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June 15, 2015

Steve Ripp
NIC Holding Corporation (Northville)
Via Email: stever@northville.com

**Re: Fitness for Service of the Holtsville to Plainview 16-in Diameter Pipeline – Conversion of an Idled Hazardous Liquid Pipeline to a Natural Gas Pipeline**

Dear Mr. Ripp:

At the request of NIC Holding Corp. (Northville), I have reviewed documents and data concerning the design, construction, operation, and maintenance of the 16-in Holtsville to Plainview (HP) pipeline to determine if the plans outlined in the *NIC Holding Corporation Holtsville to Plainview – 16-inch Conversion Plan*, dated May 16, 2015 are sufficient to establish the pipeline's fitness for service once converted to natural gas.

The objectives of this review were to:

- Determine whether Northville has adequate records or data concerning the pipe materials, construction features, and condition of the line to fully understand and manage the integrity threats that could affect the pipeline when converted to natural gas; and
- Determine whether the 16-inch HP pipeline is fit for natural gas service at a maximum allowable operating pressure (MAOP) of 650 psig once the conversion plan is executed (and barring any surprises during implementation of the plan).

## Conclusions

I reviewed the data supplied by Northville, regulatory requirements, industry codes and standards, and best practices to come to the following conclusions:

1. The additional material testing plan proposed by Northville to determine the tensile strength, type of the seam weld e.g., high-frequency (HF) or low-frequency (LF) electric-resistance-welded (ERW), wall thickness, diameter, mechanical and chemical properties, and toughness will provide additional confirmation of the line pipe grade and strength, and consequently the MAOP. Although the number of pipe samples proposed by Northville to be used for tensile testing is not in strict compliance with the requirements in state regulations (Title 16, New York Code, Rules and Regulations (NYCRR) Section II-D of Appendix 14-B), a study carried out by Integral Analytics shows that the proposed number of samples can be expected to provide a high level of confidence for establishing the material strength of the pipeline. If this high level of confidence can be achieved for pipe tensile properties using the proposed testing

protocol, it is sufficient for meeting the intent in the state regulation, which is to establish the tensile properties with a high level of confidence. As will be discussed below, NIC also plans to perform a hydrostatic test that will provide even greater assurance as to a minimum yield strength value.

2. The February 2013 hydrostatic pressure test to 1,310 psig (approximately 2 times the proposed MAOP) for 12 hours confirmed the fitness for service of the pipeline for its proposed MAOP of 650 psig. Another 12-hour hydrostatic test is planned prior to the conversion to a minimum test pressure of 1,220 psig (approximately 1.8 x the proposed MAOP of 650 psig). The test will be performed in accordance with provisions of ASME B31.8, Appendix N5 to identify whether yielding occurs. This test is required under Title 49 CFR Part 192, Paragraphs 192.14 and 192.619(a)(1) for any conversion to gas service where any variable required by the steel pipe design formula is unknown, rather than sample testing. Such a test is superior to any material testing based on a sampling protocol because it in fact tests every joint of pipe to establish an in-situ minimum yield strength value for the entire pipeline. A pressure test with full monitoring and analysis of pressure versus volume, whether yielding occurs or not, would actually make sample testing unnecessary. This test will also confirm that the fitness for service of the line has not degraded since the 2013 hydrostatic test. The concept of pressure testing to establish the ability of a pipeline to safely hold pressure at a lower level is an accepted practice incorporated into pipeline regulations, and that is both logical and supported by industry experience and research. NTSB and PHMSA have recommended and required, respectively, hydrostatic pressure testing to revalidate pipeline operating pressures. The proposed test will be performed to a sufficient margin above MAOP to assure the integrity of the pipeline well into the future assuming routine maintenance practices such as cathodic protection monitoring and damage prevention programs continue to be implemented in accordance with applicable regulations and industry practices.

3. An assessment of the features reported by the most recent 2012 inline inspection (ILI) shows that all the features reported by this inspection are safe for operation at the proposed MAOP of 650 psig, have sufficient safety margin against failure, and the hoop stress in the pipeline at the location of unrepaired features meets the requirement of a maximum stress limit of 40% of SMYS permitted by regulation for a Class 4 location.[1] Comparison of the internal corrosion features reported by Rosen in 2012 and 2007 did not provide evidence of any significant active corrosion in the pipeline during this period. Prior to conversion another ILI will be conducted using a high resolution ultrasonic inspection wall measurement tool (UTWM) combined with a magnetic flux leakage (MFL) ILI tool to identify features that could harbor cracks, such as deformations and hard spots. The results will be aligned with previous 2012 and 2007 ILI reports to identify areas with active metal loss and any other possible locations needing remediation.

