating defects will produce an indication similar to large defects. Areas of coating damage that are larger than 1 square inch (>600mm^2) create a local depression in the level of cathodic protection and attenuation in the CP IR drop—the difference in potential between the current ON and current OFF CP readings—making these features detectable[iv]. It is noted that some cathodic protection byproducts (such as calcareous deposits) provide a barrier to the environment, acting similar to a coating, and may reduce the sensitivity of CIS for detecting areas of coating damage[v] (similar to Alternating Current Voltage Gradient, which is described on pages 7-8).

CP CIS is an established practice for onshore pipelines, and several references to submarine/ offshore use were found through industry sources such as NACE International[1] and ASM. Major service providers indicate expertise in submarine/offshore CP CIS, particularly in northern Europe. There are no obstacles specific to the application of this technology on the Dual Pipelines in the Straits.

1 NACE International serves nearly 36,000 members in over 130 countries and is recognized globally as the premier authority for corrosion-control solutions.

Direct Current Voltage Gradient Survey

Small-defect Detection	Large-defect Detection	Submarine/ Offshore Readiness	Applicability to the Dual Pipelines

Cathodically protected structures receive electrical current through the environment (i.e. water) surrounding the structure (i.e. the pipelines). This electrical current produces a voltage gradient according to ohms law: current (I) through a resistive material (R), in this case the environment, produces a voltage drop (V=I*R). This voltage drop through the environment can be measured using a voltmeter connected to two reference electrodes in contact with the environment in close proximity to the structure of interest.

Direct Current Voltage Gradient (DCVG) Survey comprises a series of voltage gradient measurements along a pipeline, using a voltmeter connected to a pair of reference electrodes. The paired reference electrodes are moved along the pipeline (similar to the CP CIS survey), producing a detailed examination of the voltage gradient along the pipeline. A pipeline with a uniform coating will produce a uniform voltage gradient. However, areas of coating damage allow a surplus of electrical current to flow between the pipe and the environment, and this surplus current produces a localized increase in the voltage gradient near the pipe. In this way, a DCVG survey can be used to identify areas of coating damage.

DCVG is quite sensitive to detecting small and large areas of coating damage. Its ability to size areas of coating damage is strongly dependent on the location and spacing of reference electrodes.

This technology is thoroughly established for onshore pipelines, particularly as associated with External Corrosion Direct Assessment procedures used to manage pipeline (corrosion) integrity on non-piggable pipelines where in-line inspection is not feasible. No actual references to DCVG submarine/offshore projects were discovered during the literature search, and no vendors of the service for submarine/offshore pipelines were identified. The use of electric-field-gradient (EFG) measurement data as an adjunct dataset for submarine/offshore CP CIS is discussed in industry literature, but the sensitivity of EFG measurements for detecting and sizing areas of coating damage on submarine/offshore pipelines is uncertain.

Considerable effort and development would be required to adapt this technology for use within the Straits.

Alternating Current Voltage Gradient Survey

Small-defect Detection	Large-defect Detection	Submarine/ Offshore Readiness	Applicability to the Dual Pipelines

Alternating Current Voltage Gradient (ACVG) Survey is similar to the DCVG in that a voltmeter is used to measure the voltage gradient in the environment surrounding a pipeline, and these reference electrodes are moved along the pipeline to produce a detailed voltage gradient survey.

However, the important difference is that ACVG uses a unique AC current signal to energize the pipeline, as well as a specialized voltmeter (tuned to this frequency) to measure the voltage gradient between the two reference electrodes. The unique signal used for ACVG enables identification of extremely small areas of coating damage (smaller than 0.01 square inch).

This technology is thoroughly established for onshore pipelines, particularly as associated with External Corrosion Direct Assessment procedures used to manage pipeline integrity on non-piggable pipelines where in-line inspection is not feasible. It is noted that some cathodic protection byproducts (such as calcareous deposits) provide a barrier to the environment, acting similarly to a coating, and can further present a barrier to ACVG current discharge at areas of coating damage, resulting in a loss of sensitivity[vi]. No actual references to ACVG survey projects on submarine/offshore pipelines were discovered during the literature search and no vendors of this service for submarine/offshore pipelines could be identified.

Considerable effort and development would be required to adapt this technology for use within the Straits.

Alternating Current Attenuation Survey

Small-defect Detection	Large-defect Detection	Submarine/ Offshore Readiness	Applicability to the Dual Pipelines

Cathodically protected structures receive electrical current through the environment surrounding the structure. The collection of electrical current along a linear structure (such as a pipeline) produces an axial current profile that is dependent on the current density received by the structure—which is dependent on the performance of the external coating system. If current measurements are recorded at regular intervals, the generalized coating performance may be assessed by examining the rate at which electrical current is collected along the pipeline.

Alternating Current Attenuation Survey involves the application of a unique AC signal to energize the pipeline. This unique signal is easier to detect than the cathodic protection current (which is DC), and the attenuation characteristics of AC current is more strongly affected by coating performance than DC current—making this more sensitive than a DC current attenuation survey, which is described in the *Cathodic Protection Current Mapper In-line Inspection* section on page 9.

Alternating Current Attenuation Survey is not a technique intended for locating areas of coating damage, but is instead intended to screen pipeline regions (lengths of 150-300 feet) for generalized coating performance variation. It is usually performed in conjunction with ACVG.

Anecdotal reports of customized underwater survey equipment were encountered during Enbridge's data-gathering efforts, but no vendors of this service for submarine/offshore pipelines were identified.

This technology is not readily available for underwater use, but could be adapted for use within the Straits.

Electromagnetic Acoustic Transducer In-line Inspection

Small-defect Detection	Large-defect Detection	Submarine/ Offshore Readiness	Applicability to the Dual Pipelines

Electromagnetic acoustic transducers (EMATs) use electromagnetic energy to induce acoustic energy into a pipe wall. Sensors are used to evaluate the transmission of this energy along short distances of the pipe wall in both the axial and circumferential directions. Pipe wall features such as cracking, metal loss, and changes in the external coating performance produce variations in the acoustic energy transmission. A detailed examination of the pipe wall is created as the in-line inspection tools transits the pipeline—propelled by fluid flow.

This in-line inspection technology was first developed to detect mid-wall flaws for gas transportation pipelines, but subsequent analysis conducted as part of pipe inspection demonstrated that the acoustic signal was modified by the type and quality of external coating[vii].

While the technology is considered 'ready' for both onshore and submarine/offshore pipelines, the extremely thick pipe wall of the Dual Pipelines adversely affects the technology's sensitivity to detecting even very large (>16-square-inch) areas of coating damage. Only one vendor was found with an EMAT in-line inspection tool capable of running in the Dual Pipelines, but the pipe wall thickness of the Dual Pipelines are outside the specified operating range—rendering this technology unfeasible at the present time.

Cathodic Protection Current Mapper In-line Inspection

Small-defect Detection	Large-defect Detection	Submarine/ Offshore Readiness	Applicability to the Dual Pipelines
🔴	🔴	🟡	🔴

Cathodically protected structures receive electrical current through the environment surrounding the structure. The collection of electrical current along a linear structure (such as a pipeline) produces an axial current profile that is dependent on the current density received by the structure—which is dependent on the performance of the external coating system. If current measurements are recorded at regular intervals, the generalized coating performance may be assessed by examining the rate at which electrical current is collected along the pipeline.

The Cathodic Protection Current Mapper (CPCM) is an in-line inspection technology that measures axial DC current flow in a pipeline directly—by measuring the voltage drop along the length of the in-line inspection tool. When electrical current passes through a metal conductor of known or calculable resistance, a reproducible axial voltage gradient is produced along the pipe.

The original intent of this in-line inspection technology was to detect step changes in axial current in pipelines such as those created by unintentional or unknown bonds to foreign structures. The attenuation profile of the CP current is also used as a general indicator of coating performance, similar to the Alternating Current Attenuation survey described on page 8. This inline inspection technology is not intended—nor is it sensitive enough—to detect small or large areas of coating damage in thick-wall pipe.

This technology was briefly available to pipeline operators from 2012 to 2018 through a single vendor, but it was removed from commercial availability in 2018.

Metal Loss In-line Inspection

Small-defect Detection	Large-defect Detection	Submarine/ Offshore Readiness	Applicability to the Dual Pipelines
🟡	🟡	🟢	🟢

For external corrosion to affect the safety of the Dual Pipelines in the Straits (i.e. creating a leak or rupture threat), several coincident requirements must be satisfied:

- There must be coating damage that exposes the pipe surface to the lake water or bottom sediments;
- The level of cathodic protection at the location of the coating damage must be inadequate to prevent corrosion;
- The environment of the pipe (lake water or bottom sediment) must be corrosive enough to drive corrosion processes; and
- Sufficient time must elapse for integrity-affecting corrosion to occur.

Metal Loss In-Line Inspection (ML-ILI) can be accomplished using a variety of technologies that measure pipe wall thickness directly or indirectly with very high resolution—typically at intervals of ¼ inch axially along the pipeline and ¼ inch circumferentially around the pipeline.

ML-ILI can only infer coating damage by detecting that measurable corrosion has occurred. External corrosion cannot occur where coating is bonded and intact because the coating prevents contact between the pipe wall and the corrosive environment. Although the absence of external corrosion does not provide assurance that a coating is in good condition, the presence of external corrosion is a very reliable indicator that coating damage is present. As such, small and large areas of coating damage that have produced small and large areas of metal loss are reliably detectable. A 'yellow' grading is assigned to this element because of the sensitivity of the technology to detecting metal loss that occurs at areas of coating damage.

ML-ILI has been used in the management of pipeline corrosion since the 1970s and is widely available from many vendors for virtually any set of pipeline specifications/parameters. Multiple technologies have been employed for this purpose, including several variations of ultrasonic and magnetic-flux leakage technologies.

Visual Examination

Small-defect Detection	Large-defect Detection	Submarine/ Offshore Readiness	Applicability to the Dual Pipelines

Visual examination of coated structures for detection of coating damage and/or external corrosion is frequently used for aboveground structures, underwater structures and within enclosed spaces. For underwater structures, such inspections may be performed using remotely operated vehicles (ROVs), or through direct examination by divers. Depending on the quality of the images produced, small and large areas of coating damage may be identified.

As part of the Line 5 Screw Anchor Inspection Work Plan executed in 2017/2018, Enbridge has already used ROV- and diver-based visual examination of the Dual Pipelines. Visual assessment of coating damage in the Straits is significantly obscured by the presence of sediment and biota (algae, plants, mussels). This method is graded yellow for both small and large defects because of the additional requirement that divers scrape or brush away sediment and biota in order to achieve satisfactory results. While this methodology has been successfully used at discrete locations, completing visual examinations with divers to examine long lengths of pipeline would be prohibitive due to logistics.

The formation of calcareous deposits as a protection layer, where the original coating may be thin but still intact, negatively affects the reliability of this coating inspection technique.

High-voltage Holiday Detection

Small-defect Detection	Large-defect Detection	Submarine/ Offshore Readiness	Applicability to the Dual Pipelines

High-voltage holiday detection, also called 'jeeping', requires an external voltage to be applied between the pipe metal and an electrode/contactor that is brushed over the coating. When an area of coating damage is encountered, detectable electrical current will flow between the pipe metal and the external electrode. Extremely small coating pinholes—even those invisible to the naked eye—are detectable using this method.

This technology is commonly used on pipelines during construction and maintenance activities to ensure the coating is in good condition.

Application of this technology to submarine/offshore pipelines is not possible due to the passage of electrical current through the water surrounding both the pipe and the external electrode/contactor. The application of open (uncontained) electric voltage sources may present danger to divers and aquatic organisms.

Conclusions

Enbridge engaged external third-party experts (Mears) and leveraged internal subject matter expertise to assess several technologies that potentially would be capable of detecting damage in the external coating used on the Dual Pipelines across the Straits. The following table provides a summary of that assessment.

Technology	Small-defect Detection	Large-defect Detection	Submarine/ Offshore Readiness	Applicability to the Dual Pipelines
Cathodic Protection Close Interval Survey	🟠	🟢	🟢	🟢
Direct Current Voltage Gradient Survey	🟢	🟢	🔴	🟠
Alternating Current Voltage Gradient Survey	🟢	🟢	🔴	🟠
Alternating Current Attenuation	🔴	🔴	🟠	🟠
EMAT In-line Inspection	🔴	🟠	🟢	🔴
CP Current Mapper ILI	🔴	🔴	🟠	🔴
Metal Loss ILI	🟠	🟠	🟢	🟢
Visual Examination	🟠	🟠	🟢	🟠
High-voltage Holiday Detection	🟢	🟢	🔴	🔴

Enbridge's internal and external assessment of technologies capable of detecting coating damage on the Dual Pipelines both concluded that the only technology that can be readily deployed on the Dual Pipelines is Cathodic Protection Close Interval Survey (CP CIS), which Enbridge will execute in the summer of 2018. This technique is capable of detecting clusters of small areas of coating damage as well as isolated large areas (>1 square inch, 600 mm^2). CP CIS, in conjunction with Metal Loss ILI, is considered industry best practice for preventing and managing external corrosion of piggable pipelines. This is further supported by the performance of the corrosion prevention system throughout the pipeline's operating history, and the resulting absence of any significant corrosion on the pipelines throughout the Straits.

DCVG and ACVG are similar and are both the next most promising technologies for detection of small, isolated areas of coating damage (<1 square inch, 600 mm^2). However, substantial development would be required to adapt these technologies for use on submarine/offshore pipelines—and doing so would provide minimal benefit over the existing activities planned in the Straits. The sensitivity of these techniques for submarine/offshore application is not known.

The related technique of electrical field measurement (EFG) is cited as a useful addition to submarine/offshore CP CIS. Enbridge CP CIS plans in 2018 include redundant reference cells and dataloggers to ensure successful collection of cathodic-protection potentials. This redundancy will be leveraged to obtain simultaneous EFG data.

References

[i] “Biota Investigation Work Plan Final Report”, Enbridge Energy, Limited Partnership, March 29, 2018. Retrieved from https://www.epa.gov/enbridge-spill-michigan/enbridge-line-5-biota-investigation.

[ii] “Anchor Inspection Work Plan: Interim Report”, Enbridge Energy, Limited Partnership, January 16, 2018, available upon request.

[iii] Segall, S., Gummow, R., Zahraee, M., Fingas, D., “Assessing the Integrity of Coating Systems on Pipelines in Trenchless Crossings”, Cataloque No. PR-444-133602-R01, Pipeline Research Council International, ©2015.

[iv] Standard Practice: “Performing Close-Interval Potential Surveys and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines”, SP0207-2007, Item No. 21121, NACE International, Houston, TX ©2007.

[v] Ukiwe, C. and McDonnell, S., “Assessing the Performance of Above Ground Coating Evaluation Surveys”, Catalogue No. L52362, Pipeline Research Council International, 2008, ©2012.

[vi] Ukiwe, C. and McDonnell, S., “Assessing the Performance of Above Ground Coating Evaluation Surveys”, Catalogue No. L52362, Pipeline Research Council International, 2008, ©2012.

[vii] “Augmenting MFL Tools with Sensors that Assess Coating Condition” (Battelle Memorial Institute), Catalogue No. L52298, Pipeline Research Council International, ©2009.

Appendix A: Mears Report

ENBRIDGE

Straits of Mackinac Line 5

Coating Assessment Technologies

State of The Art

Report

June 14, 2018

Mears Job #: 9141883308

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EXECUTIVE SUMMARY

Mears Group, Inc. (Mears) has been retained by Enbridge to provide a state-of-art report describing available survey technologies to assess coating damage on in-situ pipelines. This assessment includes a review of the current available technologies and the potential application to assess coating condition on the underwater segments of the Line 5 crossings of the Straits of Mackinac.

The scope of work consisted of three tasks:

Task 1 – Review Literature on Available Technologies,

Task 2 – Determine Applicability to Straits of Mackinac Line 5, and

Task 3 – Summarize the Findings in a State-of-the-Art Report.

The technologies reviewed in this report include Close Interval Survey (CIS), Direct Current Voltage Gradient (DCVG), Alternating Current Voltage Gradient (ACVG), AC Attenuation, Electro-Magnetic Acoustic Transducer In-Line Inspection (EMAT ILI), Cathodic Protection Pipeline Inspection (CPCM™). The industry standards, practice and guidelines are summarized for each technology. Special focus was on the applications for utilizing these techniques to assess coating anomalies on underwater pipelines such as the Line 5 crossings of the Straits of Mackinac. A literature review of these technologies was performed and summarized in this report.

The CIS survey has been successfully used throughout the world to assess CP levels on subsea and submerged pipelines and is deemed to be the most reliable indirect inspection tool for this application. NACE SP0207-2007 indicates that CIS can locate medium-to-large defects in coatings (isolated or continuous and typically >600 mm^2 [1 in^2]).

DCVG surveys are capable of distinguishing between isolated and continuous coating damage, due to the fact that the shape of the gradient field surrounding a fault provides this information. DCVG can also be used to identify isolated coating damage, such as rock damage, or continuous coating damage. The vast majority of DCVG surveys have been performed on land based buried pipelines. The commonly used instrumentation and techniques are not adapted for deep submerged pipelines making such surveys unfeasible.

ACVG can be utilized to identify several types of problems on underground pipelines with the most common use being to identify indications of coating anomalies utilizing a unique AC frequency as its signal source. ACVG survey equipment has not been for use on deep subsea or deep underwater pipelines.

The review has also shown that the EMAT tool shows promise as a coating assessment tool, but likely will not yield incremental value to the use of the CIS tool to assess and ensure CP efficacy in conjunction with periodic inspection through ILI intended to detect external metal loss anomalies. Pipe wall thickness impacts the sensitivity of the EMAT tool in detecting coating anomalies, this inspection tool is not capable of detecting small coating defects and is not additionally useful compared to the option of using CIS to detect medium to large size coating defects.

The capabilities and effectiveness of Baker Hughes Cathodic Protection Current Measurement (CPCM™) ILI for detecting coating holidays was specifically requested. The heavy wall pipe utilized in the straits crossings dis not compatible with this technique. Information obtained at the time of conducting this review indicated that the tool is no longer commercially available and thus the analysis of CPCM ILI for this application is only superficially discussed in this report.

While other coating assessment tools such as DCVG, ACVG and AC Attenuation can be reliably performed for onshore land-based pipelines, those technologies present significant challenges for underwater pipelines. The instrumentation and techniques have not been adapted for deep submerged pipelines making such surveys unfeasible at this time. The technical challenges and lack of proven detection capabilities and calibration of those techniques to an underwater pipeline introduce too much risk of unreliable and potentially misleading results to warrant serious consideration.

The use of CIS and CP measurements are demonstrated to be the most appropriate technologies to continue to evaluate the coating performance of the Straits crossings. Integrity management practices, including inline inspection to assess corrosion condition, provide an additional method of validation to confirm the performance of corrosion protection systems beyond the inspections methods evaluated herein. CIS provides adequate detection of moderate and large coating defects in addition to comprehensive cathodic protection status, while periodic metal loss ILI continues to be the preferred industry standard and best practice for monitoring corrosion.

The results of this study have shown that CIS and ILI remain the two most reliable tools for assessing the integrity of the Line 5 Straits of Mackinac pipeline crossing. Moreover, CIS has evolved into a mature and reliable technology for subsea and marine crossing pipelines.

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Acronyms and Abbreviations

A	Ampere
ACVG	Alternating Current Voltage Gradient
CP	Cathodic Protection
CSE	Copper-Copper Sulfate Reference Electrode
CIS	Close Interval Survey
CTE	Coal Tar Enamel
DC	Direct Current
DCVG	Direct Current Voltage Gradient
PCM	Pipeline Current Mapper
ECDA	External Corrosion Direct Assessment
ICCP	Impressed Current Cathodic Protection
ILI	In-Line Inspection
EMAT	Electro-Magnetic Acoustic Transducer
ROV	Remote Operated Vehicle
V	Volt

1.0 INTRODUCTION

Background

Enbridge's Line 5 is a 645-mile, 30-inch-diameter pipeline that travels through Michigan's Upper and Lower Peninsulas, originating in Superior, Wisconsin, USA, and terminating in Sarnia, Ontario, Canada. Before Line 5 traverses under the Straits of Mackinac, flow is split between two 20-inch-diameter, parallel pipelines approximately 100 feet apart that are buried onshore and gradually transition to a maximum depth of 260 feet underwater, crossing the Straits west of the Mackinac Bridge for a distance of 4.5 miles. Enbridge Line 5 pipeline was installed in 1953, constructed using heavy-wall pipe (0.812-in). The pipelines were constructed with an enamel coating and fiber wrappings. Figure 1 shows the approximate location of the pipelines.

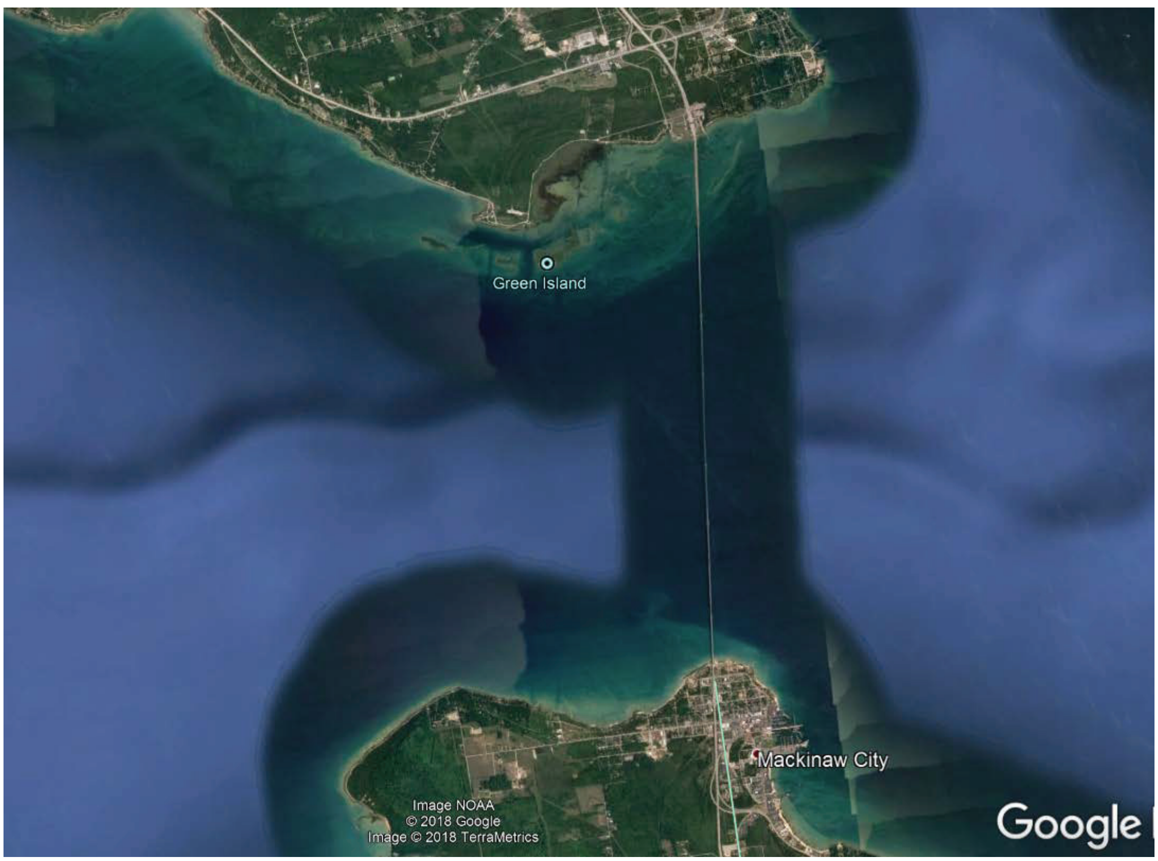

Figure 1: Location of Enbridge Line 5 Pipelines

Project Objective and Scope of Work

Mears Group, Inc. (Mears) was retained by Enbridge to prepare a state-of-the-art report summarizing presently available technologies to detect and assess coating damage on in-situ pipelines, and the applicability of these technologies to the dual pipelines in the Straits of Mackinac.

The scope of work consisted of three tasks:

Task 1 – Review Literature on Available Technologies,

Task 2 – Determine Applicability of These Technologies to Straits of Mackinac Line 5, and

Task 3 – Summarize the Findings in a State-of-the-Art Report.

The work was carried out in accordance with Mears Proposal CP 5393, February 23rd, 2018 and in accordance with Enbridge WLAW-1000010-18.

2.0 REFERENCES

The information and documentation reviewed and relied upon in these analyses is shown below:

Standards/Procedures/Specifications

- SP0169-2013 Control of External Corrosion on Underground or Submerged Metallic Piping Systems-Item No. 21001
- SP0502-2010 Pipeline External Corrosion Direct Assessment Methodology (ECDA)
- SP027-2007 Potential Surveys and DC Surface Potential Gradient Surveys on Buried or Submerged -Item No. 21121
- TM0109-2009 Aboveground Survey Techniques for the Evaluation of Underground Pipeline Coating Condition-Item No. 21254
- TM0497-2002, Measurement Techniques Related to Criteria for Cathodic Protection on Underground or Submerged Metallic Piping Systems-Item No. 21231
- ISO Standard 15589–2-2012 Petroleum, petrochemical and natural gas industries-Cathodic protection of pipeline transportation systems Part2: Offshore pipelines

Industry Literature Research

Detailed summaries of literature reviewed along with a bibliography of references are listed at the end of this report and also in Appendix A.

3.0 CATHODIC PROTECTION (CP)

CP is a widely used and effective method of corrosion control. It is commonly used as part of a corrosion prevention system, in concert with coatings on underground and submerged structures. For transmission pipelines carrying hazardous liquids and natural gas, the use of coatings and cathodic protection is required by Federal regulations (Title 49 CFR Part 195 and 192).

It is commonly accepted that protective coatings are considered the first line of defense for corrosion protection of buried and submerged pipelines[1]. It is also understood that protective coatings are not perfect and will have pinholes, flaws and defects where the pipe substrate will be protected by the application of CP, often through the development of calcareous deposits/films consisting primarily of calcium carbonate and magnesium carbonate.[2]

The following section discusses the theory of cathodic protection, and the types of cathodic protection systems in common use.

3.1 Cathodic Protection Theory

Direct current (DC) is applied to all surfaces of the pipeline through an external source. This direct current shifts the electric potential of the pipeline in the negative direction, resulting in a reduction in the corrosion rate of the metal. When the amount of current flowing is adjusted properly, it will overpower the corrosion current discharging from the anodic areas on the pipeline, and there will be a net current flow onto the pipe surface at these points. The entire surface then will be a cathode and the corrosion rate will be reduced. This concept is illustrated in Figure 2. Details of

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[1] SP0169-2013 "Control of External Corrosion on Underground or Submerged Metallic Piping Systems, NACE International, Texas.

[2] Characteristics of Cathodic Protection And Calcareous Deposits For Type 316L Stainless Steel In Simulated Deep Sea Condition by Ki-Joon Kim and William H Hartt.

the application of CP are given in Chapters 4 and 5 of the book "CONTROL OF PIPELINE CORROSION" by A. W. Peabody.

