BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy, a Division of Southern Union Company, Concerning a Natural Gas Incident at the Intersection of 107th Street and Blue Ridge Boulevard in Kansas City, Missouri	))))))	**Case No. GS-2011-0248**

STAFF'S FINAL REPORT

COMES NOW the Staff of the Missouri Public Service Commission (Staff) and, as indicated in its *Status Report* of October 31, 2011, files its *Gas Incident Report* with respect to an incident, which occurred at about 1:52 PM on February 2, 2011 at the intersection of 107th Street and Blue Ridge Boulevard in Kansas City, Missouri.

The incident was the result of a release of natural gas from a fractured 16-inch diameter steel natural gas transmission pipeline owned and operated by Missouri Gas Energy (MGE), a division of Southern Union Company. There was no ignition of the natural gas, no injuries and no known damage to property other than property owned by MGE. Since the repair, MGE has been operating at a reduced pressure (approximately 160-170 psig, which is less than 80% of the operating pressure at the time of the incident).

Staff notes that, because the affected main was repaired and remains in service, the cause of the fracture is unknown at this time.

Recommendations

The Staff has developed seven recommendations as a result of its investigation and analysis:

1. MGE should replace the entire length of the Mayfair 16-inch pipeline (both the East and West lines) purchased from Cities Service Gas Company (approximately 3.162 miles) with new pipe;

2. MGE should conduct hydrostatic pressure testing on approximately 10 miles of transmission line (Cass County Line, Bannister Line, and the Mayfair 26-inch) to establish a maximum Allowable Operating Pressure (MAOP) in a manner consistent with applicable regulations[1] and recent United States Department of Transportation – Pipeline and Hazardous Materials Administration (DOT-PHMSA) advisory bulletin[2] guidance;

3. Until the Mayfair 16-inch pipeline is replaced, the operating pressure should not exceed 178 psig (80% of the operating pressure of 222 psig at the time of the incident);

4. Once the existing Mayfair 16-inch pipeline is removed from service, MGE should perform an investigation of the fracture to determine the cause. The findings of this investigation should be used to evaluate potential threats to other similar piping remaining in the Company's transmission piping system;

5. MGE should review Company records to determine the status of documentation to establish MAOP for the remainder of the Company's transmission pipelines;

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[1] 4 CSR 240-40.030(12)(M) sets for the requirements for establishing MAOP by pressure testing, or alternatively for pipe which was installed prior to July 1, 1970, allowing the MAOP to be set at the highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970.

[2] In the January 4, 2011 Advisory Bulletin ADB-11-1, DOT-PHMSA indicated that performing a hydrostatic pressure test that stresses the pipe to a designated pressure without failure is generally the most effective method for establishing MAOP, however operators may use available design, construction, inspection, testing and other related records to calculate the MAOP, provided these records are traceable, verifiable and complete. If such documentation cannot be satisfactorily completed, the operator cannot rely upon the use of records to establish the MAOP.

6. MGE should assess the integrity of any remaining pipelines with similar coatings that are enclosed in casings; and

7. MGE should review or perform Close Interval Surveys (CIS)[3] of all of its remaining transmission pipelines to detect areas of insufficient cathodic protection (CP) or interference.

WHEREFORE, Staff prays that the Commission will accept its *Gas Incident Report* and order MGE to file a response, within 60 days of the filing of this Report, addressing the seven recommendations set out therein; and grant such other and further relief as the public interest may require.

Respectfully submitted,

s/ Kevin A. Thompson
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CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing have been mailed, hand-delivered, or transmitted by facsimile or electronic mail to all counsel of record this 9th day of December, 2011.

s/ Kevin A. Thompson

[3] A CIS is conducted by measuring pipe-to-soil potentials relative to a reference electrode placed directly above the pipe at frequent intervals along the pipeline.

Missouri Public Service Commission

Gas Incident Report

MISSOURI GAS ENERGY
Case No. GS-2011-0248

Filed on December 9, 2011

107th Street and Blue Ridge Boulevard
Kansas City, Missouri
February 2, 2011

Energy Unit ... Regulatory Review Division
December 2011
Jefferson City, Missouri

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List of Acronyms and Abbreviations

%	Percent
AC	Alternating Current
ACVG	Alternating Current, Voltage Gradient
ASME	American Society of Mechanical Engineers
CIS	Close Interval Survey
Company	Missouri Gas Energy
CP	cathodic protection
CSR	Code of State Regulations
CST	Central Standard Time
DC	Direct Current
DOT-PHMSA	United States Department of Transportation-Pipeline and Hazardous Materials Safety Administration
ECDA	External Corrosion Direct Assessment
ºF	Degrees Fahrenheit
FI	Flame Ionization
HCA	High Consequence Area
IM	Integrity Management
Locate Request	Missouri One-Call Locate Requests
MAOP	Maximum Allowable Operating Pressure
MGE	Missouri Gas Energy
MoPSC	Missouri Public Service Commission
O&M	Operations and Maintenance
PHMSA	Pipeline and Hazardous Materials Administration
psig	Pounds per Square-Inch Gauge
SCADA	Supervisory Control and Data Acquisition system
SMYS	Specified Minimum Yield Strength
Staff	Commission's Energy Unit-Safety/Engineering Section Staff
V	Volt

1.0 SYNOPSIS

At approximately 1:52 p.m. Central Standard Time (CST) on February 2, 2011, Missouri Gas Energy ("MGE" or "the Company") was notified of a leak on its 16-inch diameter cathodically protected, coated steel natural gas transmission pipeline ("the Mayfair 16-inch pipeline") installed parallel to 107th Street in Kansas City, Missouri. The Mayfair 16-inch pipeline consists of the Mayfair 16-inch East line and the Mayfair 16-inch West line. The leak was reported in the vicinity of the intersection of Blue Ridge Boulevard and 107th Street, on the Mayfair 16-inch East line. At the time of the incident, the Mayfair 16-inch steel pipeline was operating at a pressure of approximately 222 Pounds per Square-Inch Gauge (psig). The pipeline fractured, releasing gas at a sufficient pressure to blow through the overburden soil and snow cover, venting gas to the atmosphere. The fracture was observed to be circumferential, with a maximum separation of about ½ inch at the top of the pipe, and approximately 8 inches of intact material at the bottom of the pipe.

There were no injuries or damage to property other than property owned by the Company. Service was disrupted to 10 customers in the immediate area, and these customers were evacuated from their homes and businesses until the area was made safe and gas service could be restored. By 2:20 p.m. on February 3, 2011, all repairs had been made and the pressure restored to approximately 180 psig in the Mayfair 16-inch pipeline.

As part of the leak response efforts, the Company installed a full circle band clamp around the fracture and welded a repair sleeve to the pipe around the band clamp. The pipeline is currently in operation at a reduced pressure (not exceeding 180 psig) with this permanent repair. The cause of the fracture cannot be determined until the pipeline is removed from service.

Staff is making 7 recommendations to the Company as a result of its investigation:

1. Replace the entire length of the Mayfair 16-inch pipeline (both the East and West lines) purchased from Cities Service Gas Company (approximately 3.162 miles) with new pipe;
2. Conduct hydrostatic pressure testing on approximately 10 miles of transmission line (Cass County Line, Bannister Line, and the Mayfair 26-inch) to establish a maximum Allowable Operating Pressure (MAOP) in a manner consistent with applicable regulations[1] and

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[1] 4 CSR 240-40.030(12)(M) sets for the requirements for establishing MAOP by pressure testing, or alternatively for pipe which was installed prior to July 1, 1970, allowing the MAOP to be set at the highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970.

recent United States Department of Transportation – Pipeline and Hazardous Materials Administration (DOT-PHMSA) advisory bulletin[2] guidance;

3. Until the Mayfair 16-inch pipeline is replaced, the operating pressure should not exceed 178 psig (80% of the operating pressure of 222 psig at the time of the incident);
4. Once the existing Mayfair 16-inch pipeline is removed from service, perform an investigation of the fracture to determine the cause. The findings of this investigation should be used to evaluate potential threats to other similar piping remaining in the Company's transmission piping system;
5. Review Company records to determine the status of documentation to establish MAOP for the remainder of the Company's transmission pipelines;
6. Assess the integrity of any remaining pipelines with similar coatings that are enclosed in casings; and
7. Review or perform Close Interval Surveys (CIS)[3] of all of its remaining transmission pipelines to detect areas of insufficient cathodic protection (CP) or interference.