4. Corrosion and third party damage are the most significant threats to the integrity of the 16-inch HP pipeline. The measures outlined in Northville's Conversion Plan are sufficient

[1] The ILI tool's measurement error was considered in this assessment.

to validate the integrity and fitness for service of the 16-inch HP pipeline prior to operation in natural gas service.

I believe that the overall strategy in the Conversion Plan proposed by Northville for converting the 16-inch HP pipeline to gas service is sound. This plan, together with the actions proposed by Northville for verifying the material properties of the HP pipeline satisfies the requirements in the state and federal regulations (16 NYCRR 255 and 49 CFR 192), and applicable requirements of ASME B31.8, a best practice for operation of a gas pipeline.

These conclusions represent my professional opinion based on fact, observation, and interpretation of information provided by Northville.[2] The bases for my conclusions are discussed below.

### Task 1: Determine whether Northville has adequate records or data concerning the Holtsville to Plainview 16-inch pipeline

For Task 1, a large number of records concerning the 16-inch HP pipeline were reviewed including:

- The NIC Holding Corporation Holtsville to Plainview – 16-inch Conversion Plan, dated May 16, 2015.
- Test records from hydrostatic pressure tests conducted in January and February 2013.
- Results of metallurgical examinations and tests of pipeline failures during pressure testing in January 2013 and June 1995.
- ILI from 1996, 2000, 2007, and 2012. The 1996 ILI was carried out by TDW using a geometry tool, while the remaining ILIs were carried out by Rosen using high-resolution MFL and geometry tools.
- Field measurements of specific features identified by ILI tools.
- Yearly pipe to soil potential readings for test stations along the pipeline route dating back to September of 1977.
- Pipe to soil potential readings from close interval surveys (CIS) conducted in 1989, 1995, and 2007.
- File summaries of releases, extrinsic incidents, lowering and relocations, and anomaly repairs.
- Documentation related to design standards and construction specifications.
- Class location surveys and pipeline maps.
- Northville's Hazardous Liquid Integrity Management Plan, dated December 2006.

The purpose of my review of these records was to determine whether Northville has sufficient information to:

1. Select an appropriate operating pressure for the converted pipeline and comply with natural gas regulations;
2. Possess awareness of threats to pipeline integrity;
3. Perform appropriate maintenance and repair activities; and

[2] The scope of use of the information presented herein is limited to the facts as presented and examined, as outlined within the body of this document. No additional representations are made as to matters not specifically addressed within this letter. Any additional facts or circumstances in existence but not described or considered within this report may change the analysis, outcomes and representations made in this letter.

4. Execute integrity management activities.

The original design and as-built documents for the 16-inch HP pipeline were not available for review. However, Northville has made several efforts to verify the line pipe material properties and will continue to supplement this information during implementation of the Conversion Plan. These verification efforts are based on engineering analyses and testing that were completed on sections of pipes that failed during previous pressure tests and on available documents from individuals familiar with the pipeline construction. Available information will be supplemented with pipe property data gathered during the material testing program proposed in the Conversion Plan.

Currently, available records indicate the 16-inch HP pipeline is constructed from API 5L Grade X52 ERW line pipe of 0.250-inch and 0.281-inch nominal wall thickness[3]. The original mill test pressure was documented as 1,622 psig, approximately 2.5 times the MAOP of 650 psig[4]. My review of the documentation provided by Northville found that the description of the pipe is based on documentary evidence of some type, even though much of the evidence relies on first-hand recollections from individuals involved in the pipeline construction.

As part of the HP Pipeline Conversion Plan, Northville plans to supplement the evidence from first-hand accounts of construction with metallurgical analyses at 38 dig locations along the HP pipeline. These analyses will establish the wall thickness, seam type, mechanical, and chemical properties for the pipe body and heat affected zone (HAZ) in each location. The decision to excavate and cut out pipe from 38 locations was based on a study that was completed by Integral Analytics Inc.[5], which established that it is possible to use 38 test samples to establish the tensile properties of the pipe within 3%, and with a 97% confidence. Although not in strict accordance with the sample quantity specified in state regulations (16 NYCRR section II-D of Appendix 14-B), it is evident that the proposed sample plan provides a high level of confidence, which is consistent with the intent of the regulations.

