SOIL CORROSION MONITORING NEAR A PIPELINE UNDER CP

Sophie J. Bullard, Bernard S. Covino, Jr., Stephen D. Cramer
Gordon R. Holcomb, and Małgorzata Ziomek-Moroz
Albany Research Center, U.S. Department of Energy
1450 Queen Avenue, S.W.
Albany, OR 97321

Margaret L. Locke and Michael R. Warthen
NW Natural
220 NW Second Avenue
Portland, OR 97209

Russell D. Kane and Dawn C. Eden
InterCorr International Inc.
14503 Bammel North Houston, Suite 300
Houston, TX 77014

ABSTRACT

Electrochemical noise (EN), linear polarization resistance (LPR), and harmonic distortion analysis (HDA) were used with three-electrode probes to monitor the corrosion occurring in soil in dry and wet conditions near a gas pipeline under cathodic protection. The test site was a cathodic protection (CP) test station where impressed current CP was applied to a 2 in. (5.1 cm) diameter FBE coated steel pipe using an 84 in. (0.2 m) TA-2 high-silicon cast iron anode. Electrochemical measurements were made at three locations, two inside the CP field and one outside the CP field. Electrochemical measurements were first made with the CP system off to establish the baseline corrosion and then with increasing levels of CP. The degree of protection was based on polarized potential and the adequacy of protection was determined by depolarization measurements. CP of an adjacent pipeline did not affect the measurement of either corrosion rate or pitting factor when using buried soil corrosion probes and the EN, LPR, and HDA techniques.

INTRODUCTION

An analysis[1] of 5872 pipeline incidents in the U.S. from 1970 to 1984 reported that 54% of the service failures of natural gas pipelines were attributable to outside forces such as earth movement, weather, and equipment operation by outside parties, 17% to corrosion, and 17% to material failures. A later analysis[2] of 12,137 failures in Canada from 1980 to 1997 concluded that 63% of pipeline failures were caused by corrosion, with 50% due to internal corrosion and 13% due to external corrosion. Corrosion failures represent a significant proportion of the total number of failures of natural gas pipelines. Probes that can detect internal and external corrosion in real time before failure occurs will enhance gas transmission pipeline reliability.

External corrosion of gas transmission pipelines is usually controlled by the application of various polymeric coatings augmented with cathodic protection (CP). When corrosion does occur on the outside of the pipeline, the combination of general and localized corrosion with the high stresses in the pressurized pipelines can sometimes lead to stress corrosion cracking (SCC). In cases where CP is inadequate or non-existent, pipelines exposed to ground waters can experience transgranular SCC due to low pH (6.5) carbon dioxide containing water.[3] Even when CP is adequate, gas pipelines may be susceptible to intergranular SCC due to the higher pH external environment generated by CP. One method to address this type of corrosion problem is to place corrosion rate probes to monitor the corrosivity of the soil in areas that have a higher risk for corrosion.

Laboratory studies have shown that electrochemistry-based corrosion rate probes can be used to monitor the corrosion of steels in soils.[4] Corrosion rates were shown to have a good agreement with gravimetric weight loss measurements and were also sensitive to changes in soil moisture and salt content. Others have shown that electrical resistivity probes can be used to monitor the effectiveness of cathodic protection (CP) of pipelines.[5,6]

While there are a variety of electrochemical techniques that can be used to measure the corrosion rates of metals in soils, the effect CP will have on the corrosion rate measurements is unknown. The purpose of the research reported here is to verify that corrosion rate and pitting factor measurements can be made in the soil adjacent to a natural gas transmission pipeline under applied CP without being affected by CP. This would allow a continuous direct assessment of the corrosivity of the soil and ground water around natural gas transmission pipelines.

EXPERIMENTAL DESIGN

All of the electrochemical corrosion tests were performed using three-electrode electrochemical probes with electrodes made of the same material and surface area. The first electrode was used as the working electrode, the second as the counter electrode, and the third as the reference electrode.

