# Exhibit 2

# Declaration of Richard Kuprewicz

**UNITED STATES COURT OF APPEALS**
**FOR THE DISTRICT OF COLUMBIA CIRCUIT**

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| **CITY OF BOSTON, DELEGATION** | ) | |
| | ) | **DOCKET NO. 16-1081** |
| | ) | **consolidated with** |
| | ) | **16-1098, 16-1103** |
| **TOWN OF DEDHAM, MASSACHUSETTS** | ) | |
| **RIVERKEEPER, INC. *et al.* PETITIONERS** | ) | |
| **v.** | ) | |
| **FEDERAL ENERGY REGULATORY COMMISSION** | ) | |

## DECLARATION OF RICHARD KUPREWICZ

Pursuant to 28 U.S.C. § 1746, Richard Kuprewicz hereby declares as follows:

1. My name is Richard Kuprewicz and I am president of Accufacts Inc. located at 8040 161st Ave NE, #435, Redmond, WA 98052.

2. As a chemical engineer and president of Accufacts Inc., I specialize in gas and liquid pipeline investigation, auditing, risk management, siting, construction, design, operation, maintenance, training, SCADA, leak detection, management review, emergency response, and regulatory development and compliance. See attached CV.

3. I have consulted for various local, state and federal agencies, NGOs, the public, and pipeline industry members on pipeline regulation, operation and design, with particular emphasis on operation in unusually sensitive areas of high population density or environmental sensitivity.

4. I am currently representing the public as a member of the federal Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC), a technical committee established by Congress to advise the Pipeline and Hazardous Materials Safety Administration (PHMSA) on pipeline safety regulations. The Committee members are appointed by the Secretary of Transportation.

5. On November 21, 2014, the Town of Cortlandt submitted to FERC an expert report I had prepared on their behalf which commented on the Draft Environmental Impact Statement for the AIM Project. See attached report (R. 1633). In this report I explained my opinion

that the Safety Evaluation and Analysis for the Indian Point Nuclear Plant ("IPEC") submitted by Entergy to NRC concerning the risk associated with the 42-inch AIM pipeline is seriously deficient and inadequate.

6. A 42-inch pipeline rupture would be a far greater release event than that from the pre-existing 26- or 30-inch lower MAOP (Maximum Allowable Operating Pressure) gas transmission pipelines that had previously been operating in close proximity to IPEC.

7. A primary deficiency in Entergy's Analysis, which was approved by the NRC, is the critical assumption of a three minute response time to identify, acknowledge, and close appropriate gas mainline remote isolation valves in the event of a pipeline rupture.

8. This assumption is unrealistically optimistic, ignoring both systemic dynamics (compressor and pipeline system rupture dynamics/interactions that mask remote rupture identification), uncertainty in the SCADA monitoring that will further delay remote recognition of a pipeline rupture, and control room operator confusion and related human factors that will also easily further delay control room remote response actions of a pipeline rupture, all of which will work to drive the response time well beyond the assumed 3 minute time.[1]

9. In addition, the 3 minute assumption disregards initial release and subsequent blowdown times dictated by the laws of thermodynamics related to the rupture of pipelines, even large 42-inch gas transmission pipelines.

10. History is filled with clear examples of gas transmission pipeline rupture events generating high heat flux and multiple explosion events well past an hour. Therefore, the 3-minute response assumption in the analysis approved by NRC is highly unrealistic and not appropriate for this sensitive infrastructure site, especially with a 42-inch high MAOP pipeline.

11. On September 25, 2015, the NRC sent a letter to New York State Assemblywoman Sandy Galef responding to her concerns about the agency's analysis of the safety risk posed by the AIM pipeline project's proximity to Indian Point. My review of this letter is part of the FERC record. As explained herein the three major assumptions stated by NRC in its letter clearly demonstrate that the agency's analysis was not conservative and is seriously flawed.[2]

12. NRC stated in this letter: "Based on input from Spectra Energy, the initial analysis assumed a closure time of 3 minutes on pipeline isolation valves. In addition to the 3-

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[1] SCADA stands for Supervisory Control and Data Acquisition, which incorporates various methods to remotely monitor and control the operation of a pipeline, usually through a centralized control center that may and can be located in a different state.

[2] See Accufacts' October 12, 2015 observations on NRC's Response Letter Dated September 25, 2015 Concerning "Indian Point Nuclear Generating Unit Nos. 2 and 3 – Response to Letter Dated August 4, 2015 from New York Assemblywoman Sandy Galef" (R. 2127).

minute valve closure case, the NRC evaluated a bounding case. This second case assumes the upstream side of the ruptured pipe is connected to an infinite source of gas for 1 hour." However, a three minute closure time does not indicate how long the gas has been releasing (at incredibly high rates) out of a pipeline rupture on this specific system at this location before valve and, ironically, after valve closure. The NRC assumption also appears not to consider that gas release even with closed valves will continue at very high rates for a considerable period of time. A transient graph of mass release versus time will indicate a characteristic gas pipeline rupture fingerprint form that will dispel any attempts to quickly remotely identify, much less actually trigger, valve closure even for automatic valves. Such a graph will also reveal the case irrelevancy of a ruptured pipeline connected to an infinite source of gas for one hour in the matter of this safety analysis.

13. The NRC also stated: "The NRC staff modeled a pipe break at the location closest to plant structures. Because of a limitation of the ALOHA software, the staff doubled the predicted gas release from the upstream side of a pipe break to account for flow escaping from both sides of the break. This approach is conservative because in the event of an actual break, the downstream side of the pipe would release much less gas than the estimated release from the upstream side." However, based on many past pipeline rupture investigations I have been involved in, a true transient graph of rupture mass release versus time on this system at the specific location near the Indian Point nuclear plant will easily demonstrate that mass rate of release will be much higher than "double" as assumed by the NRC. While it is true that the downstream side of the rupture pipe will eventually release gas at lower rates than the upstream side, the gas release rates will still be considerable, especially in the early stages of the rupture release. A transient analysis will further demonstrate this point and also prove the NRC analysis is not conservative on this remotely monitored system at this highly sensitive site.

14. NRC further asserted: "For the evaluation of the explosion hazard, the NRC used the peak gas release rate resulting from a pipe rupture to estimate the mass of natural gas. This approach predicts more gas released than other approaches such as a time dependent gas release or a release averaged over time." NRC's analysis ignores the reality that transient release rates for a 42-inch pipeline rupture so close to a compressor station will significantly increase "peak rupture rates" well above those of pipeline design capacity, compressor design capacity, and well above "double," as pipe system pressure curves are significantly reduced, compressors run out on their curves, and initial pipeline pressure at time of rupture on both the upstream and downstream ends of the rupture release at the sonic speed in the gas which is higher than the speed of sound. My experience indicates pipeline rupture gas rates of release will be incredibly high, well above the NRC's inferred "double," for quite some time.

15. Furthermore, NRC dismissed the safety risk of the close proximity of the AIM pipeline to IPEC as a very low probability based on unrealistic and unsupported assumptions that released gas from a pipeline only becomes ignited 5% of the time, and that only 1% of pipeline accidents result in a complete pipe break. NRC's analysis ignores the very real possibility that a 42-inch pipeline rupture will occur, and fails to consider the extreme forces associated with such a high pressure large diameter gas transmission pipeline

rupture that always, because of pipe rupture mechanics, releases as dual full bore pipeline releases.

16. Entergy's analysis that was approved by the NRC identified that in the vicinity of IPEC the 42-inch pipeline will be enhanced, or upgraded, to consist of X-70 API 5L grade pipe with a thicker wall thickness of 0.72 inches, buried to a minimum depth of four feet. While I approve of these specific proposed safety enhancement measures to increase the safety of a 42-inch pipeline near IPEC, additional arguments presented in the Analysis are very misleading or inappropriate so as to cause one to underrepresent the real risks of pipeline rupture on/near IPEC, even with the enhancements. These additional arguments are far from complete in preventing a pipeline rupture. For example, the argument to install a concrete barrier over the pipeline to prevent possible damage from third parties at first blush sounds like an appropriate step. Unfortunately, I have seen too many pipeline near misses where such barriers were defeated, negating the effectiveness of such barriers to avoid serious damage to high-pressure pipelines that could result in pipeline rupture.

17. I have yet to see a steel pipeline that cannot be damaged by third party threat activities, especially damage that could result in delayed pipeline rupture. I have seen similar misguided arguments presented in the Analysis that steel pipelines can be made difficult to puncture, reflected in some very poor pipeline risk management approach studies and safety risk analyses trying to improperly convey the impression that pipelines cannot be made to rupture. Delayed pipeline ruptures generating massive explosions and flames are caused by damage that seldom punctures the pipe, but the pipe is weakened to where it eventually fails in time as a rupture, a large pipeline fracture that occurs in microseconds during operation resulting in full bore pipeline releases.

18. An independent risk analysis is needed to more thoroughly assess the impact of a pipeline rupture on IPEC facilities and operation. Such a safety hazard analysis is unique to the IPEC facilities and should thoroughly evaluate and document a process safety management approach to assess the real effect on IPEC of the proposed 42-inch, 850 MAOP, gas transmission pipeline if it should rupture. Given the seriousness of a nuclear plant loss-of-containment incident, that analysis should reflect actual gas rupture dynamics and realistic heat flux release duration and impact for this specific location and system. Such an analysis should be performed and subjected to a true independent process hazard analysis that would assure any equipment loss impacted by such a large diameter pipeline rupture would not prevent the "failsafe" shutdown of IPEC, nor loss of radiation storage containment that could cascade into a radiation release in this highly populated and sensitive location.

19. The stark reality is that pipeline safety regulations and industry standards do not provide FERC with siting precautions for such sensitive locations. Integrity management ("IM") pipeline safety regulations have attempted to instill certain additional safety precautions in such potential High Consequence Areas, or HCAs. Unfortunately, the first phase of these IM regulations, in effect for more than ten years now, have met with very mixed success as evidenced by many high profile pipeline ruptures indicating further

improvements in IM regulation are warranted.

20. To further emphasize the risks associated with new pipelines as well as undermine the myth that new pipelines are immune to pipeline rupture, PHMSA, following various recent new pipeline construction project investigations, held a series of public meetings where PHMSA observed serious deficiencies/problems during the construction phase of new pipelines. Many of these concerns are associated with issues that introduced pipeline threats that could result in future pipeline rupture. The newness of a pipeline does not guarantee that such pipelines are immune from future pipeline rupture from threats introduced from poor construction and/or inspection practices.[3]

21. In addition, in 2015 the National Transportation Safety Board (NTSB), in evaluating the effectiveness of the first generation gas transmission pipeline safety integrity management approach, found many areas needing improvement to prevent gas transmission pipeline ruptures.[4] Specifically during the period in which the databases were comparable, "The NTSB concludes that from 2010-2013, gas transmission pipeline incidents were overrepresented on HCA pipelines compared to non HCA pipelines."[5] Effective regulation of HCAs should have resulted in a downward trend not an over representation. NTSB's observation comes as no surprise to me given my many investigations associated with pipeline rupture, which have uncovered numerous pipeline operator failures to comply with the intent of the integrity management federal minimum pipeline safety regulations.