The fact that Northville may not know all facts about every piece of pipe or component in the 16-inch HP pipeline does not cause me great concern considering that the pipeline in its current condition was successfully pressure tested in 2013 to a level that supports the MAOP of 650 psig. The most recent hydrostatic test confirmed the ability of the pipeline to safely operate at the MAOP for at least the near-term future. Moreover, Northville plans to conduct another hydrostatic test to a minimum pressure of 1,220 psig in accordance with provisions of ASME B31.8, Appendix N5 for monitoring pressure versus volume during the test and determining whether yielding occurs. A test performed in this manner is required under 192.14 and 192.619(a)(1) for conversion to gas service where any variable required by the steel pipe design formula is unknown, rather than determining strength by sample testing. Such a test is superior to sample testing as required by 16 NYCRR because it tests every joint of pipe to establish a minimum in-situ yield strength value for the entire pipeline. The MAOP must then

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[3] There have been system modifications since construction of the HP pipeline in 1973. Northville's Conversion Plan provides a list of pipeline components that were installed in 1985 including 720 feet of 16-inch outer diameter (OD), 0.375-inch wall thickness, API 5LX-42 ERW line pipe; fourteen 16-inch OD, 0.375-inch wall thickness MSS SP-75 WPHY-Y42 elbows; one 2-inch 800# Gate Valve, Elbow; and two 1-inch 800# Gate Valves.

[4] Geraghty & Miller, Inc., *"Evaluation of the Hydrogeologic Environment of the Northville Pipeline in Nassau and Suffolk Counties Long Island"*, New York, June 1973.

[5] The report by Integral Analytics, Inc. was not part of my review and therefore I did not independently verify the findings from this report. The margin of error and confidence level was as quoted in the Conversion Plan.

be established using 80% of the test pressure that produces yielding,[6] divided by the standard test pressure ratio (1.25 for Classes 1 and 2, or 1.5 for Classes 3 and 4). For an anticipated Class 3 location this would result in a minimum necessary test pressure ratio of 1.875. This test will also further affirm the 16-inch HP pipeline integrity and demonstrate that the integrity has not degraded since the 2013 pressure test.

The basis for my opinion regarding the value of pressure testing as a means of establishing the integrity of the pipeline is discussed in detail in Task 2. I also believe that the data sources retained by Northville are sufficient for Northville to understand the integrity threats that could affect the 16-inch HP pipeline.

## Task 2 – Determine whether the 16-inch HP pipeline is fit for natural gas service at a maximum allowable operating pressure (MAOP) of 650 psig once the conversion plan is executed

Northville's Conversion Plan outlines activities necessary to safely convert the 16-inch HP pipeline from a hazardous liquid to a natural gas pipeline operating at an MAOP of 650 psig. The main assessments outlined in the plan are:

- Pipe material verification
- Hydrostatic testing to confirm MAOP
- Inline inspection for integrity threats (metal loss, cracks, deformation, and hard spots)
- Aboveground surveys and inspections (cathodic protection, exposed pipe segments, right of way)
- Repair/Replacement of items requiring remediation
- Documentation and training

The question of whether the 16-inch HP pipeline will be fit for natural gas service can be evaluated in terms of: (1) whether there is evidence that integrity threats mitigated by the 2013 hydrostatic test and 2012 ILI repairs have worsened; (2) whether integrity threats not mitigated by the 2013 hydrostatic test and pipeline repairs appear to be affecting the pipeline; and (3) whether Northville's Conversion Plan effectively addresses integrity threats that may worsen or were not mitigated by the previous hydrostatic testing or inspections.

These issues were addressed by considering each category of pipeline integrity threat identified for integrity management purposes by ASME B31.8S and as specified in 49 CFR 192, Subpart O – Gas Transmission Pipeline Integrity Management, Paragraph 192.917. The integrity threats specified by ASME B31.8S are: external corrosion, internal corrosion, stress-corrosion cracking, pipe manufacturing defects, construction/fabrication-related defects,[7] equipment,[8] mechanical

[6] It is unnecessary for actual yielding to occur. If the entire line remains elastic, one cannot be sure that it would not have yielded at a slightly higher pressure; in that case the highest pressure achieved is taken to represent a minimum in-situ yield pressure.
[7] The construction/fabrication-related defects category includes a features associated with older vintage or obsolete methods of constructing pipelines such as couplings, miter bends, and wrinkle bends, as well as defective girth welds or fabrication welds (but not seam welds made during manufacturing of pipe).
[8] The equipment-related integrity threats category includes faulty mechanical equipment or components thereof, and failures of pressure relief and pressure control devices or systems.

damage,[9] incorrect operation, and natural events.[10] Federal regulations supplement the potential threats list by requiring specific procedures to address the following conditions: those that could cause fatigue; pipe manufacturing defects, construction features, or ERW seams that have experienced prior failures or where an increase in operating pressure has occurred; and coating materials and environments where corrosion has previously occurred; however, these additional requirements are elaborations of integrity threat categories already defined by B31.8S. Each threat category was examined in light of available information to ascertain whether important, or any, degradation in the integrity of the 16-inch HP pipeline has occurred since the last integrity assessments (2012 ILI and 2013 hydrostatic test).