For the tests, cylindrical electrodes were made from No. 12, Grade A615 rebar. The chemical composition of the cylindrical electrodes is shown in Table 1. The electrodes were 1.5 in. (3.8 cm) in diameter. The exposed area was 1.77 in.^2 (11.4 cm^2). To construct the corrosion probe, three electrodes were place in a triangle with 1.375 in. (3.5 cm) between adjacent electrodes and cast in epoxy. Wires were attached to each electrode and all soldered connections were enclosed with epoxy prevent corrosion of the wire from the moisture in the soil and the wires were routed to the surface, Figure 1. The surfaces of the electrodes in the corrosion probes were finished to 600 grit with SiC paper. Prior to the test the surface of the electrodes were cleaned and degreased in methanol.

The site selected for the field test was one located in western Oregon and operated by a natural gas distribution company Figure 2. The test site consists of (Figure 3): 1) a 2 in. (5.1 cm) diameter bare steel pipe (Pipeline 1); 2) a 2 in. (5.1 cm) diameter fusion bonded epoxy (FBE) coated steel pipe (Pipeline 2); 3) a 4 in. (10.2 cm) diameter bare steel casing surrounding a second 2 in. diameter FBE coated steel pipe; 4) an insulated isolation flange connecting the 2 in. (5.1 cm) diameter FBE coated steel pipe inside the 4 in. (10.2 cm) diameter bare steel casing with the second 2 in. (5.1 cm) diameter FBE coated steel pipe, 5) a protected coupon which is a test coupon that can be connected to the 2 in. (5.1 cm) diameter pipe when CP is applied, and 6) a native coupon which is a test coupon that remains unpolarized . Pipeline 2 and the "protected" and "native" test coupons were used in this research.

There were two CP systems available: 1) an impressed current CP system that uses an 84 in. (213 cm) TA-2 high-silicon cast iron anode with the top of the anode is about 24 in. (61cm) below the soil surface; and 2) a sacrificial (galvanic) CP system that uses 17 lb (7.7 kg) magnesium anodes with the top of the anode was 24 in. (61 cm) below the soil surface. Either cathodic protection system could be applied to either Pipeline 1 or Pipeline 2. The impressed current CP system using the high-cast iron anode was used in this research.

Corrosion probes 1, 2, and 3 were buried in the soil at locations, A, B, and C, respectively. The probe locations with respect to the pipelines are shown in Figure 3. Locations A and B were within the CP zone with A directly in the path of current flow between anode and FBE pipeline and B very close to the FBE pipeline. Location C was well outside the zone that could be influenced by CP. All three probes were buried with the top of the probe at 24 in. (61 cm) below the surface of the soil, Figure 1. 10 to 15 gallons (37.9 to 56.8 L) of water were added at each location after the soil had been backfilled. This was done to settle the fill dirt and to provide a means for corrosion of the probes to start. The tests were run from August to October 2003 and February to April 2004.

The soil at the test locations can be characterized as a rocky heavy clay type of soil. Soil from the bottom of each hole was sampled and tested for pH and chemical composition. The analyses of the soil from these three locations showed ranges of pH = 4.8 to 5.4, wt pct moisture = 15.8 to 17.3, [Fe] = 250 to 550 mg/kg soil (ppm), and [Cl] = 2 to 31 mg/kg soil (ppm), Table 2. Four point resistance measurements, using a soil resistance meter and four stainless steel probes, were made in situ at the bottom of the holes (Figure 4) before the probes were installed. These calculated initial soil resistivities were 12,500, 9,100, and 12,900 Ω-cm for locations A, B, and C, respectively, Table 3. Using a published soil corrosiveness guideline based on soil resistivity,[7] the soils at locations A and C can be classified as "slightly corrosive" (10,000 to 25,000 Ω-cm) and the soil at Location B classified as the slightly more corrosive "moderately corrosive" (3,000 to 10,000 Ω-cm) at location B. The soil at all three of the test sites was on the acidic end of the range of most soils.[7] At the end of the tests, the soil resistance was again measured in situ. For locations A, B, and C, the calculated soil resistivities were 12,450, 7,600, and 5,800 Ω-cm respectively, Table 3. The corrosiveness of locations A and B remained relativity the same but location C became more corrosive.