22. My extensive experience in pipeline rupture investigations, spanning many decades, indicates that Entergy, the NRC, and others making statements that a 42-inch pipeline rupture can be quickly isolated and implying that the pipeline operator can quickly remotely recognize and isolate the pipeline rupture within minutes (such as shutdown in three minutes) are misleading and downright false. A transient pipeline rupture analysis for the proposed 42-inch, 850 psig MAOP pipeline in the vicinity of IPEC needs to be properly performed, subject to independent verification of key assumptions, and gas pipeline rupture possible impacts to IPEC reviewed to confirm that such a rupture event near IPEC and its associated key facilities would not prevent the facilities from safely shutting down and/or place the public at great risks.

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[3] See PHMSA website http://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=151 summarizing issues identified during PHMSA inspection of 35 construction projects.

[4] This 2015 NTSB report was referenced in PHMSA's recent Notice of Proposed Rulemaking Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 FR 20722, 20729 ("The NTSB noted, in a 2015 study, that IM requirements have reduced the rate of failures due to deterioration of pipe welds, corrosion, and material failures. However, pipeline incidents in high-consequence areas due to other factors increased between 2010 and 2013, and the overall occurrence of gas transmission pipeline incidents in high-consequence areas has remained stable.").

[5] See attached NTSB, "Safety Study: Integrity Management of Gas Transmission Pipelines in High Consequence Areas," *NTSB SS-15/01,* January 27, 2015, p. 21.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on September 12, 2016.

Richard Kuprewicz

1. R. Kuprewicz CV
2. Town of Cortlandt Report (prepared by Accufacts), submitted to FERC (November 21, 2014), R. 1633
3. Accufacts Comments (October 12, 2015) re: NRC Response Letter dated September 25, 2015 re: Indian Point Nuclear Facility.
4. Extract from Safety Study: Integrity Management of Gas Transmission Pipelines in High Consequence Areas, NTSB SS 15-01, Section 3.2, p. 20-21 (January 27, 2015). Full report available at http://www.ntsb.gov/safety/safety-studies/Documents/SS1501.pdf.

R. Kuprewicz CV

# Curriculum Vitae.

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**Redmond, WA 98052**

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**E-mail: kuprewicz@comcast.net**

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**Profile:**

As president of Accufacts Inc., I specialize in gas and liquid pipeline investigation, auditing, risk management, siting, construction, design, operation, maintenance, training, SCADA, leak detection, management review, emergency response, and regulatory development and compliance. I have consulted for various local, state and federal agencies, NGOs, the public, and pipeline industry members on pipeline regulation, operation and design, with particular emphasis on operation in unusually sensitive areas of high population density or environmental sensitivity.

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**Employment:**

**Accufacts Inc.** **1999 – Present**

Pipeline regulatory advisor, incident investigator, and expert witness on all matters related to gas and liquid pipeline siting, design, operation, maintenance, risk analysis, and management.

**Position:** President
**Duties:**
> Full business responsibility
> Technical Expert

**Alaska Anvil Inc.** **1993 – 1999**

Engineering, procurement, and construction (EPC) oversight for various clients on oil production facilities, refining, and transportation pipeline design/operations in Alaska.

**Position:** Process Team Leader
**Duties:**
> Led process engineers group
> Review process designs
> Perform hazard analysis
> HAZOP Team leader
> Assure regulatory compliance in pipeline and process safety management

**ARCO Transportation Alaska, Inc.** **1991 - 1993**

Oversight of Trans Alaska Pipeline System (TAPS) and other Alaska pipeline assets for Arco after the Exxon Valdez event.

**Position:** Senior Technical Advisor
**Duties:**
> Access to all Alaska operations with partial Arco ownership
> Review, analysis of major Alaska pipeline projects

**ARCO Transportation Co.** **1989 – 1991**

Responsible for strategic planning, design, government interface, and construction of new gas pipeline projects, as well as gas pipeline acquisition/conversions.

**Position:** Manager Gas Pipeline Projects
**Duties:**
> Project management
> Oil pipeline conversion to gas transmission
> New distribution pipeline installation
> Full turnkey responsibility for new gas transmission pipeline, including FERC filing

**Four Corners Pipeline Co.** **1985 – 1989**

Managed operations of crude oil and product pipelines/terminals/berths/tank farms operating in western U.S., including regulatory compliance, emergency and spill response, and telecommunications and SCADA organizations supporting operations.

**Position:** Vice President and Manager of Operations
**Duties:**
> Full operational responsibility
> Major ship berth operations
> New acquisitions
> Several thousand miles of common carrier and private pipelines

**Arco Product CQC Kiln** **1985**

Operations manager of new plant acquisition, including major cogeneration power generation, with full profit center responsibility.

**Position:** Plant Manager
**Duties:**
> Team building of new facility that had been failing
> Plant design modifications and troubleshooting
> Setting expense and capital budgets, including key gas supply negotiations
> Modification of steam plant, power generation, and environmental controls

**Arco Products Co.** **1981 - 1985**

Operated Refined Product Blending, Storage and Handling Tank Farms, as well as Utility and Waste Water Treatment Operations for the third largest refinery on the west coast.

**Position:** Operations Manager of Process Services
**Duties:**
> Modernize refinery utilities and storage/blending operations
> Develop hydrocarbon product blends, including RFGs
> Modification of steam plants, power generation, and environmental controls
> Coordinate new major cogeneration installation, 400 MW plus

**Arco Products Co.** **1977 - 1981**

Coordinated short and long-range operational and capital planning, and major expansion for two west coast refineries.

**Position:** Manager of Refinery Planning and Evaluation
**Duties:**
> Establish monthly refinery volumetric plans
> Develop 5-year refinery long range plans
> Perform economic analysis for refinery enhancements
> Issue authorization for capital/expense major expenditures

**Arco Products Co.** **1973 - 1977**

Operating Supervisor and Process Engineer for various major refinery complexes.

**Position:** Operations Supervisor/Process Engineer
**Duties:**
> FCC Complex Supervisor
> Hydrocracker Complex Supervisor
> Process engineer throughout major integrated refinery improving process yield and energy efficiency

**Qualifications:**

Currently serving as a member representing the public on the federal Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC), a technical committee established by Congress to advise PHMSA on pipeline safety regulations.

Committee members are appointed by the Secretary of Transportation.

Served seven years, including position as its chairman, on the Washington State Citizens Committee on Pipeline Safety (CCOPS).

Positions are appointed by the governor of the state to advise federal, state, and local governments on regulatory matters related to pipeline safety, routing, construction, operation and maintenance.

Served on Executive subcommittee advising Congress and PHMSA on a report that culminated in new federal rules concerning Distribution Integrity Management Program (DIMP) gas distribution pipeline safety regulations.

As a representative of the public, advised the Office of Pipeline Safety on proposed new liquid and gas transmission pipeline integrity management rulemaking following the pipeline tragedies in Bellingham, Washington (1999) and Carlsbad, New Mexico (2000).

Member of Control Room Management committee assisting PHMSA on development of pipeline safety Control Room Management (CRM) regulations.

Certified and experienced HAZOP Team Leader associated with process safety management and application.

**Education:**

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| MBA (1976) | Pepperdine University, Los Angeles, CA |
| BS Chemical Engineering (1973) | University of California, Davis, CA |
| BS Chemistry (1973) | University of California, Davis, CA |

**Publications in the Public Domain:**

1. "An Assessment of First Responder Readiness for Pipeline Emergencies in the State of Washington," prepared for the Office of the State Fire Marshall, by Hanson Engineers Inc., Elway Research Inc., and Accufacts Inc., and dated June 26, 2001.

2. "Preventing Pipeline Failures," prepared for the State of Washington Joint Legislative Audit and Review Committee ("JLARC"), by Richard B. Kuprewicz, President of Accufacts Inc., dated December 30, 2002.

3. "Pipelines - National Security and the Public's Right-to-Know," prepared for the Washington City and County Pipeline Safety Consortium, by Richard B. Kuprewicz, dated May 14, 2003.

4. "Preventing Pipeline Releases," prepared for the Washington City and County Pipeline Safety Consortium, by Richard B. Kuprewicz, dated July 22, 2003.

5. "Pipeline Integrity and Direct Assessment, A Layman's Perspective," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated November 18, 2004.

6. "Public Safety and FERC's LNG Spin, What Citizens Aren't Being Told," jointly authored by Richard B. Kuprewicz, President of Accufacts Inc., Clifford A. Goudey, Outreach Coordinator MIT Sea Grant College Program, and Carl M. Weimer, Executive Director Pipeline Safety Trust, dated May 14, 2005.

7. "A Simple Perspective on Excess Flow Valve Effectiveness in Gas Distribution System Service Lines," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated July 18, 2005.

8. "Observations on the Application of Smart Pigging on Transmission Pipelines," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated September 5, 2005.

9. "The Proposed Corrib Onshore System - An Independent Analysis," prepared for the Centre for Public Inquiry by Richard B. Kuprewicz, dated October 24, 2005.

10. "Observations on Sakhalin II Transmission Pipelines," prepared for The Wild Salmon Center by Richard B. Kuprewicz, dated February 24, 2006.

11. "Increasing MAOP on U.S. Gas Transmission Pipelines," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated March 31, 2006. This paper was also published in the June 26 and July 1, 2006 issues of the Oil & Gas Journal and in the December 2006 issue of the UK Global Pipeline Monthly magazines.

12. "An Independent Analysis of the Proposed Brunswick Pipeline Routes in Saint John, New Brunswick," prepared for the Friends of Rockwood Park, by Richard B. Kuprewicz, dated September 16, 2006.

13. "Commentary on the Risk Analysis for the Proposed Emera Brunswick Pipeline Through Saint John, NB," by Richard B. Kuprewicz, dated October 18, 2006.

14. "General Observations On the Myth of a Best International Pipeline Standard," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated March 31, 2007.

15. "Observations on Practical Leak Detection for Transmission Pipelines – An Experienced Perspective," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated August 30, 2007.

16. "Recommended Leak Detection Methods for the Keystone Pipeline in the Vicinity of the Fordville Aquifer," prepared for TransCanada Keystone L.P. by Richard B. Kuprewicz, President of Accufacts Inc., dated September 26, 2007.

17. "Increasing MOP on the Proposed Keystone XL 36-Inch Liquid Transmission Pipeline," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated February 6, 2009.

18. "Observations on Unified Command Drift River Fact Sheet No 1: Water Usage Options for the current Mt.

Redoubt Volcano threat to the Drift River Oil Terminal," prepared for Cook Inletkeeper by Richard B. Kuprewicz, dated April 3, 2009.

19. "Observations on the Keystone XL Oil Pipeline DEIS," prepared for Plains Justice by Richard B. Kuprewicz, dated April 10, 2010.

20. "PADD III & PADD II Refinery Options for Canadian Bitumen Oil and the Keystone XL Pipeline," prepared for the Natural Resources Defense Council (NRDC), by Richard B. Kuprewicz, dated June 29, 2010.