1. External Corrosion

Corrosion is a natural process driven by chemical energy that seeks to reduce the binding energy of metals. At the anode, iron ions become dissociated from the pipe surface, releasing electrons that travel a conductive path to the cathode where they combine with hydrogen ions to preserve overall electrical neutrality, evolving hydrogen gas in the process. External corrosion of steel pipelines in the soil environment is prevented by an external barrier coating.

The coating protecting the 16-inch HP line is factory-installed plasticized coal tar enamel with fiberglass felt wrap. Field joints are a polyurethane wrap. The selected coatings do not shield the pipe from the cathodic protection (CP) current.

All pipeline coatings are potentially susceptible to a number of damage or deterioration mechanisms (e.g., mechanical damage, cracking, disbondment) over time. Secondary protection from corrosion is provided by CP systems. Corrosion being an electrochemical process involves the flow of electrons, which means it can be influenced by a voltage. The CP system applies a voltage so as to assure that electrical current flows from the soil environment onto the pipe surface at all points where the pipe surface is exposed, thus preventing or slowing the rate of corrosion. Steel gas pipelines are required by regulations to be cathodically protected. The functioning of the CP system is monitored by periodically checking the pipe-to-soil electrical potential at test leads spaced at long intervals (e.g. every half mile to several miles) along the pipeline. Regulations and industry standards specify that potentials more negative than −850 millivolts (mV) indicate effective cathodic protection.

Northville has monitored CP levels at 55 test stations along the 16-inch HP pipeline on a yearly basis since approximately one year after the HP pipeline began operation. During this time there have been periods when low potential readings were observed along the westerly portion of the HP pipeline due to stray currents from the Long Island Railroad and the Long Island Lighting Company (LILCO). Over the years of operation, Northville monitored the effects of these stray currents and maintained adequate ON potentials in these locations. More recently, the Plainview rectifier had been removed when the pipeline was idled in November 2008 and therefore only the Holtsville half of the HP pipeline maintained adequate CP levels from November 2008 to November 2012 when a new Plainview rectifier was installed.

Northville conducted an ILI with a dual purpose (geometry and MFL) tool in October 2012. The majority of external corrosion features were reported along the westerly portion of the HP

[9] The mechanical damage category includes damage caused by contact from any type of equipment that works in the soil (such as construction or agricultural equipment) and operated by any party (the operator, his contractor, or an unaffiliated person), latent damage caused previously, and vandalism.

[10] The natural events category includes flooding, storms, frost heave, earthquake, ground subsidence, and slope instability, among many other phenomena.

pipeline near Plainview. Verification digs were performed at two locations with reported metal loss greater than 50%. Measurements in the ditch indicated that the anomaly depths were less than what was reported during the ILI. Both anomalies were repaired with a Clockspring composite wrap repair. Additional repairs were conducted in 2012 to remediate anomalies reported during a 2007 ILI. In two locations, the anomalies were cut out and sections of the pipe replaced to remediate a dent with 86% metal loss and a location with 53% metal loss. Four other locations with metal loss greater than 48% were repaired with Clocksprings.

Although there have been periods when portions of the HP pipeline were under-protected by the CP system and the ILI indicates more extensive external corrosion along the westerly portion of the HP pipeline, the 2013 hydrostatic test verified that no external corrosion existed at that time that could cause a rupture.

Since the last hydrostatic test, a 2014 annual CP survey was conducted demonstrating that the corrosion prevention system has continued to provide effective mitigation of external corrosion in most locations along the HP pipeline. Locations between test station 24 and 34 did exhibit some low OFF potential readings (minimum of -0.594 mV at test station 28) as well as low ON potential readings at test stations 28 and 29 (0.756 and 0.770, respectively).

Even though there have been low CP readings since the last integrity assessment, Northville's Conversion Plan will address whether the external corrosion threat may have worsened through 1) a hydrostatic test to 1,220 psig (approximately 1.8 x the proposed MAOP); 2) inline inspection using a high resolution UTWM tool in combination with an MFL tool configured to identify features that could harbor cracks such as deformations and hard spots; 3) CIS and direct current voltage gradient (DCVG) surveys to determine coating and CP effectiveness; 4) UT wall thickness measurements of exposed pipe; 5) repair/replacement of broken or malfunctioning CP components; and 6) repairs of any threats identified in these inspections and tests that may affect the pipeline integrity.

2. Internal Corrosion

Internal corrosion occurs in natural gas pipelines where either significant quantities of free water accumulate, or where moisture plus gas impurities such as $CO_2$ are present enabling the formation of acidic fluids. Moisture enters natural gas pipelines from gas production or storage formations. The HP pipeline is expecting to receive gas from Iroquois or Algonquin pipelines which are well downstream of gas production or storage wells and which transport consumer quality gas with sufficiently low levels of moisture and impurities that internal corrosion does not appear to be an integrity threat.