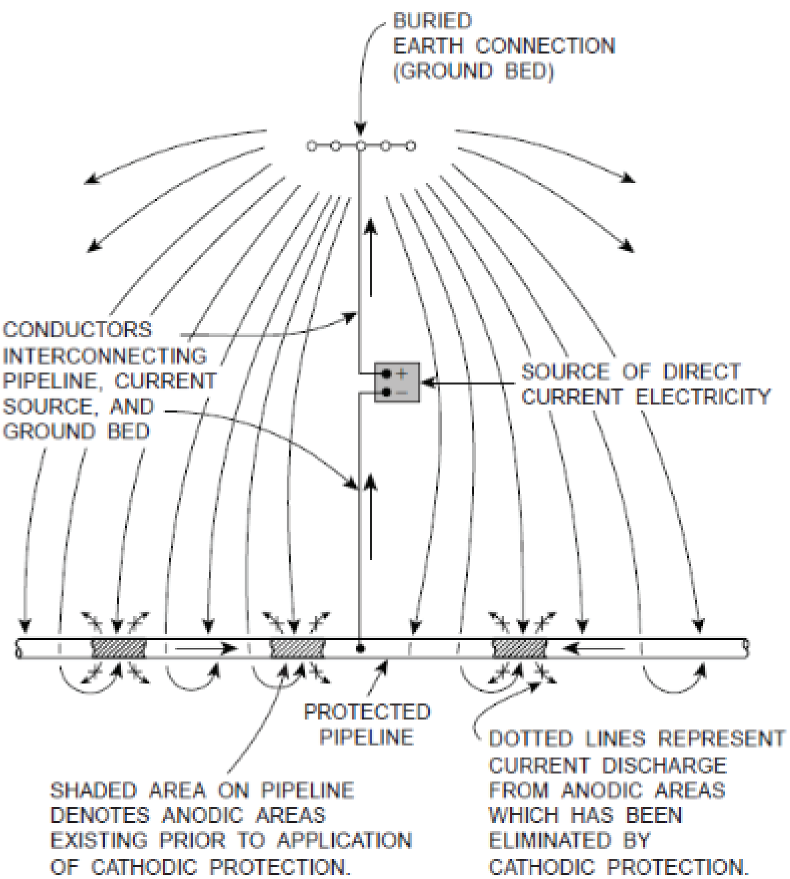

Figure 2: Basic CP Theory[3]

The CP system requirements, procedure, design, installation, operation and maintenance processes are also recommended by NACE standard practice SP0169 "Control of External Corrosion on Underground or Submerged Metallic Piping Systems"[1].

[3] A.W. Peabody, "*Control of Pipeline Corrosion" by Peabody*, NACE International, the Corrosion Society, Texas, 1967, 2001.

3.2 Cathodic Protection Types

There are two general types of cathodic protection installation that differ primarily in the manner in which a voltage is obtained to supply cathodic protection current. These two types are commonly referred to as impressed current cathodic protection and galvanic (or sacrificial) anode cathodic protection[4]. These are described below.

Impressed Current CP (ICCP)

ICCP installations utilize an external power source to create the direct current used to protect the pipe. The current from this source is impressed on the circuit between the pipeline to be protected and the anode bed. The essential components of such a system are shown in Figure 3.

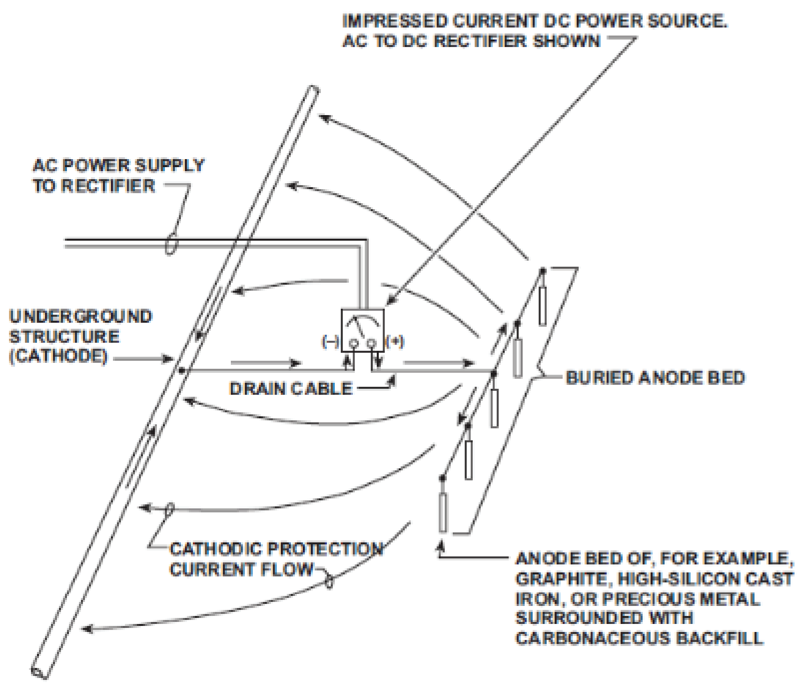

Figure 3: Impressed Current CP.[4]

[4] *Appalachian Underground Corrosion Short Course- Education and Training for Corrosion Control*, West Virginia University, Morgantown, West Virginia, Copyright 2011.

Galvanic (or Sacrificial) Anode Cathodic Protection

This type of cathodic protection depends on the voltage difference between dissimilar metals to cause protective direct current to flow. A typical galvanic anode cathodic protection installation is shown in Figure 4. The anode material can be magnesium (as shown in Figure 4), zinc or aluminum. The anode material is normally available in cast shapes of various sizes to fit the requirements of differing galvanic anode cathodic protection installation designs.

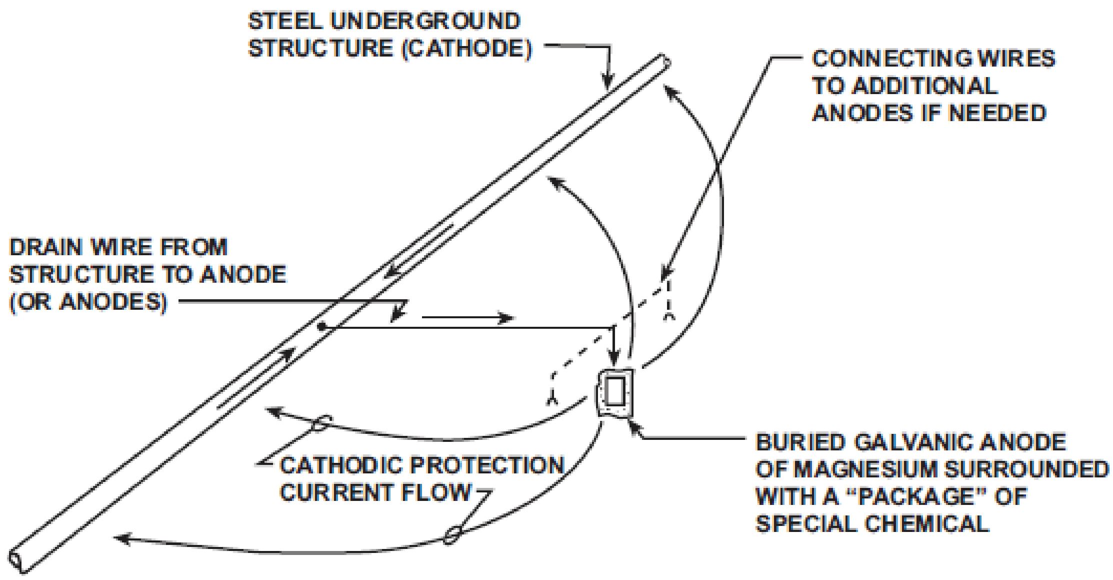

Figure 4: Galvanic (or Sacrificial) Anode Cathodic Protection[4]

3.3 Effect of Coating on Cathodic Protection

A protective coating applied to the pipe surface serves to isolate the pipeline from potentially corrosive environments in which the pipeline is installed. CP with a high-resistance barrier coating between the pipeline and the environment is shown in Figure 5. Current from the CP ground bed is flowing to all areas where pipe metal is exposed. This area is substantially reduced due to the presence of the coating. In addition to the current flowing to defects, current also flows through the coating material itself. No coating material is a perfect insulator (even when absolutely free of any defects) and will conduct some current. The amount will depend on the electrical resistivity of the material and its thickness.

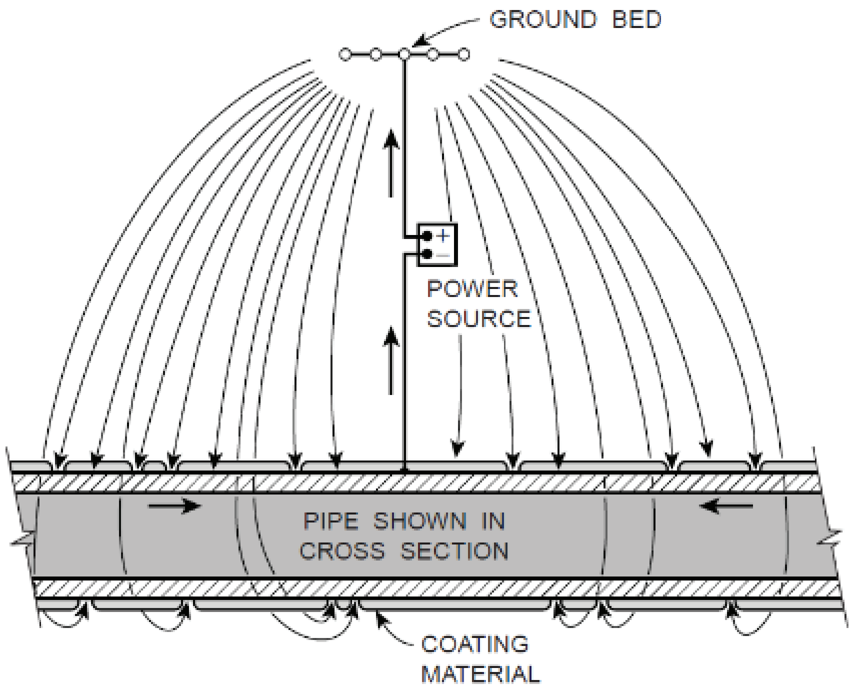

Figure 5: Cathodic protection of a coated pipeline[3]

ISO Standard 15589–2-2012 Petroleum, petrochemical and natural gas industries-Cathodic protection of pipeline transportation systems Part2: Offshore pipelines, provides guidance on coating breakdown factors (Table 3 of ISO 15589-2-2012 – Figure 6), acknowledging that coatings are expected to degrade, have flaws, age and require consideration of CP requirements to assure adequate corrosion protection.

Table 3 — Coating breakdown factors, f_c, for pipelines without concrete weight coating

Factory-applied coating type	Field joint coating type	f_i	Δf
Fusion-bonded epoxy (FBE)	Heat-shrinkable sleeves (HSS[a])	0,080	0,003 5
	FBE	0,060	0,003 0
Three-layer coating systems including epoxy, adhesive and polyethylene (3LPE)	HSS[a]	0,009	0,000 6
	FBE	0,008	0,005
	Multilayer coating including epoxy and PE (e.g. moulded, HSS[a] or flame spray)	0,007	0,000 5
Three-layer coating systems including epoxy, adhesive and polypropylene (3LPP)	HSS[a]	0,007	0,000 3
	FBE	0,006	0,000 2
	Multilayer coating including epoxy and PP (e.g. HSS[a], hot tapes, moulding or flame spray)	0,005	0,000 2
Heat insulation multilayer coating systems including epoxy, adhesive and/or PE, PP or PU	Thick multilayer coating systems including epoxy, adhesive and/or PE, PP, PU, HSS[a] or a combination of these products.	0,002	0,000 1
Thick coatings: elastomeric materials (e.g. polychloroprene or EPDM) or glassfibre-reinforced resins	Thick elastomeric materials or glassfibre-reinforced resins	0,002	0,000 1
Flexible pipelines	Not applicable (mechanical couplings)	0,002	0,000 1

[a] HSS can be used with or without primer.

Figure 6: Coating breakdown factors from Table 3 of ISO 15589-2-2012.

4.0 METHODS FOR EVALUATING CORROSION PROTECTION SYSTEMS

In order to ensure the effectiveness of the cathodic protection systems, which provides protection on the pipeline against corrosion, surveys and inspections are routinely completed. The quality and condition of the pipeline coating can significantly affect the performance of the CP system. NACE standard practice SP0169 recommends provides guidance on inspection of coating systems. In the case of buried and submerged pipelines, indirect inspections methods using electrical methodology is commonly applied to assess the CP system and coating condition.

NACE developed a standard practice to provide guidance to the industry on methodologies to assess the extent and severity of external corrosion. This standard was first developed to assist in evaluating the integrity of pipelines that could not be assessed through ILI or pressure testing. NACE standard practice SP0502 "*Pipeline External Corrosion Direct Assessment Methodology"* suggests close interval survey (CIS), direct current voltage gradient (DCVG), alternate current voltage gradient (ACVG), and alternating current (AC) attenuation surveys to assess the CP levels and the identify locations of coating holidays, as shown in Figure 6. In the absence of ILI data, a combination of the surveys listed above provide a comprehensive assessment on CP levels and pipeline coating damage or degradation to evaluate the corrosion prevention system as a whole. These concepts are embodied in the External Corrosion Direct Assessment (ECDA) process developed specifically as a tool to assess pipelines that cannot be inspected by ILI.

Table 2
ECDA Tool Selection Matrix [A]

CONDITIONS	Close-Interval Survey (CIS)	Voltage Gradient Surveys (ACVG and DCVG)	Pearson[8]	Current Attenuation Surveys
Coating holidays	2	1, 2	2	1, 2
Anodic zones on bare pipe	2	3	3	3
Near river or water crossing	2	2	2	2
Under frozen ground	3	3	3	1, 2
Stray currents	2	1, 2	2	1, 2
Shielded corrosion activity	3	3	3	3
Adjacent metallic structures	2	1, 2	3	1, 2
Near parallel pipelines	2	1, 2	3	1, 2
Under high-voltage alternating current (HVAC) overhead electric transmission lines	2	1, 2	2	2
Under paved roads	3	3	3	1, 2
Crossing other pipeline(s)	2	1, 2	2	1, 2
Cased piping	3	3	3	3
At very deep burial locations	3	3	3	3
Wetlands	2	1, 2	2	1, 2
Rocky terrain/rock ledges/rock backfill	3	3	3	2

[A] **Limitations and Detection Capabilities:** All survey methods are limited in sensitivity to the type and makeup of the soil, presence of rock and rock ledges, type of coating such as high dielectric tapes, construction practices, interference currents, and other structures. At least two or more survey methods may be needed to obtain desired results and confidence levels.

Shielding by Disbonded Coating: None of these survey tools is capable of detecting coating conditions that exhibit no electrically continuous pathway to the soil. If there is an electrically continuous pathway to the soil, such as through a small holiday or orifice, tools such as DCVG or current attenuation may detect these defect areas. This comment pertains to only one type of shielding from disbonded coatings. Current shielding, which may or may not be detectable with the indirect inspection methods listed, can also occur from other metallic structures and from geological conditions.

Pipe Depths: All of the survey tools are sensitive in the detection of coating holidays when pipe burials exceed normal depths. Field conditions and terrain may affect depth ranges and detection sensitivity.

KEY

1 = Applicable: Small coating holidays (isolated and typically < 600 mm^2 [1 in^2]) and conditions that do not cause fluctuations in CP potentials under normal operating conditions.
2 = Applicable: Large coating holidays (isolated or continuous) or conditions that cause fluctuations in CP potentials under normal operating conditions.
3 = Applicable where the operator can demonstrate, through sound engineering practice and thorough analysis of the inspection location, that the chosen methodology produces accurate comprehensive results and results in a valid integrity assessment of the pipe being evaluated.

Figure 7: ECDA Tool Selections[5]

Research of industry practices for coating assessments, including an evaluation of NACE/ISO standards, technical papers and related articles, was completed as part of this scope. The research assessed the available technologies used to detect and assess coating damage on in-situ pipelines including:

- Close Interval Survey (CIS),
- Direct Current Voltage Gradient (DCVG),
- Alternating Current Voltage Gradient (ACVG),
- AC Attenuation,
- Electro-Magnetic Acoustic Transducer In-Line Inspection EMAT (ILI), and
- Cathodic Protection Current Measurement (CPCM) ILI Tool.

The following summaries are based on the research of each technology.

5.0 CLOSE-INTERVAL SURVEY (CIS)

CIS is a potential survey performed at close spaced intervals along a buried or submerged metallic pipeline. The DC pipe-to-electrolyte potentials are measured at a regular interval over the pipeline. The objective of a CIS is to measure the pipe-to-electrolyte potential at sufficient points along a pipeline in order to:

- Confirm performance of CP system along the length of the pipeline;
- Identify the areas outside of the range of potential criteria of a pipeline not identified by test point survey;
- Determine the extent of areas outside the range of potential criteria;
- Determine the influence of CP, measure the level of CP, evaluate the effectiveness of current distribution along a pipeline, locate CP shielding areas;
- Identify the risk of interference condition;

[5] SP0502-*Pipeline External Corrosion Direct Assessment Methodology*, NACE International, Texas.

- Locate medium-to-large defects in coatings (isolated or continuous and typically > 600 mm^2 (~1 $inch^2$)[6];
- Identify shorted casings, defective electrical isolation devices, or contact with other metallic structures etc.

A general description of the CIS technology will be discussed in Section 5.1. The equipment, applications, procedures, and data analysis of the CIS are given in Section 5.2 and 5.5 . The application of CIS technology for the offshore pipeline will be given in Section 5.6. The limitations of this technology will be addressed in Section 5.7.

5.1 Description of Technology

CIS is used to measure the potential difference between the pipe and the electrolyte, such as soil or water media. Figure 7 shows a general schematic of the CIS survey methodology. An insulated wire is typically used to electrically connect the pipe test station or other electrically continuous pipeline appurtenance with a voltmeter terminal. A reference electrode is connected to the other terminal of the voltmeter and is placed directly over the pipeline at specific intervals. Because the electrical potential of the pipe is taken at such close spacing, this survey provides the most comprehensive evaluation of cathodic protection levels for pipelines.

5.2 Equipment

The details of the equipment are given in the book "Cathodic Protection Survey Procedures" by H. Brian Holtsbaum[7].

- The voltmeter has a high input resistance (typically 10 megohm or higher);
- A copper – copper sulfate (CSE) reference electrode is normally used for pipe in soil or fresh water, whereas a silver-silver chloride (Ag/AgCl) reference electrode is used in high chloride electrolytes such as seawater. Other electrodes may be used, such as a

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[6] SP0207-2007 Perforating Close-Interval Potential Surveys and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines"

[7] H. Brian Holtsbaum, "*Cathodic Protection Survey Procedures-3rd Edition*", NACE International, The Corrosion Society, Texas, 2016

saturated calomel electrode (SCE) and a hydrogen electrode; however, these are normally used in laboratory conditions.

- Test lead complete with electrically insulated spring clips or connectors. Ensure that there are low contact resistances between the instrument terminals and the wires the wire connectors, or the spring clip and the wire and the reference electrode, and
- Long electrical connection typically on a spool or reel.

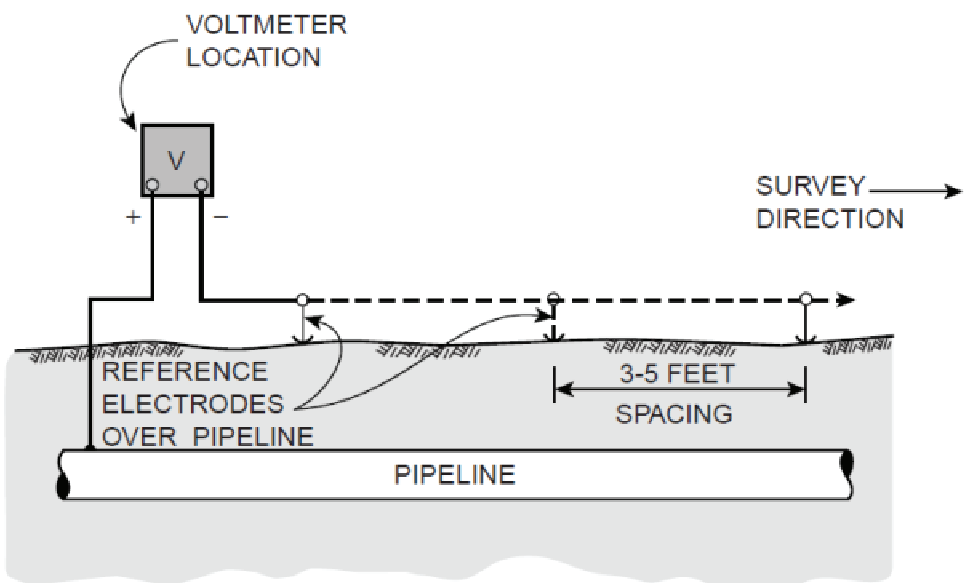

Figure 8: Schematic of CIS Survey (AW Peabody)

5.3 Potential Survey Types

The types of CIS surveys include ON/OFF potential surveys, ON potential surveys, and depolarized potential surveys[5].

5.3.1 Interrupted or ON/OFF Potential Survey

Interrupted, or ON/OFF, potential survey measures the potential difference between the pipeline and the electrolyte with the CP current source (CP system) interrupted. This survey is used to evaluate the CP system performance in accordance with CP criteria, to detect medium to large size or CP current drains, and as a screening tool for identifying areas of possible stray current interference.

ON potentials are the measurements with the CP system operating and providing the CP current to the pipeline. OFF potentials are the measurements with the CP system briefly interrupted and not providing the CP current to the pipeline and more accurately reflect the true polarized potential.

ON/OFF surveys typically incorporate electronically synchronized current interrupters at each CP current source, bond, and other current drain point that influences the pipeline potential in the survey area. Typical interrupter cycles are evenly divisible in 60 seconds, with an ON duty cycle of at least 75% to avoid significant depolarization. The selection of interrupt cycles is determined by equipment capabilities and transient behavior of the pipeline potentials during the interrupt cycle.

The accuracy of the ON and OFF data is typically verified using the following techniques:

- Wave form capture and analysis,
- Digital oscilloscope, and
- Digitized signal equipment.

5.3.2 ON Potential Survey

ON potential surveys are performed by measuring the potential difference between the pipe and the ground surface above the pipe at regular intervals while the CP is operating in its normal mode. ON potential surveys are used on pipelines protected with CP current sources that cannot be interrupted.

5.3.3 Depolarized Potential Survey

Depolarized potential surveys measure the potential difference between the pipe and the ground surface after the cathodic current has been switched off long enough for the pipe-to-soil potential to stabilize to equilibrium (‘native state’) potentials. Depolarized potential surveys are used to evaluate the effectiveness of the CP system with respect to a polarization decay criterion. The surveys are often performed in conjunction with ON/OFF potential surveys where compliance with the polarized OFF potential criterion is not achievable. All CP current sources, such as transformer-rectifiers or other DC power supplies, are de-energized by either breaking critical bonds or adjusting them so that they overcome interference effects while not providing additional CP. The pipeline is allowed to depolarize until a plot of potential versus time indicates that the pipe-to-soil potential is no longer decaying.

Figure 8 illustrates an example of the data results from these three types of CIS surveys (on, off, and native potentials).

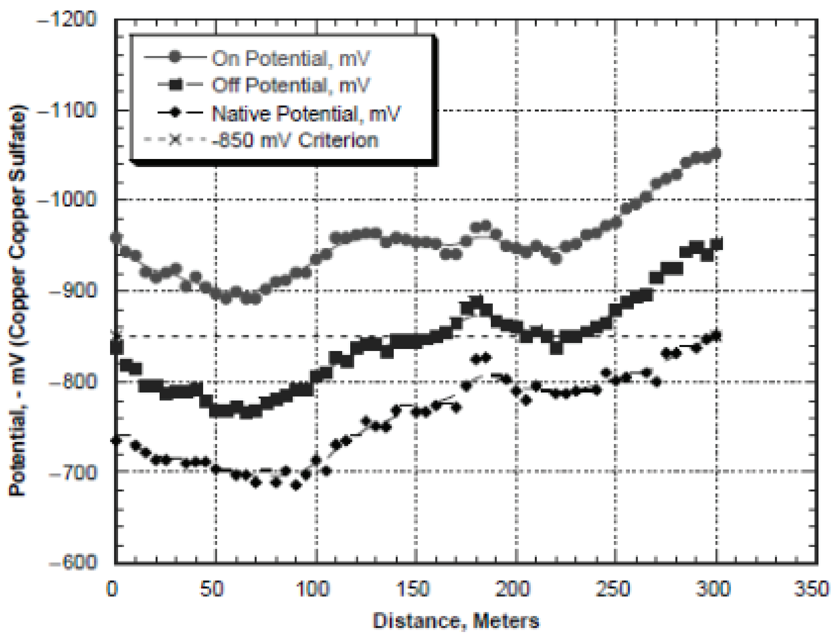

Figure 9: CIS Data Showing On, Off, And Depolarized Potentials[3]

5.4 CIS Procedures

Accurate potential measurements are critical to many areas of corrosion control work, especially when potential measurements are used for evaluating the efficacy of cathodic protection systems.

The details of CIS survey are described in "*SP0207-2007 Performing Close-Interval Potential Surveys and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines*" by NACE International[8].

5.4.1 Pipeline Location and Marking

Accurate location of a pipeline is required in order to minimize the voltage drops in the electrolyte and to obtain the highest resolution of the survey. This includes reviewing pipeline drawings prior to locating the pipeline, visual identification of the pipeline by aboveground appurtenances, casing vents, or pipeline markers. For land-based survey, the pipeline is typically flagged by survey crews using electromagnetic pipe detection equipment in advance of the CIS potential surveyor.

5.4.2 Current Interrupters

Install synchronized current interrupters in all DC power sources and all bonds that supply current to the pipe[5]. Select a long ON cycle and a short OFF to preserve as much polarization as possible. The length of the OFF cycle must be sufficient to allow to capture the instant OFF value. When multiple current sources are being interrupted, the installation of a stationary data logger is recommended to observe any loss of synchronization of the interrupters. Stationary data loggers can also be used to identify and correct for transient (time dependent) influences such as telluric earth currents and/or pipe depolarization over each survey day due to current interruption.

5.4.3 Survey Spacing Interval

For coated pipelines, the survey measurement interval (distance between individual measurements) required for a continuous evaluation of the pipeline is a function of the depth of burial and the ratio of the resistivity of the coating to the resistivity of the electrolyte. For land-based survey's the spacing is typically 3-5 feet.

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[8] *SP0207-2007 Perforating Close-Interval Potential Surveys and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines*" NACE International, Texas

5.4.4 Reference Electrode Placement

The valid pipe-to-electrolyte potential measurements require reference electrode placement and contact with the electrolyte. The reference electrode porous plug cap is removed and the porous plug is placed into the moist soil or water. For accuracy, the reference electrode should be placed directly over the pipeline.

5.4.5 Survey Areas

Potential measurements are also taken at each test station, rectifier, highway casing, railroad casing, and foreign pipeline crossing. Near ground and far ground on/off potential measurements are recorded at each point of pipeline connection to permit an evaluation of metallic IR Drop within the pipeline, and for data quality verification.

5.4.6 Survey Direction

CIS may be performed in either the upstream or downstream direction. The data shall clearly indicate which direction the survey was conducted.