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[2] In the January 4, 2011 Advisory Bulletin ADB-11-1, DOT-PHMSA indicated that performing a hydrostatic pressure test that stresses the pipe to a designated pressure without failure is generally the most effective method for establishing MAOP, however operators may use available design, construction, inspection, testing and other related records to calculate the MAOP, provided these records are traceable, verifiable and complete. If such documentation cannot be satisfactorily completed, the operator cannot rely upon the use of records to establish the MAOP.

[3] A CIS is conducted by measuring pipe-to-soil potentials relative to a reference electrode placed directly above the pipe at frequent intervals along the pipeline.

2.0 CONCLUSIONS

1. Pipeline MAOPs must be established in a manner consistent with applicable regulations and the January 4, 2011 DOT-PHMSA advisory bulletin guidance. However, the Company is not in possession of sufficient (traceable, verifiable and complete) records to demonstrate that the perceived MAOP for the Mayfair 16-inch pipeline (235 psig) was established in accordance with the January 4, 2011 DOT-PHMSA advisory bulletin guidance criteria. Considering the condition of the Mayfair 16-inch pipeline, Staff believes that it should be replaced in the near future (as noted in Section 3.0 RECOMMENDATIONS). Until the Mayfair 16-inch pipeline can be replaced, the Company shall not operate the Mayfair 16-inch pipeline above a pressure of 178 psig (80% of the operating pressure at the time of the incident), unless the Company establishes a MAOP consistent with applicable regulations and recent DOT-PHMSA advisory bulletin guidance.

2. The Company's routine annual monitoring of CP at the designated test locations[4] indicated that CP of the Mayfair 16-inch pipeline was adequate. However, results of the CIS performed in 2008 during implementation of the Company's gas transmission pipeline integrity management program[5] and findings of active corrosion during the Company's direct assessment, indicate that CP has not been sufficient at all areas along the pipeline. While the Company has taken corrective actions to mitigate the deficient CP, the discrepancy between the annual monitoring records and the results of the direct assessment indicates there are not currently sufficient CP test locations to determine the adequacy of CP at all locations along the pipeline[6].

3. The cause of the fracture is unknown at this time because the fractured segment was repaired and remains in service. The Gas Transmission Pipeline Integrity Management regulation requires that the Company identify and evaluate all potential threats to each covered pipeline segment[7]. In order to identify the risk(s) that lead to this fracture, the Company must determine the cause of the fracture.

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[4] 4 CSR 240-40.030(9)(I) requires annual testing at intervals not exceeding 15 months to determine whether the cathodic protection meets established requirements.

[5] 49 CFR 192, Subpart O: Gas Transmission Pipeline Integrity Management.

[6] 4 CSR 240-40.030(9)(K) requires sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection.

[7] As required by 49 CFR 192.917(a).

4. A section of the Mayfair 16-inch East pipeline (under Blue Ridge Boulevard) was abandoned in 1996 due to a leak detected in a casing pipe. Although the cause of the leak was not investigated (the leaking pipe was abandoned in place and not removed for investigation because it is underneath Blue Ridge Boulevard), it is reasonable to assume that the cause of the leak was due to corrosion (see Analysis in **Section 5.4: Pipeline and Coating Condition**). Since this section of pipe was in a high consequence area (HCA) which is a covered pipeline segment as defined by safety regulations[8], the Company must evaluate and remediate all pipeline segments (both covered and non-covered) with similar coating and environmental conditions[9]. The Company has not yet evaluated cased segments of pipe during implementation of its pipeline integrity management program[10].

5. The External Corrosion Direct Assessment (ECDA) conducted by the Company from 2008 to 2010 as part of its pipeline integrity management program identified areas of past external corrosion, dents, gouges, weld repairs of defects and active corrosion in addition to coating damage. The survey methods used by the Company, Alternating Current Voltage Gradient (ACVG)[11] and CIS, are only capable of identifying areas of coating defects and areas of potentially insufficient CP. Actual defects in the pipe itself were found upon excavating the pipeline to evaluate the coating for remedial action. The ACVG and CIS assessment methods used by the Company are consistent with recommended practices[12], however based on the results obtained; Staff does not believe that these assessment methods were capable of identifying all potential defects or threats to integrity on this pipeline.

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[8] HCAs are determined based on the requirements of 49 CFR 192.903.

[9] 49 CFR 192.917(e)(5) specifies actions an operator must take to address corrosion threats, and requires that if an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line, the operator must evaluate and remediate, as necessary all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics.

[10] The compliance deadline for completing the Company's baseline assessment is December 2012.

[11] See Section *4.7.5 MGE's Transmission Integrity Management Program* for discussion of this survey method.

[12] National Association of Corrosion Engineers (NACE) International. Standard Recommended Practice (RP) 0502-2007. "Pipeline External Corrosion Direct Assessment Methodology", 2002.

3.0 RECOMMENDATIONS

During the investigation, Staff had numerous discussions with MGE personnel concerning replacement and pressure testing of the Company's transmission lines. Staff was told by MGE personnel that costs for replacement of the Mayfair 16-inch pipeline, as indicated in item number 1, and hydrostatic pressure testing of the transmission lines noted in item number 2 have been included in the Company's proposed budget for 2012 and 2013. MGE personnel also agreed to continue to operate the Mayfair 16-inch pipeline at a reduced pressure until it is replaced, as noted in item 3. Staff's recommendations to the Company are:

1. By the end of calendar year 2013, replace the entire length of the Mayfair 16-inch pipeline (approximately 3.162 miles) installed by Cities Service Gas Company and then purchased by The Gas Service Company (MGE's predecessor) beginning with the segment on which the fracture occurred. Replacement should address the following:
    a. Install new steel pipe and components that meet all of the requirements of Sections 2, 3 and 4 of 4 CSR 240-40.030[13];
    b. Perform all testing required to establish MAOP as set forth in recent DOT-PHMSA advisory bulletin guidance and by Sections 10 and 12 of 4 CSR 240-40.030[14]; and
    c. After applying CP to the new pipeline, perform a CIS. The results of this survey shall be used to identify areas of potential interference currents from other direct current sources, geological current shielding problems, as well as help to determine areas of inadequate or marginal CP for the purpose of installing additional test points, bonds with interfering current sources, and the addition or adjustment of CP systems.

2. By the end of calendar year 2013, conduct hydrostatic pressure testing on each remaining segment of pipeline that was purchased from Cities Service Gas Company that has not previously been: a) hydrostatically tested; b) had an inline inspection conducted; or c) is scheduled to be removed in accordance with Recommendation 1 above. Staff estimates that this will pertain to approximately 10 miles of transmission line (including portions of the Cass County Line, Bannister Line, and the Mayfair 26-inch pipeline). The results of this hydrostatic testing will be used to establish a MAOP in a manner consistent with

[13] 4 CSR 240-40.030 Section 2 sets forth the material and mechanical property specifications, Section 3 sets forth the minimum design requirements including pressure limitations based on pipe specification, wall thickness and operating class location, and Section 4 prescribes the minimum requirements for design and installation of pipeline components and facilities, including valves, fittings, supports, anchors and pressure relief and limiting devices.

[14] 4 CSR 240-40.030 Section 10 prescribes the minimum leak-test and strength-test requirements for pipelines and Section 12 sets for the requirements for establishing MAOP based on the design pressure of the pipe and components and pressure testing.

applicable regulations[15] and recent DOT-PHMSA advisory bulletin guidance. The Company shall provide Staff with a schedule for completing this testing within 60 days from the filing of this Gas Incident Report.

3. Operate the existing Mayfair 16-inch pipeline at a pressure no higher than 178 psig (80% of the operating pressure of 222 psig at the time of the incident) during the time the existing Mayfair 16-inch pipeline remains in operation.

4. Perform an investigation to determine the cause of the fracture that resulted in this incident. This investigation should be performed after the fractured segment has been removed from service as part of the replacement program recommended above. The Company shall submit a plan and schedule for removal and testing of the fractured pipe to Staff for review and approval prior to removing this line from service and within 60 days from the filing of this Gas Incident Report.