The corrosion rate measurements were made using linear polarization resistance (LPR) and electrochemical noise (EN) techniques. LPR and EN work by measuring an electrochemical resistance, R_p and R_n, respectively, which can be converted to the corrosion rate. This resistance, which is derived as a linear approximation to the Butler-Volmer Equation[8] for equilibrium electrochemical systems, can be written as follows:

$$R_p \text{ or } R_n = \Delta E/\Delta I = B/ I_{corr} \tag{1}$$

where ΔE is the potential difference of the corroding metals, ΔI is the current difference, I_{corr} is the corrosion current or corrosion rate, and B is the Stern-Geary constant. Because B is often estimated or measured in the laboratory rather than the field, corrosion rates calculated in this manner can be in error. EN and LPR are coupled with Harmonic Distortion Analysis (HDA) that will enable the direct measurement of B. Each of those technologies is mature enough that they can be applied directly to field installations. HDA is an extension of the LPR technique, using a low amplitude, low frequency sine wave to polarize the electrodes. The EN technique involves the measurement of spontaneous changes in current and potential that are due to natural variations in the corrosion current and the corrosion potential. The corrosion rate is estimated from the resistance noise. Instability in the corrosion processes due to localized corrosion can also be identified by the technique. For this form of localized corrosion, the risk of pitting on the metal surface is derived from the EN and the HDA data. This value is termed the Pitting Factor (PF).[9] PF refers to the risk of localized attack (pitting) on the metal surface, and is always examined together with corrosion rate. The PF has a value between 0 and 1. Values of PF < 0.1 indicate no probability of pitting. For PF = 0.1 to 1, the system will be in a pitting regime rather than a regime of general corrosion.

The calculation for the PF is as follows:

$$PF = \sigma_{I_n} / (A * i_{\text{corrHDA}}) \tag{2}$$

where σ_{I_n} is the standard deviations of the electrochemical current noise, A is the electrode surface area (cm^2), and i_{corrHDA} is the HDA corrosion current density in amps/cm^2.

The purpose of the research presented here was to determine if CP interferes with LPR, EN, and HDA measurements. This was done by measuring the corrosion rates and PFs on a section of pipeline in the absence of CP for approximately 2 – 4 weeks, and then repeating the measurements for 2 -4 week intervals with the pipeline being protected by CP at different voltages. The degree of protection was based on polarized potential and the adequacy of protection was determined by depolarization measurements. The research was conducted according to the following plan:

1) Potential measurements were made on the FBE coated pipeline, a protected (polarized) coupon, and a native coupon to establish base conditions of the unprotected pipeline (Figure 5).

2) Corrosion rate and pitting factors were measured for two to four weeks to establish the baseline corrosion at the three probe locations.
3) Impressed current, CP, was applied to the pipeline (Figure 6) until the desired pipeline potential was reached.
4) The corrosion rate and pitting factors of the three electrochemical probes were measured under the influence of CP for a fixed period of time.
5) Polarized potential measurements were made on the pipeline, the protected coupon and the native coupon at the end of the period.
6) A 15-minute depolarization measurement was then taken on the pipeline.
7) Steps 3 to 6 were repeated for several levels of CP.

RESULTS AND DISCUSSION

Table 4 shows potential measurements with respect to the Cu-CuSO$_4$ electrode (CSE) made on the polarized pipeline and protected and native test coupons. Prior to applying the CP current, the open circuit potentials for the pipeline and the protected and native test coupons.were similar, -025V$_{cse}$ for the first test and –0.45 for the second test. The potential for the unpolarized native coupon remained consistent over the duration of the experiment. Polarized potentials for the pipeline and the protected coupon were also relatively constant during the days during which a potential was applied. The lower polarized potential was approximately -1.1 V$_{cse}$ and the higher polarized potentials were -1.5 and -2.0 V$_{cse}$. It is assumed that the two probes within the CP zone would have a similar potential as the protected coupon and the pipe and the probe outside the CP zone would be similar to the native coupon.