5.4.7 Start and End of Survey

Survey runs should be conducted from one metallic connection to the next in order to obtain metallic IR drop measurements. When contact points are not available at the end of the survey run/segment, metallic IR drop measurements from adjacent survey runs should be evaluated to ensure that the measurements did not include significant metallic IR drop error.

5.5 Interpretation of Data

The performance of the CP system is assessed by comparing the measured potentials along the pipe to a given criteria indicating the adequacy of the CP. Typical quantities used to assess performance include the measured potentials, changes in potentials along the pipe, separation distances between ON, OFF, and depolarized potentials, and other signal features.

5.5.1 IR Drop

The IR drop normally of most concern is that the voltage drop between the reference electrode and the pipe-to-soil boundary (red rectangle in Figure 9).

The voltage drop errors, which are often referred to as ohmic potential drop or IR drop errors, occur as a result of the flow of CP or stray current in the electrolyte (soil) or in the pipeline. IR voltage drops are more prevalent in the vicinity of an anode bed or in areas where stray currents are present and generally increase with increasing soil resistivity[1].

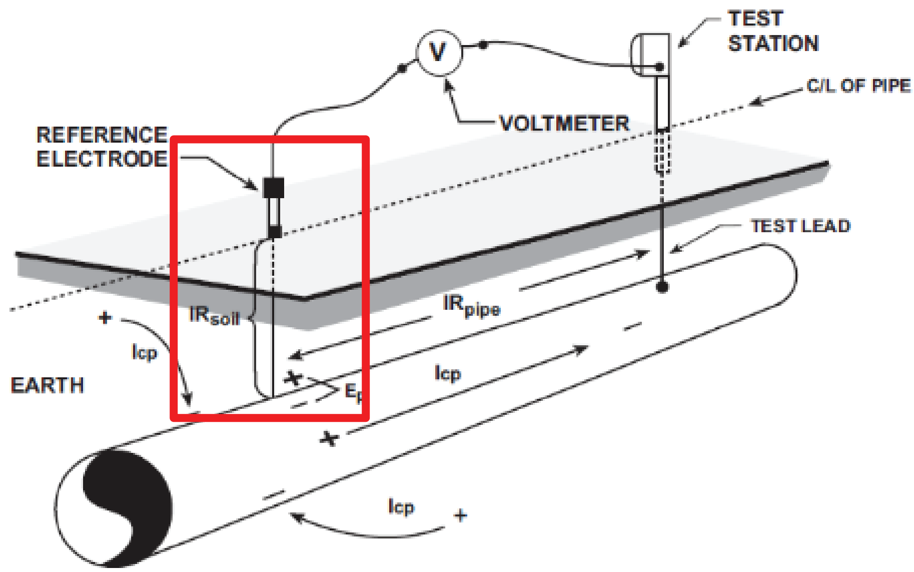

Figure 10: Pipe-to-Soil Potential Measurements[4]

IR drop minimization during CIS may be achieved by:

- For bare or very poorly coated structures, IR voltage drops can be reduced by placing the reference electrode as close as possible to the structure. For the majority of coated structures, most of the IR voltage drop is across the coating, and the measurement is less affected by reference electrode placement. IR drop may not be a significant concern when electrolyte, current densities, depth of burial, and coating condition are consistent, and the magnitude of the IR drop is known or considered to be negligible. On land based surveys, in areas of coating damage, potentials often show depressions and convergence of the On- and Off-potentials (reduction in IR drop).

- The most common method is the instant OFF potential method using synchronized current interrupters installed at CP current sources. The IR voltage drop can be minimized or eliminated by interrupting all of the direct current sources of the CP system and measuring the instantaneous OFF potential.

5.5.2 Criteria for Cathodic Protection

The primary criteria for CP of underground or submerged steel and gray or ductile cast-iron piping are listed in Section 6 of NACE Standard SP0169-2013 and other industry recognized codes:

- A structure-to-electrolyte potential of –850 mV or more negative as measured with respect to a saturated copper/copper sulfate (CSE) reference electrode. This potential may be either a direct measurement of the polarized potential or a current-applied potential. Interpretation of a current-applied measurement requires consideration of the significance of voltage drops in the earth and metallic paths.
- A minimum of 100 mV of cathodic polarization. Either the formation or the decay of polarization must be measured to satisfy this criterion. This criterion states that adequate protection is achieved with "a minimum of 100 mV of cathodic polarization between the structure surface and a stable reference electrode contacting the electrolyte".

Only one of these criteria needs to be met. When two or more dissimilar metals are coupled, the 100 mV polarization cannot be used, unless the potential of the most active (most electronegative) metal is known.

5.6 Corrosion Control Surveys for Offshore Pipeline

Marine pipelines (in seawater) are typically provided with cathodic protection by bracelet anodes of zinc or aluminum. Impressed current systems on platforms or onshore are also used, as well as hybrid systems which employ a combination of the two techniques[9].

The CP conditions can be verified by the potential measurements between the pipeline and the reference electrode in close proximity, as in the case for underground pipelines. The potential variations along the offshore pipeline protected by sacrificial bracelet anodes is illustrate in Figure 10. It should be noted that potential voltage gradients are expected to be minimized in high conductivity seawater.

[9]C. Weldon and D. Kroon. *Corrosion Control Survey Methods for Offshore Pipelines and Structures*, Corrpro Technical Library, Medina, OH, www.corrpro.com

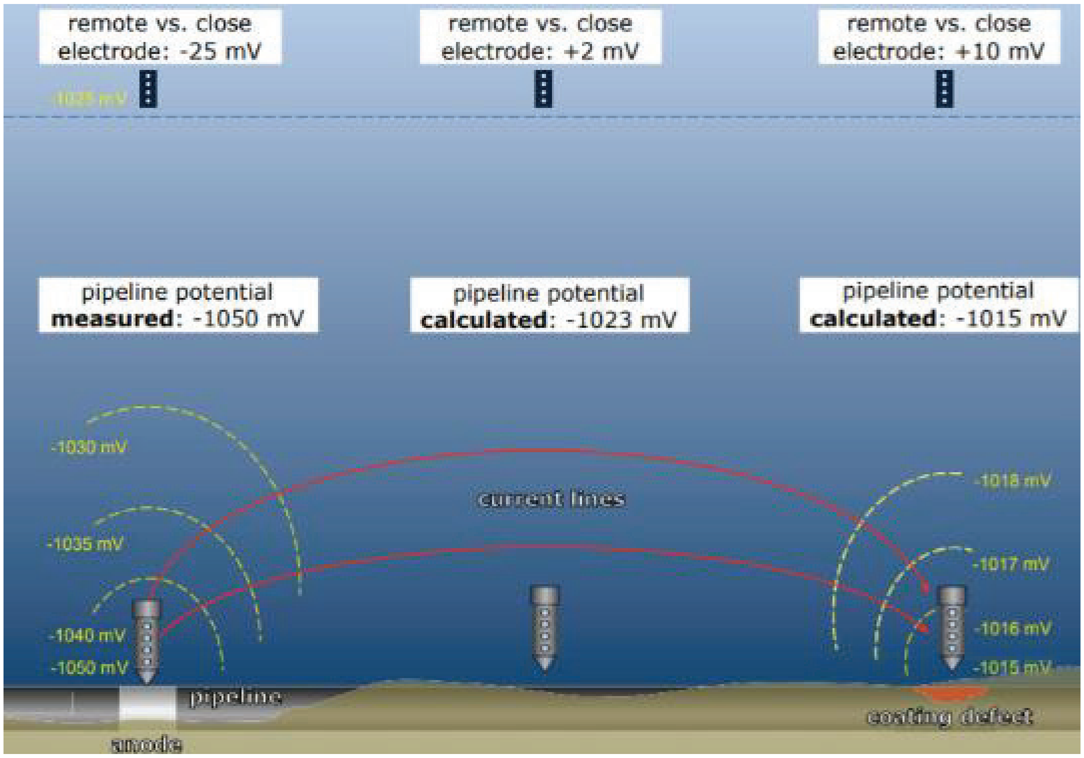

Figure 11: Potentials Variations along the Pipeline[10]

This figure illustrates that reference electrode placement incorporates both positive and negative voltage gradients that affect the measurement accuracy. The variations in seawater are considered minimal when compared to the variations expected in fresh water.

5.6.1 Equipment

The details of the CIS equipment for offshore pipeline are in Section 9 of NACE Standard SP0207-2007.

5.6.1.1 Special Equipment

Special equipment is described in Section 3.3.2 in NACE SP0207: “Rivers, lakes, ponds, swamps, and other bodies of water may require special equipment or vehicles such as boat, swamps buggies, air boats, or other equipment to survey.”

[10] Online source-Subsea Pipelines Cathodic Protection Inspections by Cesco
http://www.oceanologyinternational.com/__novadocuments/43393?v=635230661560370000

5.6.1.2 Pipeline Locator

In case of a survey performed offshore, specialized methods may be required for accurate pipeline location. If the GPS coordinates of a pipeline are accurately known, then a combination of on-boat GPS in conjunction with high resolution sonar can be used to ensure the reference electrode (fish or ROV) is maintained close to the pipeline. Survey along exposed pipe spans can be visually guided if the ROV has on-board video.

5.6.1.3 Reference Electrodes

In a marine or marsh areas with salt or brackish water, a silver-silver chloride (Ag/AgCl) reference electrodes should be used. For fresh water surveys, copper/copper sulfate (CSE) reference cells are typically used with appropriate provisions for deep submersion. All the reference electrodes must be calibrated periodically with an uncontaminated reference electrode to ensure accuracy according to the industry standard NACE TM0497.

5.6.1.4 Wire for Electrical Connections

Submerged wire during a survey must have adequate insulation for electrical isolation in submersion service, and be robust enough to resist breakage due to water currents. Reference electrode use in submersion service must utilize cable connections that are waterproof to prevent erroneous measurements.

5.6.2 Subsea Survey

The "Guidelines for Subsea Pipeline Cathodic Protection Survey" documents the methodology for ROV (remote operated underwater vehicle) pipeline CP surveys for offshore pipelines[11].

The advantages and disadvantages of reference cell configurations are discussed in the guideline. A Twin half-cell contact probe with remote cell has become a common industry practice for ROV pipeline CP survey as shown in Figure 11. Equipment such as vessel,

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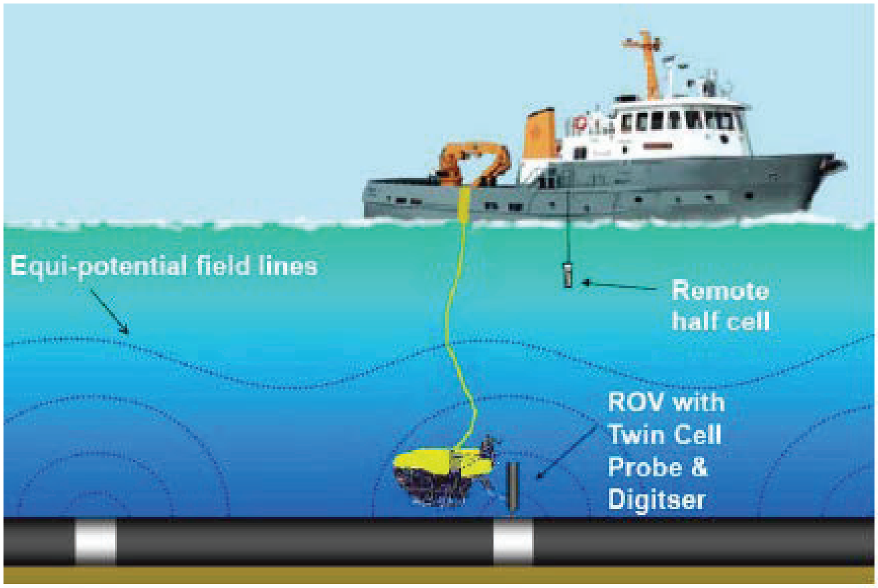
[11] Online source-*Guidelines for Subsea Pipeline Cathodic Protection Survey* http://www.ises.tech/wp-content/uploads/2013/06/Guidelines-for-Subsea-Pipeline-Cathodic-Protection-Survey.pdf

access to platform/pipeline, pipeline contact access points, ROV capability, navigation, and CP data acquisition, and video etc. are also the factors that should be considered.



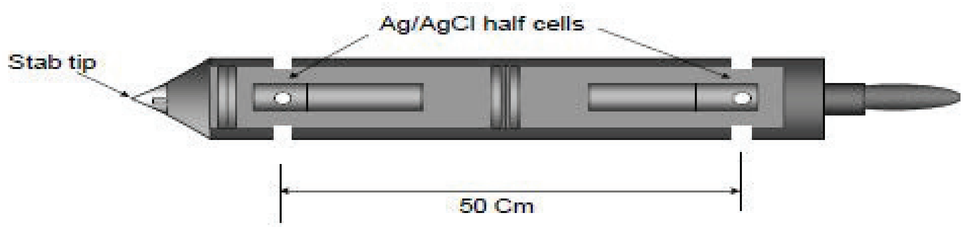


Figure 12: Example of Half Cell Contact Probe used in seawater[11] (Copper/Copper Sulfate Reference Cells Are Typically Used During Fresh Water Surveys)

Specific Inspection Requirements include pre-dive checks, CP survey and CP probe alignment. In order to maintain accuracy, the probe should be aligned correctly and the distance between the pipe surface and the probe along with the radial orientation of the probe should be optimum for the specific survey performed.

5.6.3 CIS Pipelines in Shallow Water

Shallow (up to 30 feet) water offshore surveys have used the trailing-wire/weighted-electrode survey method or other appropriate survey method[8]. A low resistance electrical connection to the pipeline can be established with a clip-on connector or clamp that is mechanically sound. A weighted reference electrode can be towed along directly over the pipeline while spooling out a light gauge insulated wire from a survey vessel. Pipeline may be located using a variety of methods including:

- Visual location, where practical,
- Electronic positioning in conjunction with the pipeline's as-built coordinates, and
- Magnetometer pipe location using buoys at an offset to mark the pipeline.

In very shallow water (where ROV/tow fish survey equipment is unfeasible), divers may be used to 'swim' the pipeline ROW.

5.6.4 CIS Pipelines in Deep Water Offshore

Deep water pipelines require additional provisions for executing a valid close interval survey. Survey techniques are discussed below.

5.6.4.1 Trailing Wire Technique

Trailing wire technique is the same technique utilized for onshore pipeline close interval surveys (CIS). A spool of insulated wire is connected to a test station, and pipe to electrolyte potentials are continuously measured and recorded using a portable data logging system.

The trailing wire technique for offshore pipeline was developed by HARCO Corporation in the 1970's utilizing the towed fish method. The trailing wire was connected to a riser at a platform, and a towed "fish" was used as half-cell, as shown in Figure 12. Remote operated vehicle (ROV) assisted trailing wire surveys were first performed in 1983, where the ROV was utilized to replace the towed fish half-cell as shown in Figure 12. The technique has been utilized in the US in both State, Federal Waters and overseas[12].

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[12] Online Source, Underwater Cathodic Protection Surveys - Facts and Fiction. http://www.mpmi.com/services/cathodic-protection-services/underwater-cathodic-protection-surveys-facts-and-fiction/

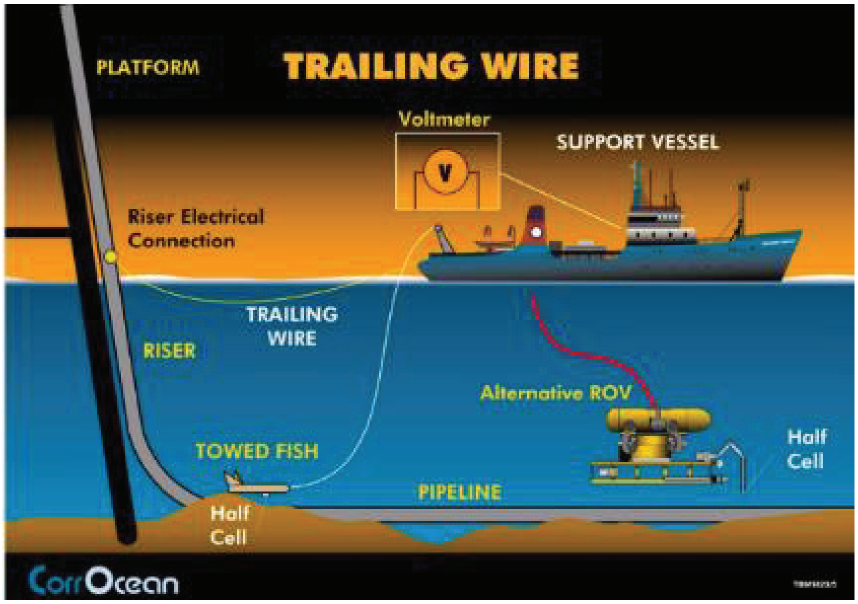

Figure 13: Trailing Wire Technique for Offshore Pipeline CIS Survey[13]

Three types of trailing wire technique will be discussed in the following sections:

Towed Fish Trailing Wire Survey: The objective of a towed fish trailing wire survey is to determine the general level of cathodic protection on a submarine pipeline. A towed fish survey can identify general areas of low CP, electrical interference from foreign CP systems, and other major anomalies such as shorted casings. Towed fish survey is not suitable for identifying small discrete coating defects, individual bracelet anodes (in seawater) or other localized anomalies due to lack of precision in guiding the reference electrode.[11] As a general rule, sensitivity of the survey to detecting localized potential variations decreases the further the CP electrodes (on the fish) are from the pipeline. A key component to an accurate survey then, is the ability to keep the fish near to the pipeline, and as such the pipeline's as-built x-y coordinates and tow fish / pipeline elevation must be utilized in conducting the survey. Some tow fish systems incorporate a depth transducer, surface and subsurface navigation, and a vessel-mounted fathometer/sonar to accurately locate the fish in relation to the seafloor and a pipeline's as-built route[12]. Figure 13 shows a pipe-to-electrolyte (P/E) potential profile with

[13] J. Grapiglia. *Cathodic Protection (CP) Surveys for Subsea Assets.* Corrosion Control Engineering

depressions in potentials in the middle either due to coating damage or anode depletion. Further analysis would be needed in order to identify the cause[14].

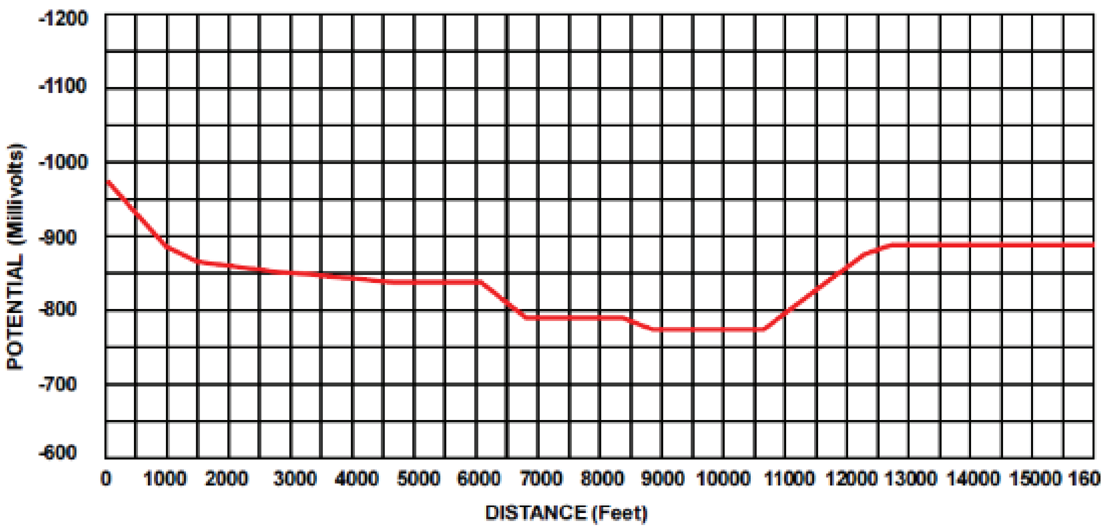

Figure 14: Pipe to Electrolyte Potential Profile-Towed Fish Trailing Wire Survey[14]

The advantages of the towed fish trailing wire technique is the relatively low cost, when compared to a submersible or diver assisted survey. Additionally, this is the only technique which can be used economically on buried pipelines and under other conditions where visual or magnetic tracking with a diver or ROV is difficult to impossible. The disadvantage is lack of sensitivity to minor anomalies such as individual anode bracelets, small coating defects, and poorly insulated field joints[14].

Submersible Trailing Wire Survey This technique uses the same principle as the towed vehicle survey, but a guided submersible/ROV is used to carry the reference electrode along the pipeline. Under normal circumstances, the reference electrode position can be maintained within a meter of the pipeline at all times. The technique permits detection of individual features such as bracelet anodes and coating holidays that cannot be detected using towed fish trailing method[14]. For example, the presence of functioning bracelet anodes and two poorly coated field joints are shown in Figure 14.

[14] C. Weldon and D. Kroon. *Corrosion Control Survey Methods for Offshore Pipelines and Structures*, Corrpro Technical Library, Medina, OH, www.corrpro.com

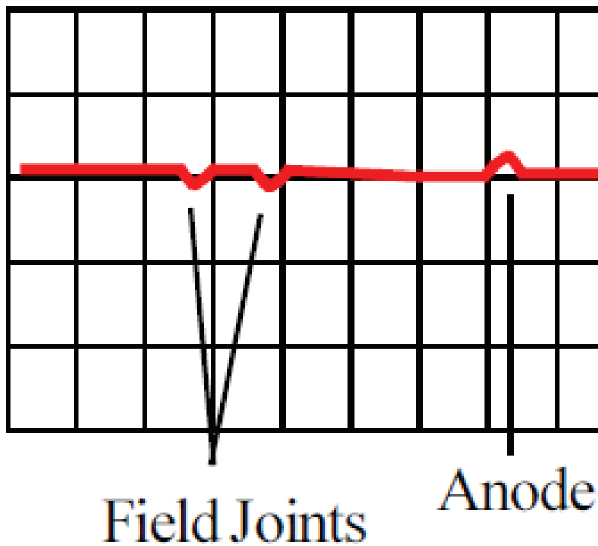

Figure 15: P/E Potential Profile-Submersible Assisted Survey[14]

The advantage of this technique is the increased sensitivity to minor changes in potential, providing the locations of problem areas. This survey has often been performed in conjunction with the electric field gradient (EFG) measurements (discussed later), and most of the surveys are performed in conjunction with other work requiring an ROV. This technique was developed to aid in pinpointing deficiencies in CP performance related to failed bracelet anodes or coating defects that impacted CP effectiveness.

ROV Assisted Trailing-Wire Method: The ROV assisted trailing wire survey is the most widely used method for monitoring CP levels along offshore and submerged pipelines. Deep water offshore surveys are performed using an ROV to replace the towed fish and connected to a survey vessel through an umbilical.

Offshore, a riser is typically used to obtain direct electrical connection to the pipeline. Two reference electrodes mounted on an ROV are carried above the pipeline while the connection to the pipeline is maintained by spooling out a light gauge insulated wire from a wire supply apparatus aboard the survey support vessel. The structure-to-electrolyte and the two reference electrodes are mounted on the ROV. Electrode configuration may vary depending on the pipeline accessibility, pipeline diameter, and operating condition. One reference electrode should be mounted on the ROV and located approximately 6 to 12 inches above the pipeline. The second electrode is mounted approximately 24 inches away from the first electrode. The wire should be attached to a weighted calibrated reference electrode that is lowered to the sea floor near the pipeline. The location of the electrode is not critical because it serves simply as a fixed voltage source.

Potential measurements should be continuously recorded onboard the surface vessel. The pipe-to-electrolyte potential should be measured using the electrode placed closest to the pipeline.

5.6.4.2 Remote Electrode Technique

ROV Assisted Remote Electrode Method This method may only be used on unburied or partially buried pipelines in water depths in excess of 100 feet, and not where the pipeline is adjacent to the onshore riser. The survey utilizes a remote electrode as a stable voltage source instead of a connection to the riser or as a stationary electrode. An electrode is defined as remote when the distance between the electrode and the pipeline being surveyed is such that a change of electrode position does not change the measured potential between the electrode and the pipeline. On a typical coated subsea pipeline cathodically protected by sacrificial bracelet anodes, an electrode is considered remote at a distance of 100 feet or more[8].

At the start of a remote electrode survey, a direct contact pipe-to-electrolyte potential should be measured between the remote electrode and the pipe using a metallic contact probe aboard the ROV. The survey should proceed by continuously measuring the potential between the remote electrode and an electrode mounted on the ROV. Direct contact potential measurements should be taken at approximately 1-mile intervals to recalibrate the remote electrode and adjust the offset voltage accordingly. Figure 15 illustrates the scheme of ROV assisted remoted-electrode method. The ROV survey can provide high resolution and low-resolution systems. Low resolution systems give only potential profiles. High resolution systems measure accurate potential profiles and current density of the pipeline. A typical graph displayed by the high resolution system is shown in Figure 16[13].

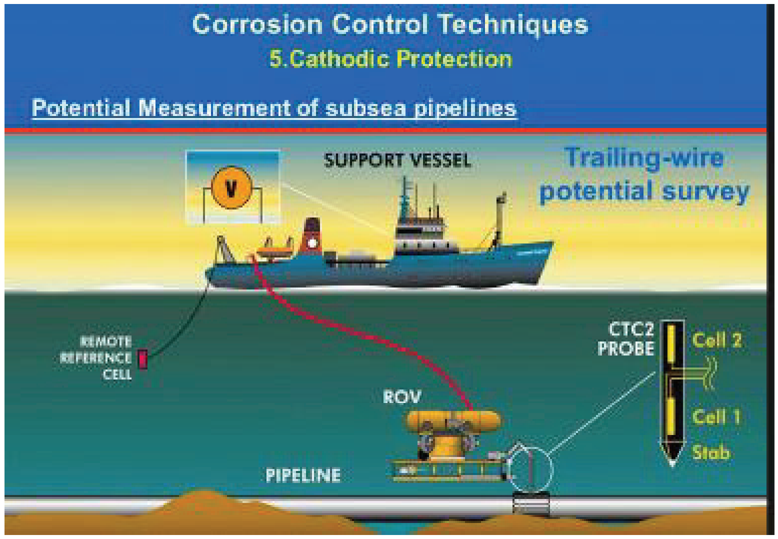

Figure 16: ROV Survey Method of Gathering CP Data[15]

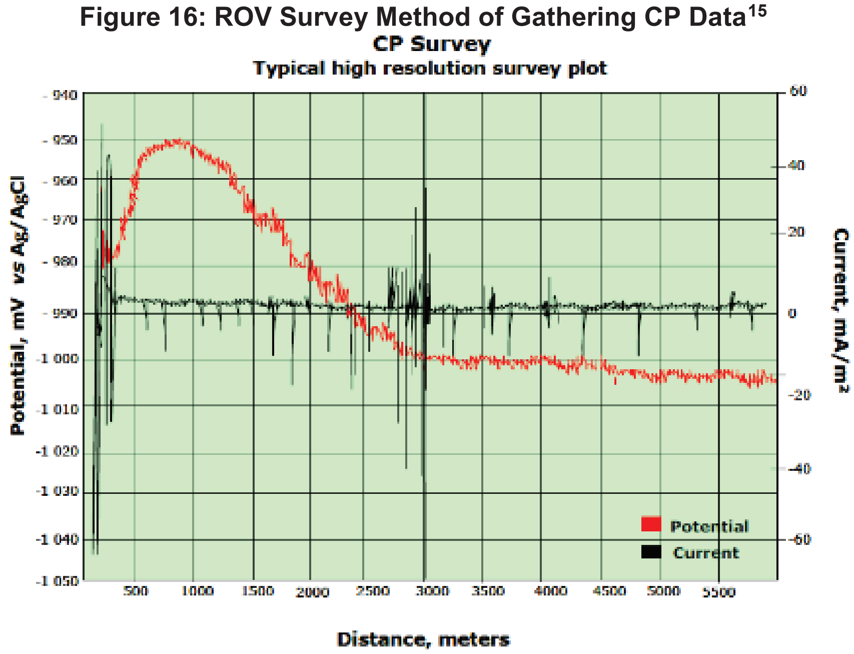

Figure 17: High Resolution Survey Plot for a CP Survey[13]

The primary advantage of this method is its relative ease of operation. The primary disadvantage of this method is that direct contact potential readings are required to establish the original voltage offset and to recalibrate the measurements at frequent intervals[14].