5. Review its records to ascertain if each segment of each transmission line that the Company operates has a MAOP that was established by pressure testing, and provide an updated listing of the MAOP determination to Staff. If such documentation cannot be found for an individual segment, the Company shall report this finding to Staff. The Company shall provide Staff with a schedule for completing this review within 60 days from the filing of this Gas Incident Report.

6. Review its records to determine which pipeline segments remaining in service (excluding the pipeline which will be abandoned per item number 1 above) have similar coatings and are in similar environmental conditions as those that existed in the cased section of the Mayfair 16-inch pipeline beneath Blue Ridge Boulevard. Since a previous leak occurred on the bitumastic[16] coated pipe in casing beneath Blue Ridge Boulevard, the Company should at minimum evaluate and remediate all pipeline segments (both covered and non-covered) with similar coating and environmental conditions. The Company shall provide Staff with a schedule for completing this review within 60 days from the filing of this Gas Incident Report.

7. Perform a systematic evaluation of the adequacy of CP on the entire transmission line system.

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[15] 4 CSR 240-40.030(12)(M) sets forth the requirements for establishing MAOP by pressure testing, or alternatively for pipe which was installed prior to July 1, 1970, allowing the MAOP to be set at the highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970.

[16] Bitumastic is a trade name associated with coating materials made from coal tars and blends of resins such as epoxy.

a. Begin by reviewing the results of all CIS data recently obtained in conjunction with its Pipeline Integrity Management (IM) program;
b. If the CIS results indicate any areas of insufficient CP, the Company shall investigate and take prompt action to remediate the deficiencies. Report the remedial actions taken to Staff within 60 days of the Commission's order in this case;
c. If a CIS has not been performed on certain segments of the Company's transmission lines, a CIS should be performed on these lines and the results evaluated. The Company shall provide Staff with a schedule for completing this review within 60 days from the filing of this Gas Incident Report.

4.0 FACTS

NOTE: Except for the information gathered during the on-site investigation and/or interviews, the information used to compile this portion of the report was obtained in record and/or statement form.

4.1 The Incident

At approximately 1:52 p.m. CST on February 2, 2011, MGE dispatch was notified of a public reported leak at 7000 E 107th Street in Kansas City, Missouri. The approximate location of the leak is shown on Figure 1. A 16-inch diameter cathodically protected, coated steel transmission pipeline fractured, resulting in the release of natural gas. The pipeline was operating at approximately 222 psig at the time of the rupture. The natural gas was released at a sufficient pressure to blow through approximately 9 feet of overburden soil and snow cover, creating a hole through which the released natural gas escaped and vented to the atmosphere. There was no ignition of the gas.

4.2 Personal Injuries

No injuries resulted from this incident.

4.3 Property Damage

The only property damage was to MGE owned property. No damage was reported to public or other privately owned property.

4.4 Site Description

The incident occurred in a Class 3[17], HCA, near the intersection of 107th Street and Blue Ridge Boulevard in Kansas City, Missouri (see Figure 1). This area was determined to be an HCA using Method 2[18] due to the proximity to several businesses and a daycare facility. The nearest building is the A-1 Auto Repair, located at the northwest corner of the intersection. The fracture occurred on cathodically protected, coated steel pipe located beneath the greenway on the north side of 107th Street, and adjacent to the parking lot of A-1 Auto Repair, approximately 35 feet south of the A-1 Auto Repair building (shown as A-1 Brakes and A-1 Mufflers on Figure 1).

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[17] Area classifications were determined based on the requirements of 4 CSR 240-40.030(1)(C).

[18] 49 CFR 192.903 provides 2 methods for establishing HCAs. Method 2 is an area within a potential impact circle containing 20 or more buildings intended for human occupancy or an identified site. One example of an identified site is a daycare facility.

4.5 Meteorological Data and Conditions

On February 1, 2011, a snowfall of ten to twelve inches[19] accumulated and was on the ground February 2, 2011. The temperature ranged from 2 to 17 ºF on February 2, 2011 and from -7 to 13 ºF on February 3, 2011[20].

4.6 Natural Gas System

Natural gas service in the Kansas City, Missouri area is provided by MGE.

The 16-inch diameter, coated and cathodically protected steel transmission pipeline (the Mayfair 16-inch pipeline) was installed parallel to and on the north side of 107th Street. Most of this pipeline is currently located within a Class 3 area, with many residences and businesses located along the pipeline. The total length of this pipeline is approximately 3.2 miles. The Company further divides this pipeline into two segments: The Mayfair 16-inch East line (approximately 1.82 miles; See Figure 2) and the Mayfair 16-inch West line (approximately 1.39 miles). The incident occurred on the Mayfair 16-inch East line. At the time of the incident, the depth of cover was measured at the incident location as approximately 9 feet. The Mayfair 16-inch pipeline was installed in 1948-1949, and was purchased by MGE on or about September 23, 1960, from Cities Service Gas Company.

Natural gas is supplied to the Mayfair 16-inch pipeline at two locations: from the Mayfair regulator station outlet to the west of the incident location and from the Kinder Morgan outlet to the east of the incident location. At the time of the incident, the pipeline was operating at a pressure of approximately 222 psig as measured at both supply locations and recorded by the Company's Supervisory Control and Data Acquisition (SCADA) system.

The manufacturer of the Mayfair 16-inch pipeline pipe is unknown. The pipe material specification is also unknown. The pipe wall thickness is nominally 0.25 inches. The actual yield strength of the pipe material is unknown, so the material is assumed to have a specified minimum yield strength (SMYS) of 24,000 psi[21] for purposes of calculating the percent of SMYS at the MAOP. Assuming a yield strength of 24,000 psi, a 16-inch nominal diameter, a wall thickness of 0.25 inches, a Class 3 location, and no de-rating factors for longitudinal

[19] Ten inches reported at Kansas City Downtown Airport, twelve inches reported at Lee's Summit Reed Wildlife Refuge.

[20] Based on combined observations from Kansas City Downtown Airport, and Lee's Summit Reed Wildlife Refuge.

[21] 4 CSR 240-40.030(3)(D)2. requires that if the yield strength is unknown, 24,000 psi must be assumed to be the yield strength.

joints or operating at an elevated temperature (above 250 ºF), the design pressure[22] for this pipe is calculated to be 375 psig.

Historically, the MAOP of the Mayfair 16-inch pipeline was established at 235 psig based on a Company record indicating that the pressure had been seasonally adjusted in the winter time every year to 235 psig[23]. At a pressure of 235 psig, the hoop stress in the pipe is calculated to be 31.3% of SMYS, which classifies the Mayfair 16-inch pipeline as a transmission line[24].

As part of its pipeline integrity management program, the Company performed an evaluation to identify HCAs along its Mayfair 16-inch pipeline. Two HCAs were identified. The area where the fracture occurred is within one of these HCAs, as discussed in Section 4.4: Site Description. A second HCA was identified in the vicinity of the intersection of Wallace Avenue and 107th Street, approximately 4,100 feet east of the intersection of Blue Ridge Boulevard and 107th Street.

4.7 Previous Company Actions

4.7.1 Leak Surveys and Patrols

Prior to the incident, a leak survey was conducted on the involved section of pipe on July 29, 2010[25]. The leak survey was conducted according to the MGE Operations and Maintenance (O&M) Standard Procedure using a Flame Ionization (FI) detector. No leaks were found during this leak survey.

A patrol of the pipeline was conducted on November 30, 2010, to observe surface conditions in the pipeline right-of-way[26]. No problems were observed during this patrol.

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[22] 4 CSR 240-40.030(3)(C) provides the required design formula to use for steel pipe and accounts for yield strength, wall thickness, area location classification as well as other material and operating variables.

[23] 4 CSR 240-40.030(12)(M)1.C. allows for setting the MAOP of pipelines that were installed before the regulations were promulgated based on the highest actual operating pressure to which the pipe segment was subjected during the five years preceding the date of the applicable regulation, in this case the five years preceding July 1, 1970.

[24] 4 CSR 240-40.030(1)(B)32.B. specifies that a pipeline is transmission if it operates at 20% or more of SMYS.

