Report of the U.S. Nuclear Regulatory Commission Expert Evaluation Team on Concerns Pertaining to Gas Transmission Lines Near the Indian Point Nuclear Power Plant

April 8, 2020

Executive Summary

This report provides the results of a review by the U.S. Nuclear Regulatory Commission (NRC) staff of issues raised in the NRC Inspector General's Event Inquiry titled "Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant" (Case No. 16-024). In response to the Event Inquiry, the NRC's Executive Director for Operations tasked a team of NRC and external experts to review the findings in the Event Inquiry and to prepare a report that could be submitted to the NRC Commission by April 9, 2020. The team members were chosen to be independent from the previous work described in the Event Inquiry and included both NRC staff and external members with expertise regarding the concerns that were raised.

The team determined that, even though Entergy (the plant owner) and the NRC made some optimistic assumptions in analyzing potential rupture of the 42-inch natural gas transmission pipeline, the Indian Point reactors remain safe. The team drew two key conclusions related to this statement.

- **A rupture of the newly installed 42-inch natural gas transmission pipeline that runs near Indian Point is unlikely.** This pipeline was installed using modern techniques, stringent quality standards, and construction precautions that limit the likelihood of later pipeline damage. This stretch of pipeline was designated as a high consequence area under Department of Transportation requirements, meaning that additional inspection, integrity threat assessment, pipe remediation, and documentation requirements apply. Given the remaining operating life of Units 2 and 3 (mere weeks to a year, respectively), the risk of a pipeline rupture affecting the reactor units is very small.
- **If a rupture occurred on the stretch of 42-inch pipeline near Indian Point, the nuclear power plant would remain protected.** The plant's safety systems are all far from the pipeline. They are two or more times the "potential impact radius" that the U.S. Department of Transportation designates for protecting people from pipeline ruptures and also far outside the distance where heat flux would be high enough to affect wooden structures, let alone the robust concrete structures that house the plant's safety equipment.[1] The potential impact radius bounds most pipe rupture impacts observed in real-life accidents. In a more detailed transient analysis, the team found that the robust concrete structures housing the plant's safety-related equipment, spent fuel pool, and dry fuel storage containers would withstand the heat and pressure impacts of an explosion or fire that could follow a pipeline explosion. The safety-related equipment would be able to safely shut down the reactors and maintain them in a safe shutdown condition. Equipment or structures outside these buildings could be affected, but these serve as backups or alternatives to the safety-related equipment. The team also conducted a risk assessment to consider the uncertainties of the events that could unfold at Indian Point and found that the risk of serious consequences from a postulated pipeline rupture was very small.

Entergy should be asked to revisit the assumptions it made regarding the consequences of a postulated rupture of the 42-inch pipeline. Entergy used a best-case timeframe and valve spacing for isolating the ruptured pipeline, meaning that a less-than-realistic amount of gas was

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[1] See Section 2.3 for details on the calculation of the potential impact radius. In other documents, "impact radius" or "PIR" has been used informally to refer to distances where certain effects can be found, calculated through a variety of approaches. Where the term "potential impact radius" is used in this report, the team is referring to the radius calculated under 49 CFR 192.

analyzed. Entergy should be asked to assess the importance of these assumptions to its original conclusions and update its analysis, if needed.

The NRC needs to improve its processes and practices for technical reviews, inspection support, petition reviews, pipeline analysis, and coordination with other agencies. Separate from the technical matters, the team substantiated many of the Inspector General's procedural findings. The team identified several areas where the NRC could improve its processes. Highlights of these findings are:

- **NRC staff peer reviews need to be done more rigorously and consistently**. Recently updated guidance concerning the expected quality of NRC technical products should help achieve this goal, if staff and managers are properly trained on its use.
- **Inspectors and technical experts need better guidelines for arranging formal and informal technical support to inspections**. Understanding and documenting expectations up front, then providing clear responses to the initial queries, will make NRC inspections more effective.
- **The NRC needs to improve its petition review processes even more**. While the process was recently updated, the team still found weaknesses in the consistency and independence of reviews, documentation of decisions, and level of detail reviewed at each stage.
- **The NRC needs to improve how it supports other agencies' reviews.** When the NRC's expertise or decisions will be cited by another agency, the NRC should follow practices it already has in place for its own environmental reviews, formalizing and documenting the interactions across agencies. This approach would provide for a mutual understanding of each agency's objectives and regulatory context.