[15]Online Source-CP Inspection Methods by CorrOcean

Additionally, the remote cell is moving and is subject to some potential drift or variation over time.

5.7 CIS Limitations

Certain conditions may make CIS survey impractical to perform, or the data from the CIS survey difficult to interpret correctly[8].

- Areas of high contact resistance: pipeline located under concrete or asphalt pavement, pipeline under frozen ground, or very dry conditions.
- Adjacent buried or submerged metallic pipelines within 50 feet.
- Surface conditions limiting access to the electrolyte.
- Telluric or other dynamic stray current interference that are not compensated through specific survey procedures and data analysis.
- High levels of induced alternating current (AC) that could influence potential measurements or present a safety hazard,
- Pipelines that are buried very deep where it is impossible to place the roving electrode within 10-20 feet for the onshore pipeline.
- Locations at which coating cause electrical shielding, and
- Lack of electrical continuity such as some forms of mechanically coupled pipe that have not been made electrically continuous through the use of bonding cables or straps welded across each coupling.

CIS is typically used to determine CP levels, shorts or to other structures, stray current issues, and medium to large coating defects (isolated or continuous and typically >600 mm^2 [1 in^2])[5]. CIS is limited in detecting small coating holidays[5].

5.8 Applicability to Subsea or Submerged Pipelines

The CIS survey has been successfully used throughout the world to assess CP levels on subsea and submerged pipelines and is deemed to be the most reliable indirect inspection tool for this application. NACE SP0207-2007 indicates that CIS can locate medium-to-large defects in coatings (isolated or continuous and typically >600 mm^2 [1 in^2]).

6.0 DIRECT CURRENT VOLTAGE GRADIENT SURVEYS (DCVG)

Direct Current Voltage Gradient (DCVG) surveys have been in use for over 40 years for onshore pipelines, and primarily are used to locate coating defects or holidays. A DCVG survey is a method of measuring the change in electrical voltage gradient in the soil along and around a pipeline[16]. During the pipeline CP normal operating situation, the voltage gradients are a result of CP current pickup or discharge at indications as shown in Figure 17.

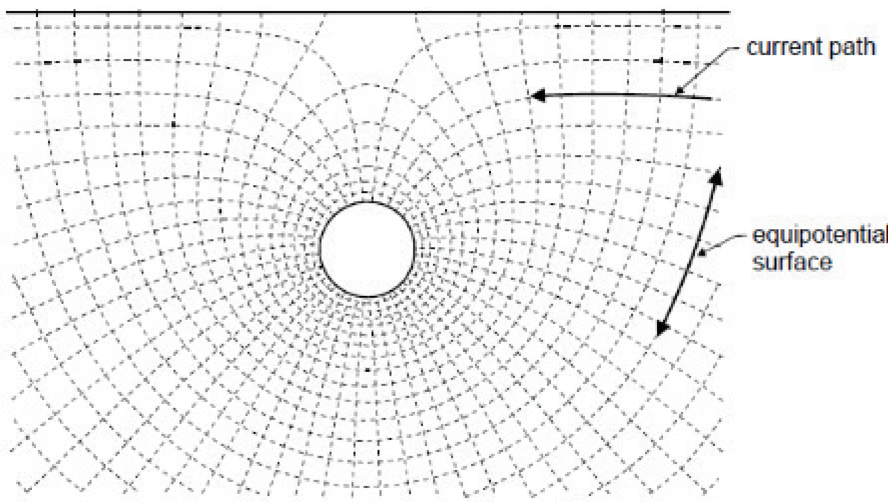

Figure 18: Voltage Gradient in the Earth Around A Catholically Protected Bare Pipeline [NACE Class CP3]

DCVG surveys are capable of distinguishing between isolated and continuous coating damage, due to the fact that the shape of the gradient field surrounding a fault provides this information. DCVG can also be used to identify isolated coating damage, such as rock damage, or continuous coating damage.

[16] P. Nicholson, *Combined CIPS and DCVG Surveys for Improved Data Correlation*, NACE Paper No. 07181, 2007.

In a DCVG survey, the existing pipeline or a temporary CP system is interrupted to produce a pulsed CP current applied to the pipeline. The DCVG signal magnitude maybe raised by increasing the DC output of a CP current source or by installing a temporary DC supply and connecting it to the pipeline. No direct continuous electrical connection to the pipeline in the DCVG technique when used to locate coating faults.

6.1 Equipment

The DCVG survey equipment consists of a current interrupter, voltmeter, connection cables, and two probe electrodes filled with electrolyte[17]. The details of the equipment are described in the NACE standard TM 0109-2009, "*Standard Practice* for *Aboveground Survey Techniques for the Evaluation of Underground Pipeline Coating Condition-Item No. 21254.*DCVG Procedure

6.2 DCVG Procedure

DCVG Survey Procedure as defined by in NACE TM0109-2009. Below sections are summarizing the DCVG Procedure from this standard.

DCVG surveys may be performed with foreign impressed current CP systems energized. A current interrupter shall be installed in the CP system or temporary CP current supply to be interrupted. The DCVG signal strength should be adequate to enable the surveyor to detect small indications distant from the CP current source.

Two probes are placed directly above the pipeline centerline, with one probe in front of the other in contact with the soil. The probes are separated by approximately 3 to 4 ft apart.

Every third step (~10 Feet), one probe should be placed at 90 degrees to the survey direction while the other probe is placed where the surveyor is located to ensure the survey is being conducted on top of the pipeline, as shown in Figure 18. The voltage gradient readings measured with the electrodes place at the 90 degree locations are conducted at both sides of the survey direction.

[17] TM0109-2009 *Aboveground Survey Techniques for the Evaluation of Underground Pipeline Coating Condition*-Item No. 21254, NACE International, Taxes.

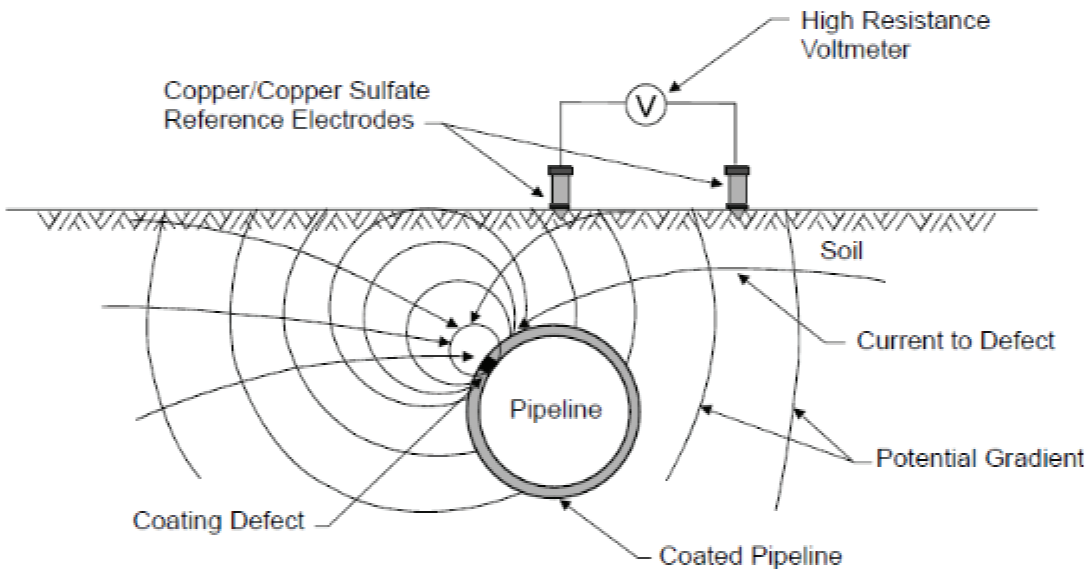

Figure 19: Coating Holiday Detection Using Voltage Gradient Method [NACE Class CP3]

The direction and the magnitude of the voltmeter illustrate the location and the shape of the indication. As the indication is approached, the magnitude increased and reverses direction when the indication is passed. No pulse (a null) is observed when the indication epicenter lies midway between the two probes. With one probes placed at the indication, and one placed approximately 4 feet away, the DCVG pulse magnitudes are measured at the four locations (two along the pipeline centerline, and two 90 degree on the sides), and used to determine the shape of the indication.

6.3 Interpretation of Data

The DCVG Signal Strength at Indication are calculated based on the guidance in NACE Standard TM0109-2009.

The size of the holiday is measured in terms of percentage IR (%IR), which is defined as the ratio between the lateral gradient shift measured with respect to remote earth and the pipe-to-soil shift measured with respect to remote earth. The shift represents the difference between the ON and OFF values, when DC source(s) is/are interrupted[18].

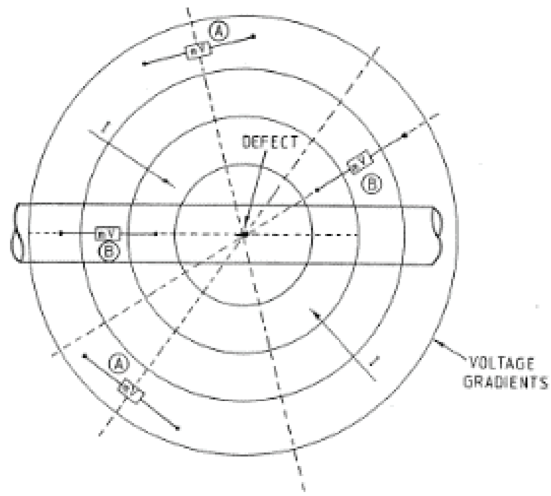

Figure 20: Voltage Gradient (NACE Class CP2)

6.4 Limitations

The interpretation of DCVG data involves comparison of potential gradient shift magnitudes at coating flaw indications. The magnitude of this voltage gradient is influenced by several factors, including the magnitude of the current source, the distance from the current source, soil moisture/resistivity, pipeline depth of cover, and relative position of other flaw indications.

6.4.1 Depth of Cover

According to NACE standard TM0109, "The indirect inspection tools covered in this standard are less sensitive when pipeline burials exceeded normal depth ranges (2-6 feet). Field conditions and terrain may affect depth and detection sensitivity". The magnitude of a defect, which is indicated by the DCVG on the measuring tool, will diminished as the depth of cover increases. This magnitude will also be used to illustrate the size of the defect. Therefore, the size information from DCVG will not be accurate. The approach to solve this problem is to

[18] *Assessing the Integrity of Coating Systems on Pipelines in Trenchless Crossings*, PRCI Catalog No.PR-444-133602-R01, 2015.

employ voltage gradient probes with adjustable spacing. The probes are in contact with positions of larger differential gradients on the soil that is measurable, and then normalizing the same probe spacing used for other locations to ensure consistency[21].

6.4.2 Interference

Another limitation on the interpretation of DCVG data is that the presence of some flaws may be masked by the presence of other flaws, either larger flaws in close proximity or flaws that are nearer to the source of test current. The basic approach to DCVG attempts to utilize cathodic protection current as the test current.

6.4.3 Signal Strength

Sometimes it is necessary to increase source outputs and/or use supplemental current sources to provide sufficient signal strength. Because the locations for test current sources are limited and the distribution patterns of the test current are not known in advance, it is not always possible to detect all coating flaws.

6.4.4 Applicability to Subsea or Submerged Pipelines

The vast majority of DCVG surveys have been performed on land based buried pipelines. The instrumentation and techniques have not been adapted for deep submerged pipelines making such surveys unfeasible at this time. Use of this technique on the Line 5 assets would require significant development and testing prior to deployment.

6.5 Integrated CIS/DCVG Survey

This method also called “intensive measurement survey,” according to German Standard DIN 50 925 has been successfully applied in numerous projects[18].

The same principles governing the independent Close Interval Potential Survey (CIPS) and DCVG techniques apply to this method. In an integrated CIPS/DCVG survey, the two surveys are conducted simultaneously, and the data are recorded either on two back-to-back data loggers, as shown in Figure 20 or more recently on two-channel data loggers.

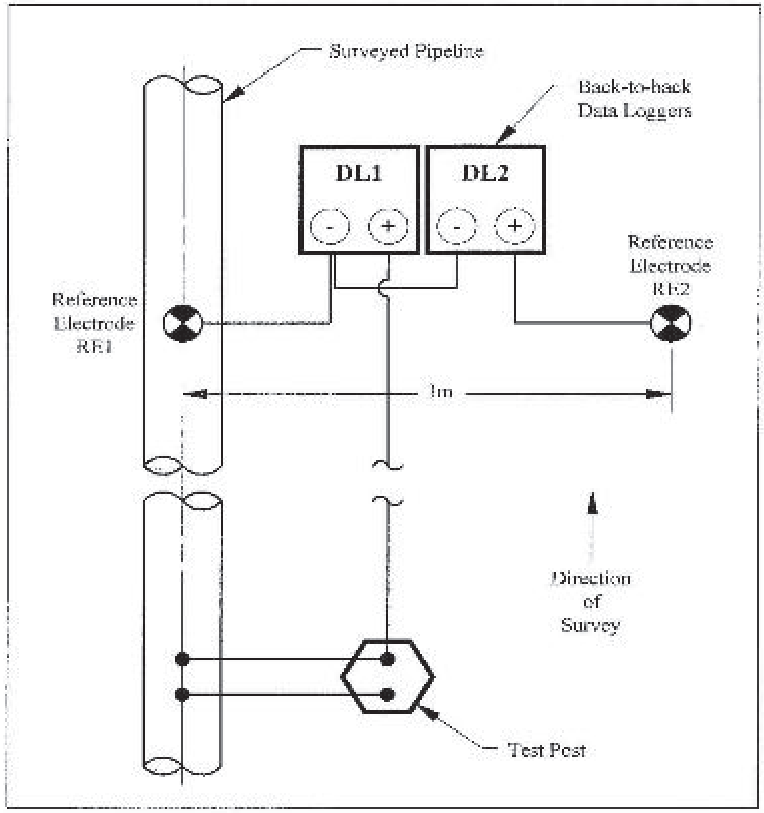

Figure 21: Integrated CIPS/DCVG Arrangement [19]

CIS appears to be the only reasonable tool for estimating the cathodic protection level of the pipe and subsequently the risk of corrosion activity. The DCVG survey has been successfully used to detect, locate and estimate the size of coating holidays in almost every area on onshore pipelines, except where limited by high contact resistance or significant dynamic stray current activity.

In many applications, these two complimentary indirect tools are used independently, with the CIS followed by a fast-paced DCVG survey, often using different instrumentation. The main problem in this approach is aligning the indications from the two surveys, although flagging the

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[19] S.M. Segall, R.G. Reid, R.A. Gummow, *Use of an Integrated CIPS/DCVG Survey in the ECDA Process*, Corrosion, Paper No. 10061, NACE, 2010.

suspect coating fault locations and using sub-meter GPS co-ordinates can minimize or even eliminate this problem. A second disadvantage of separate surveys is the possibility of errors when calculating the percentage IR to classify the severity of the holiday. Since the pipe-to-soil potentials are not measured during the DCVG survey, they are typically interpolated from potential measurement records at adjacent test posts. When the soil resistivity varies significantly, the error introduced by this interpolation becomes appreciable.

The main advantages of this approach for onshore pipelines are the ease with which the survey data is aligned and the instant access of the operator to two different sets of data that facilitates the identification of an indication (i.e. coating holiday or protection level). Developments in instrumentation, such as multi-channel data loggers give the integrated method additional technical facility. Identification of indications based on potentials and gradient profile is shown in Figure 21.This survey is not considered feasible for the Line 5 crossings of the Straits.

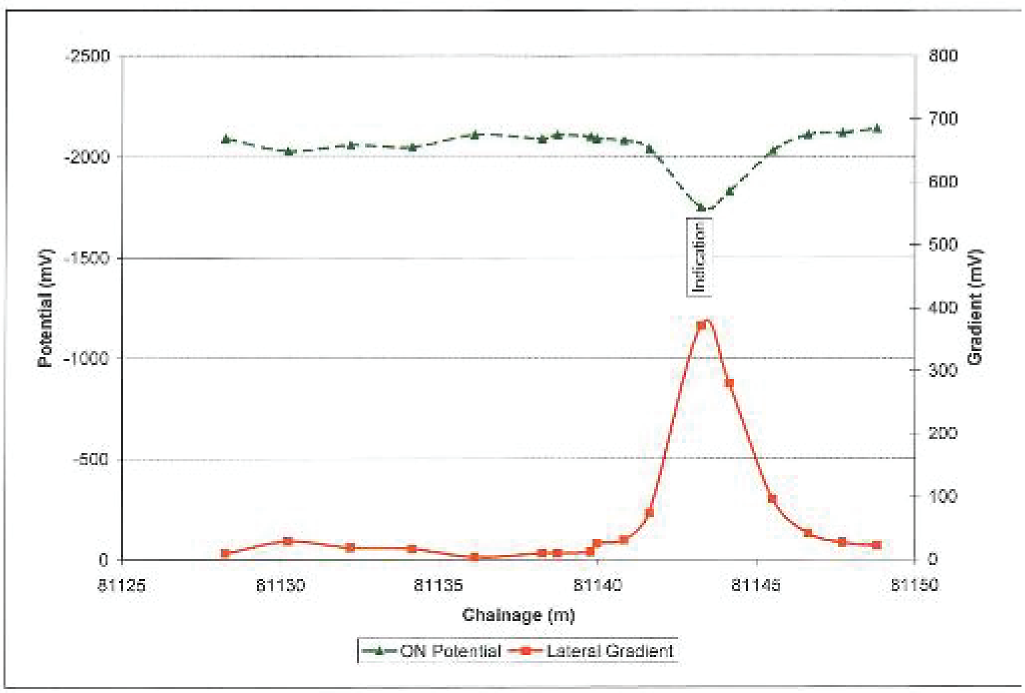


Figure 22: 16" Pipeline Identification of Indication Based on Potential and Gradient Profile[19]

7.0 ALTERNATING CURRENT VOLTAGE GRADIENT (ACVG)

7.1 Description

ACVG can be utilized to identify several types of problems on underground pipelines with the most common use being to identify indications of coating anomalies utilizing a unique AC frequency as its signal source. One type of ACVG came into use for pipeline in the USA in the late 1990's although the technique was utilized in other underground infrastructure types such as electric, telephone and cable well before this. ACVG became a mainstream tool for identifying indications of coating defects after the passage of the Pipeline Safety Improvement Act of 2002 and publication of the External Corrosion Direct Assessment Standard SP0502 by the NACE International. ACVG is known for pinpointing indications, ease of use and providing a relative severity of the indications where "corrosion activity has occurred, is occurring, or may occur." ACVG is recognized by NACE TM0109-2009 standard as "used to evaluate in detail the coating condition on buried pipelines and identify and classify coating holidays".

7.2 Application of ACVG

The technique is performed from above ground at grade over the pipeline. A transmitter with unique signal is connected to a nearby test station to produce the signal needed to perform the survey (see Figure 22). A digital receiver connected to an A-frame device (see Figure 23 and Figure 24) with two fixed distance probes is utilized to pinpoint indications of possible underground coating damage. The A-frame device is in contact with the surface (i.e. soil, pavement, concrete) and looks at the difference in the electrical field in the ground and measures minute voltage differences and pinpoints an indication of a coating defect (see Figure 32). The ACVG indications are categorized by their value which is in decibel microvolts (dBμV) (see Figure 26). This dBμV at the indication is then compared to the amount of current flow at the indication in milliamperes and adjusted so as to account for the different amounts of current flow at each indication and its effect on the dBμV indication level (see Figure 33). The magnitude of the signal strength is related to the level of coating damage. However, many factors will affect the dBμV level including but not limited to resistivity, depth of the pipeline, amount of transmitted signal, pipe diameter, coating type, clock position of the indication (i.e. 12 o'clock versus 6 o'clock), pipeline length, number of indications in the area and A-frame contact to the surface. The same pipeline with the same general conditions will produce ACVG indications that may be compared to each other.

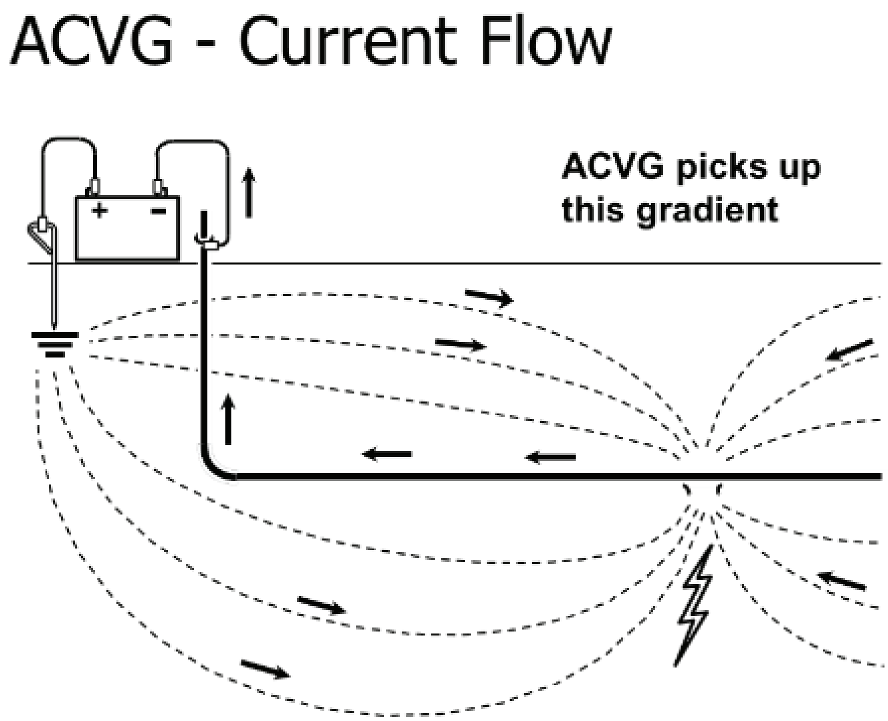


Figure 23: Example of Transmitter Connection for ACVG[20]

[20] Radiotection Pipeline Current Mapper User's Manual.

Figure 24: Picture of A Display from An ACVG Receiver

Figure 25: Picture of a Typical A-frame Utilized for ACVG[20]

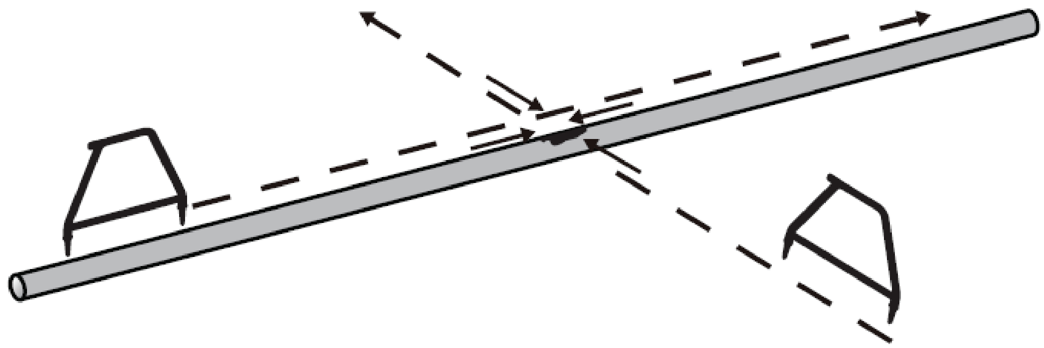
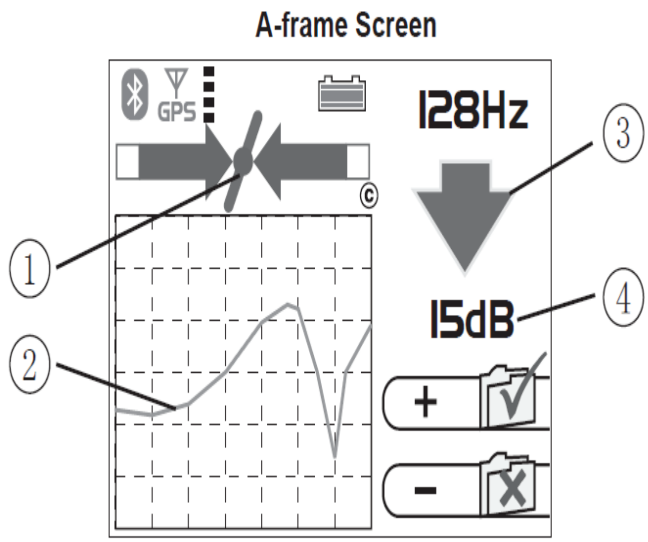


Figure 26: Pinpointing the Indication with Four Arrows Pointing to the Same Location[20]



1	Locate Icon
2	Graph
3	Coating Defect Indication Direction
4	Coating Defect Indication Signal

Figure 27: A-frame Digital Display with Locate and ACVG Signals Being Displayed Together[20]

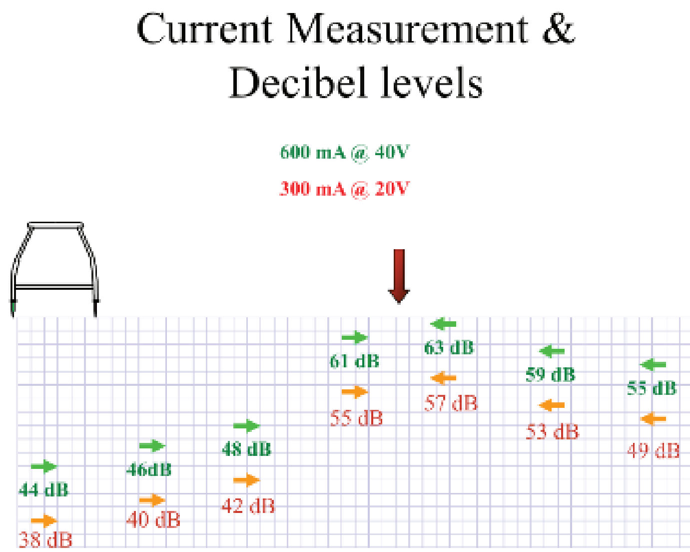


Figure 28: dB Microvolt Levels Will Rise When Approaching the indication and Current at the Indication Will Affect the dB Microvolt Value[20]

7.3 Limitations

As other indirect inspection techniques used for coating condition assessments, the uncertainty generally results from the complexity of some underground pipeline and environment conditions, making it difficult to adopt a unifying standard under all conditions[21].