Fifteen-minute depolarization measurements on the pipeline were made after impressing a current until the desired voltage was reached, Table 5. For the first test, the results gave values of 59 mV for what was termed the adequately protected case (-1.1 V$_{cse}$) and 97 mV for the higher potential (-1.5 V$_{cse}$). For the second test, the values were 127, 92, and 163 mV for the potentials of –1.17, -1.55, and –2.0 respectively. One of the guidelines[10] for adequate protection is to have a depolarization of at least 100 mV in 4 hours. 100 mV was achieved in 15 minutes for two of the depolarization measurements, for the remaining depolarization measurements, it seems likely that they would have depolarized the additional 21 to 41 mV if left for 4 hours. If that did happen then there would be sufficient current to simulate the conditions that would exist for a pipeline that was being adequately protected.

The corrosion rate measurements for the three corrosion probes and the applied potentials are shown in Figure 7 as a function of time for both tests. Figure 7 shows low corrosion rates of 0.02 to 0.03 mm/yr for probes 1, 2, and 3. The low corrosion rates for all three probes in general seem consistent with the categorization of the corrosivity of the soil by soil resistivity.[6] The slight increase in the corrosion rate of probe 3 at the end of the second test can be attributed to the change in soil corrosivity from “slightly corrosive” to “moderately corrosive.” There were no events in the corrosion rate-time data that could be correlated to the application of CP current, the increase in CP current, or any other cause. The conclusion is that applying CP near a corrosion probe that is being tested using EN, LPR, or HDA techniques is not a problem. The CP current will not interfere with those electrochemical measurements. The Stern-Geary constant as measured by HDA was 0.026 V for all tests and probes.

The pitting factor measurements and the applied potentials are shown in Figure 8 for probes 1, 2, and 3. The results show that the pitting factors are on the order of 0.01, which indicates that there would be no pitting corrosion. There was no effect of applying the CP currents densities on the PF-time data. There were no other trends observed that could be correlated to any other factors.

CONCLUSIONS

- Corrosion rates of the three soil corrosion probes (2 in the CP zone and 1 outside the CP zone) remained low (0.02 to 0.03 mm/yr) over time.
- The pitting factors of the three soil corrosion probes were on the order of 0.01, which indicated that pitting corrosion would not occur.
- CP of an adjacent pipeline did not affect the measurement of either corrosion rate or pitting factor when using buried soil corrosion probes and the EN, LPR, and HDA techniques.

REFERENCES

1. R. I. Eiter, D. J. Jones, G. S. Kramer, “Outside Force Causes Natural Gas Pipeline Failures,” Oil and Gas Journal, 85(11), 16 Mar 1987, pp 52-57.

2. Alberta Energy and Utilities Board, “Pipeline Performance in Alberta 1980-1997,” Report 98-G, Calgary, Alberta, Canada, December 1998.

3. R. N. Parkins, “A Review of Stress Corrosion Cracking of High Pressure Gas Pipelines,” Paper no. 00363, CORROSION/2000, 2000.

4. S. J. Bullard, B. S. Covino, Jr., G. R. Holcomb, J. H. Russell, S. D. Cramer and M. Ziomek-Moroz, “Laboratory Evaluation of an Electrochemical Noise System for Detection of Localized and General Corrosion of Natural Gas Transmission Pipelines,” Paper no.03371, CORROSION/2003, NACE International, Houston TX, 10 pp., 2003.

5. N. A. Khan, “Use of ER Soil Corrosion Probes to Determine the Effectiveness of Cathodic Protection,” Paper no. 02104, COROSION/2002, NACE International, Houston, TX, 12 pp., 2002.

6. S. J. Bullard, B. S. Covino, Jr., S. D. Cramer, G. R. Holcomb, M. Ziomek-Moroz, M. L. Locke, M. Warthen, R. D. Kane, D. A. Eden, and D. C. Eden, “Electrochemical Noise Monitoring of Corrosion in Soil Near a Pipeline Under Cathodic Protection,” Paper No. 04766, Corrosion/2004 (New Orleans, LA, March 28-April 1, 2004), NACE International, Houston TX, 2004.