21. "The State of Natural Gas Pipelines in Fort Worth," prepared for the Fort Worth League of Neighborhoods by Richard B. Kuprewicz, President of Accufacts Inc., and Carl M. Weimer, Executive Director Pipeline Safety Trust, dated October, 2010.

22. "Accufacts' Independent Observations on the Chevron No. 2 Crude Oil Pipeline," prepared for the City of Salt Lake, Utah, by Richard B. Kuprewicz, dated January 30, 2011.

23. "Accufacts' Independent Analysis of New Proposed School Sites and Risks Associated with a Nearby HVL Pipeline," prepared for the Sylvania, Ohio School District, by Richard B. Kuprewicz, dated February 9, 2011.

24. "Accufacts' Report Concerning Issues Related to the 36-inch Natural Gas Pipeline and the Application of Appleview, LLC Premises: 7009 and 7010 River Road, North Bergen, NJ," prepared for the Galaxy Towers Condominium Association Inc., by Richard B. Kuprewicz, dated February 28, 2011.

25. "Prepared Testimony of Richard B. Kuprewicz Evaluating PG&E's Pipeline Safety Enhancement Plan," submitted on behalf of The Utility Reform Network (TURN), by Richard B. Kuprewicz, Accufacts Inc., dated January 31, 2012.

26. "Evaluation of the Valve Automation Component of PG&E's Safety Enhancement Plan," extracted from full testimony submitted on behalf of The Utility Reform Network (TURN), by Richard B. Kuprewicz, Accufacts Inc., dated January 31, 2012, Extracted Report issued February 20, 2012.

27. "Accufacts' Perspective on Enbridge Filing to NEB for Modifications on Line 9 Reversal Phase I Project," prepared for Equiterre Canada, by Richard B. Kuprewicz, Accufacts Inc., dated April 23, 2012.

28. "Accufacts' Evaluation of Tennessee Gas Pipeline 300 Line Expansion Projects in PA & NJ," prepared for the Delaware RiverKeeper Network, by Richard B. Kuprewicz, Accufacts Inc., dated June 27, 2012.

29. "Impact of an ONEOK NGL Pipeline Release in At-Risk Landslide and/or Sinkhole Karst Areas of Crook County, Wyoming," prepared for landowners, by Richard B. Kuprewicz, Accufacts Inc., and submitted to Crook County Commissioners, dated July 16, 2012.

30. "Impact of Processing Dilbit on the Proposed NPDES Permit for the BP Cherry Point Washington Refinery," prepared for the Puget Soundkeeper Alliance, by Richard B. Kuprewicz, Accufacts Inc., dated July 31, 2012.

31. "Analysis of SWG's Proposed Accelerated EVPP and P70VSP Replacement Plans, Public Utilities Commission of Nevada Docket Nos. 12-02019 and 12-04005," prepared for the State of Nevada Bureau of Consumer Protection, by Richard B. Kuprewicz, Accufacts Inc., dated August 17, 2012.

32. "Accufacts Inc. Most Probable Cause Findings of Three Oil Spills in Nigeria," prepared for Bohler Advocaten, by Richard B. Kuprewicz, Accufacts Inc., dated September 3, 2012.

33. "Observations on Proposed 12-inch NGL ONEOK Pipeline Route in Crook County Sensitive or Unstable Land Areas," prepared by Richard B. Kuprewicz, Accufacts Inc., dated September 13, 2012.

34. "Findings from Analysis of CEII Confidential Data Supplied to Accufacts Concerning the Millennium Pipeline Company L.L.C. Minisink Compressor Project Application to FERC, Docket No. CP11-515-000," prepared by Richard B. Kuprewicz, Accufacts Inc., for Minisink Residents for Environmental Preservation and Safety (MREPS), dated November 25, 2012.

35. "Supplemental Observations from Analysis of CEII Confidential Data Supplied to Accufacts Concerning Tennessee Gas Pipeline's Northeast Upgrade Project," prepared by Richard B. Kuprewicz, Accufacts Inc., for Delaware RiverKeeper Network, dated December 19, 2012.

36. "Report on Pipeline Safety for Enbridge's Line 9B Application to NEB," prepared by Richard B. Kuprewicz, Accufacts Inc., for Equiterre, dated August 5, 2013.

37. "Accufacts' Evaluation of Oil Spill Joint Investigation Visit Field Reporting Process for the Niger Delta Region of Nigeria," prepared by Richard B. Kuprewicz for Amnesty International, September 30, 2013.

38. "Accufacts' Expert Report on ExxonMobil Pipeline Company Silvertip Pipeline Rupture of July 1, 2011 into the Yellowstone River at the Laurel Crossing," prepared by Richard B. Kuprewicz, November 25, 2013.

39. "Accufacts Inc. Evaluation of Transco's 42-inch Skillman Loop submissions to FERC concerning the Princeton Ridge, NJ segment," prepared by Richard B. Kuprewicz for the Princeton Ridge Coalition, dated June 26, 2014, and submitted to FERC Docket No. CP13-551.

40. Accufacts report "DTI Myersville Compressor Station and Dominion Cove Point Project Interlinks," prepared by Richard B. Kuprewicz for Earthjustice, dated August 13, 2014, and submitted to FERC Docket No. CP13-113-000.

41. "Accufacts Inc. Report on EA Concerning the Princeton Ridge, NJ Segment of Transco's Leidy Southeast Expansion Project," prepared by Richard B. Kuprewicz for the Princeton Ridge Coalition, dated September 3, 2014, and submitted to FERC Docket No. CP13-551.

42. Accufacts' "Evaluation of Actual Velocity Critical Issues Related to Transco's Leidy Expansion Project," prepared by Richard B. Kuprewicz for Delaware Riverkeeper Network, dated September 8, 2014, and submitted to FERC Docket No. CP13-551.

43. "Accufacts' Report to Portland Water District on the Portland – Montreal Pipeline," with Appendix, prepared by Richard B. Kuprewicz for the Portland, ME Water District, dated July 28, 1014.

44. "Accufacts Inc. Report on EA Concerning the Princeton Ridge, NJ Segment of Transco's Leidy Southeast Expansion Project," prepared by Richard B. Kuprewicz and submitted to FERC Docket No. CP13-551.

45. Review of Algonquin Gas Transmission LLC's Algonquin Incremental Market ("AIM Project"), Impacting the Town of Cortlandt, NY, FERC Docket No. CP14-96-0000, Increasing System Capacity from 2.6 Billion Cubic Feet (Bcf/d) to 2.93 Bcf/d," prepared by Richard B. Kuprewicz, and dated Nov, 3, 2014.

46. Accufacts' Key Observations dated January 6, 2015 on Spectra's Recent Responses to FERC Staff's Data Request on the Algonquin Gas Transmission Proposal (aka "AIM Project"), FERC Docket No. CP 14-96-000) related to Accufacts' Nov. 3, 2014 Report and prepared by Richard B. Kuprewicz.

47. Accufacts' Report on Mariner East Project Affecting West Goshen Township, dated March 6, 2015, to Township Manager of West Goshen Township, PA, and prepared by Richard B. Kuprewicz.

48. Accufacts' Report on Atmos Energy Corporation ("Atmos") filing on the Proposed System Integrity Projects ("SIP") to the Mississippi Public Service Commission ("MPSC") under Docket No. 15-UN-049 ("Docket"), prepared by Richard B. Kuprewicz,

dated June 12, 2015.

49. Accufacts' Report to the Shwx'owhamel First Nations and the Peters Band ("First Nations") on the Trans Mountain Expansion Project ("TMEP") filing to the Canadian NEB, prepared by Richard B. Kuprewicz, dated April 24, 2015.

50. Accufacts Report Concerning Review of Siting of Transco New Compressor and Metering Station, and Possible New Jersey Intrastate Transmission Pipeline Within the Township of Chesterfield, NJ ("Township"), to the Township of Chesterfield, NJ, dated February 18, 2016.

51. Accufacts Report, "Accufacts Expert Analysis of Humberplex Developments Inc. v. TransCanada Pipelines Limited and Enbridge Gas Distribution Inc.; Application under Section 112 of the National Energy Board Act, R.S.C. 1985, c. N-7," dated April 26, 2016, filed with the Canadian Nation Energy Board (NEB).

52. Accufacts Report, " A Review, Analysis and Comments on Engineering Critical Assessments as proposed in PHMSA's Proposed Rule on Safety of Gas Transmission and Gathering Pipelines," prepared for Pipeline Safety Trust by Richard B. Kuprewicz, dated May 16, 2016.

53. Accufacts' Report on Atmos Energy Corporation ("Atmos") filing to the Mississippi Public Utilities Staff, "Accufacts Review of Atmos Spending Proposal 2017 – 2021 (Docket N. 2015-UN-049)," prepared by Richard B. Kuprewicz, dated August 15, 2016.

Town of Cortlandt Report (prepared by Accufacts), submitted to FERC (November 21, 2014), R. 1633

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November 21, 2014

**VIA eFiling**

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street NE, Room 1A
Washington, DC 20426

**Re: FERC Proceeding CP14-96: Algonquin Gas Transmission, LLC Algonquin Incremental Market ("AIM") Project**

Dear Ms. Bose:

Enclosed for filing please find the report of Accufacts, Inc. prepared on behalf of the Town of Cortlandt, commenting on the Draft Environmental Impact Statement for the AIM Project. Exhibits 4 and 5 of the report refer to Critical Energy Infrastructure Information ("CEII") materials. Consistent with FERC's eFiling guidelines, we are filing both a public copy of the report from which Exhibits 4 and 5 have been redacted and, under seal, a full copy including Exhibits 4 and 5.

Please contact me if you require any additional information.

Sincerely,

Daniel Mach

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**November 3, 2014**

**To: Mr. Thomas Wood**
**Town Attorney**
**Town of Cortlandt**
**1 Heady Street**
**Cortlandt Manor, NY 10567**

**Re: Review of Algonquin Gas Transmission LLC's Algonquin Incremental Market ("AIM Project"), Impacting the Town of Cortlandt, NY, FERC Docket No. CP14-96-0000, Increasing System Capacity from 2.6 Billion Cubic Feet (Bcf/d) to 2.93 Bcf/d**

**Executive Summary**

Accufacts Inc. was retained by the Town of Cortlandt ("Cortlandt") to perform a basic system review and to provide a brief analysis of the above FERC filing as it may affect Cortlandt. The project as submitted to FERC is asking for several major modifications on the Algonquin gas transmission system to increase gas capacity by approximately 342 dekatherms per day (Dth/d) from Ramapo, NY, to move gas eastward to Connecticut, Rhode Island and Massachusetts markets. The AIM proposal impacting Cortlandt upgrades the existing 26-inch and 30-inch looped pipelines between the Stony Point and the Southeast Compressor Stations in New York, by removing sections of existing 26-inch lower 674 psig Maximum Allowable Operating Pressure ("MAOP") pipe, replacing it with approximately 8 miles of new 42-inch higher 850 psig MAOP pipe, and installing new interconnecting pressure reducing/letdown valves to take advantage of the higher MAOP pipe (See Exhibit 1).[1, 2, 3] A segment of the new 42-inch installation may also involve approximately 2 miles of pipe looped on new right-of-way ("ROW") running south of the Indian Point nuclear power plant complex within Cordlandt. Modifications to a metering and regulating station servicing the Cortlandt, NY area are also

[1] Looping is the connection of two or more pipes between two points, splitting gas flow to reduce pressure drop through the connected sections of the pipeline due to pressure limitations or for increasing the flow rate in a bottlenecked or constrained segment or section.
[2] MAOP is a term defined in federal minimum pipeline safety regulations that defines the maximum pressure under which a gas pipeline may normally be operated. Pressures greater than MAOP are allowed in certain situations.
[3] There are varying numbers in AIM Project filings to FERC for the miles of pipe replacement within Cortlandt. The 8 mile figure is derived from Exhibit G data.

included in the project. This report focuses on the gas transmission infrastructure that could impact Cortlandt.