[25] 4 CSR 240-40.030(13)(D) requi res that leak surveys of a transmission line must be conducted at intervals not exceeding seven and one-half months and at least twice each calendar year in Class 3 locations.

[26] 4 CSR 240-40.030(13)(C) requires that for transmission pipelines in Class 3 locations, patrols be conducted at least 4 times per year at intervals not exceeding 4.5 months at highway and railroad crossings and at least twice a year at intervals not exceeding 7.5 months at all other locations to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity and other factors affecting safety and operations.

4.7.2 Cathodic Protection

According to the records available from the sale of the pipeline in 1960, CP was first applied to the Mayfair 16-inch pipeline in or around 1951; however because there were no regulations at that time requiring application of CP, monitoring or retention of CP monitoring records, the exact nature and adequacy of the CP at that time is unknown[27]

The regulations provide four different criteria that may be used to demonstrate the effectiveness of CP[28]. The Company has elected to use the criterion requiring a polarized voltage of at least -0.85 volt (V) or more negative, with reference to a saturated copper-copper sulfate half cell.

Currently, the Mayfair 16-inch pipeline is part of a larger protected steel pipeline system that is cathodically protected by two rectifiers[29]. In order to measure the polarized potential, the rectifiers must be interrupted and the voltage determined immediately upon interruption of the protective current[30]. The potential measured when the rectifiers are interrupted in this manner is known as the "Instant Off" potential, and represents the polarized potential of the pipeline.

Each pipeline under CP must be tested at least once each calendar year at intervals not exceeding 15 months to demonstrate compliance with the selected criterion[31]. In order to demonstrate that the pipeline has a polarized voltage of at least -0.85 V or more negative, the Company conducts an annual pipe-to-soil potential survey at selected test stations. The Company has provided records to Staff of "Instant Off" surveys for 2008, 2009 and 2010 with pipe-to-soil potentials at each of the selected test stations. The most recent "Instant Off" potential survey of the Mayfair 16-inch pipeline prior to the incident was conducted on

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[27] The June 30, 1971 regulatory requirement in 49 CFR 192.457 and 192.465 requires application and monitoring of cathodic protection.

[28] 4 CSR 240-40.030 Appendix D provides the criteria for cathodic protection:

1. A polarized voltage of at least -0.85 volt or more negative, referenced to a saturated copper-copper sulfate half cell;
2. A minimum negative polarization voltage shift of 100 millivolts;
3. A voltage at least as negative as that originally established at the beginning of the Tafel segment of the E-log-I curve; or
4. A net negative current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.

[29] Rectifiers convert alternating current (AC) power to low-voltage direct current (DC) power and impress the direct current on the pipeline to provide cathodic protection to mitigate corrosion.

[30] 4 CSR 240-40.030 Appendix D.II requires that the voltage be interrupted to account for IR drops for rectified systems.

[31] 4 CSR 240-40.030(9)(I)1.

January 21, 2010. In this survey, as with the 2008 and 2009 surveys, all of the "Instant Off" readings were more negative than -0.85 V.

Although the test station monitoring results did not indicate any problems with the CP of the Mayfair 16-inch pipeline, results of the integrity management external corrosion direct assessment study revealed areas of inadequate protection, coating damage, mechanical damage and historical and active corrosion (See below: *Section 4.7.5: MGE's Transmission Integrity Management Program).*

4.7.3 Active Leaks, Trouble or Leak Calls in the Vicinity

During the month prior to the incident, there were no known active leaks, or any trouble, leak or odor calls within a one-block radius of the incident location.

4.7.4 Past Leaks on this transmission line

The Mayfair 16-inch pipeline originally passed through a casing pipe beneath Blue Ridge Boulevard. In April of 1996, natural gas was detected in a vent from the casing pipe, indicating a probable leak in the Mayfair 16-inch pipeline carrier pipe within the casing pipe. The Company installed a section of new pipe by directionally boring under Blue Ridge Boulevard, and tying into the existing Mayfair 16-inch pipeline on either side of Blue Ridge Boulevard. The 16-inch carrier pipe inside the casing pipe was abandoned in place; consequently the cause of the leak was not determined.

4.7.5 MGE's Transmission Integrity Management Program

The Company has implemented a pipeline integrity management program (Company O&M Standard 3125) for its transmission pipelines[32]. As part of its integrity management program, the Company contracted with an engineering firm to perform an ECDA survey of the Mayfair 16-inch pipeline. The Company elected to perform a more extensive ECDA survey of the non-cased pipeline segments of the Mayfair 16-inch East pipeline than would have been required by regulation (only the approximately 1,060 feet of Mayfair 16-inch East pipeline within HCAs would have been required to be surveyed). The ECDA survey was completed in June 2008. It consisted of performing two above ground surveys:

1. An ACVG survey; and
2. A CIS.

[32] 4 CSR 240-40.030(16) requires compliance with the federal requirements for integrity management of transmission pipelines set forth in Subpart O and Appendix E of 49 CFR Part 192.

Certain sections of pipe could not be surveyed in this manner, including sections of the pipeline encased within casing pipe beneath road and railroad crossings. These pipe sections were identified as “skips” in the survey. A total of 271 feet of pipeline was skipped during this ECDA survey[33] of the Mayfair 16-inch East pipeline.

An ACVG survey detects anomalies in coatings. To conduct the ACVG survey, an AC generating transmitter is used to impress a unique AC signal on the pipeline. A technician then moves a receiver along the pipeline right-of-way over the pipeline, measuring the signal strength as it is transmitted along the pipeline. Current from the transmitter creates a voltage gradient around coating defects and the magnitude of the voltage gradient is greatest at the interface between a defect and the surrounding environment. The objective of the survey is to identify areas of high voltage gradient, which signify areas of potential coating defects. These signal strengths are recorded in decibels of microvolts (dBμV where decibels here refer to a logarithm of the ratio of the voltage gradients). In theory, higher dBμV readings correspond to larger defects in the coating.

The results of the ACVG survey of the Mayfair 16-inch pipeline identified a total of 173 locations with potential coating faults. The severity of these anomalies was ranked from minor to severe, and each category was assigned a relative ranking score as follows:

- 30 to ≤50 dBμV: Minor. An ACVG score of 4 was assigned.
- >50 to <70 dBμV: Moderate. An ACVG score of 6 was assigned.
- ≥70 dBμV: Severe. An ACVG score of 8 was assigned.

The 173 locations of suspected coating faults were marked along the pipeline so that the locations would be clear to the CIS crew.

A CIS can be used to locate areas of depressed potentials on cathodically protected pipelines. A CIS is conducted by measuring pipe-to-soil potentials relative to a reference electrode placed directly above the pipe at frequent intervals along the pipeline.

As discussed in *Section 4.7.2: Cathodic Protection*, the Mayfair 16-inch pipeline is cathodically protected by the output of 2 rectifiers. To demonstrate compliance with regulatory criteria, the cathodic voltage must be measured immediately after interruption of the protective current from both rectifiers. The CIS conducted along the Mayfair 16-inch pipeline measured both “ON” (with protective current applied) and “OFF” (immediately after interruption of protective current) pipe-to-soil potentials at 5-foot intervals along the pipeline.

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[33] Of the 271 feet total, only 26 feet were located in a HCA, a cased segment beneath Wallace Avenue.

The rectifiers were interrupted on a 1.5 second “ON” and 0.5 second “OFF” cycle so that “ON” and “OFF” potentials could be measured at each 5-foot interval.

At each of the 173 locations where the ACVG survey had indicated a coating anomaly, the CIS readings at these locations were ranked as follows:

- “Off” value more negative than -0.85V: A CIS score of 5 was assigned. This was the case at 140 of the 173 locations.
- “Off” value more positive than -0.85V and “On” value more negative than -0.85V: A CIS score of 8 was assigned. This was the case at 15 of the 173 locations.
- “On” value more positive than -0.85V: A CIS score of 10 was assigned. This was the case at 18 of the 173 locations.

In general, it is expected that the “ON” value will be at least as negative as the “OFF” value. It should be noted, however, that in the CIS conducted over the Mayfair 16-inch pipeline, there were several locations where the reverse was noted, caused by interference from other rectified lines in the area. These areas of reverse current were investigated and corrected by installation of an interference bond.