7. W. C. Robinson, “Testing Soil for Corrosiveness,” Materials Performance, Vol. 32, No. 4, pp. 56-58, April 1993.

8. J. O’M. Bockris and A. K. N. Reddy, “Modern Electrochemistry,” Volume 2, Plenum Press, New York, NY, 1970, p. 883.

9. “SmartCET^{TM} Technology Overview 8-6-1,” InterCorr International Ltd., Houston, TX.

10. S. D. Cramer and B. S. Covino, Jr., Handbook Editors, Volume 13A-Corrosion: Fundamentals, Testing, and Protection, ASM Handbook, ASM International, Materials Park, OH, p. 1005, 2003.

See the following pages for the Tables and Figures mentioned in this paper.

Table 1 - Chemical composition of the steel electrodes

	Composition, wt %								
Electrodes	C	Mn	P	Cu	Ni	Si	Mo	Cr	Fe
No. 12, Grade A615 rebar	0.31	1.36	0.013	0.41	0.14	0.25	0.27	0.081	Bal

Table 2 – Soil Analyses

Location	pH	$H_2$0, wt %	Fe, mg/kg	Cl, mg/kg
A	5.3	16.3	520	31.7
B	5.4	15.8	340	8.1
C	4.8	17.3	250	2.2

Table 3 – Resistivity, Σ-cm

Location	Start of Test	End of Test
A	12,500	12,450
B	9,100	7,600
C	12,900	5,800

Table 4 - Potential Measurements

Date	Pipeline, V_{cse}	Protected Coupon, V_{cse}	Native Coupon, V_{cse}
First Test			
8-13-03 to 9-12-03	-0.255	-0.255	-0.280
9-12-03 to 9-26-03	-1.04	-1.031	-0.294
9-26-03 to 10-10-03	-1.53	-1.531	-0.271
Second Test			
2-10-04 to 2-24-04	-0.446	-0.441	-0.456
2-24-04 to 3-9-04	-1.172	-1.172	-0.424
3-9-04 to 4-6-04	-1.554	-1.554	-0.254
4-6-04 to 4-14-04	-2.004	-2.006	-0.137

Table 5 - 15-minute Depolarization

Pipeline Potential,V_{cse}	Pipeline Depolarization, mV
First Test: 8-13-03 to 10-10-03	
-1.10	59
-1.52	97
Second Test: 2-10-04 to 4-14-04	
-1.17	127
-1.55	92
-2.0	163

Figure 1 – Three electrode corrosion probe.

Figure 2 – Test location

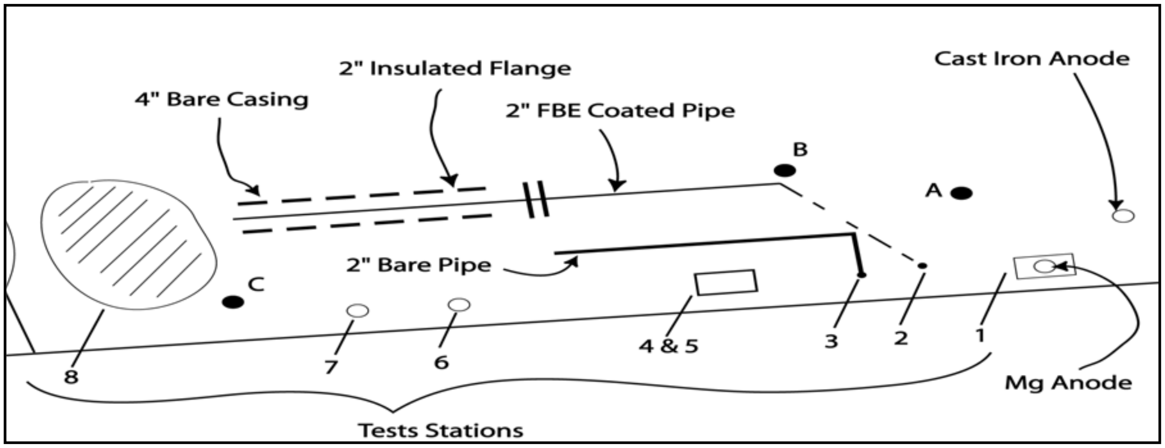

Figure 3 – Test site showing the locations of the equipment used in the field test: the buried corrosion probes at locations A, B, and C; the 2" Bare Pipe; and the Cast Iron Anode. Also shown:Mg anode, other pipes described in the text, and test station locations 1-8.