The following are major findings and observations from my analysis of the AIM Project proposal, sections of the AIM DEIS, and a detailed review of CEII information supplied in the Exhibit Gs submitted to FERC by Algonquin that contain important system information.[4] Exhibits 4 and 5, which are included as attachments, contain more detailed information bolstering my general observations and findings, but these two specific Exhibits are CEII protected under a nondisclosure agreement ("NDA"), and are not for public release or distribution, even among Cortlandt officials, unless they have also signed a FERC CEII NDA.

**Major Accufacts Findings and Observations for Cortlandt concerning the AIM Project:**

1) The new 42-inch pipeline in Cortlandt is considerably oversized/overbuilt for the stated capacity increase of 342 Dth/d claimed for this project.

2) Actual gas velocities, an important variable driving design, for the pre-AIM existing gas transmission pipelines spanning Cortlandt are within acceptable ranges, but after the AIM installation are so low that considerable future possible throughput increases can be easily accommodated for these segments.

3) Further Algonquin Pipeline pipe expansions in New York State are likely given the 42-inch pipe installations proposed for AIM, and the extremely high gas velocities in other existing segments of the New York system further downstream of Cortlandt. However, the AIM proposal and the DEIS contain no evaluation of the impacts of these future expansions.

4) The Safety Evaluation and Analysis for the Indian Point Nuclear Plant ("IPEC") submitted by Entergy concerning the risk associated with the 42-inch AIM pipeline is seriously deficient and inadequate.

5) Additional precautions are warranted for the proposed southern 42-inch pipeline route near the Buchanan-Verplanck Elementary school.

Expanding on the above major findings and observations:

**1) The new 42-inch pipeline in Cortlandt is considerably oversized/overbuilt for the stated capacity increase of 342 Dth/d claimed for this project.**

The following Exhibits included as Attachments supplement this report:

1) Exhibit 1 is a simple schematic developed from information in the public domain of the existing and proposed major pipeline segments for the AIM Project that could impact

[4] Accufacts requested the CEII information from FERC on September 11, 2014 and received the files from Algonquin on October 6, 2014.

Cortlandt. The AIM Project is proposing to modify the pipeline segments between the Stony Point and Southeast Compressor Stations into two significantly different operating loops via new mainline interconnects utilizing pressure reducing/letdown valving installations, and various pig launcher/receiver modifications (to be installed within Cortlandt) to produce: (a) a "Smaller Loop" mainline system consisting of first an existing 30-inch pipeline reducing to an already existing 26-inch mainline, and (b) a "Larger Loop" mainline system consisting of new proposed 42-inch pipe reducing down to an already existing downstream 30-inch mainline (See Exhibit 1).[5]

2) Exhibit 2 is a figure captured from the AIM Project DEIS showing the relative location of where the existing 26-inch pipeline will be removed and replaced by new 42-inch pipeline that AIM has labeled "Take-up and Relay (T&R)," in essentially the same right-of-way ("ROW") through most of Cortlandt.[6]

3) Exhibit 3 is a figure taken from the AIM DEIS depicting existing and proposed Algonquin Hudson River crossings for the AIM Project.[7]

4) Exhibit 4 (CEII Protected) is a hydraulic profile (pipeline pressure vs. pipeline milepost) developed by Accufacts for the smaller diameter (30-inch and 26-inch) lower MAOP pipeline (Smaller Loop) segment within New York State, pre and post AIM Project, for the pipelines between the Stony Point and Southeast compressor stations, incorporating Exhibit G information provided by Algonquin's submission to FERC.

5) Exhibit 5 (CEII Protected) is a hydraulic profile developed by Accufacts for the larger diameter (42-inch and 30-inch) higher MAOP pipeline (Larger Loop) segment within New York State, pre- and post-AIM Project, for the pipelines between the Stony Point and Southeast compressor stations, incorporating the Exhibit G information provided by Algonquin's submission to FERC.

Exhibits 1, 2, and 3 provide a quick perspective of the pipeline changes and general routing for the AIM Project in that specific segment of concern between the compressor stations that bridge Cortlandt. Exhibits 4 and 5 provide a more detailed technical perspective of some of the hydraulics (pressures, MAOP, and gas velocities at certain locations along the pipelines) for the flow cases that drive various Accufacts conclusions and findings. For ease of reference in Exhibit 4 and 5, I have set the milepost ("MP") reference for the segments beginning at the Stony Point, NY compressor station at zero. The pipelines crossing Cortlandt generally begin at the landfall on the east side of the Hudson River, and are thus

[5] Pig launcher/receivers are above ground installations to permit the periodic launching or receiving, depending on their location within the system, of multi-ton inline inspection tools inserted into an operating transmission pipeline to assess for various pipeline imperfections, or certain possible threats, to pipeline integrity.

[6] Algonquin Gas Transmission LLC Docket No. CP14-96-000, FERC/EIS-0254D, "Algonquin Incremental Market Project Draft Environmental Impact Statement," filed to the FERC Docket on 8/6/14, p. 2-2.

[7] *Ibid.*, p. 3-20.

between approximately MP 3.5 and 11.5 as indicated on Exhibits 4 and 5. Exhibit 4 contains an approximately 5 mile shorter length for the Smaller Loop between compressor stations post versus pre AIM, which Accufacts cannot explain from the Exhibit G data provided. This discrepancy suggests an error in this important submission to FERC. This difference does not affect Accufacts' major findings or conclusions, however.

In addition, I have reviewed the Hudson River crossing DEIS discussions currently consisting of: two existing 24-inch pipelines, and an existing 30-inch pipeline, and a proposed new 42-inch pipeline crossing to be routed either south of the existing three gas pipeline river crossings or at a more northern crossing (the Hudson River Northern Route Alternative, or "HRNRA") near the existing three pipelines (See Exhibit 3).[8] This new 42-inch Hudson River crossing, to be installed via Horizontal Directional Drill, or HDD, if possible, would connect to new onshore 42-inch pipelines installed on each side of the Hudson River as part of AIM. The southern 42-inch crossing option would incorporate a new additional pipeline right-of-way of approximately 1 3/4 miles within Cortlandt as it is routed out of the existing pipeline ROW and south of the Indian Point Energy Complex passing a church and an elementary school. The route eventually rejoins the existing 26-inch ROW east of IPEC to continue its route through Cortlandt in the existing ROW as indicated in Exhibit 3 filed to the FERC Docket on August 6, 2014 as the Draft Environmental Impact Statement, or DEIS.

A detailed review of the CEII files captured by the hydraulic profile in Exhibit 5 clearly demonstrates the 42-inch pipeline is not needed for the AIM project claimed capacity increases of 342 Dth/d. The Larger Loop is taking considerable pressure drop introduced from a new "midstream" mainline pressure reducing/letdown valve located at the end of the new pipe MAOP 42-inch upgrade at the edge of Cortlandt, essentially wasting horsepower added at the Stony Point compressor station (See Exhibits 1 and 5). The 42-inch proposal overbuilds the system for the capacity/horsepower increases submitted for AIM. The Stony Point Compressor station after the AIM project, fails on both the Larger Loop and Smaller Loop mainline systems to operate anywhere near Stony Point Compressor Station discharge pipeline MAOP, and the 42-inch to 30-inch mainline pressure reducing/letdown valve takes a major pressure drop for the stated maximum flow conditions.[9] This indicates that added AIM horsepower is wasted at the Stony Point Compressor station increasing pollution emissions.

Exhibit 5 can also be used to demonstrate that a new smaller (i.e., 30 or 36-inch 850 psig MAOP pipe instead of the proposed 42-inch) can provide the additional 342 Dth/d claimed in the AIM proposal. Installation of higher rated MAOP pipe on the discharge segment of Stony Point Compressor Station deals with one bottleneck on this segment spanning the compressor stations. AIM is incomplete, however, as it fails to also adequately address the

[8] The proposed installation of the 42-inch across the Hudson River and south of Indian Point is in a new ROW within the Town of Cordlandt. The existing two, 24-inch and one, 30-inch crossings under the Hudson River will remain active and pressurized, in "standby" backup service if ever needed, which is a reasonable operating approach for this river crossing.

[9] For the Exhibit G CEII cases reviewed, the Smaller Loop does not take pressure drop at the new pressure reducing/letdown valve to stay within the 26-inch mainline MAOP.

weaker bottleneck mainline segments downstream of Cortlandt entering the Southeast Compressor Station that are experiencing extremely high actual gas velocities.

Installation of the overbuilt/oversized AIM 42-inch pipe appears to be an initial effort by Algonquin to minimize future construction impacts by installing a pipeline larger than that needed for the present stated application, but positions the system for future major increased expansions. This is especially true if further downstream pipeline "bottlenecks" to the Southeast Compressor Station can be overcome with additional pipe replacements/upgrades to reduce the extreme actual gas velocities in these remaining existing mainline pipes.

The AIM Project is clearly oversized and is only a partial step toward a more system-wide pipe upgrade path within the state of New York. The AIM Project thus appears to be either an unjustified pipeline expansion or a segmentation of a larger, system-wide upgrade. The AIM Project effort is substituting quicker-to-install compressor horsepower placed at Stony Point against additional needed pipe replacement. Such a quicker path may be an attempt to avoid a proper environmental review and introduces a substantial loss of pipeline system efficiency via wasted horsepower and subsequent increased air pollution emissions. This inefficiency is not addressed in AIM's DEIS.

2) **Actual gas velocities, an important variable driving design, for the existing gas transmission pipelines spanning Cortlandt are within acceptable ranges, and after the AIM installation are so low that considerable future possible throughput increases can be easily accommodated for these segments.**

For a natural gas transmission pipeline a critical variable, actual gas velocities (in ft/sec, or fps) along the system, is very relevant, usually driving piping mainline modification/addition decisions and compressor horsepower installations. Actual gas velocities within a pipeline segment are mainly a function of:

1. the internal pipeline diameter,
2. the required gas flow along a given pipeline segment, usually reported at standard flow conditions,
3. pipeline pressure, which decreases and varies down a pipeline, and
4. pipe segment MAOP.[10]

Because natural gas is compressible as pressure decreases along a pipeline, actual gas velocities increase for the same cross-sectional area of the pipe and same gas flow stated at standard conditions. Gas flow as stated at standard conditions of temperature and pressure can vary depending on possible major additions and takeoffs along a specific pipeline segment, though many segments do not have major receipts or deliveries. Because the pressure at the downstream segment is less than the upstream pressure, actual mainline velocity is usually (but not always, depending on such factors as receipts/deliveries) highest for pipeline segments immediately upstream of compressor stations (at lowest segment

[10] There is an associated effect of gas temperature on gas velocity but this influence in long transmission pipelines is usually not leveraging.

pressure). High gas velocities can also be experienced in segments where the effective cross sectional area of a pipeline, or looped pipelines, is restricted or "pinched," compared to the rest of the segments experiencing similar standard flows and pressures.