For each of the 173 locations where the ACVG survey had indicated a suspected coating fault, the ACVG scores were added to the CIS score at that location. A value of 2 was added to each combined ACVG + CIS score to obtain a total ECDA score at each location. The range in the total ECDA scores therefore ranged from a minimum of 11 (4 from ACVG for minor coating fault + 5 from CIS for adequate CP + 2 = 11) to a maximum of 20 (8 from ACVG for severe coating fault + 10 from CIS for inadequate CP + 2 = 20).

The total ECDA scores were used to prioritize locations for direct examination. In general, the Company prioritized by selecting the locations with the highest total ECDA scores for examination. To examine the selected locations, the Company excavated the soil above and around the pipe, exposing a total of 42 of the originally identified 173 coating defect locations. A number of locations with lower total ECDA scores were also examined during the course of the work, due to proximity to higher scoring locations or because utility crossings were known or suspected to be near the defect location. Examples of the defects observed during the direct examination are shown in Appendix C.

The coating conditions observed ranged from “good” to “very poor.” Defects in the coating included disbondment, brittleness, foreign object (tree root) penetration, and areas with poor and/or missing coating. Even at some of the locations that had received total ECDA scores of 11 (the lowest combined score), some severe coating defects were found. As a result of these findings, three re-coating projects were undertaken by the Company and were completed between 2008 and 2010.

The pipe condition was also examined at these excavated areas. Both pitting and general corrosion were noted at several locations along the pipeline, with four areas of active corrosion being observed. Several dents and gouges were also observed. In a number of locations, defects in the pipe had been repaired at some unknown time in the past by depositing weld metal. The integrity of the pipe was evaluated in these cases by using the deepest pit size to calculate a safe assessed MAOP using American Society of Mechanical Engineers (ASME) Standard B31G[34] and ASME Modified B31G. The most severely damaged areas were repaired by installing composite sleeves around the pipe prior to re-coating.

The closest ACVG anomaly to the incident site was approximately five feet west of the incident location. The ACVG measurement at this location was 48 dBµV (minor defect, score = 4) and the CIS readings were "On" = -0.99V, "Off" = -0.93V (CIS Score = 5); Total ECDA score = 11. Due to the relatively low Total ECDA score, no excavation was performed at this location during the direct assessment phase.

4.7.6 Previous Excavations Nearby

In cases where there is proposed excavation work close enough that a transmission pipeline is expected to be exposed or affected by the excavation work, the Company requires that an inspector be present on-site during that work. Prior to this incident, the Company would have been made aware of proposed excavation, drilling and boring projects in the vicinity of the incident through its review of Missouri One Call locate requests. The Company is not aware of any third-party excavations that would have affected the integrity of the pipeline and/or its support in the vicinity of the incident.

4.7.7 Odorization

The Company odorizes the gas in the Mayfair 16-inch pipeline[35] and monitors odor intensity[36] at various locations monthly. The incident location is closest to the odor intensity monitoring location at 107th Street and Elm Avenue (see Figure 2, Elm Avenue is at the eastern terminus of the Mayfair 16-inch pipeline). On January 4, 2011, the Company determined that odorant

[34] ASME Standard B31G "Manual for Determining the Remaining Strength of Corroded Pipelines" is a supplement to ASME B31, "Code for Pressure Piping."

[35] 4 CSR 240-40.030(12)(P) requires odorization of gas in both transmission and distribution lines.

[36] 4 CSR 240-40.030(12)(P) requires that the odorant be readily detectable by a person with a normal sense of smell when the natural gas concentration in air of one-fifth of the lower explosive limit.

was detectable at 0.30% gas-in-air[37] at the 107th Street and Elm Avenue monitoring location. Following the incident on February 7, 2011, the Company again checked odor intensity and determined that odorant was detectable at 0.30% gas-in-air.

4.8 MGE's Actions to Meet MoPSC Reporting Requirements

The Missouri Public Service Commission (MoPSC) incident reporting requirements[38] were completed as follows:

1. The Company called the MoPSC answering service on February 2, 2011 at 3:37 p.m. to provide notification of the incident;

2. MoPSC contacted the Company on February 2, 2011 at 3:40 p.m. and was apprised of the incident status and that the incident would be federally reportable;

3. The Company made initial telephonic notification to DOT-PHMSA on February 2, 2011 at 5:55 p.m.; and

4. The Company filed an incident report with DOT-PHMSA on March 4, 2011.

4.9 MGE's Actions in Response to Leak/Odor Calls

The Company was notified of the leak on February 2, 2011 at 1:52 p.m. At 1:53 p.m., a Company dispatcher dispatched a service person and then notified a supervisor at 2:00 p.m. The supervisor advised dispatch to send additional personnel to the incident location.

The first responding service person arrived on site at 2:25 p.m. on February 2, 2011, and additional Company personnel began arriving at 3:08 p.m. At 3:59 p.m., the Company began closing valves to reduce the pressure in the line. By 4:41 p.m., the pressure in the Mayfair 16-inch pipeline had been reduced from approximately 222 psig to about 35 psig (in the vicinity of the fracture). At 4:42 p.m., the Company began excavating soil around the fractured pipe. The fractured section of the Mayfair 16-inch pipeline was exposed by 5:30 p.m. and the Company observed a circumferential break in the line. At this point, the Company began planning the emergency repair, ordering materials and shoring equipment. At 8:20 p.m., shoring boxes arrived on site and the rectifiers supplying CP were turned off. By 9:06 p.m., the shoring boxes were installed and the Company was able to enter the excavation to clean

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[37] A measurement of 0.30% gas-in-air corresponds to a detection of odorant when the natural gas concentration is approximately one-fifteenth of the lower explosive limit; therefore the gas was adequately odorized.

[38] 4 CSR 240-40.020(4)(A) requires initial telephonic notice to designated commission personnel within 2 hours of Federal Incidents and 4 CSR 240-40.020(4)(C) requires completion of an incident report form within 30 days of the incident.

the pipe. A shelf of rock was noted below the pipe, running the length of the excavation. The pipe was not resting directly on the rock, but was separated by about 8 inches or less of soil between the rock and the bottom of the pipe. The Company used a breaker and jackhammer to break out the rock to a depth of about 12 inches below the pipe so that repairs could be made.

At 10:00 p.m. on February 2, 2011, the Company determined that the break was approximately 7 inches east of a girth weld, with a maximum separation of about 0.5 inches at the top, and approximately 8 inches of intact material at the bottom of the pipe. At 11:30 p.m., the Company began installation of a full circle band clamp. By 12:45 a.m. on February 3, 2011, the full circle band clamp was installed, and pressure was holding in the line between 35 and 40 psig (in the vicinity of the fracture). At 2:25 a.m., welders began installing a 16-inch reinforcing sleeve around the band clamp. Water running into the excavation from a damaged sewer slowed the installation, which was completed at 6:00 a.m.

At 6:20 a.m. on February 3, 2011, the Company began to increase the pressure on the Mayfair 16-inch pipeline. By 6:40 a.m., the pressure was up to 143 psig, and a very small leak was discovered in a fillet weld on the bottom of the repair sleeve. The Company decided to keep the pressure up to accommodate the morning load due to extremely cold ambient air temperatures. For the safety of the public and for worker safety, the Company closed a section of 107th Street between Blue Ridge Boulevard and the Kansas City Southern Railroad tracks approximately 700 feet to the west. At 8:40 a.m., the leaking sewer drain was repaired. By 1:30 p.m. on February 3, 2011, the repair sleeve leak was repaired. Valves were opened and pressure was increased in the line. By 2:20 p.m. on February 3, 2011, all repairs had been made and the pressure had been restored to approximately 180 psig in the Mayfair 16-inch pipeline.

During the course of the incident, gas service was turned off to 10 customers in the immediate area for safety. These customers were evacuated from their homes and businesses. These customers were provided natural gas from another pipeline (distribution main) and not from the fractured transmission line. Service was restored to the 3 customers at 10700, 10706 and 10704 Cambridge Avenue by 6:30 p.m. on February 2, 2011. By 9:45 p.m. on February 2, 2011, 7 of these customers were still without service, and the Company made arrangements for the customers to go to a motel. By 1:00 a.m. on February 3, 2011, service was restored to customers at 6905, 7001 and 7002 East 107th Street and at 10700 Blue Ridge Boulevard. By 2:30 a.m., service was restored to customers at 7003 and 7005 East 107th Street. By 4:55 p.m. on February 3, 2011, service was restored to the last of these 10 customers: the A-1 Auto Repair at 10624 Blue Ridge Boulevard.