7.3.1 Shielding Coatings

The ACVG method is not applicable for detecting pipeline steel that is electrically shielded from the electrolyte bulk by disbonded coatings with no electrically continuous path to the electrolyte.

7.3.2 Pipe Depth of Cover.

All of the indirect inspection tools are less sensitive when pipe burials exceed normal depth ranges. Field conditions and terrain may affect depth and detection sensitivities.

[21] C, Ukiwe and S. McDonnell. Optimization of the Coating Anomaly Detection and Priortization Methodology Using voltage Gradient Surveys. Corrosion, Paper No. 11132, NACE, 2011

7.3.3 High resistant ground conditions

In some cases holes may have to be drilled if applying water on the pavement is not sufficient for good electrical contact with the probes. If the pipe is no more than 5 feet away from soil contact, it may be possible to conduct the survey offset and parallel to the pipeline.

7.3.4 Rocky Terrain

When in rocky terrain it may be necessary to wet the ground in order to obtain good electrical contact with the probes. If the pipe is no more than 5 feet away from an area where concrete or soil contact can be made, it may be possible to conduct the survey offset and parallel to the pipeline.

7.3.5 Very Dry Soil

When in very dry soil conditions it may be necessary to wet the ground in order to obtain good electrical contact with the probes.
If the pipe is no more than 5 feet away from an area where concrete or better soil contact can be made, it may be possible to conduct the survey offset and parallel to the pipeline.

7.3.6 Probe Spacing

The measured voltage gradient increase with probe spacing till the remote earth is reached, as shown in Figure 28. Therefore, the probe spacing should be maintained consistently during the survey[21].

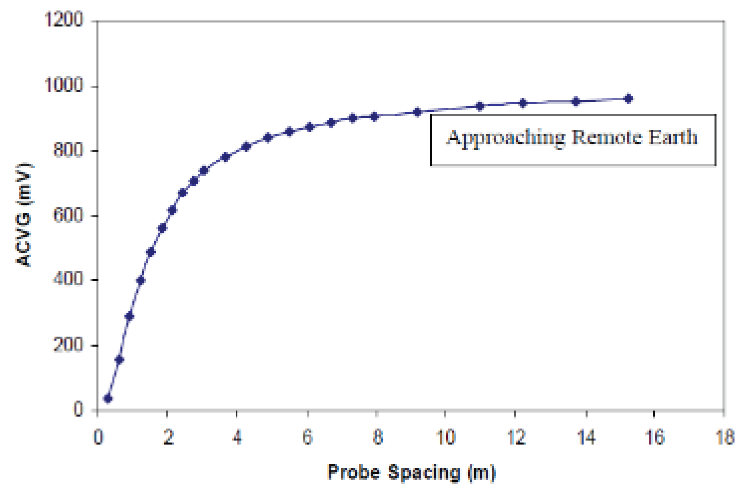


Figure 29: The Effect of Probe Spacing on the ACVG

7.4 Coating Assessment

An ACVG indication is measured and viewed in decibel microvolts (dBµV). The dBµV is normally on a scale from 0 to 100 dBµV although it is rare to find any indications less than 25 dBµVNot all manufacturers have the exact same dBµV scale although the two top producers of tools are similar. The indication viewed in dBµV is affected by the amount of current applied to the pipe and flowing across the coating holiday indication. More current flow across an indication would produce more voltage change and therefore a different dBµV value. The amount of change in the dBµV at an indication will change by approximately 6 dBµV for when the current is doubled (or halved). This would mean that an ACVG indication of 60 dBµV when 0.500 Amperes of 4Hz current is flowing across the coating holiday is equal to a 66 dBµV indication when 1 Amperes of 4Hz current is flowing across the coating holiday. Therefore it is vital to perform some sort of post process analysis to “normalize” the dBµV according to the amount of current flow at each indication. The actual mathematical formula for this calculation to provide a dBµV with 1 Ampere flowing on the pipeline at the ACVG indication is as follows:

a = b-(20*LOG(c))

Where:

a = normalized/calculated dBμV (the result)

b = dBμV as found in the field with the instrument

c = Amperes of current flowing across the holiday (3Hz or 4Hz normally)

Or to normalize to 0.1 Ampere the formula would be: a = b-(20*LOG(c/.1))

7.5 Applicability to Subsea or Submerged Pipelines

ACVG survey equipment has not been used on deep subsea or underwater pipelines. The instrumentation and techniques have not been adapted for deep submerged pipelines making such surveys unfeasible at this time. Use of this technique on the Line 5 assets would require significant development and testing prior to deployment.

8.0 AC ATTENUATION

8.1 Description

A Current Attenuation survey (also known as an Electromagnetic Survey or Alternating Current Attenuation) is used to determine the relative coating condition of a buried pipeline. The pipeline coating condition of a buried pipeline can be assessed by measuring the current attenuation of an applied AC or interrupted DC signal. Readings are normally taken at 50 or 100 foot intervals although larger distances between readings may be utilized. The more current that attenuates between the readings, the greater the coating degradation. It is generally accepted as a lower resolution tool in that it finds the larger types of coating problems (severe coating deterioration or damage) or unintended contacts and bonds on a pipeline. The instrument can also provide an estimated depth of the pipeline.

The information needed for the survey is detected from the electromagnetic field created when a specific frequency flows along a pipeline. The amount of current flowing in the area being surveyed will affect the size of the magnetic field and therefore how strong the signal will be. Various soils, water and ground cover will not affect the electromagnetic field and therefore no direct contact to the electrolyte is necessary for the receiver to obtain the information in a Current Attenuation survey.

8.2 Application of AC Attenuation

A transmitter with unique frequencies is connected to the pipeline by connecting the output lead to the pipeline at an above ground appurtenance or test station and the return lead to an independent ground away from the area to be surveyed. The current output is adjusted to the needed level usually 1, 2, or 3 Amperes to insure adequate coverage to the next test station or pipeline access point.

The horizontal position of the pipeline is determined by moving the receiver blade over the pipeline and perpendicular to the position of the pipeline. In the peak locate mode when you reach the highest signal strength you should be over the center of the pipeline. Depth measurement function is performed by setting the receiver on the ground over the pipeline and pressing the depth button. The information will be viewed on the screen in inches up to 35 inches and feet and inches for depths 3 feet and greater. After accurate location and depth measurements have been taken, the current measurement button is utilized to obtain the current values on the pipeline. The current measurement will be recorded and takes approximately 4 seconds to obtain each measurement, during which time the instruments location and orientation must be maintained (stable). The current direction is also obtained during this process.

The information is recorded into the data logger along with the flag number, GPS coordinates, and depth. A sub-meter GPS data logger is utilized for recording pipeline survey information when conducting a CA survey.

8.3 Limitations

The Current Attenuation method is not applicable for detecting pipeline steel that is electrically shielded from the electrolyte by disbonded coatings with no electrically continuous path to the electrolyte. All indirect inspection tools are less sensitive when pipe burials exceed very deep ranges. Field conditions and terrain may affect depth and detection sensitivities.

If normal fluctuations of more than 10% are obtained at the same location, there may be interference that must be mitigated to obtain an accurate current attenuation survey.

Bonds to close parallel structures may cause fluctuations in the measurements. If there are fluctuations over 10% at normal intervals, an effort should be made to disconnect any bonds before continuing the survey.

Other sources of electrical interference in large amounts may affect the accuracy of the measurements. Removing interrupters or conducting the survey at a time when the DC interference is less may be necessary to achieve accurate results.

8.4 Coating Assessment

Once a transmitter has been connected and a sufficient amount of current is traveling down the pipeline, the receiver will detect the magnetic field and be able to obtain location, depth, current and current direction readings. How the current attenuates will signify if there is little or no damage to the coating or if there are larger areas of concern about the coating. Typical findings of a current attenuation tool include:

- Shorts to other structures,
- Grounding to electric neutral,

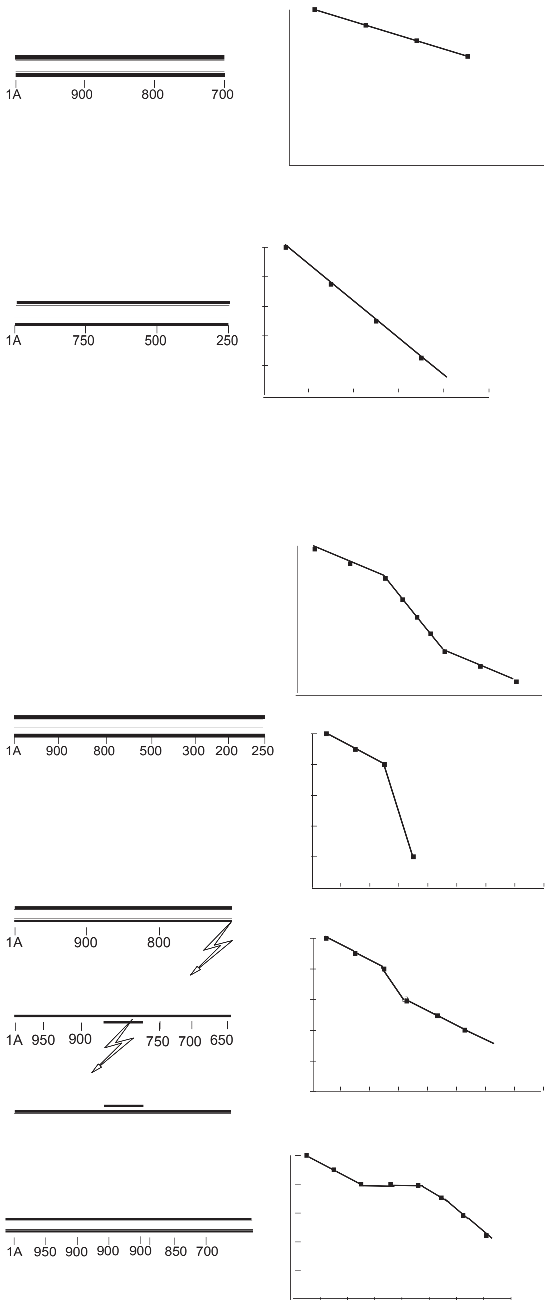
- Faulty insulators,
- Large coating defects,
- Shorted casings, and
- Other current distribution problems.

Figure 29 illustrates the typical examples of the types of analysis from current attenuation surveys.

8.5 Applicability to Subsea or Submerged Pipelines

Underwater locators/receivers are available to conduct a current attenuation survey on subsea or submerged pipelines. Since this technique represents a low resolution assessment of coating quality, it may not provide additional benefit to the existing tools being utilized to assess the Line 5 crossing. Further assessment and development of the tool would be required for application to the Straits.

Examples of different current attenuation surveys as listed in PCM manual.



Pipe coating in good condition is shown as very little loss of current.

Pipe coating in poor condition is shown as a rapid loss of in current.

Mixture of good and poor coating which is shown as greater current loss over the section of pipe with poor coating.

The effect of a short or contact with another service is a sudden current loss.

The effect of a poorly coated steel shield in contact with the pipeline is to show reduced current in one measurement section.

This effect is either a section of perfect coating or ground conditions that are shielding the signal – dry or rocky ground.

Figure 30: Types of Analysis From Current Attenuation Surveys

9.0 ELECTRO-MAGNETIC ACOUSTIC TRANSDUCER (EMAT)

9.1 Description of EMAT

The EMAT inline inspection technology can be used to locate pipeline defects, both internally and externally in the pipeline carrying oil, water, or gas at normal system conditions. While normally deployed to inspect buried pipelines, EMAT tool can also inspect pipelines on pipe supports or lying on the ground, and can identify corrosion, erosion, cracking and other defects[22].

The application of the traditional piezoelectric transducers has been used for wall thickness measurements and crack detection for inline inspection. It requires a liquid couplant for ultrasonic energy and signal transfer into the pipe wall. This requirement for a liquid couplant limits the cost-effective use of such tools for gas filled pipelines. Electro Magnetic Acoustic Transducers (EMAT) are dry-coupled sensors[23].

9.2 EMAT Principle

As illustrated in Figure 30, an alternating current in a wire induces an eddy current in the metal surface and transmits it into the pipe wall. This eddy current is combined with a static magnetic field to produce a force, which causes the steel metal grid to oscillate, thus generating a guided ultrasonic sound wave in the pipe wall[24].

Guided waves can be categorized into Lamb waves and tailored horizontal polarized shear waves of different order. In general, the horizontal shear wave, characterized by distinct frequencies, has an especially high energy concentration at the surfaces of the wall and hence are sensitive for possible cracks or slots inside the sound beam[25].

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[22] G. Peck, Cost Effective On-Stream Inspection Technique Using EMAT Technology for Pipeline Integrity at ELK Hills, Paper No. 01635, NACE 2001.

[23] M. Klann et al. *Pipeline Inspection with The High Resolution EMAT ILI–Tool: Report on Field Experience*, IPC2006-10156, International Pipeline Conference, September 25-29, 2006, Calgary, Alberta, Canada

[24] S. Shrestha, *In-Lin Inspection EMAT Utilizing an Oblique Field*, Corrosion, Paper No.2012-0001318, NACE 2012.

[25] T. Bueker et al. *Review of Advanced In-Line Inspection Solutions for Gas Pipelines*. November 17th, 2010.

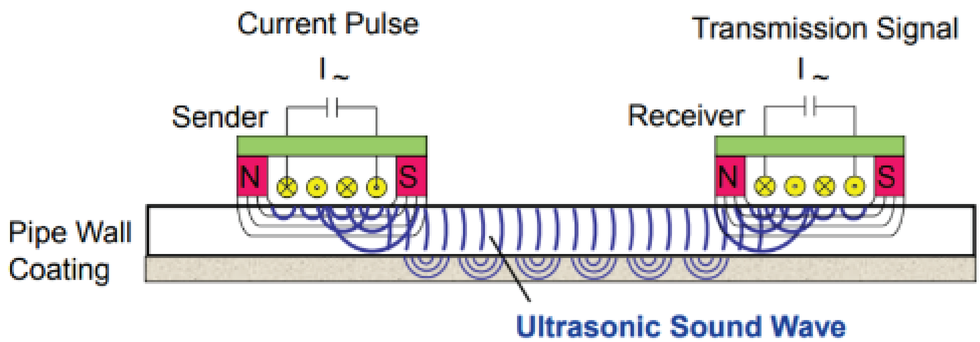

Figure 31: EMAT Principles[24]

Figure 31 illustrates the EMAT sensor arrangement (one EMAT sender and two EMAT receivers), and modules used to inspect a distinct area (pixel) of the pipeline.

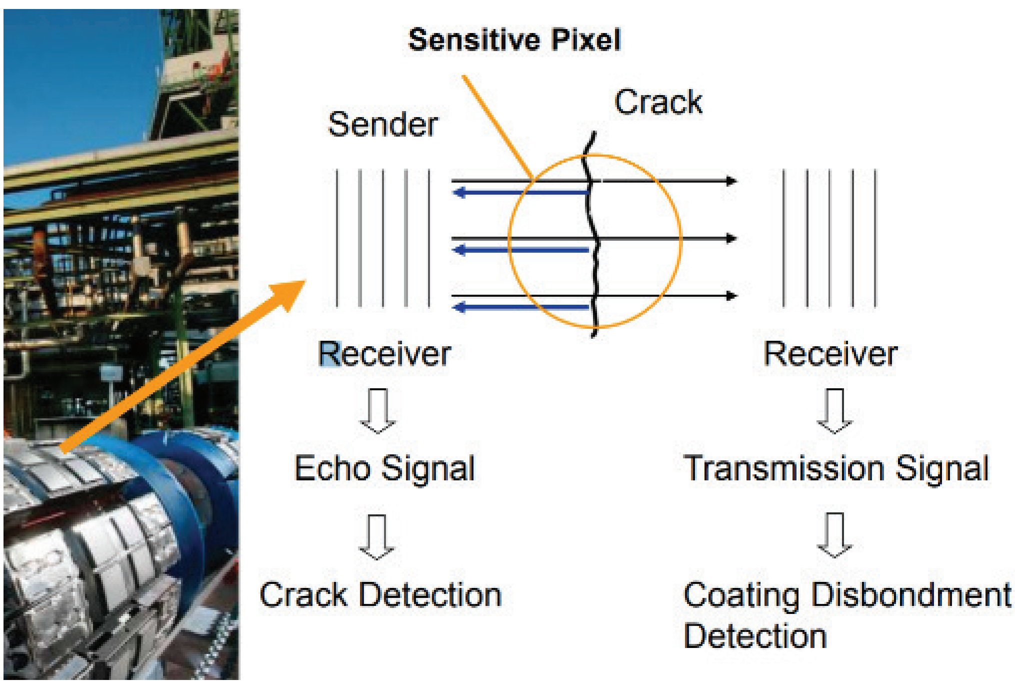

Figure 32: Configuration of Individual EMAT Sensor Representing One of EMAT ILI Tool[24]

Guided waves, as generated by an EMAT transducer, propagate between the external and the internal pipe surface as a boundary condition. Two acoustic data channels exist for each pixel (one transmission and one echo channel).

The overall wave amplitude from the sender to the receiver depends on the amount of lift-off, the presence of a defect, and the existence (and type) of external coating. A coating present on the outer surface of the pipeline attenuates the guided shear wave significantly. Therefore, a reduction in the bonding quality of the coating leads to a significant increase in the signal amplitude.

The ultrasonic waves only travel a short distance between the EMAT sender and the receiver. As a result, data evaluation is relatively simple and false alarms can also be avoided. The details of the EMAT principle was discussed in the reference paper[24,26].

9.2.1 EMAT Resolution

On low resolution, EMAT tools are equipped with few EMAT sensors on the circumference only, as shown in Figure 32. A guided wave has the ability to travel around the perimeter, but demands a cumbersome interpretation of a single waveform that contains information from a large area. Moreover, the signal quality and reliability are reduced since the guided wave is attenuated and dispersed on its way between transmitter and receiver.

A Coating generally dampens the acoustic wave. This is a serious issue in a low resolution approach since this attenuation decreases the signal amplitude obtainable if the EMAT receiver is positioned at a large distance to the transmitter.

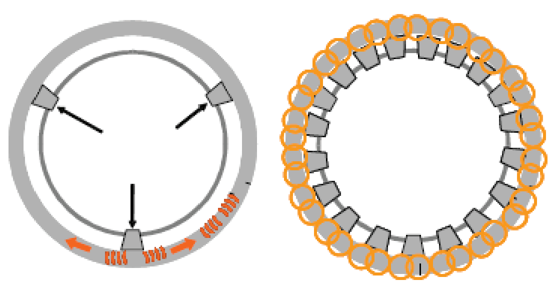

Figure 33: Low Resolution Approach (left) and High Resolution Approach (right)[27]

[26] R. Kania et al. *Validation of EMAT ILI Technology for Gas Pipeline Crack Inspection: A Case Study for 20",* (9th Pipeline Technology Conference, 2014)
[27] W. Krieg, *A Novel EMAT Crack Detection and Coating Disbondment (RoCD2)*, ILI Technology Pipeline Technology Conference, 2007

A high-resolution approach with a large number of individual EMAT sensors distributed around the circumference of the pipeline is arranged on an in-line inspection tool as shown in Figure 32. Each individual sensor is sampling a distinct area that is a fraction of the whole circumference. Since the sound path is limited to a short distance between transmitter and receiver, both propagation loss and dispersion effects between transmitter and receiver are negligible on crack detection capabilities. This provides a superior signal-to-noise ratio of the EMAT sensor which simplifies the subsequent data evaluation and avoids misinterpretations. The generated waves are travelling in both clockwise and counter clockwise direction and are reflected preferentially by axially oriented features. This interrogates irregular cracks from two different sides[23].

9.3 Application of EMAT

EMAT inspection technology can be applied to pipelines carrying all products (e.g. natural gas, LNG, crude oil and liquids) due to the fundamental EMAT principle. EMAT provides a detailed view of the dimensions and distribution of the defects around the circumference and along the pipeline axis.

While specifically designed and intended to detect pipeline wall defects, it is reported that EMAT can identify the coating type and the accurate sizing of the disbondment area through a high density of EMAT sensors and high sampling rates. EMAT can also reliably identify and characterize composite repairs and field coatings. An example is shown in Figure 33. The details of EMAT coating assessment is discussed in Section 9.4.

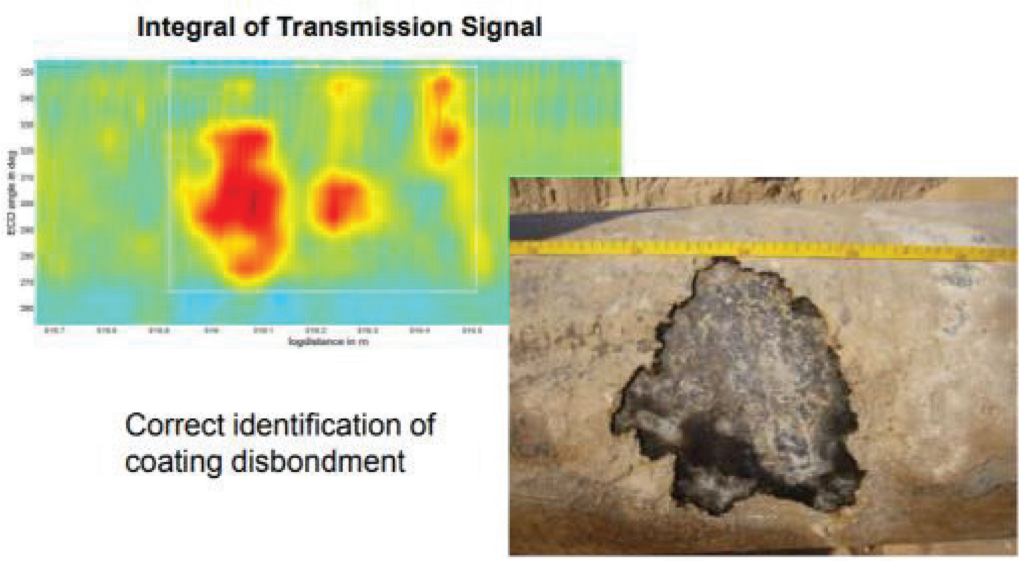

Figure 34: Coating Disbondment (Loss of Adhesion) Detection by EMAT[23]

9.4 EMAT for Coating Assessment

EMAT inspection technology, originally designed and intended for detection of stress corrosion cracking (SCC), is also reported to be sensitive to areas of disbonded coating, other crack-like features, and anomalies like gouging and channeling. High resolution EMAT tool provides advanced maps and better visualization to aid the analyst in coating condition assessment. The tool is reported to be capable of identifying coating disbondment and areas of missing coating as well as identifying different types of coating repair material

The external coating attenuates the transmission signal significantly as it transmits through the wall. In the case of intact coating, lower signal amplitude is captured by the receiver. In the case of coating disbondment or coating holidays, higher signal amplitude is captured since the attenuation is reduced as shown in Figure 34.

Detection of very large (3.94 inch x 3.94 inch) areas of coating damage was listed in commercial EMAT tool specifications with a minimum size at POD 85%[28]. These areas of damage are

[28] Rosen RoDD EMAT Service In-Line High Resolution Coating Disbondment Analysis

significantly larger than those detectible by CIS (medium-to-large defects in coatings isolated or continuous and typically >600 mm^2 [1 in^2]).

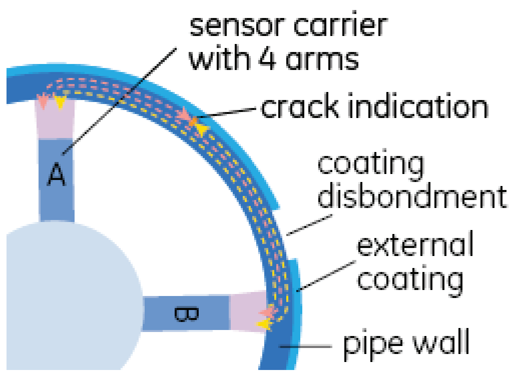

Figure 35: Signal Transmitted by One Sensor Received by Remote Sensor[24]

9.4.1 Identifying Disbonded Coatings

An attenuation map corresponding to the pipe surface is calculated from the contrast of transmission signal amplitudes from various signals. Changes in attenuation indicate differences in bond integrity of the pipe coating, as shown in Figure 33 in Section 9.3.

Coating disbondment is detectable as an increase of the transmission amplitude, as shown in Figure 35. The minimum detectable disbondment area is approximately 20 mm long and 50 mm wide. As suggested by the figure, the sensitivity of this tool diminishes with increasing wall thickness. The heavy wall pipe utilized in the straits would further diminish the tools sensitivity.

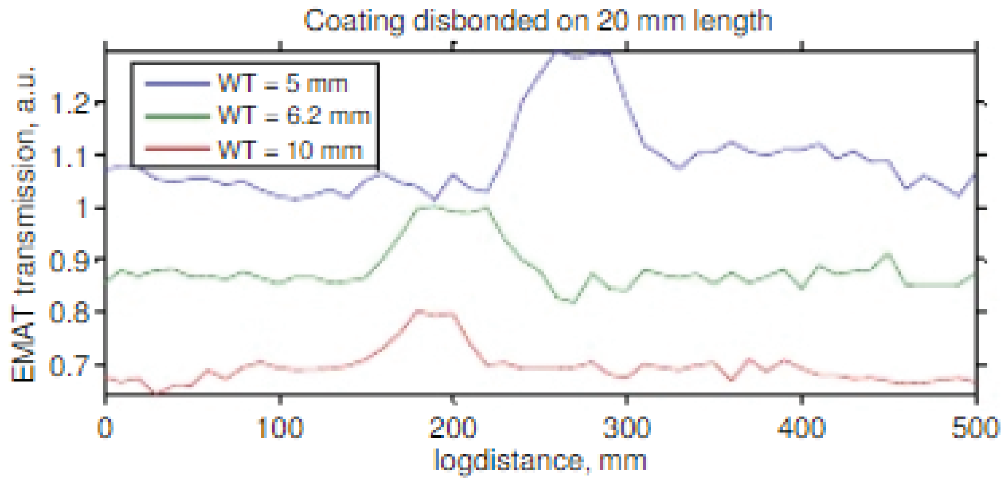

Figure 36: Increase of Transmission Signal in Regions with Disbonded Coating[23]

9.4.2 Identify Coating Types

A high-resolution attenuation map of the pipe surface is constructed with the attenuation map being synonymous with a map of the coating condition due to the signal amplitude only slightly attenuated. In this configuration the absolute transmission amplitude obtained depends on the types of coating present as shown in Figure 36 and Figure 37.