Accufacts has observed that maximum actual gas velocities along a specific pipeline have usually been set by company internal standards that keep velocities well below those that could result in mainline erosion and based on other considerations. As a result, federal minimum pipeline safety regulations have not established maximum gas velocities for gas transmission pipelines. Unfortunately, Accufacts has found that more than one company has elected to change, ignore, or modify their own internal maximum historical gas velocity standards in recent FERC filings in order to minimize project costs and/or accelerate applications/approvals with FERC and project startup on multibillion dollar expansion projects. For example, I place little credence in studies or industry standards submitted to FERC that try to convey that a maximum gas velocity of 100 fps is appropriate for gas transmission pipelines.[11] For many reasons, including close proximity to population areas, gas transmission velocities should be set at limits well below those of production pipelines.

For gas transmission pipelines, two cases are usually important in actual gas velocity determinations: the velocities at "design" capacity, and the velocities at "peak flow" which will usually be higher than the design case. These two terms are often not defined in a FERC process and their misuse or misapplication can have serious consequences on safe and appropriate operation of a gas transmission pipeline.

Peak flow cases and their probable duration usually establish the maximum actual gas velocity design control within a transmission pipeline segment, as well as the needed additional horsepower and pipeline operating pressure, but this should be confirmed by the development of a hydraulic profile (pipeline operating pressure vs milepost) of the boundary case incorporating the gas additions and removals along a pipeline system that may differ between the cases. Peak flow cases usually set the maximum operating pressure which can affect a safety design review within a pipeline segment, but not always. The information provided in Exhibit Gs usually permits one to develop such a simple hydraulic profile as that captured in Exhibits 4 and 5. Fortunately, the Exhibit Gs and supporting documents for the AIM Project provided under CEII Nondisclosure Agreements provided sufficient relevant details to reliably evaluate this system at important points where actual gas velocities may be critical for the AIM Project and provide an indication where pipeline bottlenecks remain for possible future capacity increases.

A detailed analysis of the information provided under FERC CEII nondisclosure and Algonquin NDA agreements has allowed Accufacts to develop the hydraulic profiles of Exhibits 4 and 5.[12] Further, Accufacts' calculations based on this CEII protected data

[11] Accufacts Report to Delaware Riverkeeper, "Evaluation of Actual Velocity Critical Issues Related to Transco's Leidy Expansion Project," dated Sept 8, 2014 (FERC Docket No. CP13-551, Accession No. 20140910-5084 submitted 9/10/2014).

[12] Accufacts was required to take a highly unusual step of signing an Algonquin NDA, which raises serious questions about the CEII process in this FERC filing.

indicate that actual gas velocities do not exceed prudent velocities in the pipeline segments spanning Cortlandt for both the AIM base and expansion cases. In fact, the resulting very low gas velocities for these segments after AIM suggest the pipelines crossing Cortlandt will be able to easily accommodate considerable future expansions via horsepower increases at the Stony Point compressor station.

3) **Further Algonquin Pipeline pipe expansions in New York State are likely given the 42-inch pipe installations proposed for AIM, and the extremely high gas velocities in other existing segments of the New York system further downstream of Cortlandt. However, the AIM proposal and the DEIS contain no evaluation of the impacts of these future expansions.**

While the gas transmission pipelines crossing Cortlandt for the CEII cases reviewed indicate actual gas velocities well within acceptable ranges, this is not the case for much of the existing looped pipelines remaining downstream of Cortlandt but upstream of the Southeast Compressor Station in New York. Actual gas velocities on these existing 26 and 30-inch downstream transmission pipelines are at the highest levels that Accufacts has observed in the many FERC CEII filings we have been asked to review (well beyond 60 feet per second). Such high gas velocities suggest further pipe replacement projects in the Algonquin system in New York are needed or forthcoming. Such additional expansions should not be segmented in phases, but should be considered as one overall project requiring a complete environmental review considering their cumulative environmental impact. FERC needs to pursue this important possible segmentation question in further detail.

Because of gas compressibility, pipeline segments facing high gas velocities from increased demand can reduce velocities by increasing compressor horsepower with one or a combination of the following approaches: (1) increase system operating pressure subject to the MAOP limitations of the pipe, (2) rerate or uprate the segment of the pipe MAOP following certain pipeline safety minimum regulations for such upgrades that can introduce some serious risks unless a proper integrity hydrotest is performed, (3) replace or loop the pipeline usually with higher MAOP rated pipe, to yield a larger effective diameter for the segment, and/or (4) shorten the interval between compressor stations by adding new compressor stations that essentially raise the system average operating pressure.

While the 42-inch take and replace segments (42-inch to replace portions of the existing 26-inch) overcompensate for basically the upstream half of the looped system between Stony Point and Southeast Compressor Stations within New York, the remaining existing looped New York pipeline systems downstream of Cortlandt are a serious impediment given inefficiencies of the looped remaining pipeline system both in limited pipe diameter and low MAOP. I would anticipate further 26-inch pipe replacement proposals on this segment downstream of Cortlandt and upstream of the Southeast Compressor Station in the near future that take full advantage of additional capacity of the 42-inch proposed installation applied for in this Docket. Commensurate with such an additional pipe segment upgrading will most likely be a need for additional compressor horsepower at Stony Point.

**4) The Entergy-submitted Safety Evaluation and Analysis for the Indian Point Nuclear Plant ("IPEC") concerning the risk associated with the 42-inch AIM pipeline is seriously deficient and inadequate.[13]**

After a careful review, Accufacts has concluded that the above referenced Entergy Safety Evaluation and Analysis ("Analysis"), which includes enhanced pipeline measures proposed by the pipeline operator for the 42-inch pipe segment near IPEC fails to adequately capture the threat and, more importantly, prudently demonstrate that rupture of the new 42-inch higher MAOP pipeline will not markedly impact IPEC facilities, including IPEC's ability to "failsafe" shutdown from such a pipeline rupture. A 42-inch pipeline rupture is a far greater release event than that from the existing 26- or 30-inch lower MAOP gas transmission pipelines now operating in close proximity to IPEC.

A primary deficiency in the Analysis is the critical assumption of a three minute response time to identify, acknowledge, and close appropriate gas mainline remote isolation valves in event of a pipeline rupture. This assumption is unrealistically optimistic, ignoring both systemic dynamics (compressor and pipeline system rupture dynamics/interactions that mask remote rupture identification), uncertainty in the SCADA monitoring that will further delay remote recognition of a pipeline rupture, and control room operator confusion and related human factors that will also easily further delay control room remote response actions of a pipeline rupture, all of which will work to drive response well beyond the assumed 3 minute time. In addition, the 3 minute assumption disregards initial release and subsequent blowdown times dictated by the laws of thermodynamics related to pipeline rupture, even large 42-inch gas transmission pipelines. History is filled with clear examples of gas transmission pipeline rupture events generating high heat flux events well past an hour, so the 3-minute response assumption in the Analysis is highly unrealistic and not appropriate for this sensitive infrastructure site, especially with a 42-inch high MAOP pipeline. Such important issues must be taken into consideration in any prudent and realistic safety analysis concerning critical energy infrastructure, such as a nuclear power plant, where gas transmission pipeline rupture interactions, such as loss of nearby power grid or substations and resulting loss of power to IPEC, may cascade or snowball, driving the nearby IPEC facility to failure or prevent emergency access.

The Analysis has identified that in the vicinity of IPEC the 42-inch pipeline will be enhanced, or upgraded, to consist of X-70 API 5L grade pipe with a thicker wall thickness of 0.72 inches, buried to a minimum depth of four feet.[14] While I approve of these specific proposed safety enhancement measures to increase the 42-inch pipeline safety near IPEC, additional arguments presented in the Analysis are very misleading or inappropriate so as to cause one to underrepresent the real risks of pipeline rupture on/near IPEC, even with the enhancements. These additional arguments are far from complete in preventing a pipeline

[13] Entergy letter to U.S. Nuclear Regulatory Commission, "10 C.F.R 50.59 Safety Evaluation and Supporting Analysis Prepared in Response to the Algonquin Incremental Market Natural Gas Project Indian Point Nuclear Generating Unit Nos. 2 & # Docket Nos. 5-247 and 50-286 License Nos. DPR-26 and DPR-64," dated August 21, 2014.
[14] *Ibid*., Sheets 3 to Sheet 10 of 21.

rupture. For example, the argument to install a concrete barrier over the pipeline to prevent possible damage from third parties at first blush sounds like an appropriate step. Unfortunately, Accufacts has seen too many pipeline near misses where such barriers were defeated, negating the effectiveness of such barriers to avoid serious damage to high-pressure pipelines. Accufacts has yet to see a steel pipeline that cannot be damaged by third party threat activities, especially damage that could result in delayed pipeline rupture. I have seen similar misguided arguments presented in the Analysis that steel pipelines can be made difficult to puncture, reflected in some very poor pipeline risk management approach studies and safety risk analyses trying to improperly convey the impression that pipelines cannot be made to rupture. Delayed pipeline ruptures generating massive explosions and flames are caused by damage that seldom punctures the pipe, but the pipe is weakened to where it eventually fails in time as a rupture, a large pipeline fracture that occurs in microseconds during operation.

The Analysis should more thoroughly assess the impact of pipeline rupture on IPEC facilities and operation. Such a safety hazard analysis is unique to the IPEC facilities and should thoroughly evaluate and document a process safety management approach to assess the real effect on IPEC of the proposed 42-inch, 850 MAOP, gas transmission if it should rupture. Given the seriousness of a nuclear plant loss-of-containment incident, that analysis should reflect actual gas rupture dynamics and realistic duration and impact for this specific location and system. Such an analysis should be performed and subjected to a true independent process hazard analysis that would assure any equipment loss impacted by such a large diameter pipeline rupture would not prevent the "failsafe" shutdown of IPEC, nor loss of radiation storage containment that could cascade into a radiation release in this highly populated and sensitive location. Risk management analysis should be considered seriously deficient if it dismisses low probability events with catastrophic consequences as no probability. History has repeatedly demonstrated that when it comes to complex systems, low probability events can easily become linked, substantially increasing the likelihood and risks, and may even drive a system to catastrophic failure with all too predictable disastrous consequences. A more thorough and truly independent safety analysis of the 42-inch pipeline and its possible rupture effects to IPEC are warranted and the results made public given the deficiencies and many failings of the current Analysis to instill confidence in the public.