At the time the incident occurred on February 2, 2011, Interstate 70 was closed between Jefferson City and Kansas City and hazardous road conditions prohibited an immediate investigation by Staff. At the direction of the Utility Regulatory Engineering Supervisor, three Staff members traveled to the incident site on February 3, 2011. When Staff arrived, 107th Street was closed to traffic west of Blue Ridge Boulevard. The excavation was opened and shored (see Appendix A, PHOTOGRAPH 1). Staff observed the installed repair sleeve in the excavation (see Appendix A, PHOTOGRAPHS 2 and 3). MGE discussed the chronology of events associated with the incident and repair with Staff.

5.0 ANALYSIS

5.1 MAOP Requirements

Historically, the MAOP of the Mayfair 16-inch pipeline has been considered to be 235 psig. As a result of this incident, and in light of the January 4, 2011 advisory bulletin guidance from DOT-PHMSA regarding requirements for establishing MAOP[2], Staff requested a copy of the Company's documentation for establishing this MAOP for the Mayfair 16-inch pipeline. It is Staff's and the Company's opinion that the existing documentation is not sufficient to establish a MAOP under current DOT-PHMSA guidance. Given the lack of information on the pipe material and installation, Staff believes that a hydrostatic pressure test would be required to establish a MAOP for this line under current DOT-PHMSA guidance.

While the successful completion of a hydrostatic pressure test would be necessary for the pipeline to remain in service, Staff does not believe that successful completion of a hydrostatic pressure test alone would be sufficient to allow this pipeline to remain in service. Since the pipe fractured circumferentially, there is no indication that internal pressure contributed to the incident. Had the failure been caused by internal pressure alone, the most likely outcome would have been a longitudinal rupture rather than a circumferential fracture. For a thin walled cylinder (which is how a pipeline is modeled), internal pressure creates hoop stress[39] of roughly twice the magnitude of axial (longitudinal) stress. Since cracks generally propagate perpendicular to the direction of the greatest applied force, over-pressurization would create the greatest stress circumferentially, resulting in crack propagation in the longitudinal direction[40]. Because it does not appear that over-pressurization caused the fracture that resulted in this incident, Staff does not believe that conducting a hydrostatic pressure test to properly establish MAOP would address all of the potential risks for this pipeline.

5.2 CP Monitoring Locations

The Company monitored CP annually at selected test stations as required by regulations, yet did not find any indication of deficient protection (see Section 4.7.2: Cathodic Protection). However, when the Company performed a CIS in 2008, areas of depressed CP were noted (see Section 4.7.5: MGE's Transmission Integrity Management Program). The Company's routine annual monitoring is performed at only a few locations pre-selected by the Company for this purpose. The CIS in contrast is performed at 5-foot intervals along the entire length

[39] Hoop stress is circumferential stress in a thin walled cylinder. Pipelines are generally modeled as thin walled cylinders since the radius of a pipeline is more than 5 times the wall thickness.

[40] Hertzberg, R.W. (1996). *Deformation and Fracture Mechanics of Engineering Materials, Fourth Edition.* John Wiley & Sons, Inc., pp. 45-48.

of the pipeline, and is therefore a much more detailed indication of the level of CP along the entire length of the pipeline. Regulation requires that CP monitoring be performed at sufficient test stations to determine the adequacy of CP[41]. It became evident after reviewing the results of the CIS that the number of CP monitoring stations used by the Company was not sufficient to determine the adequacy of CP along the entire length of the pipeline. The Company has taken steps to mitigate the areas of deficient CP identified by the CIS along the pipeline, including installation of an interference mitigation bond, recoating of the pipeline and installation of anodes. There currently is no indication that the incident was caused by external corrosion. However, given the apparent insufficiency of monitoring stations along this section of pipe, Staff recommends that the Company use CIS results to re-evaluate the sufficiency of CP monitoring locations on all of its transmission pipelines.

5.3 Cause of Fracture

In order to effectively implement a pipeline integrity management program, an operator must identify and evaluate all potential threats to each covered pipeline segment.[42] The cause of fracture that initiated this incident is unknown at this time. Further, the fracture occurred at a location along the pipeline that had not previously been identified or investigated during the Company's ECDA for this pipeline. It is therefore possible that there is an existing threat to pipelines with similar characteristics to the Mayfair 16-inch pipeline that has not yet been identified or assessed in the Company's pipeline integrity management program. In order to identify this threat, the cause of this fracture must be determined. Once the threat is known, the Company, in conjunction with Staff, must evaluate the results and assess the risk to all of the transmission lines the Company operates.

5.4 Pipeline and Coating Condition

The Company's integrity management program for the Mayfair 16-inch East pipeline included performing an ACVG along the pipeline (except at cased crossings) to identify areas of possible coating defects. The results were combined with results from a CIS of the Mayfair 16-inch East pipeline, then ranked in priority to select locations to excavate and directly examine. As noted in *4.7.5 MGE's Transmission Integrity Management Program*, the Company observed instances of coating damage and active corrosion at locations which had not been selected for direct examination by the prioritizing ranking system. Additionally, the Company found multiple locations with deep corrosion pits, gouges, dents and defects, some of which had been repaired in the past by depositing weld metal over the defects. The ACVG and CIS surveys are not capable of identifying these types of defects. These were only found

[41] 4 CSR 240-40.030(9)(K)
[42] 49 CFR 192.917.

by the Company upon excavating the pipe to inspect it for coating damage. Further, the ACVG is not effective at locating defects on pipelines within casings, therefore 271 feet of the pipeline that is encased in casings was not evaluated.

In April of 1996 the Company detected a leak in the Mayfair 16-inch transmission line located in a casing pipe running beneath Blue Ridge Boulevard. The segment of Mayfair 16-inch pipeline that was found to be leaking was not removed from the casing to determine the cause of the leak but was abandoned in place. Steel pipes installed inside of casings are often subjected to adverse operating conditions due to water and other contaminants that seep past the end seals of the casings and fill the annular space between the carrier pipe and the casing. This in turn sets up a corrosion condition within the casing pipe that in most instances cannot be mitigated by CP processes because the casing pipe and the end seals provide a shielding affect to the applied CP currents. Due to this shielding of the CP currents, the carrier pipe inside of water filled casings is subjected to corrosion that cannot easily be mitigated. Because of this environment, most leaks on steel pipe inside of a casing are due to corrosion. Although the pipe that was leaking inside the casing under Blue Ridge Boulevard was not removed to determine the actual cause of the leak, it can be assumed that the leak was due to corrosion.

The section of the pipeline underneath Blue Ridge Boulevard was determined to be in a HCA (a covered pipeline segment) as defined by the pipeline safety regulations. If corrosion that could adversely affect the integrity of a pipeline is identified on a covered segment of that pipeline, the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics[43]. Because of this requirement, the Company should now, under current IM regulations, evaluate all such segments (not only in identified HCAs) in all of the Company's transmission pipelines having similar coating and environmental characteristics. Staff believes this would include as a minimum all segments in casings under roads, driveways, etc. along the entire Mayfair 16-inch pipeline, as well as any other transmission pipelines having similar coating and environmental characteristics.

The Company has indicated that it would have been conducting further assessment of cased segments on the Mayfair 16-inch pipeline if this line were to remain in service. Following this incident, however, the Company has included the cost of replacing the entire Mayfair 16-inch pipeline in its proposed budget for 2012 and 2013. Assuming the Mayfair 16-inch pipeline will be replaced as budgeted by the end of calendar year 2013, further investigation

[43] 49 CFR 192.917(e)(5) specifies actions an operator must take to address corrosion threats.

of the cased segments along this line would not be productive. However, similar cased segments of pipeline on the Company's other transmission pipelines should be evaluated.