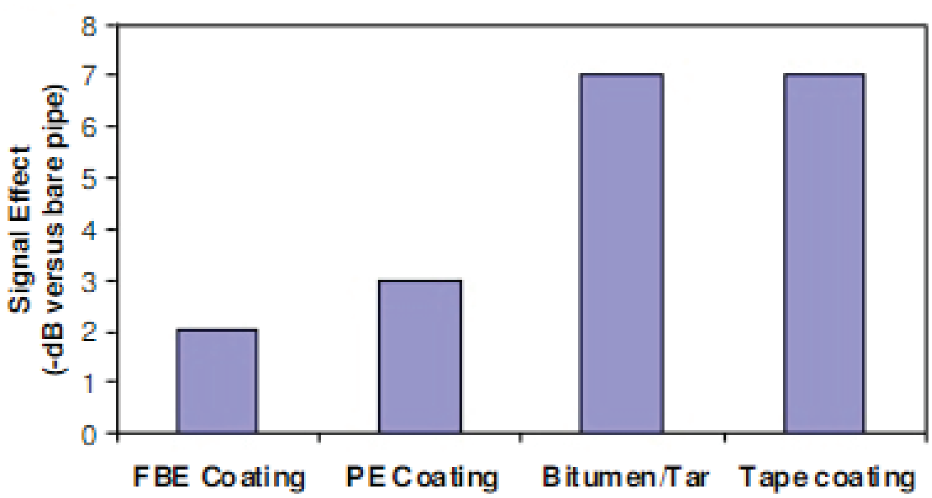

Figure 37: Signal Effect with Different Coatings[23]

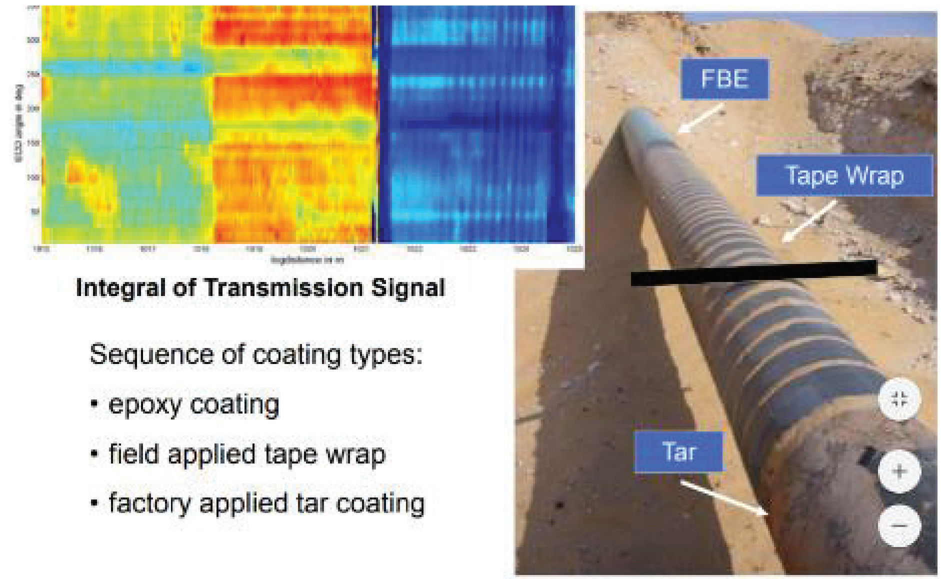

Figure 38: EMAT Identification of Different Coatings[23]

EMAT technology has been used to assess different types of coating. The distribution of coating types inspected with the EMAT tools is shown in Figure 38.

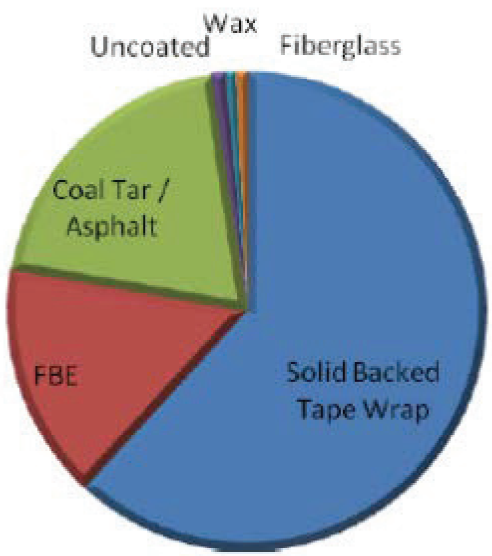

Figure 39: Distribution of Coating Types by EMAT by Now[29].

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[29] R. Norsworthy et al. *Importance of Locating Disbonded Coatings with Electro-Magnetic Acoustic Transducer Technology*, Paper No. 0001673, NACE 2012.

The population of pipelines inspected by EMAT for coating assessments is reported to be very small when compared to the use of EMAT for pipeline defect assessments.

9.5 Limitations and Challenges for Coating Assessments

9.5.1 EMAT Sensor Operation

The following are key requirements and issues that present challenges:

- A magnetic field must be applied in the steel,
- The transducer coil must be very close (approximately 1 mm) to the surface of the steel plate during the inspection, and
- The receiver must be extremely sensitive.

9.5.2 Noise Ratio

Several factors play in determining signal to noise ratio. The first is the strength of the reflected signal compared to background. Since pipe coating has an attenuating effect on the signal as it travels in the pipe wall, sensor spacing in the circumferential direction was considered. Here, a trade-off is required. The closer the receiver is to the reflector, the stronger the return signal will be. Therefore, this closeness dictates an increase in the number of sensors arranged on the circumference[27].

The entire signal is not reflected by a feature, which allows the unreflected portion of the wave to travel farther through the pipe. This wave then affects the signal of neighboring sensors. This increased density has diminishing returns because increasing noise is detected from other sensors or an overly complicated firing sequence must be devised to limit noise from neighboring sensors.

9.5.3 High Wear of Sensor

Another operational challenge encountered in the initial inspection was high wear of sensor surfaces from girth welds and pipe surface due to the dry coupling environment. Extensive testing in the lab did not accurately simulate harsh wear conditions of a real pipeline. An improved wear material was implemented to extend the inspection range of the tool, but impacted the sensitivity of the sensor by introducing extra background noise into the pipe wall.

9.5.4 Impact of Pipe Wall Thickness

Given the effect of pipe wall thickness on the sensitivity of the EMAT tool in detecting coating anomalies, this inspection tool is not capable of detecting small coating defects and is not additionally useful compared to the option of using CIS to detect coating defects.

10.0 CPCM ILI TOOL

The CPCM ILI tool relies upon the electrical resistance of the pipe wall to calculate electrical current magnitude and direction based upon the voltage drop between two contacts on the tool. As such, the tool is only capable of measuring significant amounts of current or large changes in the amount of current such as what might occur at an electrical short to a foreign structure. This would be considered to be a 'macro' tool in terms of assessing coating quality, as very large areas of coating damage would be required to show a significant change in the line current. Resolution of the line current for the Line 5 lines is further hampered by the heavy wall pipe (low electrical resistance).

Based upon the information provided by Enbridge, the raw data from the CPCM inspection is highly subject to electrical contact 'noise' which produces large swings in the foot by foot axial current measurement. This noise limits the tools ability to reliably detect small variations in axial current and precludes its use for detection of localized coating defects.

11.0 LITERATURE REVIEW

A detailed literature search was performed to support the SOTA. The review included technical papers to online articles. The following summaries are based on the research of relevant literature. The details of the literature review for each paper are shown in Appendix A.

11.1 Literature Review on CIS/DCVG/ACVG

Direct Assessment Pipeline Integrity Management (Corrosion 2011 Paper No.11126)

Authored By: Asokan P. Pillai

This paper provides an overview of the various inspection tools that are used to locate areas on the pipeline where corrosion might be taking place. The most common inspection tools include close interval surveys (CIS), direct current voltage gradient surveys (DCVG) soil type and topography surveys. All these tools are used during the implementation of the External Corrosion Direct Assessment (ECDA) in order to evaluate the pipeline integrity. One of the main requirements of Direct Assessment is to carry out a minimum of 2 complimentary indirect inspection techniques for each pipeline that is being investigated. The paper explains the application, practicality and limitations of each inspection tool. For the purpose of this report, the discussion will be concentrated on the CIS and DCVG tools technology.

Improvements to Cathodic Protection Performance using DCVG Prioritization (Corrosion 2016 Paper No.7091)

Authored By: C. Onuaha, S. McDonnell, E. Pozniak, M. Krywko, V. Shankar

This paper shows the importance of correlating close interval survey (CIS) and direct current voltage gradient (DCVG) during the implementation of an external corrosion direct assessment (ECDA) implementation to select location that might present external corrosion.

The paper is mainly focused on DCVG but it provides important case studies where the CIS surveys were used as a complementary technique to DCVG. It also confirms the important role of CIS and DCVG to locate areas where a coating anomaly and exposed pipe might be present.

Use of Close-Interval Survey Data in Applying ECDA and SCCDA (Corrosion 2007 Paper No.07157)

Authored By: Andrew Hevle

This paper concentrates mainly on the role of close interval surveys (CIS) as the primary indirect inspection tool in applying direct assessment on pipelines. The paper also indicates that close-interval surveys are often performed in conjunction with coating assessment surveys such as DCVG or ACVG or current attenuation surveys to identify areas at risk. The paper clearly indicates that the interpretation of the data helps to identify areas outside the range of acceptable industry criteria, locating defects on coatings (isolated or continuous and typically >600 mm^2 (1 $in.^2$))..

The paper also provides guidance on selecting types of close-interval surveys based on the specific pipeline condition to be encountered and the ability to reliably detect corrosion activity.

PHMSA-Sponsored Research: Improvements to ECDA Process – Severity Ranking (Corrosion 2010 Paper No.10054)

Authored By: David Kroon, James Carroll, Dale Lindemuth, Marlene Miller

This paper highlights a PHMSA sponsored research project directed toward enhancing external corrosion direct assessment (ECDA) classification and prioritization for effective of possible areas where corrosion might be present on a pipeline. CIS and DCVG were included in this study as part of the indirect inspection tools that are actually used during the ECDA process.

The approach in this study considers CIS, DCVG, ACVG, etc. and operational/maintenance data, as well as from soils data tools.

In the study, CIS is considered as an indirect inspection tool that is capable of assessing different aspects of pipeline polarization characteristics including CP effectiveness and coating condition.

Based on the data and analysis that was included in this study, the group developed an enhanced severity classification. The content of the tables is also based on effective ECDA programs of many operators' pipeline integrity programs.

DCVG – Analysis of practical limits and suggestions for improvements (Corrosion 2009 Paper No.09132)

Authored By: L. Bortels, P.J.Stehouwer, K. Dijkstra

This paper studies the practical limitations of the DCVG methods and introduces a new improvement named as DCVG calibration electrode.

The calibration electrode provides an idea of the size and location of defects that can be detected during a practical situation.

Based on these results, a study was put in place which resulted in the introduction of a calibration method to assess the practical limits of the DCVG coating survey method.

ACVG or DCVG – Does it matter? Absolutely it Does (Corrosion 2017 Paper No.9374

Authored By: Jim Walton

The paper describes the applicability of DCVG and ACVG and their ability to successfully detect coating defects.

The ACVG indications are categorized by their value which is in decibel microvolts (dBμV). The decibel microvolt at the indication is then compared to the amount of current flow at the indication in mill amperes and adjusted to account for different amounts of current flow at each indication and its effect on the dBμV indication level. The larger the indication, the more severe the coating damage.

The DCVG indications are categorized in percentage IR (%IR). The larger the indication the more severe the coating damage.

The main differences between both techniques arealso discussed in the paper. :The author concludes that ACVG and DCVG can provide suitable results in some cases, but ACVG with higher levels of accuracy, it is more sensitive, requires less operator interpretation and can be implemented in a more efficient manner.

Use of an Integrated CIPS/DCVG Survey in the ECDA Process (Corrosion 2006 Paper No. 06193)

Authored By: S.M. Segall, P. Eng., R.G. Reid, P. Eng., R.A. Gummow, P. Eng.

The research study consisted of the following items:

1. The paper reviews two indirect inspection tools, close interval potential survey and DC voltage gradient survey, applied in combination as one integrated survey.
2. The paper presents the results of the ECDA process completed by Corrosion Service Company Limited (CSCL) on three pipelines for Union Gas Limited (UGL).

3. The measured voltages and gradients were tabulated and graphed to represent the effectiveness of applying an integrated CIPS/DCVG survey.

A simple procedure was derived for the longitudinal gradient profile for possible application to validate the lateral DCVG results, analyze previous CIPS survey conducted with no associated DCVG and validation of the results of AC attenuation surveys conducted in conjunction with CIPS.

How Deep is too Deep for Indirect Inspections (Corrosion 2017 Paper No. 9378)

Authored By: Jim Walton

Test an area where a lack of CP on a pipe that is buried less than 10 feet deep and to conduct CIS at an offset of 10 feet, 25 feet and 50 feet. If the voltage potential measurements that are consistent to the regular survey over the pipe, then utilize this technique on pipes with similar coatings/CP systems that are buried deep.

Depending on the length of the deep section of pipe, take a measurement before and after the deep section to see how much current change over the deep section of pipe by comparing the two measurements. Another useful technique for deeper pipe sections is to increase the amount of applied signal on the pipe.

To increase the sensitivity for ACVG, lengthen the probe spacing of the "A-frame" to be a 10 foot or even 20-foot length.

11.2 Literature Review on Offshore Pipeline Survey

Inspection Technologies and Tools Used to Determine the Effectiveness of Cathodic Protection for Subsea Pipelines in the Gulf of Mexico – A Review, (Corrosion 2009 Paper No. 09527 NACE)

Authored By: M. Galicia

The general effective tools and technologies applied to monitor, characterize and assess the effectiveness of a cathodic protection systems for subsea pipelines are discussed. For the existing pipeline, permanent technologies and portable technologies are utilized to provide a reliable concept to implement the CP system. Permanent technologies such as permanently mounted sensors include current density sensors, anode current monitors, coating efficiency monitors and various reference electrodes. Portable technologies can provide a comprehensive status of CP in real time, especially with the use of ROV mounted survey systems.

11.3 Literature Review on EMAT

Cost Effective On-Stream Inspection Technique Using EMAT Technology for Pipeline Integrity at ELK Hills, (Corrosion 2001 Paper No. 01635 NACE)

Authored By: G. E. Peck

EMAT tool was selected to perform inspection on the oil and gas pipelines at Elk Hills, which is one of the giant oilfields in western Kern County, California. The field was discovered in 1918 and was operated as a petroleum reserve prior to 1998.

The EMAT inspection was used for inspection. The tool is motorized on wheels that move the magnetically coupled EMAT along the pipeline at a rate up to 50 feet/minute. Unexpected details such as clear right of way was experienced in this project. The accuracy, tool coverage, survey speed, and the cost were discussed in the paper.

In-Line Inspection with High Resolution EMAT Technology Crack Detection and Coating Disbondment, (Corrosion 2007 Paper No. 07131, NACE)

Authored By: A.O. Al-Oadah, W. A. Borjailah

A 16” EMAT high resolution tool was selected to perform inspections on two FBE coated pipes experienced presence of SCCs and coating damages: one in gas pipeline and the other one in an oil pipeline during operation conditions. The echo signal and transmission signal were evaluated, and field results of echo signal and transmission signal were discussed.

Echo channels are sensitive to both defects in the axial and in the circumferential direction. A weaker or even disbonded coating indications were observed by transmission channel in strong red colored areas;Transmission channels are sensitive to large reflections (signals decrease) and are also sensitive to coating qualities (signals increase as coating is disbonding)

Acceptance of EMAT Based In-Line Inspection Technology for the Assessment of Stress Corrosion Cracking and other Forms of Cracking in Pipelines, (Corrosion 2009 Paper No. 09108 NACE)

Authored By: T. Beuker, C. Doescher, B.Brown

Sensitivity of the EMAT tool was discussed by inspecting of several gas pipelines and a series of pull tests results.

With increasing the length of defect, the detection of shallower defects becomes more likely. The minimum dimension found by the EMAT was 0.79 inch long and 0.026 inch deep with a probability-of-detection (POD) of 92%.

Coating Assessment: EMAT inspection system can provide both characteristics about the coating types as well as characteristics about the disbanded coating. This information is derived from the attenuation of the signal from the “coating” channel (transmission channel). The differentiation between the coal tar and FBE coating is reflected very well. Disbonded area is also identified by a change in transmission amplitude and reported as individual features.

EMAT, pipe Coatings, Corrosion Control and Cathodic Protection Shielding (Corrosion 2013 Paper No. 2378, NACE)

Authored By: R. Norsworthy, J. Grillenberger, S. Brockhaus, M. Ginten

EMAT not only can be used to identify the disbanded coatings, but also be used to identify different types of coating, coating disbondment and the associated failure scenarios. The coating type and coating adhesion condition are critical to make decision about when and where to make repairs or replacement of the coating or pipes.

Validation of EMAT ILI Technology for Gas Pipeline Crack Inspection: A Case Study for 20", (9th Pipeline Technology Conference, 2014)

Authored By: R. Kania, K. Myden, R. Weber, S. Klein

EMAT tool was selected to perform inspections on two 20 inches gas pipelines with the length of 186.4 miles and 93.2 miles, respectively. Sensitivity of the EMAT is influenced by the signal-to-noise-ratio of the time-integral of the EMAT echo amplitude. A total of 66,694 anomalies have been initially detected by EMAT tool in the pipe body and 22,839 anomalies in the longitudinal weld area. A total of 755 crack-like defects have been reported above the criteria.

Investigating EMAT Dig Results for a Low Frequency EWR Seam Inspection, (Corrosion 2017 Paper No. 9184, NACE)

Authored By: S. Moran, R. Meyers

The efficacy of EMAT technology is validated run in conjunction with a multiple dataset platform by analyzing the seam of a 16", low-frequency electric resistance welded (LF-ERW) liquid pipe with 38 miles in length. The comparison the field and EMAT results were compared well. 131 NDE dig results were correlated with the EMAT results, the depth accuracy of the EMAT results to NDE were within +/- 20% of nominal wall thickness at an 89.3% certainty. The length performance results from all 131 EMAT features to NDE results did not indicate a positive correlation.

Four ILI tools were chosen for the assessment the same pipeline. Multiple Dataset (MDS), Circumferential Magnetic Flux Leakage (CMFL), Ultrasonic Crack Detection (UTCD), and EMAT. A list the features types from each of the four ILI technologies had various descriptions for crack-like defects. After combining these features types, a total of 562 cracks were reported The majority of the cracks were reported by EMAT.

11.4 Literature Review on CPCM

P.K. Scott and M.W. Mateer. Cathodic Protection Monitoring Via In-Line Inspection. Pigging Products and Services Association. 2007.

- The results show that CP currents can be quickly, accurately and efficiently gathered without access to the outside surface of the pipe.
- CPCM provides two advantages:
  - Measures CP current direction and magnitude in the pipeline
  - Allows the operator to easily gather CP information regardless of ROW conditions
- Pipe product cannot be conductive.

D.C. Janda. ILI tool enhances CP monitoring. Pipeline and Gas Technology. 2009

- ***This publication is more or less a copy of the paper referenced above by Scott and Mateer.***
- CPCM Cathodic Protection In-Line Inspection Services provide for a reliable, cost-effective, time-saving way to monitor, validate, or troubleshoot a pipeline's CP system.
- CPCM tool measures CP current direction / magnitude, and allows the pipeline operator to easily gather CP information regardless of ROW conditions.
- Interpretation of CPCM data continues to be refined. More work is needed to fully exploit all the capabilities of the inspection tool and the resulting measurements.

12.0 SUMMARY OF STATE OF THE ART

The results of this study have shown that CIS, complemented by regular ILI remain the two most reliable tools for assessing the integrity of the Line 5 Straits of Mackinac pipeline crossing. Moreover, CIS has evolved into a mature and reliable technology for subsea and marine crossing pipelines. NACE SP0207-2007 suggests that CIS surveys for buried and submerged structures can locate medium to large defects in coatings (isolated or continuous and typically >600mm^2 [1 in^2]). While other coating assessment tools such as DCVG, ACVG and AC Attenuation can be reliably performed for onshore land based pipelines, those technologies present significant challenges for the application of the Line 5 crossing. The technical challenges and lack of proven detection capabilities and calibration of those techniques to a subsea pipeline introduces too much risk of unreliable and potentially misleading results to warrant serious consideration.

The review has also shown that the EMAT tool shows promise as a coating assessment tool, but likely will not yield incremental value to the use of the CIS tool to assess and ensure CP efficacy in conjunction with periodic inspection through ILI intended to detect external metal loss anomalies. Further the sensitivity of the tool is greatly diminished for thicker wall pipe.

Similarly, The CPCM tool is not expected to yield meaningful results regarding coating assessment as the pipe wall thickness and linear resistance, when coupled with the applied CP current will yield a very small linear voltage drop that is likely below the detection limit of the tool.

The use of CIS and CP measurements coupled with periodic ILI inspections represents the best technology to assess the integrity of Line 5.

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APPENDIX A

A detailed literature search was performed to support the SOTA. The review included technical papers to online articles. The following summaries are based on the research of relevant literature.

Literature Review on CIS/DCVG/ACVG

Direct Assessment Pipeline Integrity Management (Corrosion 2011 Paper No.11126)

Authored By: Asokan P. Pillai

This paper provides an overview of the various inspection tools that are used to locate areas on the pipeline where corrosion might be taking place. The most common inspection tools include close interval surveys (CIS), direct current voltage gradient surveys (DCVG) soil type and topography surveys. All these tools are used during the implementation of the External Corrosion Direct Assessment (ECDA) in order to evaluate the pipeline integrity. One of the main requirements of Direct Assessment is to carry out a minimum of 2 complimentary indirect inspection techniques for each pipeline that is being investigated. The paper explains the application, practicality and limitations of each inspection tool. For the purpose of this report, the discussion will be concentrated on the CIS and DCVG tools technology.

Close interval potential survey is basically a pipe-to-soil survey conducted at close intervals along a pipeline to assess the performance of the cathodic protection system and to estimate the location of coating holidays.

Direct current voltage gradient (DCVG) is normally considered a secondary indirect inspection tool during the ECDA process and it is normally implemented to measure the voltage gradients resulting from current pickup and discharge points at coating holidays. DCVG is used to detect coating holidays and size them by determining the percent IR.

The author also describes ways to analyze the data. Reference is being made to the NACE SP0502 “Pipeline External Corrosion Direct Assessment Methodology” classification approach which consists on the following:

- Minor – indications that can be considered inactive or with the lowest likelihood of corrosion activity, e.g. small On/OFF potential above CP criteria (small dips)
- Moderate – indications considered as experiencing possible corrosion activity, e.g. OFF potentials below CP criteria (medium dips).
- Severe – indications considered as having the highest probability of corrosion activity, e.g. On/OFF potentials below CP criteria (large dips).

This information can be correlated to voltage ranges as follows: small dips as less than 50mV, medium dips as between 50 mV to 100mV or below CP criteria, and large dips as anything greater than 100mV or below CP criteria.

The following Table from the paper shows the corresponding link of CIS severity ranking to a risk index.

Table 3: CIPS Severity Classification relative to Risk Index

Severity Classification	Criteria		Suggested Risk Index
	ON and OFF Potential Range	ON and OFF Potential Dips	
Insignificant	ON and OFF potentials both more negative than -0.850V wrt CSE	Less than 25mV Dip	1
Minor	ON and OFF potentials both more negative than -0.850V wrt CSE	25mV to 50mV Dip	2
Moderate	ON potentials more negative than -0.850V and OFF potential not more negative than -0.850V wrt CSE	50mV to 75mV Dip	3
Major	ON and OFF potentials both not more negative than -0.850V wrt CSE	75mV to 100mV Dip	4
Severe	ON and OFF potentials both not more negative than -0.850V wrt CSE	Greater than 100mV Dip	5

The risk index ranges from 1 to 5 with I indicating the lowest likelihood of any corrosion activity and 5 indicating the highest likelihood of corrosion activity. This risk ranking is automatically computed to the collected close interval survey data. The index can be combined with another complementary indirect inspection tool survey like Direct Current Voltage Gradient (DCVG) to prioritize direct examination locations.

Like the Close interval survey, the most critical challenge in a DCVG survey is the analysis of the data. The NACE SP0502's approach is as follows:

- Category 1 - 1-15% IR: Holidays in this category are considered of low importance, and repair is not required.
- Category 2 – 16 to 35% IR: Holidays in this category are generally considered of no serious threat and can be protected by maintaining adequate levels of CP. Generally

considered for repair, based on proximity to groundbeds or other structures of importance.

- Category 3 – 36-60% IR: Holidays in this category will be considered a threat to the overall integrity of the pipeline and will be scheduled for repair.
- Category 4 – 61-100%IR: Holidays are generally recommended for immediate repair and are considered likely to pose a threat to the integrity of the pipeline.

Additionally, there are four possible statues of corrosion for each:

C/C – cathodic/cathodic: Holidays that are consumers of CP but are not actively corroding.

C/N – cathodic/neutral: These holidays consume current and may corrode when there is an upset in CP.

C/A – cathodic/anodic: These holidays may corrode even when the CP system is properly operating and they also consume CP current.

A/A – anodic/anodic: Holidays that may be corroding and may or may not consume current.

As per NACE SP0502 "Pipeline External Corrosion Direct Assessment Methodology" classification approach which consists on the following:

- Minor: Small indication (low voltage drop and cathodic condition at indication when CP is On and OFF).
- Moderate: Medium indication (medium voltage drop and/or neutral condition at indication when CP is OFF).
- Severe: Large indication (high voltage drop and/or anodic condition when CP is ON or OFF).

The following Table shows the corresponding link of DCVG severity ranking to a risk index.

Table 4: DCVG Severity Classification relative to Risk Index

Severity Classification	Criteria		Suggested Risk Index
	%IR	Corrosion Status	
Insignificant	0	Perfect Coating	1
Minor	1% to 15%	Cathodic/Cathodic	2
Moderate	15% to 35%	Cathodic/Neutral	3
Major	35% to 70%	Cathodic/Anodic	4
Severe	70% to 100%	Anodic/Anodic	5

Improvements to Cathodic Protection Performance using DCVG Prioritization (Corrosion 2016 Paper No.7091)

Authored By: C. Onuaha, S. McDonnell, E. Pozniak, M. Krywko, V. Shankar

This paper shows the importance of correlating close interval survey (CIS) and direct current voltage gradient (DCVG) during the implementation of an external corrosion direct assessment (ECDA) implementation to select location that might present external corrosion.

The paper is mainly focused on DCVG but it provides important case studies where the CIS surveys were used as a complementary technique to DCVG. It also confirms the important role of CIS and DCVG to locate areas where a coating anomaly and exposed pipe might be present.

The DCVG %IR methodology involves linear interpolation of the measured IR drop difference measured in the pipe to soil potential (measured to remote earth) at the upstream and downstream point of the pipe segment that is being inspected.

New technologies have been developed that integrate CIS and DCVG survey data. The analogy to follow during the evaluation and analysis of the data will depend on the level of cathodic protection, soil corrosivity and DCVG %IR. For example, if a pipeline is receiving good cathodic protection and the DCVG %IR is greater than 70, the probability for corrosion will be low when compared to another pipeline with the same condition but not receiving enough cathodic protection. Another analogy is also presented where a pipeline with small DCVG %IR is not receiving enough cathodic protection and the pipe is buried in a highly conductive and corrosive soil. The presence of a tiny coating anomaly could expose the metal to highly corrosive metal. The section will become anodic (creating a small anode to a large cathode) to the rest of the coated pipe leading to a severe localized corrosion.

The following Table and Figure present the results of some case studies that are presented in the paper. The correlation of the CIS and DCVG data can provide useful information on severity of corrosion.