**5) Additional precautions are warranted for the proposed southern 42-inch pipeline route near the Buchanan-Verplanck Elementary school.**

Given the various concerns raised from involved officials and citizens about the risks associated with the southern routing option of the new 42-inch proposed pipeline in close proximity to the Buchanan-Verplanck Elementary School, Accufacts will comment on pipeline related safety concerns concerning this matter. Ironically, current federal pipeline minimum safety regulations, industry codes, or best practices, do not specifically or adequately address siting issues or risks related to natural gas pipelines near schools. Pipeline safety regulations are moot concerning such important siting related issues for various reasons.

Nevertheless, there are several precautions that Accufacts recommends that would prove helpful to minimize the consequences of a 42-inch pipeline rupture if the new pipeline is routed in such a sensitive location near the school. There is no requirement that a pipeline be placed in an existing or new ROW, or even in the middle of a pipeline ROW. The placement of the pipeline right-of-way and the actual location of the pipeline within the ROW should be carefully reviewed and assured so as to minimize the removal of trees that buffer between the proposed pipeline and the school. Such large and numerous trees can reduce the impact of blast and thermal radiation to structures and individuals, buying critical time that can markedly reduce injury or loss of life associated with a possible pipeline rupture. In addition the Buchanan-Verplanck Elementary School is constructed mostly of masonry that has a much greater tolerance, or survivability, during a rupture event. Such more hardened structures also serve as excellent radiation shields to shelter individuals from blast and thermal radiation. While there is no requirement, placement of school ball and play fields where individuals are most likely to be caught unsheltered, are best situated as presently located, in the shadow of the building away from the gas transmission pipeline. Sheltering substantially increasing the likelihood of individual survival should a pipeline rupture.

The stark reality is that pipeline safety regulations and industry standards do not provide FERC with siting precautions for such sensitive locations. Integrity management ("IM") pipeline safety regulations have attempted to instill certain additional safety precautions in such potential High Consequence Areas, or HCAs. Unfortunately, the first phase of these IM regulations, in effect for more than ten years now, have met with very mixed success as evidenced by many high profile pipeline ruptures indicating further improvements in IM regulation are warranted.[15]

**Conclusion**

It should be clear, from a review of the Exhibits and the above discussions, that the attempt to replace segments of the 26-inch pipeline segment with a 42-inch pipeline across Cortlandt are not in sync with the claimed increased gas demands identified in the current AIM FERC filing and subsequent DEIS. The operator appears to be positioning for further expansions on the Algonquin system and there are still serious bottlenecks on the looped system between the Stony Point and Southeast Compressor Stations that should have been included with this FERC application. The operator appears to be attempting to utilize horsepower compressor additions that can be permitted more quickly than pipe installations, in an attempt to overcome pipeline bottleneck inefficiencies in remaining segments spanning New York State.

Accufacts cannot overstress the importance of performing a full and complete process hazard safety analysis, independently demonstrating, especially to the public, that there will be no interplay between a possible gas transmission pipeline rupture and the IPEC facilities to failsafe shutdown or cause a loss of radiation containment in such a sensitive and highly populated area

[15] Sites where significant numbers of people can gather near a pipeline, such as churches and schools, fall under the definition of High Consequence Areas, meriting additional pipeline safety integrity management precautions as per Subpart O of 49CFR§192 for gas transmission pipelines.

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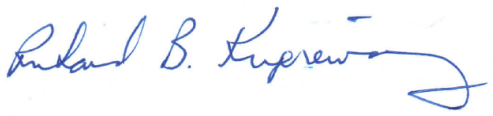
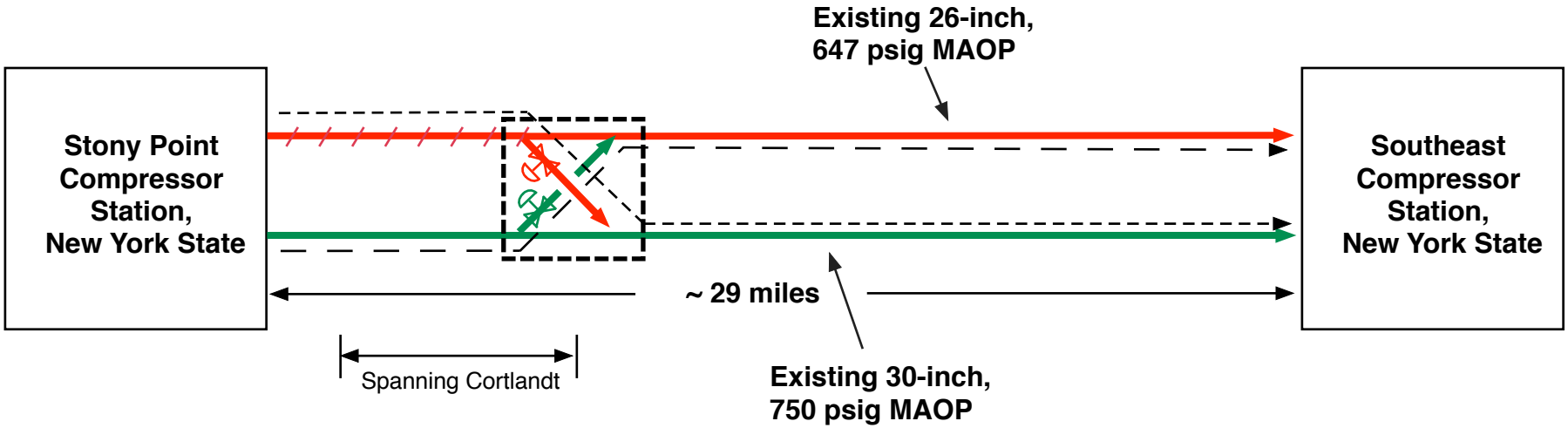
of the country. A proper and thorough hazard review and analysis may suggest another 42-inch route is warranted to assure the safety of IPEC from this gas transmission pipeline infrastructure. While Accufacts can appreciate attempts to keep certain information of such an important safety analysis somewhat secret, much more detailed effort is needed to assure the public that prudent and complete safety analysis efforts have been performed in choosing possible pipeline options in this location.



Richard B. Kuprewicz
President,
Accufacts Inc

# Exhibit 1

## Simplified Schematic - Algonquin Gas Transmission Pipelines
## Stony Pt to Southeast Compressor Stations Looped Segment
## Pre & Post AIM Project Proposal




26-inch 647 psig MAOP replaced with 42-inch, 850 psig MAOP

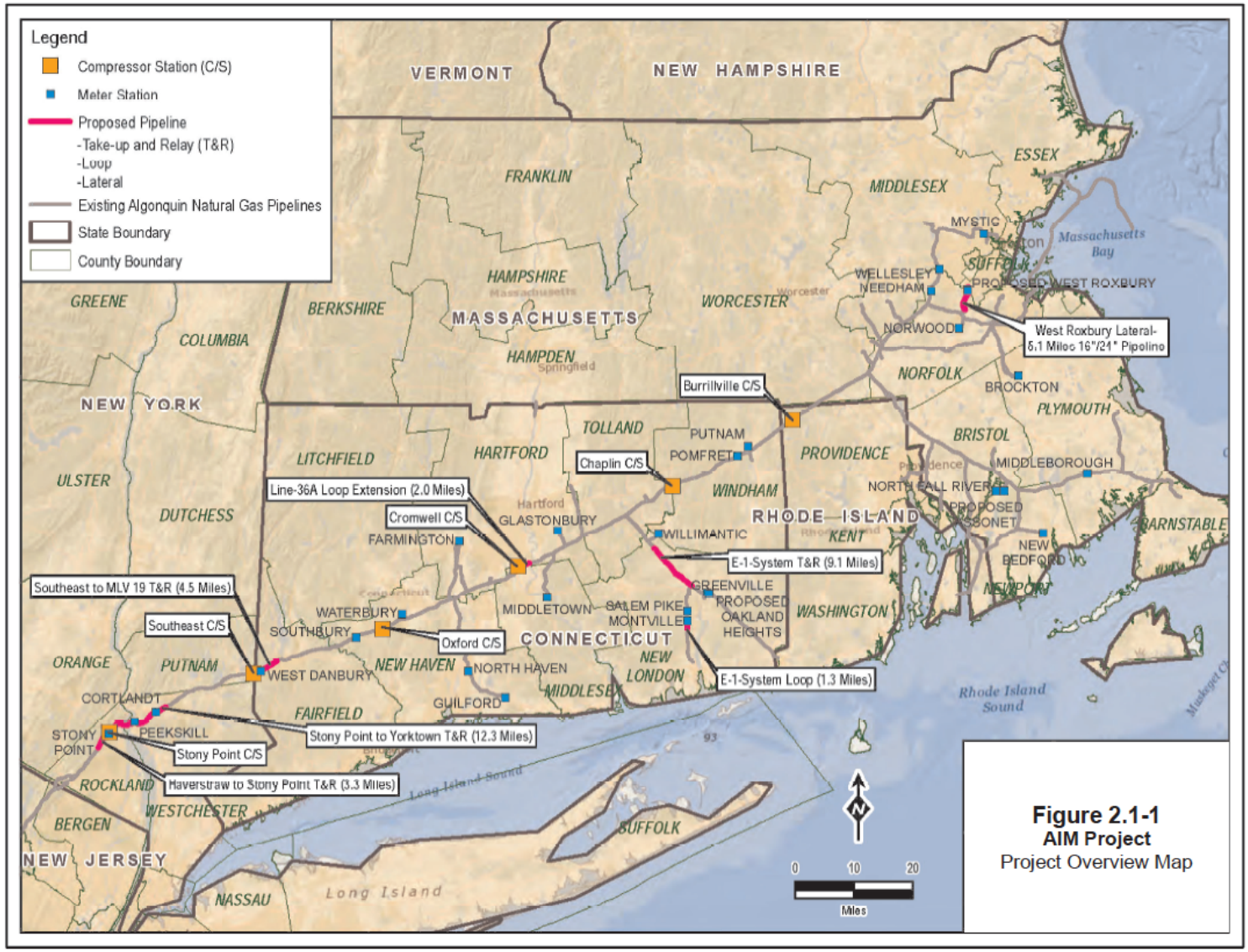
= New installation of pressure reducing/letdown valves ( ) and interconnections

= Larger Loop gas flow after AIM

= Smaller Loop gas flow after AIM

Accufacts Inc. 11/2/14 - Not to Scale

# Exhibit 2 – AIM Project Overview Map from DEIS Showing General Location of Replacement of 26-inch with 42-Inch Pipeline Across Cortland, NY