Inline inspections conducted when the HP pipeline was in hazardous liquid operation did suggest that internal corrosion was an integrity threat that affected the HP pipeline prior to it being idled in 2008. However, the 2012 ILI did not indicate any active internal corrosion and the 2013 hydrostatic test effectively demonstrated the integrity of the pipeline with respect to internal corrosion to the same extent as with external corrosion. Moreover, with the activities spelled out in the Conversion Plan, Northville will mitigate this threat through 1) a hydrostatic test to 1,220 psig; 2) inline inspection using a high resolution UTWM tool in combination with an MFL tool configured to identify features that could harbor cracks such as deformations and hard spots; 3) UT wall thickness measurements of exposed pipe; 4) air sampling for contaminants (iron oxide) and to measure dew point; 5) repairs of any threats identified in these inspections and tests that may affect the pipeline integrity; and 6) pipeline cleaning and drying prior to natural gas operation.

## 3. Stress-Corrosion Cracking

Stress-corrosion cracking (SCC) is a form of environmentally induced cracking. SCC requires three factors to be present: a susceptible material (which all commonly used grades of line pipe are), a tensile stress (which is usually present with a pressurized pipe), and a conducive environment. Two forms of SCC are recognized to affect natural gas pipelines, "high-pH" and "near-neutral-pH". Typically only one form of SCC affects a pipeline, and not all pipelines are susceptible to either form of SCC.

High-pH SCC occurs in a narrow range of cathodic potentials, −600 mV to −750 mV and pH above 9 representing an impaired cathodic condition,[11] and elevated pipe operating temperatures (usually in excess of 90° F) associated with operating downstream of compressor stations that do not implement aftercooling. Near-neutral-pH SCC occurs at the free corrosion potential as occurs in an absence of CP, or with shielding of the pipe from CP, and pH between 5.5 and 7.5, normal soil temperatures, and strictly anaerobic conditions. Soil type, hydrology, and coating type affect the potential for the local environment at the pipe surface to support SCC.

Both forms of SCC require the presence of a moderate to high tensile stress, oriented either longitudinally or circumferentially. Stresses below 50% of SMYS are generally considered to indicate a low susceptibility to SCC even if the electrochemical environment that supports SCC is present. At the MAOP of 650 psig, the HP pipeline would operate at hoop stresses less than 50% of SMYS based on known pipe attributes, including the pipe replacements. (The calculation of hoop stress as a percentage of SMYS does not account for seam joint efficiency factors that are less than 1.0, which need not be considered in the calculation when reconfirming or revising the MAOP under Paragraph 192.611 based on a pressure test.[12])

The 16-inch HP pipeline is not anticipated to operate downstream of compression or at warm temperatures, and is therefore not considered to be susceptible to high-pH SCC. The selected coating type does not inherently shield the pipe from cathodic protection current, reducing the susceptibility to near-neutral-pH SCC. In review of inspection and repair documents, Northville has never identified SCC of either type in its system when operating as a hazardous liquid pipeline. It is noted that the conditions that support microbe induced corrosion (MIC) are similar to those that support near-neutral-pH SCC except for the stress threshold. Northville has not heretofore identified MIC or suspected MIC on the 16-inch HP pipeline, so this can be interpreted to indicate that the environmental conditions that would support near-neutral-pH SCC also appear to be absent.

SCC does not appear to be an integrity threat of concern with the 16-inch HP pipeline, but in any case the 2013 hydrostatic test was effective to establish the integrity of the pipe with respect to SCC. The CP readings indicate that cathodic protection levels continue to be maintained at levels effective for prevention of SCC. Northville's plans to inspect rectifier and anode installations (as well as performing CIS and DCVG surveys), install test stations at all casings, and repair any broken or malfunctioning CP equipment during the conversion will further mitigate any SCC threats.

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[11] National Energy Board, "Public Inquiry Concerning Stress Corrosion Cracking on Canadian Oil and Gas Pipelines", Report of the Inquiry, MH-2-95, November 1996.

[12] DeLeon, C., Assoc. Dir. for Pipeline Safety Regulation, letter to Dolgoy, D., PHMSA Interpretation PI-79-035, October 12, 1979.

## 4. Pipe Manufacturing Defects

Pipe manufacturing processes can cause defects in the pipe. Defects located in the longitudinal seams are potentially susceptible to failure due to enlargement in service from the effects of operational pressure cycles. The most severe pipe manufacturing defects are eliminated by nondestructive testing and hydrostatic pressure testing of pipe joints at the pipe mill. API 5L required a pressure test at the pipe mill for all X-grades of 16-inch pipe to a nominal hoop stress of 85% of SMYS starting in 1949. The required mill test pressure for the 16-inch HP line was 1,380 psig, which is more than double the proposed operating pressure.