The pipeline integrity data show that:

Table 1: Pipeline Integrity Data from Figure 1					
CP CIPS On Potential (mV/CSE)	CP CIPS Inst off Potential (mV/CSE)	Depolarized Potential (mV/CSE)	DCVG %IR	Soil Resistivity (Ω-cm)	Comment
-972	-891	-704	76	723.9	Soil resistivity taken at pipe depth

The pipeline integrity data show that:

a) The polarized and depolarized potentials are -891mV/CSE and -704mV/CSE, respectively. As per NACE requirements, the pipeline should be receiving enough CP. The sudden drop in the polarized potential could mean that the exposed bare metal is consuming much of the CP current.
b) The difference between "Instant OFF" and ON potential is 81 mV. This could indicate a possible coating anomaly creating a low resistive path.
c) The soil resistivity of 723.9 Ω-cm indicates that the soil could be highly corrosive to the exposed metal.
d) The DCVG IR of 76% indicates an immediate repair is recommended.

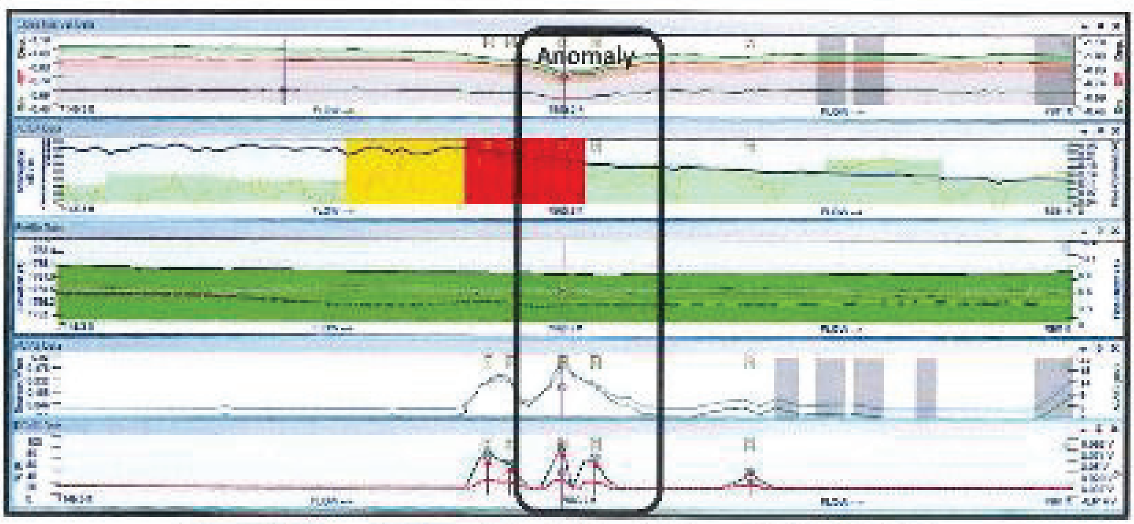

Figure 4: Presentation of Low CP and Strong DCVG Indication

Use of Close-Interval Survey Data in Applying ECDA and SCCDA (Corrosion 2007 Paper No.07157)

Authored By: Andrew Hevle

This paper concentrates mainly on the role of close interval surveys (CIS) as the primary indirect inspection tool in applying direct assessment on pipelines. A close-interval survey (CIS) is a series of structure-to-electrolyte direct current (DC) potential measurements performed at regular intervals for assessing the level of cathodic protection (CP) on buried or submerged pipelines. The paper also indicates that close-interval surveys are often performed in conjunction with coating assessment surveys such as Direct Current Voltage Gradient (DCVG) or Alternating Current Voltage Gradient (ACVG) or current attenuation surveys to identify areas at risk. The paper clearly indicates that the interpretation of the data helps to identify areas outside the range of acceptable industry criteria, locating defects on coatings (isolated or continuous and typically >600 mm^2 (1 $in.^2$)., locating areas of stray current pickup and discharge or at risk for interference corrosion, identify possible shorted casings, defective electrical isolation devices, or unintentional contact with other metallic structures, and locating possible high pH stress corrosion cracking risk areas.

The paper also provides guidance on selecting types of close-interval surveys based on the specific pipeline condition to be encountered and the ability to reliably detect corrosion activity.

The author stresses the fact that care must be exercised to ensure that the data collected during a CIS survey is accurate, valid, and capable of integration with other data sets. The success of a CIS and its ability to detect coating faults and exposed areas depends on the following:

- Detailed close-interval survey specifications.
- Proper preparations should be made prior to the start of the survey.
- Proper locating and distance measurement techniques should be selected and performed.
- Implementing additional measurements to ensure that the data is valid and accurate, that current interrupters are synchronized, that IR drop in the soil and along the pipeline are minimized, and sufficient measurements to evaluate the effectiveness of electrical isolation and the influence of foreign cathodic protection systems.
- Sufficient field comments should be entered while conducting the survey to documents any physical features that may significantly affect the measurement or aid in the location of indications.
- Implement data validation methods to ensure that the CIS data is accurate and valid.

PHMSA-Sponsored Research: Improvements to ECDA Process – Severity Ranking (Corrosion 2010 Paper No.10054)

Authored By: David Kroon, James Carroll, Dale Lindemuth, Marlene Miller

This paper highlights a PHMSA sponsored research project directed toward enhancing external corrosion direct assessment (ECDA) classification and prioritization for effective of possible areas where corrosion might be present on a pipeline. Close-interval surveys (CIS) and Direct Current Voltage Gradient surveys (DCVG) were included in this study as part of the indirect inspection tools that are actually used during the ECDA process.

The classification and prioritization methodologies provided in the NACE SP0502 are considered very general and provide limited guidance for accurately classifying and prioritizing indirect inspection indications under various conditions.

The approach in this study considers close interval surveys (CIS), DC voltage gradient (DCVG), AC voltage gradient (ACVG), etc. and operational/maintenance data, as well as from soils data tools.

With respect to CIS, the field data includes Polarized CP, ON Profile Depression, OFF Profile Depression, ON/OFF Convergence, and Polarization (Native or Static OFF). In the study, CIS is considered as an indirect inspection tool that is capable of assessing different aspects of pipeline polarization characteristics including CP effectiveness and coating condition.

Based on the data and analysis that was included in this study, the group developed an enhanced severity classification table which is shown in Table 1 and 2. The content of the tables is also based on effective ECDA programs of many operators' pipeline integrity programs.

The two Tables were also enhanced using a soil texture modifier factor. The addition of this factor in Table 1 provides a notable improvement from NACE SP0502-2008 in that objective measurable values are assigned to each indirect inspection technique. Additionally, consideration of soil characteristics improves the prioritization action shown in Table 2.

TABLE 1: PROPOSED SEVERITY TABLE

Measure	IDI Classification: Minor	Moderate	Severe
IDI TOOL = CIS			
A = OFF (Polarized) Potential [mV]	-950 mV < A < -850 mV	-850 mV < A < -450 mV	-450 mV < A
	OR	OR	AND
B = ON Potential [mV]	-1000 mV < B < -900 mV	-900 mV < B < -850 mV	-850 mV < B
	AND	AND	AND
C = ON/OFF Convergence [mV]	50 mV < C < 70 mV	30 mV < C < 10 mV	10 mV < C
	OR	OR	AND
D = ON and/or OFF Profile Depression within 100ft span [mV/span]	50 mV/span < D < 100 mV/span	100 mV/span < D < 200 mV/span	200 mV/span < D
IDI TOOL = ACCA			
E = Current 50 Hz Frequency Signal Loss(-) [mdB/(mA)/ft]	7 mdb(mA)/ft < E < 3 mdb/ft	12 mdb(mA)/ft < E < 7 mdb(mA)/ft	12 mdb(mA)/ft < E
	AND/OR	AND/OR	AND/OR
F = Current 4 Hz Frequency Signal Loss(-) [mdB/(mA)/ft]	30 mdb(mA)/ft < F < 40 mdb(mA)/ft	40 mdb(mA)/ft < F < 60 mdb(mA)/ft	60 mdb(mA)/ft < F
	AND	AND	OR
CP Level Modifier	Adequate CP Level	Adequate to Marginal CP Level	ALL indications with inadequate CP Level
IDI TOOL = ACVG			
G = Voltage Signal Loss(-) [dB(mV)]	44 dB(mV) < G < 60 dB(mV)	60 dB(mV) < G < 70 dB(mV)	70 dB(mV) < G
	AND	AND	OR
CP Level Modifier	Adequate CP	Adequate to Marginal CP Level	ALL indications with inadequate CP
IDI TOOL = DCVG			
H = Coating Defect Size [%IR]	5%IR < H < 20%IR	20%IR < H < 50%IR	50%IR < H
	AND	OR	OR
I = Corrosion State Assessment (Normal Operating Conditions)	I = Cathodic/Cathodic or Cathodic/Neutral	All indications 35%IR < H < 50%IR where I = Cathodic/Anodic	All indications where I = Anodic/Anodic
	AND	AND	OR
CP Level Modifier	Adequate CP	Adequate to Marginal CP Level	ALL indications with inadequate CP
IDI TOOL MODIFIER - USDA Soils Data - Soil Texture Designation (Not an Independent TOOL)			
J = USDA Soil Texture Designation (12 types)	J = Sand, Loamy Sand, Sandy Loam, Loam, Silt Loam or Silt	J = Sandy Clay Loam, Sandy Clay, Clay Loam, Silty Clay Loam	J = Clay and Silty Clay
	AND	AND	OR
CP Level Modifier	Adequate CP	Adequate to Marginal CP Level	ALL area with inadequate CP

TABLE 2: PROPOSED PRIORITIZATION TABLE

USDA Soil Texture Modifier	Two Tools with Soil Modifier	IDI Tool 1 Classification: Severe	Moderate	Minor
Severe	IDI Tool 2 Classification: Severe	Immediate	Immediate	Scheduled
	Moderate	Immediate	Scheduled	Scheduled
	Minor	Scheduled	Scheduled	Monitored
Moderate	Severe	Immediate	Scheduled	Scheduled
	Moderate	Scheduled	Scheduled	Monitored
	Minor	Monitored	Monitored	Monitored
Minor	Severe	Immediate	Scheduled	Monitored
	Moderate	Scheduled	Monitored	Monitored
	Minor	Monitored	Monitored	Monitored

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The study concluded that the enhanced classification and prioritization Tables contribute to effectively, economically, efficiently and safely address the external corrosion threat to pipeline integrity.

DCVG – Analysis of practical limits and suggestions for improvements (Corrosion 2009 Paper No.09132)

Authored By: L. Bortels, P.J.Stehouwer, K. Dijkstra

This paper studies the practical limitations of the Direct Current Voltage Gradient (DCVG) methods and introduces a new improvement named as DCVG calibration electrode. The approach is based on:

- The combination of numerical calculations, and
- Development of a calibration electrode (pen) which can be used in the field to simulate coating defects.

The calibration electrode provides an idea of the size and location of defects that can be detected during a practical situation.

The DCVG calibration technique is based on the combination of sound mathematics and advance 3D computer simulations (based on Finite element Method). The model takes into account ohmic drop effects in the soil (multi-layer/domain) and anodic and cathodic reaction polarization behavior.

In order to prove the limitations of the DCVG technology, the authors presented in Figure 3 the calculated DCVG signal for a defect on a 42” pipe with 120 cm coverage, located at the top, side and bottom.

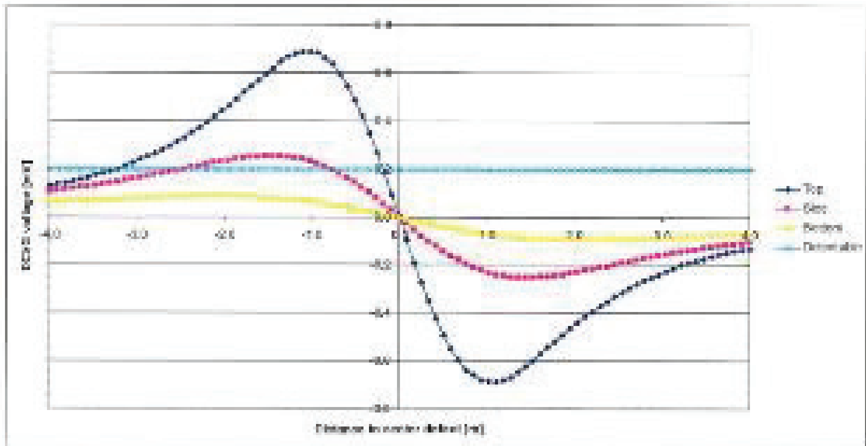

Figure 3: DCVG simulation results (42" pipe with 120 cm coverage)

As per Figure 3 above, defects on the side and bottom of the pipe give DCVG signals are almost 3 and 8 times smaller than the size defect at the top of the pipe. Additionally, using a 100 mV ON/OFF switch, the bottom defect generates a DCVG signal that is smaller than the typical detection limit of 0.2 mV, therefore it was not detected.

Based on these results, a study was put in place which resulted in the introduction of a calibration method to assess the practical limits of the DCVG coating survey method.

The DCVG calibration consisted on using a calibration electrode to simulate the effect of a coating defect by an electrode that is connected to the pipe and produces the same DCVG profile at the surface level as the actual defect.

The details of the calibration electrode, mathematics and modelling are presented in the paper. An example is provided which shows the success of the calibration process.

The example shows DCVG signals of an actual defect located on the side of the pipeline with 90 cm coverage and the pen with optimized depth and series are presented in Figure 7. The results are shown for pipe diameters ranging from 8" to 48" and show excellent agreement.

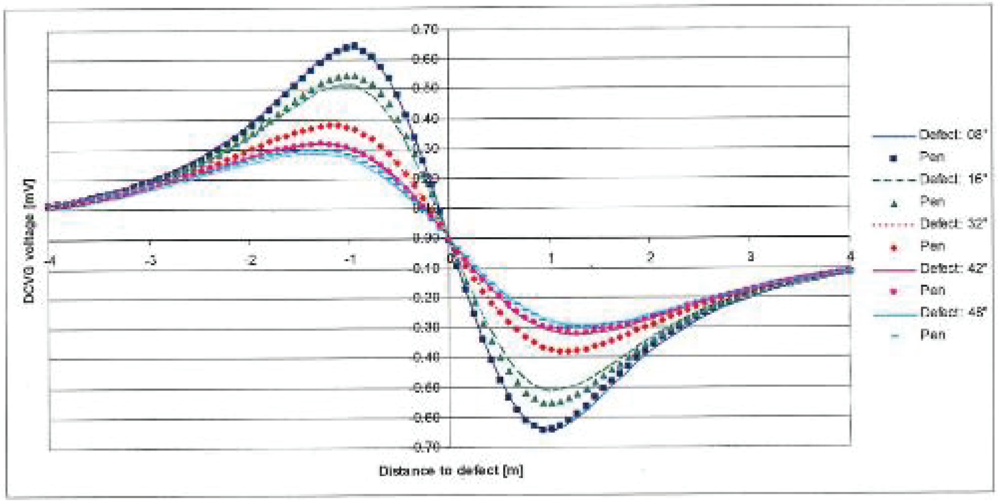

Figure 7: Comparison between DCVG signal of defect and pen

ACVG or DCVG – Does it matter? Absolutely it Does (Corrosion 2017 Paper No.9374

Authored By: Jim Walton

The paper describes the applicability of Direct Current Voltage Gradient (DCVG) and Alternating Current Voltage Gradient (ACVG) and their ability to successfully detect coating defects.

Details related to both techniques are provided in the report. A summary of each technique is provided as follows:

The ACVG indications are categorized by their value which is in decibel microvolts (dBμV). The decibel microvolt at the indication is then compared to the amount of current flow at the indication in mill amperes and adjusted to account for different amounts of current flow at each indication and its effect on the dBμV indication level. The larger the indication, the more severe the coating damage. The dBμV level can be affected by:

- Soil resistance,
- Depth of the pipeline, amount of transmitted signal,
- Pipe diameter,
- Coating type,
- Clock positon of the indication,
- Pipeline length, number of indications in the area, and

- A-frame contact to the surface.

The DCVG indications are categorized in percentage IR (%IR). The larger the indication the more severe the coating damage.

The %IR level can be affected by:

- Soil resistance,
- Depth of the pipeline,
- Pipe diameter, Coating type, clock position of the indication, Pipeline length,
- Number of indications in the area, and
- Probe contact to the surface.

Both techniques are capable of finding and locating the following:

- Large coating defects,
- Small coating defects,
- Relative severity of the coating defect, possible interference areas. Shorted casings (both metallic and electrolytic conditions),
- CP cable breaks, and Position of anodes.

The main differences between both techniques are as follows:

- DCVG uses interrupted CP sources. ACVG uses either low frequency AC or interrupted DC.
- DCVG uses two poles with half-cell type of contact probes. ACVG uses two metal probes.
- DCVG probe varies. ACVG probe specie is fixed.
- DCVG can be interfered with existing or stray DC sources. ACVG normally is not.
- DCVG normally requires 400-800 mV shift which cannot be obtained in all pipeline conditions without significant effort. ACVG requires a minimum amount of low frequency applied current.
- DCVG can be less sensitive under paved surfaces than ACVG therefore requiring the use of drilled holes in pavement.
- ACVG requires less operator interpretation because of the fixed spacing.
- DCVG can provide a relative cathodic/anodic condition of CP at an indication.
- CP current may create a state of passivation in which little or no current change is occurring at the holiday. DCVGG is not able to identify an indication at these locations.

The author concludes that ACVG and DCVG can provide suitable results in some cases, but ACVG with higher levels of accuracy, it is more sensitive, requires less operator interpretation and can be implemented in a more efficient manner.

Use of an Integrated CIPS/DCVG Survey in the ECDA Process (Corrosion 2006 Paper No. 06193)

Authored By: S.M. Segall, P. Eng., R.G. Reid, P. Eng., R.A. Gummow, P. Eng.

The research study consisted of the following items:

4. The paper reviews two indirect inspection tools, close interval potential survey and DC voltage gradient survey, applied in combination as one integrated survey.
5. The paper presents the results of the ECDA process completed by Corrosion Service Company Limited (CSCL) on three pipelines for Union Gas Limited (UGL).
6. The measured voltages and gradients were tabulated and graphed to represent the effectiveness of applying an integrated CIPS/DCVG survey.

The testing was applied to the 16” pipeline, where an interrupted CIPS was completed over top of the pipeline, and a gradient measurement was collected 3 m laterally.

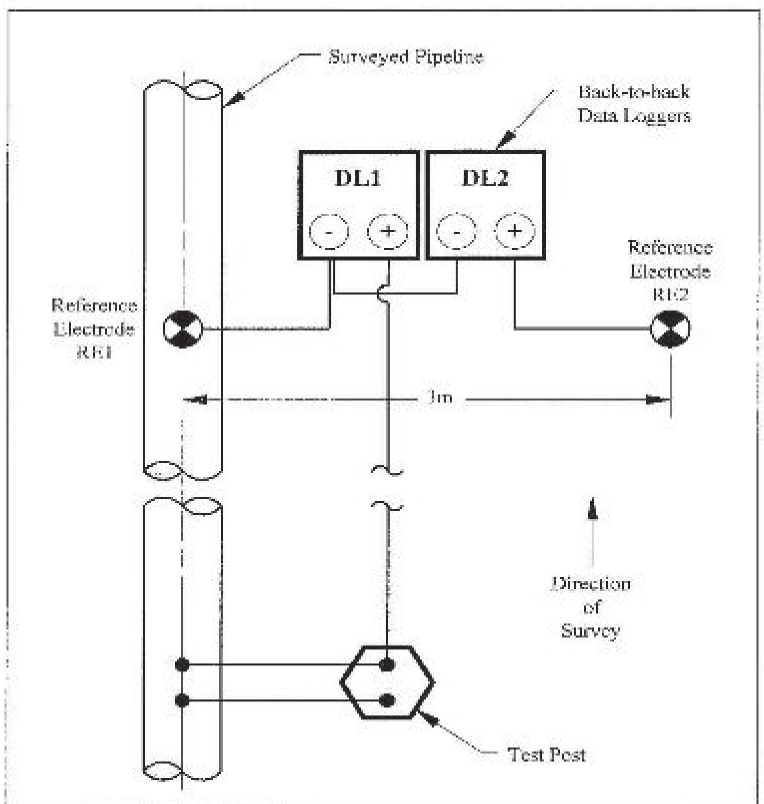

Figure 1. Integrated CIPS/DCVG Arrangement

The measured data was plotted to compare the potentials to the measured gradients. In addition, the %IR was calculated from the recorded data, which was based on a ratio comparison of pipe depth and holiday size to the 3 m gradient. Formulas were developed to calculate the %IR with respect to remote earth. The accuracy of this formula was verified by five measurements to remote earth on the 16” pipeline.

A simple procedure was derived for the longitudinal gradient profile for possible application to validate the lateral DCVG results, analyze previous CIPS survey conducted with no associated DCVG and validation of the results of AC attenuation surveys conducted in conjunction with CIPS.

How Deep is too Deep for Indirect Inspections (Corrosion 2017 Paper No. 9378)

Authored By: Jim Walton

As a pipeline installation depth becomes greater, there is a reduced sensitivity of the indirect inspection tools. The question becomes how deep is too deep to run a successful indirect inspection and still have valid results?

You will have exceeded the depth at which CIS is valuable when the average voltage gradient would mask all indications of a lack of cathodic protection. One way to test this theory is to test an area where you have a lack of CP on a pipe that is buried less than 10 feet deep and to conduct CIS at an offset of 10 feet, 25 feet and 50 feet. If you can still see the voltage potential measurements that are consistent to what you saw in the regular survey over the pipe, then you may be able to utilize this technique on pipes with similar coatings/CP systems that are buried deep.

Depending on the length of the deep section of pipe, you may be able to take a measurement before and after the deep section to see how much current change you had over the deep section of pipe by comparing the two measurements. Another useful technique for deeper pipe sections is to increase the amount of applied signal on the pipe.

One technique to increase the sensitivity for ACVG is to lengthen the probe spacing of the “A-frame” to be a 10 foot or even 20-foot length. This will further increase the sensitivity of the tool. You could also perform a similar test utilizing ACVG/DCVG like you can with CIS by completing an offset survey to see what you can and cannot see with the tool. Another technique is increasing the amount of applied signal on the pipe.

Indirect inspections are valid survey techniques at many depths including those where the pipeline is very deep. The validity of the data can vary pipeline to pipeline depending on environmental conditions.

A direct quote from the paper: “Indirect Inspections are valid survey techniques at many depths including those where the pipeline is very deep. I have heard for years now people try to put pipelines that are more than ten feet deep in a category of not being able to be inspected. Some have even said their locating instrument can’t locate pipe greater than 10 feet deep. This simply is not true! I have great confidence in the tools where the pipeline is buried 30 feet deep and with the right circumstance can go much deeper than this. It is true that if you ask to survey a pipe that is 80 or 100 feet deep, it is unlikely that we will obtain good results. I have however in many cases been able to obtain decent results 50 or more feet deep. It just depends.”

Literature Review on Offshore Pipeline Survey

Inspection Technologies and Tools Used to Determine the Effectiveness of Cathodic Protection for Subsea Pipelines in the Gulf of Mexico – A Review, (Corrosion 2009 Paper No. 09527 NACE)

Authored By: M. Galicia

The general effective tools and technologies applied to monitor, characterize and assess the effectiveness of a cathodic protection systems for subsea pipelines are discussed. For the existing pipeline, permanent technologies and portable technologies are utilized to provide a reliable concept to implement the CP system. Permanent technologies such as permanently mounted sensors include current density sensors, anode current monitors, coating efficiency monitors and various reference electrodes. Portable technologies can provide a comprehensive status of CP in real time, especially with the use of ROV mounted survey systems.

The below table summarized the monitoring technologies identified as applicable to subsea pipeline in the Gulf of Mexico, with emphasis to the possible applicability in the Mexican territory, and highlights some advantages and disadvantages, strengths and weaknesses.

TABLE 1. SUMMARY OF MONITORING TECHNOLOGIES			
Technique	**Brief Description**	**Advantages**	**Disadvantages**
Trailing Wire Tow Fish Method	Uses a reference electrode on a 'fish' towed behind a support vessel as it moves along the pipeline route[10]. A wire connection is made to either end of the pipeline ***as shown in Figure 3.***	- Accuracy ranging from +10/-100 mV to +50/-500 mV - Fast - Provides continuous potential profile	- Lack of accurate and verifiable data point. - Subject to wide range of errors both technically and operationally.
Measurement of Radial Field Gradient[12]	Measures the radial field strength along the pipeline and its anodes by means of reference electrode pairs, or by coils mounted on a submersible.	- Calculates current densities entering or leaving surfaces	- Profile derived by mathematical algorithms. - Accuracy dependent on the mathematical model used.
BLF Survey Method (Bottom-towed, Lateral-Field gradient)	Lateral field gradient intersects with pipeline and along the sea bed.[11]	- Accurate data point at defined interval. - Enough data acquisition with the fixed intervals to verify CP status interval	- Only 200-300 meters spacing
ROV surveys[4,5,12-16]	Permits the calculation of anode current output and life predictions. Compiled with video and/or bathymetric survey data which provides a complete picture of pipeline status. ***Represented in Figure 2.***	- It does not require continuous contact with the pipeline. - Potential readings at 1-meter intervals - Accuracy (errors less than ± 1 mV achievable). - Direct potential profile plotting. - No cumulative errors.	- It is not always practical due to difficult accessibility of some places of the structures. - Cost effective
Multi-sensors array[13]	Field gradient measurement.	Two dimensional pictures can be constructed for each measurement location. The results can be used to feedback mathematical modeling tools	- Accessibility when mounted on ROV - Cost effective

Below table lists the recent developments in instrumentation technology coupled with inspection equipment used to carry out the most recent technology survey applied on CP monitoring, which lead to the fabrication of new kinds of ROV systems.

Coating Assessment Technologies State of The Art

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TABLE 2
SUMMARY OF INSPECTION EQUIPMENT FOR MONITORING TECHNOLOGIES
INSTRUMENTATION TECHNOLOGY

Instrumentation	Brief Description	Advantages	Disadvantages
Optic-fiber sensors[17,18]	- Real-time data, light weight and small size. - Robust, long life, inert and corrosion resistant. - High sensitivity, compact electronics and support hardware. - Multifunctional, require no electric current	- Conventional sensor system is incorporated as required. - Immunity to electromagnetic interference (EMI), ruggedness - Long-distance transmission ability - Have no impact on the physical structure.	- Currently is limited usage - Cost effective
Smart (Self Monitoring) CP systems[13]	- Electrochemical sensors sending potential and current data. - Instrumentation and control methods.	- Use a single monitoring installation. - Real time monitoring and control of flow assurance issues. - Systems are designed for robust, long term usage. - Trouble free operation is expected for many years	- Requires 99% efficient coating on bottom
Database Management Tools[17]	- Integrated by submarine (ROV) inspection technology, digital video and GPS.	- Can assist in inspection managing and in reporting the results of the inspections as well as the setup of a database for long term management of the pipeline.	- Accessibility to some places when coupled to ROV. - Cost effective
High tech subsea modems[19]	-Data transference devices	- Modulation of signals through the pipelines and flow lines.	-Communication Infrastructure to set up the devices

Literature Review on EMAT

Cost Effective On-Stream Inspection Technique Using EMAT Technology for Pipeline Integrity at ELK Hills, (Corrosion 2001 Paper No. 01635 NACE)

Authored By: G. E. Peck

EMAT tool was selected to perform inspection on the oil and gas pipelines at Elk Hills, which is one of the giant oilfields in western Kern County, California. The field was discovered in 1918 and was operated as a petroleum reserve prior to 1998.