# Exhibit 3 – Algonquin Pipeline Hudson River Crossings, Existing and Proposed from AIM DEIS

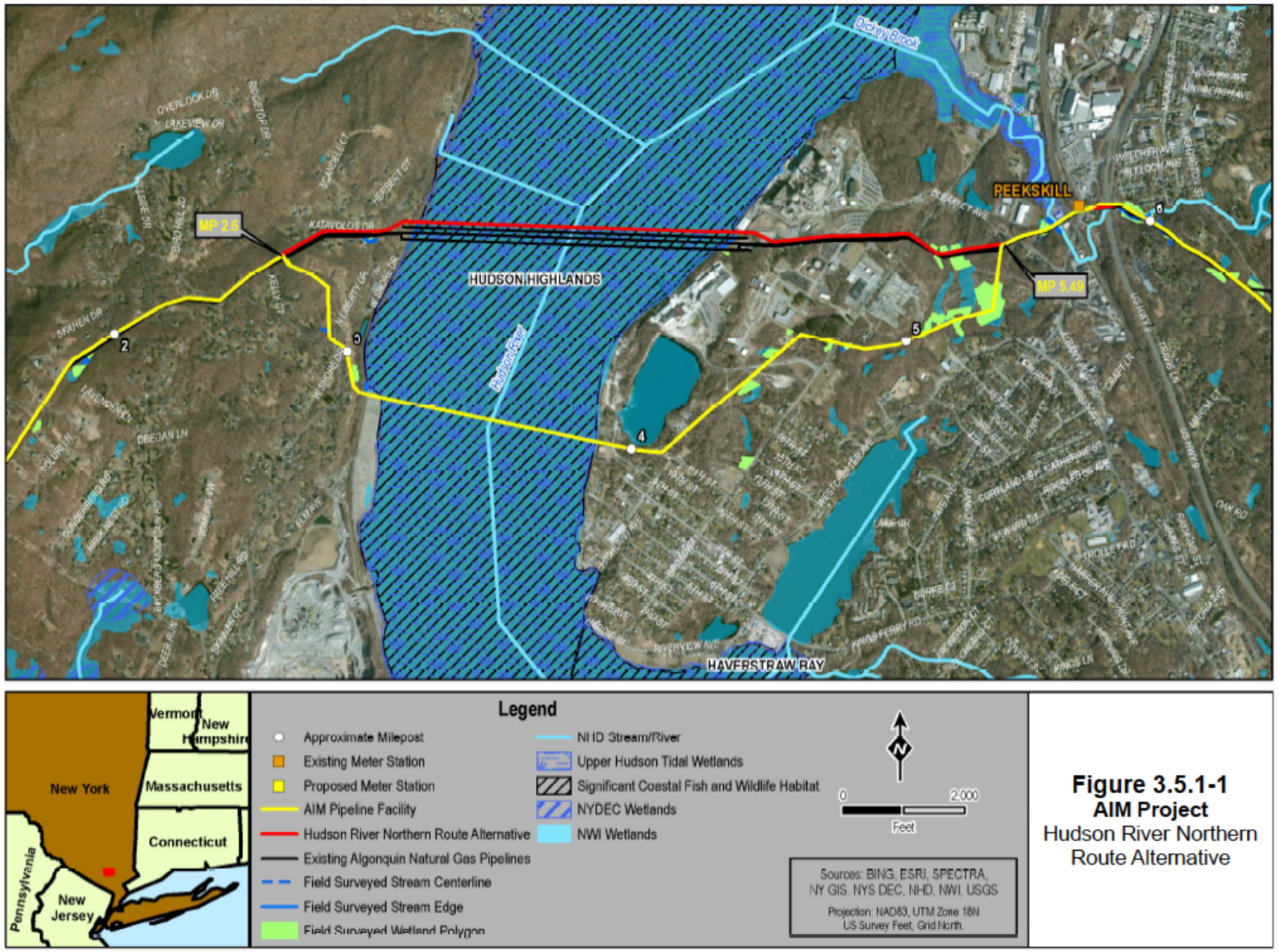



**Figure 3.5.1-1**
**AIM Project**
Hudson River Northern Route Alternative

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Document Content(s)

Accufacts Comments (October 12, 2015)
re: NRC Response Letter dated September 25, 2015
re: Indian Point Nuclear Facility.

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**October 12, 2015**

**To: The Honorable Sandy Galef**
**New York Assemblywoman**
**95th Assembly District**
**2 Church Street**
**Ossining, NY 10562**

**Re: Accufacts' Observations on NRC Response Letter Dated September 25, 2015 Concerning "Indian Point Nuclear Generating Unit Nos. 2 and 3 – Response to Letter Dated August 4, 2015."**

I have reviewed the above NRC September 25, 2015 letter to you and continue to find the NRC demonstrating an inability to grasp simple but important scientific and engineering process safety concepts related to whether the Indian Point nuclear facility is at risk in the event of a rupture of the nearby proposed 42-inch high pressure gas transmission pipeline. The NRC's assumptions and comments instill no confidence that their analysis is either relevant or appropriate. Their approach and statements clearly demonstrate that the NRC does not grasp the tremendous energy releases and dynamics associated with pipeline rupture of this very large diameter pipeline, and therefore should not be using their current approaches to evaluate gas transmission pipeline rupture impacts on their facilities. Attempting to use inappropriate models that fail to capture the unique transient impacts of a high-pressure large diameter gas transmission pipeline rupture in a highly sensitive site is a poor and inappropriate approach that Accufacts has found in far too many incident investigations associated with misinformation. A true transient release dynamics graph (release rate versus time) of the proposed 42-inch pipeline rupture case near the Indian Point nuclear facility should clearly demonstrate the many flaws in the NRC's recent letter to you for this very uniquely sited pipeline.

While the case to be calculated should not be that difficult to set up, it requires that certain information declared "secret or confidential" be disclosed. The transient calculations for this gas transmission system pipeline rupture near the nuclear site can be quite involved, however, and are not well nor scientifically captured by models or unwise assumptions never intended for such purpose, such as the ALOHA model cited by the NRC. I would advise that you continue to pursue this effort until the NRC produces such a transient analysis that actually reflects a rupture impact of the high-pressure 42-inch gas transmission pipe near the nuclear facility. There should be mechanisms that would permit you, as an Assemblywoman, to gain access to declared sensitive information that would allow you to reach a prudent conclusion that an analysis is complete and prudent concerning their rupture approach, which appears is not the case for the NRC's position cited in their recent letter.

A closer review of the NRC letter's three major stated assumptions will also clearly demonstrate the NRC's approach **is not conservative** and is seriously flawed. For example:

**NRC Assumption Statement**

"Based on input from Spectra Energy, the initial analysis assumed a closure time of 3 minutes on pipeline isolation valves. In addition to the 3-minute valve closure case, the NRC evaluated a bounding case. This second case assumes the upstream side of the ruptured pipe is connected to an infinite source of gas for 1 hour."

**Accufacts Observation**

This NRC statement is meaningless and does not permit an independent evaluation that the parties performing such a potential impact analysis understand the extremely high transient rupture gas rates and very high heat fluxes that can be released on this pipeline system at this site. For example, a three minute closure time does not indicate how long the gas has been releasing (at incredibly high rates) out of a pipeline rupture on this specific system at this location before valve and, ironically, after valve closure. The NRC assumption also appears not to consider that gas release even with closed valves will continue at very high rates for a considerable period of time. A transient graph of mass release versus time will indicate a characteristic gas pipeline rupture fingerprint form that will dispel any attempts to quickly remotely identify, much less actually trigger, valve closure even for automatic valves. Such a graph will also reveal the case irrelevancy of a ruptured pipeline connected to an infinite source of gas for one hour in the matter of this safety analysis.

**NRC Assumption Statement**

"The NRC staff modeled a pipe break at the location closest to plant structures. Because of a limitation of the ALOHA software, the staff doubled the predicted gas release from the upstream side of a pipe break to account for flow escaping from both sides of the break. This approach is conservative because in the event of an actual break, the downstream side of the pipe would release much less gas than the estimated release from the upstream side."

**Accufacts Observation**

Based on many past pipeline rupture investigations, Accufacts believes a true transient graph of rupture mass release versus time on this system at the specific location near the Indian Point nuclear plant will easily demonstrate that mass rate of release will be much higher than "double" as assumed by the NRC. While it is true that the downstream side of the rupture pipe will eventually release gas at lower rates than the upstream side, the gas release rates will still be considerable, especially in the early stages of the rupture release. A transient analysis will further demonstrate this point and also prove the NRC analysis <u>is not conservative</u> on this remotely monitored system at this highly sensitive site.

**NRC Assumption Statement**

> "For the evaluation of the explosion hazard, the NRC used the peak gas release rate resulting from a pipe rupture to estimate the mass of natural gas. This approach predicts more gas released than other approaches such as a time dependent gas release or a release averaged over time."

**Accufacts Observation**

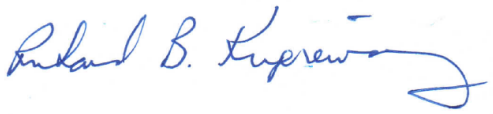
> Accufacts cannot reach any conclusions concerning "peak gas release rate resulting from a pipeline rupture," from the above NRC assumption statement, but given the less than accurate information released to date and our experience in rupture investigations, such a peak rate will most likely be well above that utilized in the NRC analysis. Transient release rates for a 42-inch pipeline rupture so close to a compressor station will significantly increase "peak rupture rates" well above those of pipeline design capacity, compressor design capacity, and well above "double," as pipe system pressure curves are significantly reduced, compressors run out on their curves, and initial pipeline pressure at time of rupture on both the upstream and downstream ends of the rupture release at the sonic speed in the gas which is higher than the speed of sound. Our experience indicates pipeline rupture gas rates of release will be incredibly high, well above the NRC's inferred "double," for quite some time.

The NRC's further comment that they are using a conservative assumption by arguing that they are using peak rates over a longer period appear to be disingenuous. Pipeline ruptures of this magnitude generate incredibly high gas rates with extremely high heat fluxes that I have seen melt steel and vaporize aluminum at considerable distances. Such averaging misses the incredibly high heat fluxes associated with transient gas pipeline rupture releases. Lastly, I must comment on an additional statement made in the NRC letter to you that: "Likewise, a postulated fire at the gas pipeline would create a heat flux at the Indian Point site fence that could be a threat to humans, but would not be sufficient to melt plastic." While the above statement does not define the distance to the fence line from the rupture point it is my understanding that there is Indian Point "safety critical equipment" (approximately 100 feet from the pipeline) that is nearer than the fence boundary, and needed to safely cool down the facility during a plant emergency shutdown. A clear drawing needs to be provided to you that identifies the location of such "safety critical" equipment and its distance from the pipeline rupture site utilized in any process safety evaluation.

In conclusion, the NRC does not have the expertise nor have they called on appropriate expertise to provide a thorough and complete evaluation of the impact of this "first of its kind" proposed installation of a large diameter high-pressure natural gas transmission pipeline near a nuclear facility in a highly sensitive area. Such a prudent review requires special precautions to assure analyses are scientific, complete, and thorough (including possible interactions). It appears the claims of "need for security" have undercut verification that such a prudent analysis has been adequately performed. The NRC's review is not conservative and I would advise that you continue your pursuit of this matter until a complete and proper transient graph and subsequent analysis, as well as other important information is provided that would permit verification that

the 42-inch pipeline rupture will not prevent the safe shutdown of the Indian Point nuclear facility. It is my understanding that the close proximity of the plant switchgear station handling power leaving the nuclear plant would most likely be quickly lost in a nearby pipeline rupture, necessitating a nuclear facility emergency shutdown. It is thus important that parties demonstrate that such an event, even if low probability, will not prevent the nuclear facility from an emergency trip cool down. While I can appreciate the need for some security concerns, such concerns should not justify the use of poor tools or assumptions that provide little confidence that this issue has been adequately or prudently analyzed.