Figure 4 - Soil resistivity measurements.

Figure 5- Junction box for measuring potentials of the pipe and coupons.

Figure 6 – Rectifier box for applying CP.

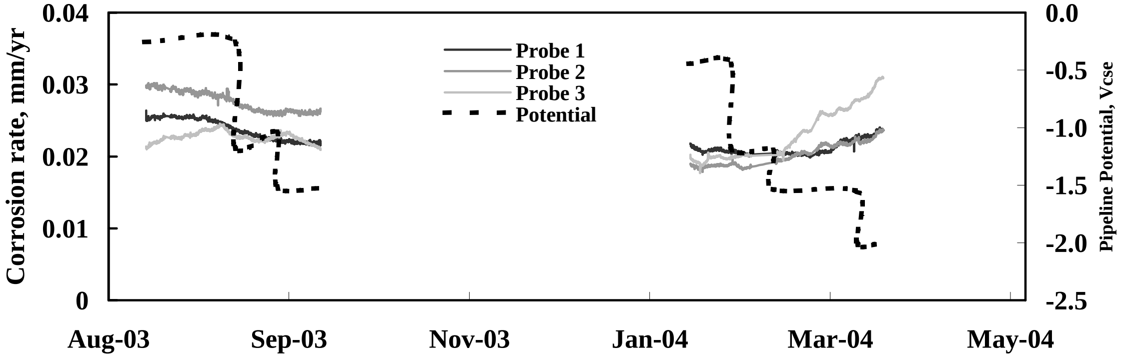

Figure 7 – Corrosion rates of the three probes and the pipeline potentials over time.

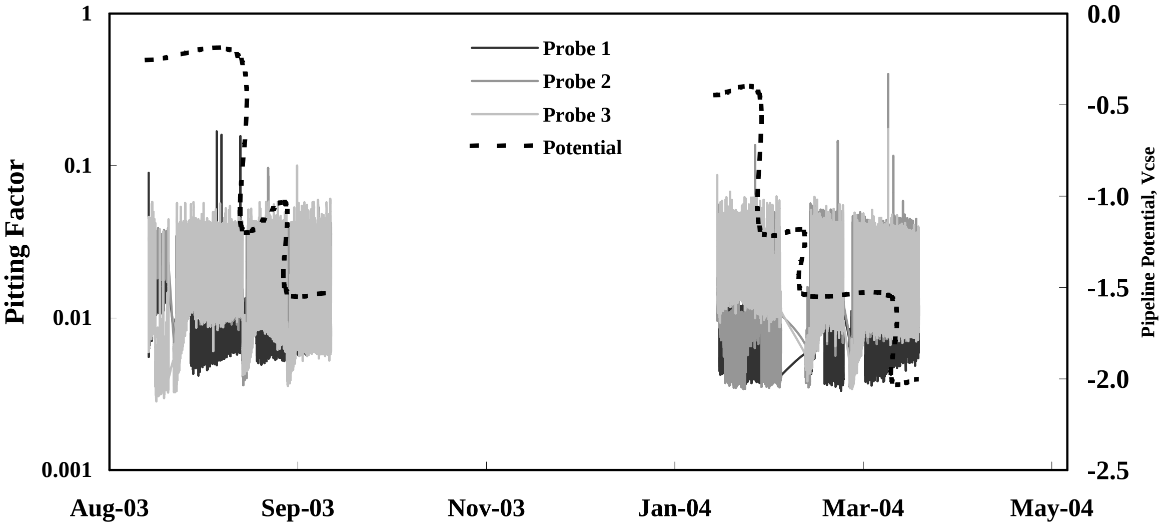

Figure 8 – Pitting factors of the three probes and the pipeline potentials over time.

Return to
Table of Contents