Natural gas pipelines tested to an adequate margin above the MAOP are not generally susceptible to fatigue crack growth (especially relative to liquid transportation pipelines).[13, 14] The occurrence of the San Bruno incident demonstrated that absent a pressure test to a sufficient level that eliminates gross defects, pressure cycles in natural gas service can induce fatigue, and is not inconsistent with the findings of referenced studies. A pressure test to 1.25 times the MAOP has been considered adequate to avoid this problem in a highly-stressed pipeline, because the test imposes a very high stress that only small flaws can survive. However, 1.25 times MAOP may not be adequate for a pipeline operating at low to moderate stresses because the stress imposed by the test is low enough to be survived by comparatively large defects. Large defects grow faster by fatigue than small defects. Therefore, it is necessary to increase the test pressure ratio from 1.25 in pipe operating at low to moderate stress levels as the 16-inch HP pipeline has and will operate once converted.

The 2007 ILI reported five manufacturing anomalies while the 2012 ILI reported nine manufacturing anomalies. Comment in the 2007 report indicated that they may potentially be laminations in the pipe wall. The date of construction of the pipeline in 1973 suggests that the manufacturing features have survived a mill test at a pressure substantially greater than the proposed MAOP of 650 psig (40% of SMYS). Following repairs in 2012, the pipeline was hydrostatically tested for 90 minutes at 1,550 psig (approximately 95% of SMYS, at which point a mechanical damage defect failed) and subsequently for 12 hours at a pressure level of 1,310 psig (approximately 81% of SMYS). All the reported manufacturing features have survived numerous hydrostatic tests, and more severe pressure cycling in previous liquid operation without evidence of significant growth or failure.

Prior to the conversion, Northville plans to 1) conduct another hydrostatic test to 1,220 psig (approximately 1.8 x the proposed MAOP); 2) run a high resolution UTWM tool in combination with an MFL tool configured to identify cracks, deformation, and hard spots; and 3) repair any threats identified in these inspections and tests that may affect the pipeline integrity. Based on these results and overall considerations for the value of hydrostatic pressure testing, the 16-inch HP pipeline is not expected to be susceptible to premature failure in pipe seam or pipe body manufacturing defects at the proposed MAOP of 650 psig.

## 5. Construction/Fabrication Defects

The principal concern with construction or fabrication-related integrity threats are the installation of components associated with now-obsolete construction methods such as wrinkle bends, miter bends, or couplings (for example), or low-strength or poor quality girth welds. Such components generally do not fail solely due to internal pressure. The explanation for this

[13] Kiefner, Stability of Manufacturing and Construction Defects.
[14] Kiefner, J.F., and Rosenfeld, M.J., "Effects of Pressure Cycles on Gas Pipelines", Gas Research Institute, GRI-04/178, September 17, 2004.

is that, in a buried pipeline, the longitudinal stress (which is the stress component that would act to separate a girth weld, coupling, bend, or other feature) is only 30% of the hoop stress. So even in a pipeline operating at a very high hoop stress, the stress component induced by pressure acting to separate the pipeline feature is very low. Instead, these types of pipeline features are usually stable unless they become exposed to very high external loadings, typically soil movement associated with natural events. Consequently the 2013 hydrostatic test (and any future hydrostatic test) was not an effective assessment or mitigation for this integrity threat category. Exposure to threats associated with natural events is discussed later in this letter, so this section focuses on whether potentially threatened components exist within the 16-inch HP pipeline.

The use of wrinkle bends, miter bends, and couplings in pipeline construction generally ceased in the 1950s, well before the 16-inch HP line was constructed. None of the documents provided by Northville indicated the presence of such features in the 16-inch HP pipeline. Such features would be identified in the course of conducting in-line inspection.

Since the 1950s pipeline girth welds have been required to be produced by qualified welders using qualified welding procedures, but girth welds may nevertheless contain workmanship flaws. The pipeline welding standard API 1104 provides for detection of welding defects by nondestructive examination (typically radiography), and limits the size of such defects so as to assure adequate strength for normally encountered operating conditions.

Although radiographic reports, qualified welding procedures, and technician qualification records were not available for review, first-hand accounts from individuals involved in the construction of the 16-inch HP pipeline affirmed that 100% of all girth welds were radiographed during construction and all unsatisfactory girth welds were rejected. In addition, the most recent 2012 MFL ILI did not report significant girth weld anomalies and historically there have not been reports of girth weld leaks or failures in the 16-inch HP pipeline.