Respectfully,



Richard B. Kuprewicz,
President,
Accufacts Inc

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Document Content(s)

Extract from Safety Study: Integrity Management of Gas Transmission Pipelines in High Consequence Areas, NTSB SS 15-01, Section 3.2, p. 20-21 (January 27, 2015). Full report available at http://www.ntsb.gov/safety/safety-studies/Documents/SS1501.pdf.

# Integrity Management of Gas Transmission Pipelines in High Consequence Areas


**Safety Study**

NTSB/SS-15/01
PB2015-102735

National Transportation Safety Board

NTSB/SS-15/01
PB2015-102735
Notation 8565A
Adopted January 27, 2015

# Safety Study

## Integrity Management of Gas Transmission Pipelines in High Consequence Areas

National Transportation Safety Board

490 L'Enfant Plaza, SW
Washington, DC 20594

**National Transportation Safety Board. 2015. *Integrity Management of Gas Transmission Pipelines in High Consequence Areas*. Safety Study NTSB/SS-15/01. Washington, DC.**

**Abstract:** There are approximately 298,000 miles of onshore natural gas transmission pipelines in the United States. Although rare, failure of these pipelines poses a significant risk to the public, especially when pipelines traverse populated areas, known as high consequence areas (HCA). To ensure the physical integrity of their systems in HCAs, gas transmission pipeline operators have been required by the Pipeline and Hazardous Materials Safety Administration (PHMSA) to develop and implement integrity management programs since 2004.

The NTSB undertook this study because of concerns about deficiencies in the operators' integrity management programs and the oversight of these programs by PHMSA and state regulators—concerns that were also identified in three gas transmission pipeline accident investigations conducted by the NTSB in the last five years. These accidents resulted in 8 fatalities and over 50 injuries, and they also destroyed 41 homes. This study used both quantitative and qualitative approaches. Data analysis was combined with insights on industry practices and inspectors' experiences obtained through interviews and discussions with pipeline operators, state and federal inspectors, industry associations, and other stakeholders.

This study found that while the PHMSA's gas integrity management requirements have kept the rate of corrosion failures and material failures of pipe or welds low, there is no evidence that the overall occurrence of gas transmission pipeline incidents in HCA pipelines has declined. This study identified areas where improvements can be made to further enhance the safety of gas transmission pipelines in HCAs. Areas identified for safety improvements include (1) expanding and improving PHMSA guidance to both operators and inspectors for the development, implementation, and inspection of operators' integrity management programs; (2) expanding the use of in-line inspection, especially for intrastate pipelines; (3) eliminating the use of direct assessment as the sole integrity assessment method; (4) evaluating the effectiveness of the approved risk assessment approaches; (5) strengthening aspects of inspector training; (6) developing minimum professional qualification criteria for all personnel involved in integrity management programs; and (7) improving data collection and reporting, including geospatial data.

The National Transportation Safety Board (NTSB) is an independent federal agency dedicated to promoting aviation, railroad, highway, marine, pipeline, and hazardous materials safety. Established in 1967, the agency is mandated by Congress through the Independent Safety Board Act of 1974 to investigate transportation accidents, determine the probable causes of the accidents, issue safety recommendations, study transportation safety issues, and evaluate the safety effectiveness of government agencies involved in transportation. The NTSB makes public its actions and decisions through accident reports, safety studies, special investigation reports, safety recommendations, and statistical reviews.

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From 1994–2013, total gas transmission pipeline mileage increased from 293,438 miles to 298,302 miles — an overall increase of only two percent. However, significant incidents increased considerably during this period. Figure 5 shows that the rates of significant gas transmission pipeline incidents exhibited a gradual increasing trend throughout the 20-year period. The average annual significant incident rate increased from 0.13 (pre-gas IM rule, 1994–2003) to 0.19 (post-gas IM rule, 2004–2013) incidents per 1,000 miles of pipeline. One potential factor is a price change over time that can impact the determination of whether an incident is considered significant.[42] Using data presented in Table 2, the average number of injured persons increased from 8 persons per year from 1994–2003 to 10 persons per year from 2004–2013, while average fatalities remained at two fatalities per year for both time periods. The NTSB concludes that there has been a gradual increasing trend in the gas transmission significant incident rate between 1994–2004 and this trend has leveled off since the implementation of the integrity management program in 2004.

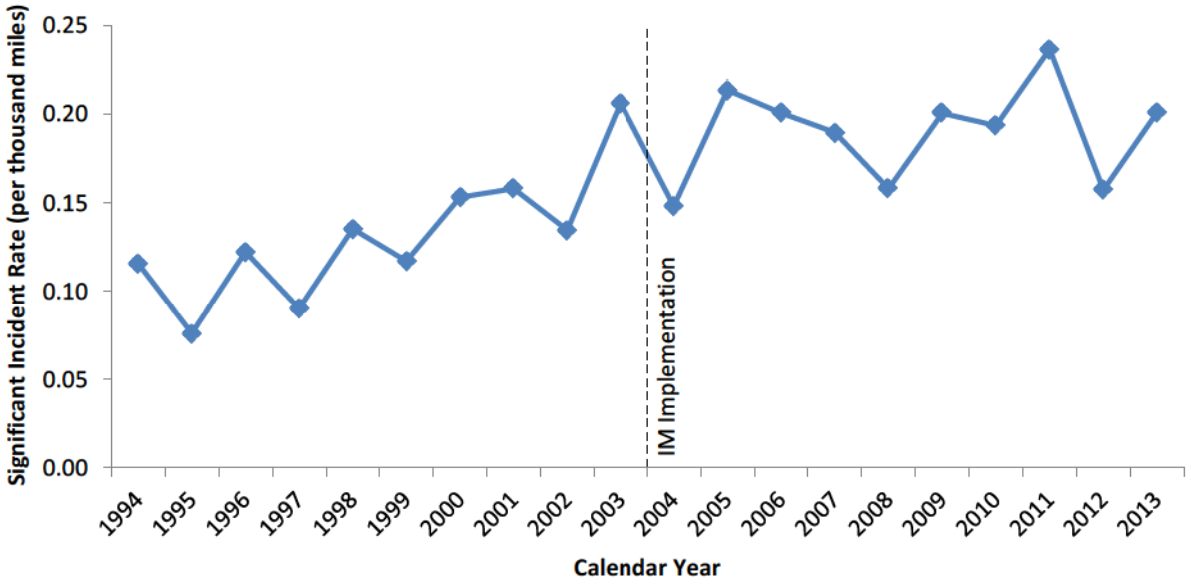


**Figure 5.** Significant incident rate per thousand miles (1994–2013)

## 3.2 HCA Incidents

PHMSA's annual report provides mileage data for all gas transmission pipelines but only began to report HCA mileage in 2010.[43] Therefore, HCA-related incident rates can only be calculated from 2010–2013. Table 3 shows incident counts and mileage by HCA classification from 2010–2013.[44] Due to the reporting criteria change in 2011 and the short time frame, it is

[42] Based on communication with PHMSA staff.

[43] HCA mileages for 2010-2013 were obtained from data from PHMSA's Annual Report, section L. Specifically, we used onshore gas transmission pipeline IM program mileage. Non-HCA mileage was computed by subtracting HCA mileage from the total onshore gas transmission pipeline mileage.

[44] The cost of lost gas was removed as an incident reporting criterion, and the quantity of lost gas was added as an incident reporting criterion. See http://primis.phmsa.dot.gov/comm/reports/safety/docs/IncidentReportingCriteriaHistory1990-2011.pdf.

difficult to discern trends in the data; rather, averages of incidents and mileages by HCA classification are presented for the four-year period. The percentage of HCA pipeline miles compared to all gas transmission pipeline miles remained constant. On average, seven percent of all onshore gas pipelines are HCA pipelines. However, 11 percent of all reported onshore gas transmission pipeline incidents occurred on HCA pipelines. Figure 6 shows that for all reported incidents as well as significant incidents, the average incident rates were higher for HCA pipelines when compared to non-HCA pipelines. While it may seem expected that incident rates would be higher in densely populated areas like HCAs due to the greater likelihood of property damage and casualties, gas IM requirements are specifically designed to reduce risk in HCAs. The NTSB concludes that from 2010–2013, gas transmission pipeline incidents were overrepresented on HCA pipelines compared to non-HCA pipelines.

**Table 3.** Total incidents and mileage by HCA classification (2010–2013)

| Year | Incidents | | | | Miles | | | |
|---|---|---|---|---|---|---|---|---|
| | Non-HCA | HCA | All | Percent HCA | Non-HCA | HCA | All | Percent HCA |
| 2010 | 78 | 6 | 84 | 7 | 279,320 | 20,223 | 299,343 | 7 |
| 2011 | 96 | 10 | 106 | 9 | 279,372 | 20,351 | 299,723 | 7 |
| 2012 | 75 | 14 | 89 | 16 | 278,742 | 19,820 | 298,562 | 7 |
| 2013 | 84 | 12 | 96 | 13 | 278,687 | 19,615 | 298,302 | 7 |
| **Average** | **83** | **11** | **94** | **11** | **279,030** | **19,030** | **298,983** | **7** |

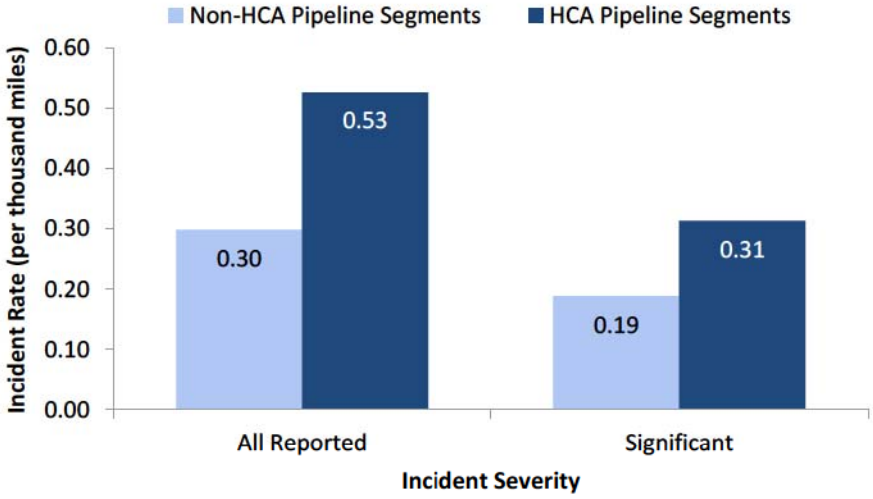


**Figure 6.** Average incident rates per 1,000 miles by HCA classification and incident severity level (2010–2013)

## 3.3 Incidents by Cause

IM programs require an evaluation of all potential threats that, if left unmitigated, may lead to pipeline incidents such as ruptures or leaks. As discussed in chapter 1, these threats must