APPENDIX A

PHOTOGRAPHS

PHOTOGRAPH 1: Incident Location, Excavation Opened (Arrow), View Looking Southwest across Pipeline towards 107th Street (Photo Courtesy of MGE).

PHOTOGRAPH 2: View Looking Down Upon Welded Repair Sleeve (Arrow) (Staff Photo).

PHOTOGRAPH 3: Weld Bead (Arrow) joining Welded Repair Sleeve to Mayfair 16-inch pipeline (Staff Photo)

APPENDIX B

FIGURES

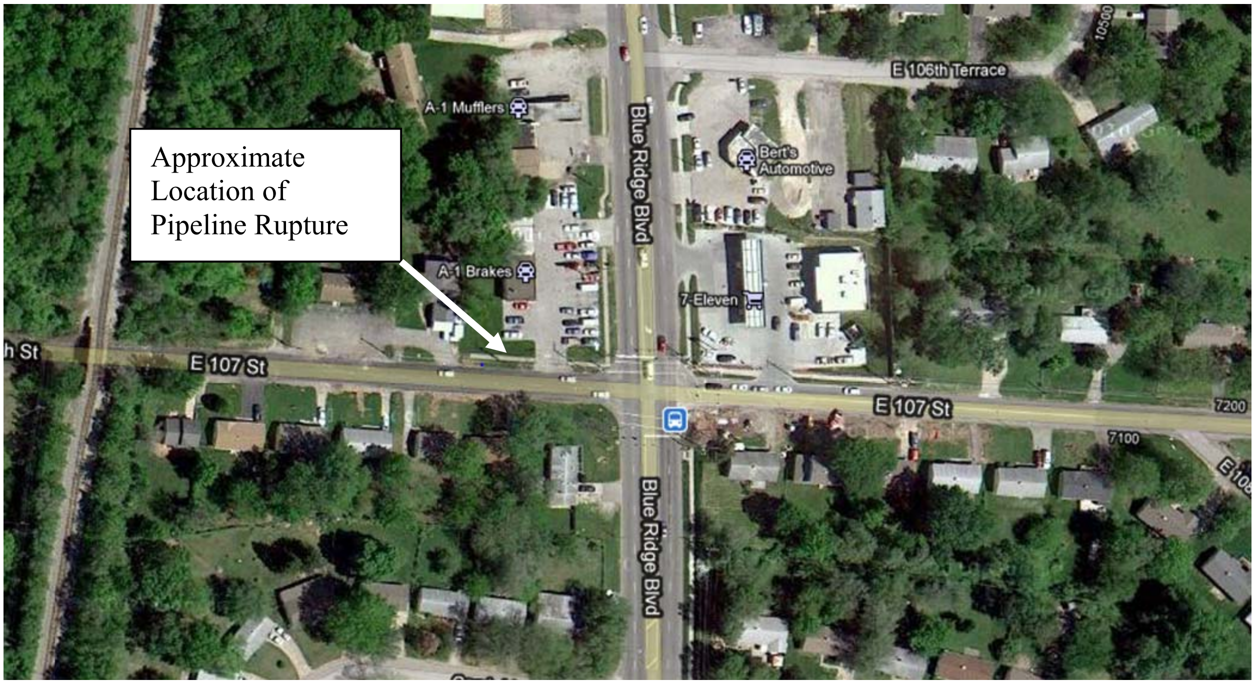


Figure 1: Approximate Location of Pipeline Rupture

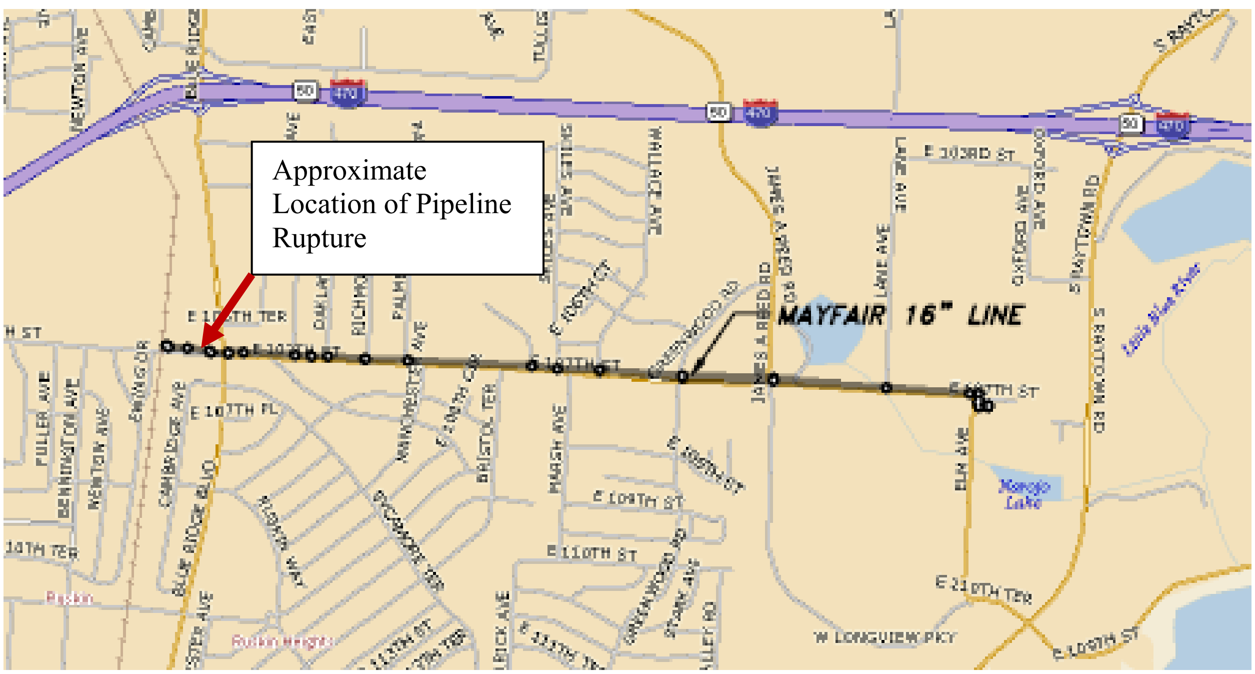


Figure 2: Mayfair 16-inch East Pipeline Involved in Incident

APPENDIX C

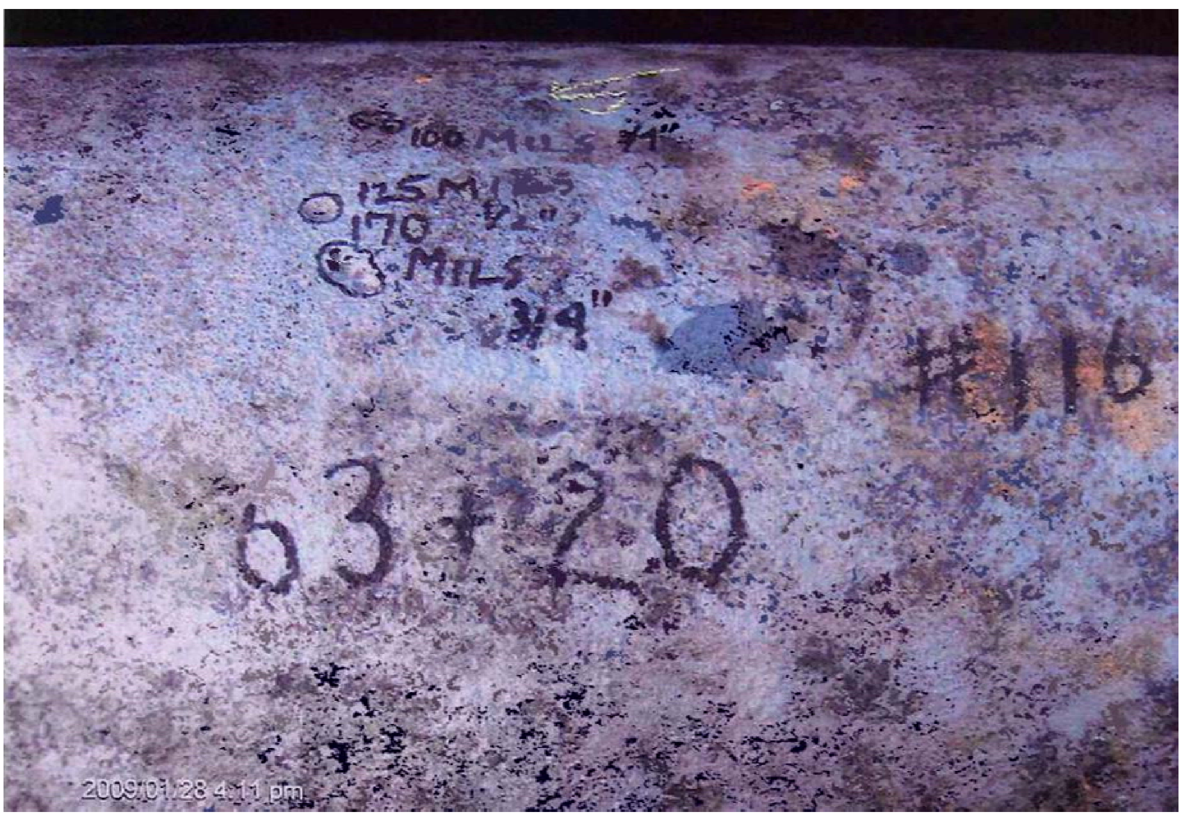
EXAMPLE PIPE AND COATING CONDITONS FOUND DURING INTEGRITY MANAGEMENT DIRECT ASSESSMENT