Several areas of the pipeline were relocated or lowered during construction of the Long Island Expressway (LIE) service roads in the 1990s. Line lowering has proven to be a routine and reliable practice. Northville's Conversion Plan states that engineering calculations prepared by Northville for pipe segment relocations or replacements assumed and support a maximum operating pressure of 650 psig. I was not provided with these calculations to verify this assertion. Data from the high resolution geometry ILI tool that will be run prior to pipeline conversion should be used to analyze the stresses at locations where the curvature corresponds to a section of pipeline that has been lowered to verify that it remains within allowable stresses and that these locations are not a credible threat.

6. Equipment

No leaks have been identified on the 16-inch HP pipeline as a result of equipment failure. Moreover, new equipment such as valves, overpressure protection devices, and metering will need to be installed during the conversion. As part of Northville's Conversion Plan, they will be conducting a hydrostatic test to 1,220 psig and generating a pressure-volume plot to validate the fitness for service and provide assurance that no undocumented materials of unsuitable design exist in the HP pipeline.

Generally, equipment failures are not a significant integrity concern as long as the equipment is operated and maintained according to the manufacturer's specifications and company operating procedures.

7. Incorrect Operation

Incorrect operation refers to an incorrect action or judgment caused by human factors or human error that could directly or indirectly cause a hazard or incident.[15] The primary incorrect operation conditions that could affect the 16-inch HP pipeline are overpressure events not caused by equipment malfunction. Suitable company operating procedures and staff training should be sufficient to control this threat. Assuming Northville develops and implements the programs outlined in Section 7 of their Conversion Plan (operating procedures, emergency response procedures, integrity management plan, control room management and training plan, operator qualification and training program, and gas commissioning plan and checklist), any threat associated with incorrect operation will be appropriately mitigated.

8. Mechanical Damage

Mechanical damage refers to damage caused by accidental contact between mechanized equipment and the pipe surface. Examples of equipment that can cause such damage include backhoes, bulldozers, plows, ditchers, and borers, to name a few. Mechanical damage introduces a scrape or gouge, usually in conjunction with an indentation (though the indentation may re-round under internal pressure in the pipe). The resulting damage is highly detrimental to the strength of the pipe due to surface and subsurface metallurgical damage locally to the scrape or gouge. There are no reliable methods for calculating the safe operating pressure of a piece of pipe affected by mechanical damage, although pipelines operating at low to moderate stresses can tolerate more severe damage than pipelines operating at the highest stresses. In any case, applicable pipeline standards and regulations require pipeline operators to conduct vigorous damage-prevention programs, respond promptly to requests by excavators to locate buried pipelines, and to promptly repair the pipe where mechanical damage is discovered to have affected the pipe.

Several incidents related to mechanical damage have been previously reported for the 16-inch HP pipeline. Two hydrostatic test failure investigations conducted by Lucius Pitkin Inc. (one in 1995 and the other in 2013) concluded that the failures were attributed to latent mechanical damage. Three mechanical damage incidents occurred in the 1980s and one incident occurred in 1991 which resulted in a loss of containment. Each defect was repaired, one with a PLIDCO sleeve, one with a coating repair, and two removed from the pipeline. The 1996 TDW Caliper survey also discovered two large dents attributed to mechanical damage. Both dents were removed from the pipeline. The 2000 ILI discovered several additional mechanical damage defects that were repaired in 2001 by removal from the pipeline. A dent was also discovered by the 2007 ILI which was removed from the pipeline in 2012. Northville believes that most of these third party damage incidents occurred prior to the widespread adoption of the One-Call system in New York City and Long Island (established in 1990) and during periods of intense road construction activities along the pipeline right of way (ROW). In addition, the latent mechanical damage that failed during the initial 2013 hydrostatic test to 1,550 psig was reported by Northville as being below the detection threshold of the ILI tools previously used.

Although existing, and planned mitigation measures are likely to minimize the risk from mechanical damage, it is difficult to completely rule out the possibility of occurrence of mechanical damage considering that the pipeline route passes through a highly built up area and that road construction or maintenance activities are likely to occur in the future. As such, Northville actively engages in a variety of damage prevention practices and programs to further

[15] http://primis.phmsa.dot.gov/comm/FactSheets/FSIncorrectOperation.htm?nocache=4528.

reduce the risk. According to the Conversion Plan, Northville has continued to perform biweekly right of way inspections. The pipeline remains in the National Pipeline Mapping System (NPMS) and Northville participates in the One-Call System, checking notifications each day and responding to mark-out requests.

As evident by the 1995 and 2013 pressure tests, hydrostatic pressure testing is an effective way to assure that gross mechanical damage is not present on a pipeline. Any undiscovered or unrepaired mechanical damage that survived the 12-hour hydrostatic test carried out in 2013 to a pressure level of 1,310 psig and the recommended spike test prior to conversion to gas service is unlikely to fail during future gas operation. The hydrostatic test and ILIs planned prior to conversion should be capable of identifying any significant damage to the pipeline that may have occurred between 2013 and the date the pipeline is put back into service. Any identified significant mechanical damage can be repaired before resumption of service and is not likely to be an issue during future operation.