The EMAT inspection was used for inspection. The tool is motorized on wheels that move the magnetically coupled EMAT along the pipeline at a rate up to 50 feet/minute. Unexpected details such as clear right of way was experienced in this project.

The paper consisted of the following items regarding the EMAT tool:

1. **Accuracy:** Defects can be located that will prove to be 15-100% of body wall penetration. Pipeline joints and the indication of worst defect in each joint were detected.
2. **Coverage:** The tool can evaluate the entire exposed surface up to welds, and connections. The tool evaluated the entire diameter and length as it travels.
3. **Speed:** The tool speed was used to inspect 2,500 to 5,000 feet per day from pipeline diameter from 3 inches to 48 inches. The inspection process is quicker where the pipeline was in good condition. When a defect was detected, the tool was stopped and reversed to center the EMAT over the defect for marking and measurement.
4. **Cost:** the inspection was done from 6 inches to 14 inches diameter of pipelines in 2001. The cost may vary due to the number of defects found, the difficulty in clearing the right-of-way, and other factors related to the speed.

In-Line Inspection with High Resolution EMAT Technology Crack Detection and Coating Disbondment, (Corrosion 2007 Paper No. 07131, NACE)

Authored By: A.O. Al-Oadah, W. A. Borjailah

A 16" EMAT high resolution tool was selected to perform inspections on two FBE coated pipes experienced presence of SCCs and coating damages: one in gas pipeline and the other one in an oil pipeline during operation conditions.

The paper consisted of the following items regarding the EMAT tool:

1. **Echo Signal Evaluation:** An echo signal will be recorded if a significant amount of energy is reflected into the EMAT echo receiver. The echo signals includes the signal amplitude, arrival time, the frequency content, and provides valuable information about the type of defect. The echo receiver only actives for a short period. Therefore, only signals reflected from a specific sensor related to the position are detected. The signals emitted from adjacent EMAT sensors or late reflections emitted from other positions will be excluded during the data evaluation process.
2. **Field Results of Echo Signal:**
    - Echo channels are sensitive to both defects in the axial and in the circumferential direction.
    - Girth welds can be easily detected by echo channel since girth welds are good reflector for acoustic waves.
    - Long seams can be observed in echo channels (increase) and transmission channel (decrease)

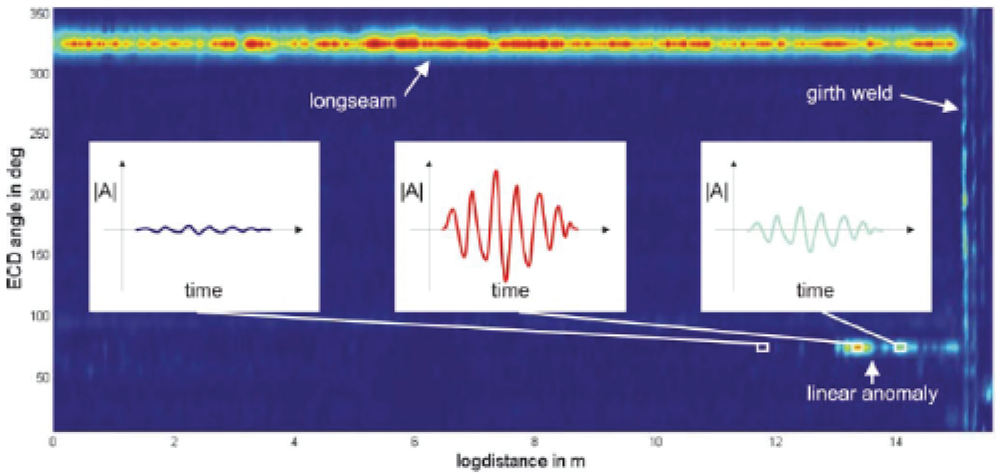


Figure 4 – C-scan of the echo channels of about 16 meters of the gas pipeline (circumferential angle as a function of the logdistance). EMAT echo signals were integrated in order to obtain one single value for each particular pipeline position. At several positions echo signals clearly stick out from the background noise, e.g. at the end of the joint (girth weld) or at the linear anomaly around 70 degrees. The three insets show sketches of the recorded wave signals at three particular pipeline positions: no-anomaly signal (left), strong linear anomaly signal (center), weaker linear anomaly signal (right).

3. **Transmission Signal Evaluation:** Transmission channel contains the information about the wave directly propagates from the EMAT sender to the transmission receiver. The amplitude of this wave depends on the lift-off, the presence of a defect and the presence of an external coating. This signal can be used to detect the coating disbondment since a coating generally attenuates the acoustic wave. A significant increase of signal amplitude can be observed if the bonding quality of coating is poor.
4. **Field Results of Transmission Signal:**
   - A weaker or even disbonded coating indications were observed by transmission channel in strong red colored areas;
   - Decreased signals amplitudes can be observed at girth welds and long seams;
   - Transmission channels are sensitive to large reflections (signals decrease) and are also sensitive to coating qualities (signals increase as coating is disbonding)

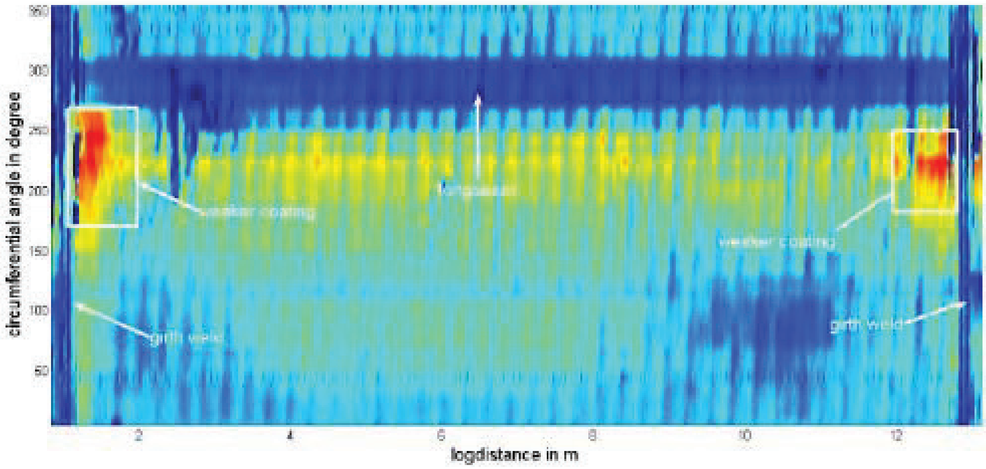


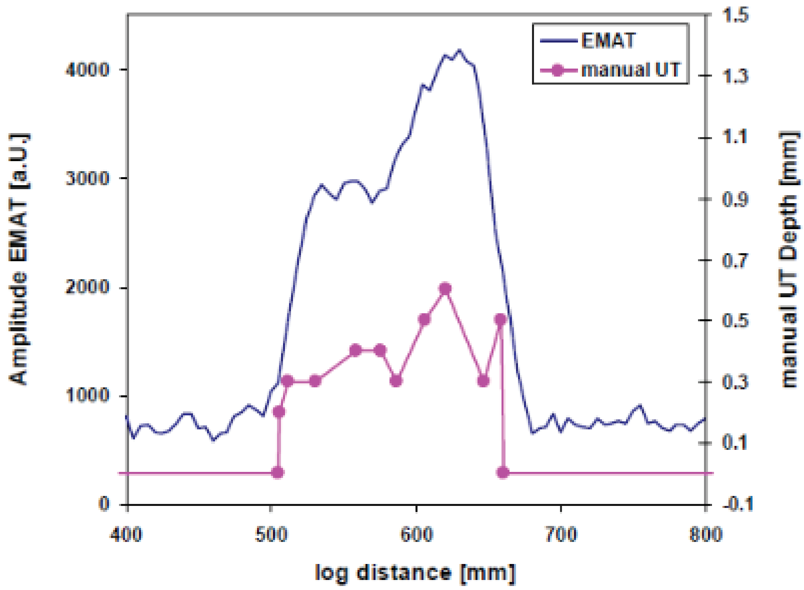
FIGURE 6 – C-scan view of the transmission channel of one particular joint of the gas pipeline run (circumferential angle as a function of the logdistance; different part of the pipeline than in Fig. 4). Significant decreases in amplitude can be observed at the beginning and the end of the joint due to lift-off effects. At the longseam a large amount of the signal energy is reflected into the echo channels and therefore the transmission signal amplitude is decreased. Increased transmission signal amplitudes indicate areas of a weaker or even loose coating like at the beginning and the end of the joint.

Acceptance of EMAT Based In-Line Inspection Technology for the Assessment of Stress Corrosion Cracking and other Forms of Cracking in Pipelines, (Corrosion 2009 Paper No. 09108 NACE)

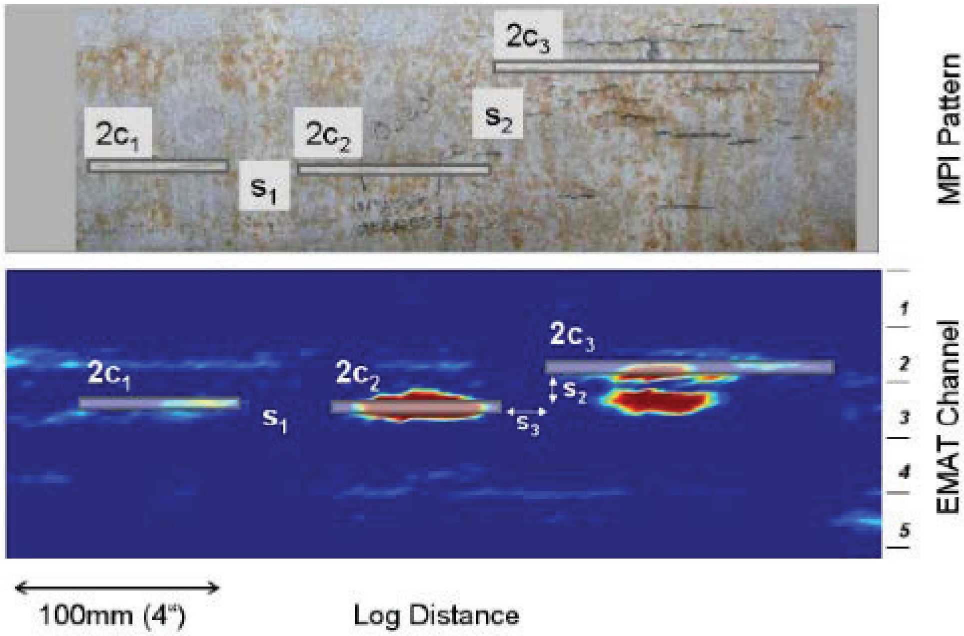
Authored By: T. Beuker, C. Doescher, B.Brown

Sensitivity of the EMAT tool was discussed by inspecting of several gas pipelines and a series of pull tests results. The paper consisted of the following items regarding the EMAT tool:

1. **Sensitivity:** With increasing the length of defect, the detection of shallower defects becomes more likely. The minimum dimension found by the EMAT was 0.79 inch long and 0.026 inch deep with a probability-of-detection (POD) of 92%. Sensitivity was compared with UT data taken manually in the ditch. High sensitivity of EMAT was illustrated from the strong EMAT amplitude as shown in the below figure.



2. **Depth Sizing:** The accuracy achieved in EMAT analysis is comparable to that found in established process for crack evaluation with other inspection technologies. The crack depth reported as part of an EMAT inspection follows the API categorization scheme.
3. **Length Sizing:** For short defects, a stable length sizing can be achieved. A slightly larger scattering of the length measurement can be observed for short features.
4. **Defect Characterization:** Multi-parameter correlation model (MPC) is used to detect the sensitivity to a particular feature type such as differentiating the crack-like features and mill related features.
5. **Clustering:** The cracks in close vicinity are classified by their length 2Ci and their distance to each other Si. The clustering method for branches cracks has been applied according to the APT 579 standard. The results from MPI and EMAT are comparable quality as shown in the below figure.



6. **Coating Assessment:** EMAT inspection system can provide both characteristics about the coating types as well as characteristics about the disbanded coating. This information is derived from the attenuation of the signal from the “coating” channel (transmission channel). The differentiation between the coal tar and FBE coating is reflected very well. Disbonded area is also identified by a change in transmission amplitude and reported as individual features.

EMAT, pipe Coatings, Corrosion Control and Cathodic Protection Shielding (Corrosion 2013 Paper No. 2378, NACE)

Authored By: R. Norsworthy, J. Grillenberger, S. Brockhaus, M. Ginten

EMAT not only can be used to identify the disbanded coatings, but also be used to identify different types of coating, coating disbondment and the associated failure scenarios. The coating type and coating adhesion condition are critical to make decision about when and where to make repairs or replacement of the coating or pipes. Below table lists the coating types and the repairs identified based on EMAT data. The EMAT data associated with each specific coating types and repair sleeves are discussed in Section 9.4.

Id	Coating Type	Description	Color
1	Tape Wrap	1 vinyl outer tape, butyl rubber based primer	White
2		2 PVC outer tape, bitumen rubber based primer	Black
3		3 PE outer tape, butyl rubber based primer	Black
4		4 heat shrinkable PVC outer tape, manual applied primer	Black
5		5 Green Tape	Green
6		6 Double Layer Tape	White
7	Enamel	Coal Tar Enamel	Black
8		Asphalt	Black
9	Tar Wrap Paper		Black
10	FBE	1	Orange
11		2	Blue
12		3	Darkred
13		4	Green
14		5	Grey
15		6	Red
16	Liquid Epoxy	1 2-part-epoxy	Darkred
17		2 Green Paint Coating	Green
18	Mastic	Visco-elastic	Green
19	Three Layer	PU Coating	Black
20	Others	1 Vinyl Ester Coating	Black
21		2 Wax Coating	Brown
22		3 Concrete Coating	Grey
23		4 Bare Pipe, uncoated	Rust
24	Repair Coating	1 Shrink Sleeves	Black
25		2 Composite Repairs	Yellow
26	Metallic Repairs	1 Stand-Off Sleeve	Black
27		2 Metallic Sleeve with Epoxy Fill	Black
28		3 Close Contact Sleeve	Black

Figure 4: Table of coating types and repairs inspected by EMAT to date.

Validation of EMAT ILI Technology for Gas Pipeline Crack Inspection: A Case Study for 20", (9th Pipeline Technology Conference, 2014)

Authored By: R. Kania, K. Myden, R. Weber, S. Klein

EMAT tool was selected to perform inspections on two 20 inches gas pipelines with the length of 186.4 miles and 93.2 miles, respectively. Both pipes have been experienced with SCC and corrosion history.

The EMAT inspection was used for inspection. The tool is motorized on wheels that move the magnetically coupled EMAT along the pipeline at a rate up to 50 feet/minute. Unexpected details such as clear right of way was experienced in this project.

The paper consisted of the following items regarding the EMAT tool:

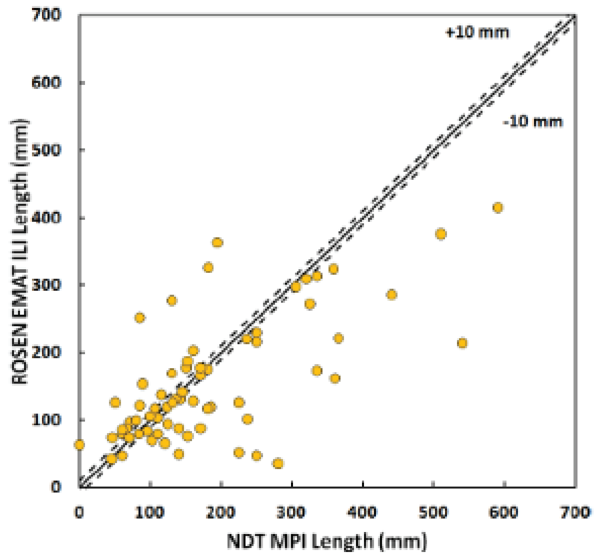
1. **Data Analysis:** A prioritization was done by analyzing and evaluation of data based on known SCC susceptibility conditions. These data include pipeline geospatial data, construction, coating conditions, pipeline history, operation experiences, soil model categorization et al. Circumference MFL (CMFL) was launched for correlation of corrosion and crack-like defects. EMAT echo signals were the leading dataset used for analysis and anomaly classification.
2. **EMAT Tool Sensitivity and Sizing:** Sensitivity of the EMAT is influenced by the signal-to-noise-ratio of the time-integral of the EMAT echo amplitude. Below table lists the sensitivity of the tool.

Table 1: Sensitivity of the EMAT Tool

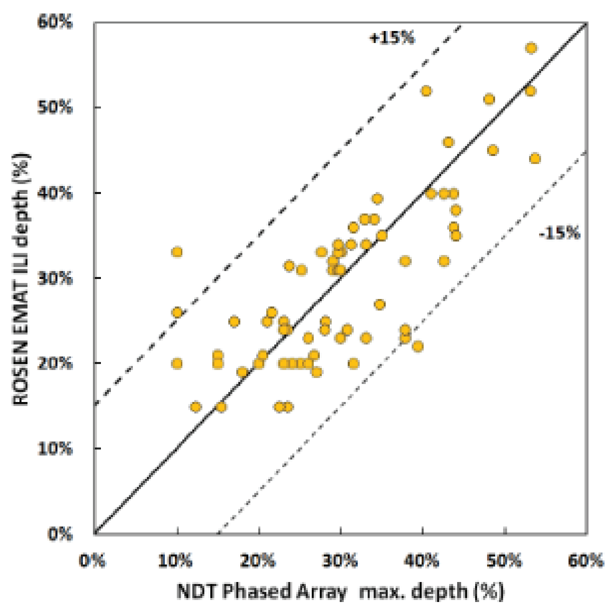
Minimum crack/crack colony by EMAT	Length (inch)	Depth (inch)	Probability of Detection (POD) %
Pipe body	1.58	0.079	90
Longitudinal weld area	1.58	0.118	90
Pipe body and longitudinal weld area for 20” pipe	0.394	0.037	80

3. **Results:** A total of 66,694 anomalies have been initially detected by EMAT tool in the pipe body and 22,839 anomalies in the longitudinal weld area. A total of 755 crack-like defects have been reported above the criteria.
4. **Comparison the Length of Field and EMAT Results:** The in-field results were obtained by using magnetic particle inspection (MPI). The difference between field and EMAT results in length is due to the fact that the EMAT signal corresponds to the effective cross section of the corresponding anomaly at the EMAT detection threshold inside the pipe wall. As a consequence, the length determined from the EMAT signal corresponds to the maximum length of the anomaly at a depth equal to the detection threshold of EMAT tool. Moreover, the MPI and interlinking are determined at the outer

surface of the pipe wall. Consequently, underestimation of the EMAT length when compared to the MPI or interlinked length is observed. The results are shown below.Figure 34



5. **Comparison the Depth of Field and EMAT Results:** The boundary of specified accuracy of 15% at 80% confidence is indicated by two dashed lines in the below figure. 96% of the crack-like indications are within the tolerance.



Investigating EMAT Dig Results for a Low Frequency EWR Seam Inspection, (Corrosion 2017 Paper No. 9184, NACE)

Authored By: S. Moran, R. Meyers

The efficacy of EMAT technology is validated run in conjunction with a multiple dataset platform by analyzing the seam of a 16”, low-frequency electric resistance welded (LF-ERW) liquid pipe with 38 miles in length. This pipe has experienced multiple in-service seam failures due to manufacturing defects related to the LF-ERW process.

The paper consisted of the following items regarding the EMAT tool:

1. **Comparison the Field and EMAT Results:**
   Verifications of five crack-like features from EMAT results were chosen and performed using two non-destructive evaluation (NDE) methods common to long seam inspections: FAST UT (FAST) and Phase Array UT (PAUT). The accuracy of three of the four depth results compared very well (+/- 10%) between NDE and EMAT, but with one feature had a large difference of 37%. All length results the NDE and EMAT compare well. The fifth feature was found to be two hook cracks and three cold welds.

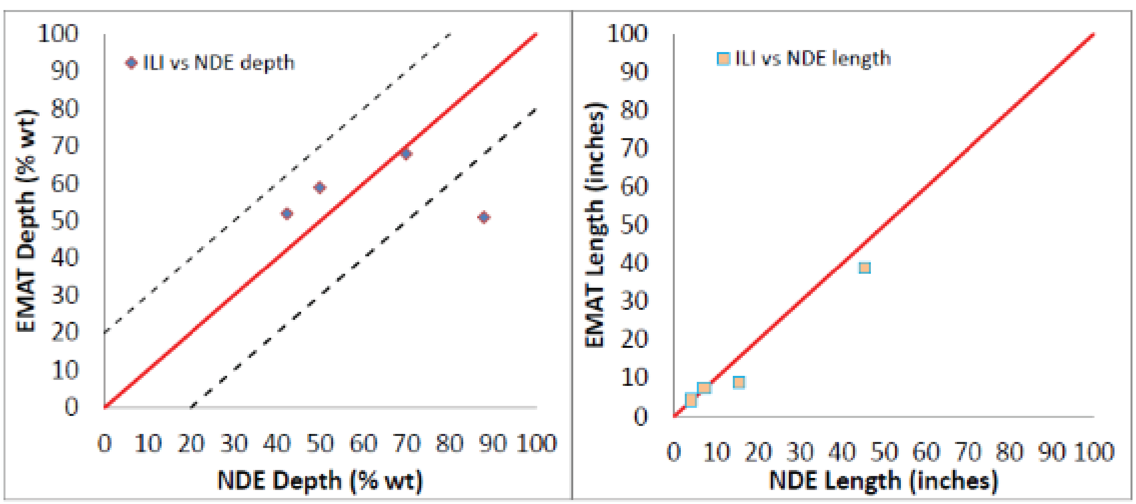


Figure 3: Unity plot comparison for EMAT depths and lengths vs. NDE depths and lengths.

2. **Validation the NDE Dig and EMAT Results:** 131 NDE dig results were correlated with the EMAT results, the depth accuracy of the EMAT results to NDE were within +/-20% of nominal wall thickness at an 89.3% certainty. The length performance results

from all 131 EMAT features to NDE results did not indicate a positive correlation. The divergence is from the difference in the detectable thresholds of ILI length vs. NDE length as shown in below figure.

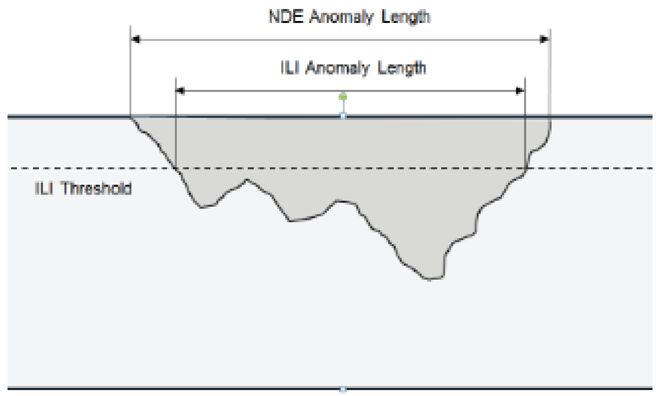


Figure 5 – Possible length differences between NDE and ILI length measurements

3. **Correlation of ILI Results:** Four ILI tools were chosen for the assessment the same pipeline. Multiple Dataset (MDS), Circumferential Magnetic Flux Leakage (CMFL), Ultrasonic Crack Detection (UTCD), and EMAT. A list the features types from each of the four ILI technologies had various descriptions for crack-like defects. For consistency, the feature types reported as crack-like defects are combined (crack-like such as axial planar, linear indication, seam feature A and B). After combining these features types, a total of 562 cracks were reported as shown in below figure. The majority of the cracks were reported by EMAT.

   The correlation of different ILI tools was also discussed by the author. A list of the correlations was shown in the paper e.g. the number of reported cracks in one ILI tool was common to the number of cracks reported to the other ILI tool.

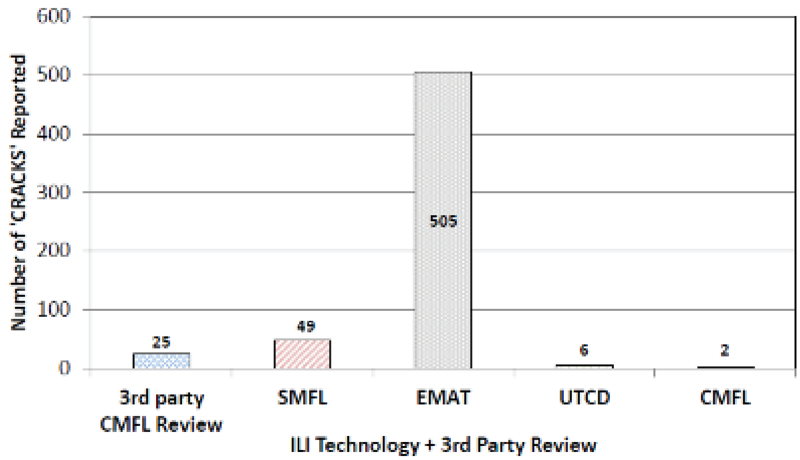


Figure 4: Final Report comparison of total cracks reported for all four ILI technologies and a 3rd party comparison of the CMFL data

Literature Review on CPCM

P.K. Scott and M.W. Mateer. Cathodic Protection Monitoring Via In-Line Inspection. Pigging Products and Services Association. 2007.

- The results show that CP currents can be quickly, accurately and efficiently gathered without access to the outside surface of the pipe.
- CPCM provides two advantages:
  - Measures CP current direction and magnitude in the pipeline
  - Allows the operator to easily gather CP information regardless of ROW conditions
- Field Trial #1 (12-inch, 8 miles):
  - Five CPCM test runs were completed on same stretch of pipeline.
    - 3 test runs were used to refine the tool configuration and design
    - 1 test run was used in a test mode. CP system and bonds were synchronously interrupted and a sampling of the casings and pipeline crossings were bonded through an interrupter using discerning time schedules.
    - 1 test run was used in the "normal" mode

- Pipe features complicated the analysis but offered valuable information. Knowledge and experience were gained with respect to the effect of the physical features such as wall thickness changes.

- Field Trial #2 (12-inch, mileage unknown)
  - Crude pipeline with low potentials. CPCM tool was used to identify the locations of shorted pipelines.
  - Paraffin build-up prevented the collection of usable data
  - Erratic voltage data indicated a lack of contact between the tool and pipe wall
- Pipe product cannot be conductive.

D.C. Janda. ILI tool enhances CP monitoring. Pipeline and Gas Technology. 2009

- ***This publication is more or less a copy of the paper referenced above by Scott and Mateer.***
- In-line inspection tools are capable of reading and recording the magnitude and polarity of current supplied by a CP system and has been tested in both crude oil and refined product pipelines.
- CPCM Cathodic Protection In-Line Inspection Services provide for a reliable, cost-effective, time-saving way to monitor, validate, or troubleshoot a pipeline's CP system.
- CPCM tool measures CP current direction / magnitude, and allows the pipeline operator to easily gather CP information regardless of ROW conditions.
- Interpretation of CPCM data continues to be refined. More work is needed to fully exploit all the capabilities of the inspection tool and the resulting measurements.
- Two field trials: 24-inch, 34 miles and 12-inch, unknown mileage. Shorts were identified and corrected in both field trials.

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