(All Photographs Provided by MGE**)**

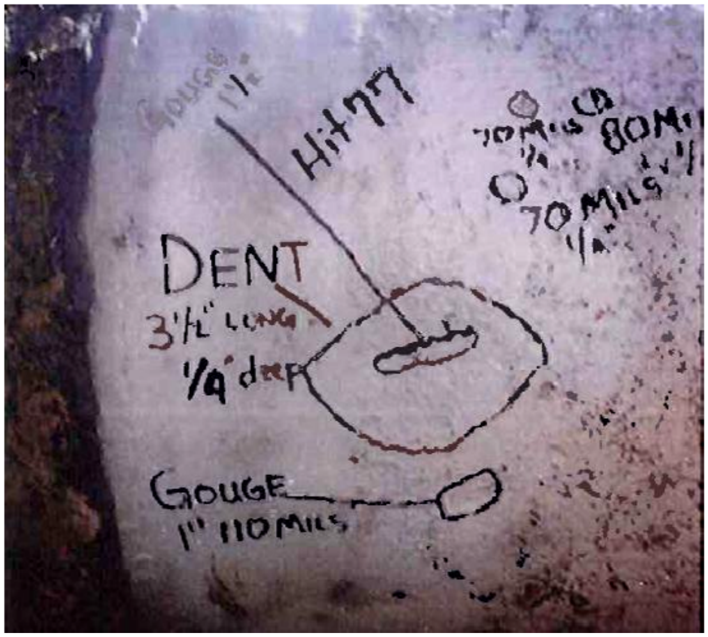
Example 1: Coating Damaged by Tree Root Intrusion (Arrow), Found in Excavation for Coating Defect No. 59, Active corrosion was observed under the coating. [45 dBμV (Minor, ACVG Score = 4); CIS "Off" = -0.867 (CIS Score = 5), Total ECDA Score = 11].

Example 2: Coating Disbonded, Found in Excavation for Coating Defect No. 137, [64 dBμV (Moderate, ACVG Score = 6); CIS "Off" = -0.821, "On" = -0.842 (CIS Score = 10), Total ECDA Score = 18].

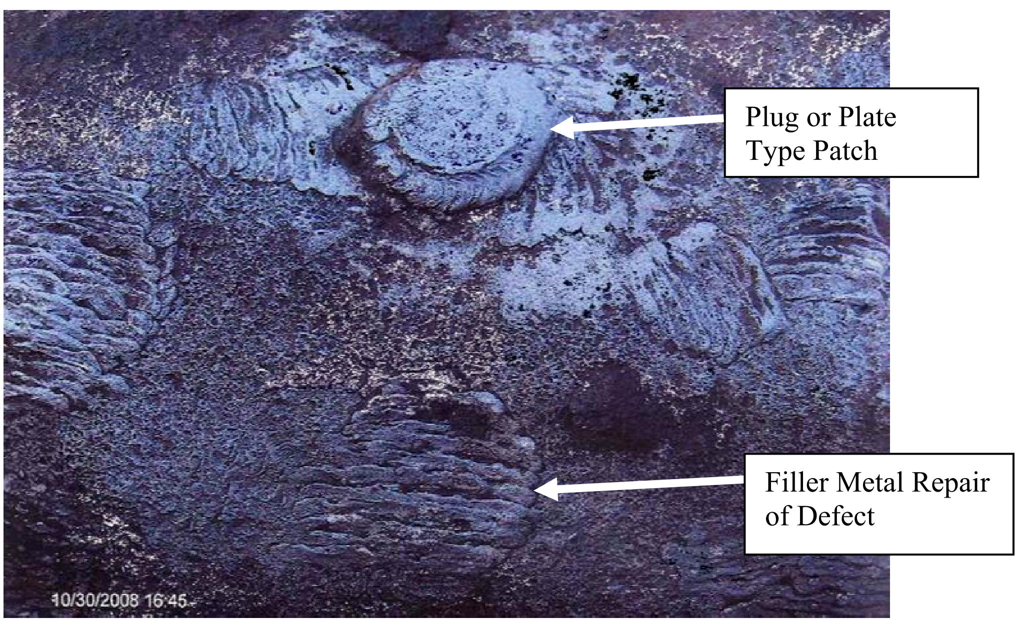
Example 3: Coating Not Properly Applied, Found in Excavation for Coating Defect No. 116, No Coating Applied to Sides, [47 dBμV (Minor, ACVG Score = 4); CIS “Off” = -0.855, “On” = -0.907 (CIS Score = 5), Total ECDA Score = 11].



Example 4: Pitting Corrosion, Found in Excavation for Coating Defect No. 116, [47 dBμV (Minor, ACVG Score = 4); CIS “Off” = -0.855, “On” = -0.907 (CIS Score = 5), Total ECDA Score = 11].



Example 5: Dents and Gouges, Found in Excavation for Coating Defect No. 77, No Coating was Observed in the Vicinity of a Water Service Crossing, Active Corrosion was also Observed at this Location, [51 dBμV (Moderate, ACVG Score = 6); CIS “Off” = -0.853, “On” = -0.893 (CIS Score = 5), Total ECDA Score = 13].



Example 6: Previous Repairs, Found in Excavation during Recoating Project, no associated Total ECDA Score. Repair Appears to Include a Plug or Plate Type Patch as well as Application of Filler Metal to Repair Defects.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy, a Division of Southern Union Company, Concerning a Natural Gas Incident at the Intersection of 107th Street and Blue Ridge Boulevard in Kansas City, Missouri	)))))	File No.: GS-2011-0248

AFFIDAVIT OF STEPHEN J. FISCHER

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Stephen J. Fischer, employee of the Staff of the Missouri Public Service Commission, being of lawful age and after being duly sworn, states that he has participated in the preparation of the accompanying Gas Incident Report, and that the facts therein are true and correct to the best of his knowledge and belief.

Stephen J Fischer
STEPHEN J FISCHER

Subscribed and affirmed before me this 9 th day of December 2011.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

Susan L Sundermeyer
NOTARY PUBLIC

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy, a	)	
Division of Southern Union Company,	)	
Concerning a Natural Gas Incident at the	)	File No.: GS-2011-0248
Intersection of 107th Street and Blue	)	
Ridge Boulevard in Kansas City, Missouri	)	

AFFIDAVIT OF KATHLEEN A. MCNELIS

STATE OF MISSOURI	**)**
	) ss
COUNTY OF COLE	**)**

Kathleen A. McNelis, employee of the Staff of the Missouri Public Service Commission, being of lawful age and after being duly sworn, states that she has participated in the preparation of the accompanying Gas Incident Report, and that the facts therein are true and correct to the best of her knowledge and belief.

Kathleen A. McNelis

KATHLEEN A. MCNELIS

Subscribed and affirmed before me this 9 th day of December 2011.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

Susan L. Sundermeyer

NOTARY PUBLIC