9. Natural Events

Northville discussed its knowledge about the geotechnical conditions affecting the area crossed by the 16-inch HP pipeline. The HP pipeline is not installed in a seismically active area and the ground in which it is installed is not subject to washouts from flooding. The pipeline route is located in heavily built up areas and along roads where significant amount of earthworks that may disturb the soil and potentially cause earth movement is unlikely.

The documents reviewed in this study and discussions with Northville did not reveal any evidence of frost heave due to extreme cold ground conditions in the pipeline route. If gas and valve operations are carried out appropriately and according to accepted procedures, such that gas cooling that may result from a 'Joule Thompson type' effect which can be caused by an adiabatic expansion of gas is minimized, it is unlikely that the pipeline will experience significant issues relating to frost heave.

Damage to the pipeline resulting from a lightning strike has previously occurred. Lightning during a thunderstorm caused a LILCO transmission line counterpoise to arc through the insulation and pipe wall resulting in a hole (approximately ½ inch in size) in the pipeline. The continued presence of this transmission line in the pipeline route and the potential for lightning during thunderstorms means that this remains a credible threat. Lightning damage can produce a small hole in the pipe (about ¼ inch in diameter), resulting in a leak. I am unaware of lightning causing a pipe rupture. Odorization of the gas will promote prompt recognition of such a leak.

This completes my evaluation of the status of the 16-inch HP pipeline. If you have further comments or questions please feel free to contact me at (614) 410-1602 or Michael.Rosenfeld@applusrtd.com.

Sincerely,

Michael J. Rosenfeld, PE
Chief Engineer

MJR:tb

# Michael J. Rosenfeld, P.E.
**Chief Engineer**
**Kiefner/Applus-RTD**

## Education

B.S., Mechanical Engineering, University of Michigan, 1979
M.S., Mechanical Engineering, Carnegie-Mellon University, 1981

## Qualifications

Since joining Kiefner & Associates, Inc. in 1991 Mr. Rosenfeld has participated in a broad range of pipeline-related projects including fitness-for-purpose assessments, loading and stress analyses, failure investigations, codes and standards development, and research. Mr. Rosenfeld was President of Kiefner & Associates, Inc. from 2001 through 2011 when KAI was acquired by Applus-RTD.

## Relevant Experience

**Fitness-for-Purpose.** Determined that mechanical damage features identified on a major oil pipeline were not immediate integrity threats, enabling the operator to avoid pressure reduction and immediate investigation, and realize significant cost savings. Assisted pipeline operators with successful waivers to operate in the US at 80% of SMYS by demonstrating fitness of the lines for uprated service.

**Pipeline Stress Analysis.** Analyzed numerous pipelines for stresses induced by external loadings due to spanning, currents in water crossings, and soil movement due to subsidence or settlement. Established criteria for monitoring or mitigation based on condition of the lines.

**Failure Investigation.** Performed investigations of failures in line pipe, appurtenances, and mechanical equipment involving diverse causes of failure such as manufacturing defects, fatigue, hydrogen cracking, stress-corrosion cracking, soil movement, welding practices, and corrosion.

**Codes and Standards.** Primary author of major revisions to the ASME B31.8 code concerning longitudinal stress design, and evaluation and repair of mechanical damage. Primary author of major rewrite of ASME B31G-2009.

**Pipeline Research.** In research projects for PRCI and GTI, demonstrated the application of B31G for pipe bends and elbows, the importance of dent shape on fatigue behavior of dents, and a method for evaluating dents affecting welds; was the first to evaluate dent strain as a screening tool; developed a criterion now in ASME codes for evaluating ripple deformations in bends; prepared comprehensive review of research on mechanical damage; demonstrated low susceptibility of gas pipelines to pressure-cycle fatigue.

## Professional Affiliations

Member, ASME B31.8 Gas Transmission Piping Systems Section Committee
Chair, B31.8 Subgroup on Design, Materials, and Construction
Member, ASME B31 Mechanical Design Technical Committee
Member, ASME B31 Standards Committee
Member at Large, ASME Board of Pressure Technology Codes and Standards
Member, B31 Forever Award Nominating Committee
Former Member, Joint ASCE-ASME Task Group on Design of Buried Pipe
Former Member, API RP-1117 Task Force on In-Service Relocation of Pipelines
Instructor, ASME Professional Development Short Course on ASME B31.8 Code
International Pipeline Conference 2006, Session Chair, Mechanical Damage
International Pipeline Conference 2010, Session Chair, Structural Integrity I
ASME Fellow, awarded January 2012
Registered Professional Engineer, State of Ohio

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