The body of this report amplifies these topics in six main sections and nine appendices:

- **Section 1** and **Appendix A** provide background information on Indian Point, the natural gas transmission pipelines that run near the plant, and analyses conducted of these pipelines.
- **Section 2** and **Appendices B, C, and D** provide technical detail. The team assessed the NRC's prior analysis of the 42-inch pipeline. The team worked with Sandia National Laboratories to conduct a transient analysis that quantified the natural gas that could be released in a pipeline rupture. The team also worked with Idaho National Laboratory to conduct a risk analysis that characterized the onsite effects at Indian Point.
- **Sections 3 and 4** of the report provide information on NRC processes. The team assessed the NRC's review of a petition regarding the new 42-inch pipeline near Indian Pont. Through this assessment and other team activities, the team developed recommendations for process improvements in five different areas.
- **Section 5** of the report focuses on the specific issues raised by the NRC Office of the Inspector General, many of which are also addressed in the other sections. The team considered each issue and determined whether the team agreed with the finding, agreed in part, or disagreed.
- **Section 6** summarizes the team's conclusions. It also presents additional issues that the team or external parties identified during the team's review. While the team remained vigilant for issues that could pose an immediate safety concern for Indian Point, most of these issues could not be addressed within the scope or timeframe provided to the team. These issues are presented for further consideration by the NRC, as appropriate.

- **Appendices E through J** provide supporting information for the remainder of the report. Appendix E summarizes the peer review of this report conducted by a member of the Advisory Committee on Reactor Safeguards. Appendices F and G provide short biographical information on the individuals who supported the report. Appendix H collects the figures referenced in the report. Appendix I and J both include reference information in different formats—Appendix I with selected events and references in chronological order and Appendix J containing the endnotes referenced throughout the document.

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1. Background

1.1. Indian Point Energy Center and Preexisting Natural Gas Pipelines

The Indian Point Energy Center, located in the village of Buchanan, NY (Westchester County), has three reactors on site.

- Unit 1 was one of the earliest reactors licensed by the U.S. Atomic Energy Commission (AEC), the predecessor to the U.S. Nuclear Regulatory Commission (NRC). Indian Point Unit 1 is permanently shut down and was operated by Consolidated Edison from August 1962 until October 1974. Entergy (the NRC licensee for Indian Point) has moved Unit 1's spent fuel to dry storage in an independent spent fuel storage installation on the Indian Point site. The spent fuel pool for Unit 1 has been drained and cleaned.
- Unit 2 began commercial operations in 1974. It is a Westinghouse pressurized-water reactor with a large dry containment. Consolidated Edison owned and operated Unit 2 until 2001, when the NRC authorized transfer of the license to Entergy. Per a 2017 settlement agreement between New York State, Riverkeeper, and Entergy, Unit 2 is scheduled to be shut down by April 30, 2020, before the expiration of its license in 2025.
- Unit 3, a design very similar to Unit 2, began commercial operations in 1976. In 1978, operating authority for Unit 3 was transferred from Consolidated Edison to the Power Authority of the State of New York, which operated Unit 3 until 2000, when the NRC authorized transfer of the license to Entergy. Under the same agreement between New York State, Riverkeeper, and Entergy, Unit 3 is scheduled to be shut down by April 30, 2021.

Figure 1 and Figure 2 *(see Appendix H for all figures)* provide aerial views of the site to orient the reader.

Underground natural gas pipelines have crossed part of the Indian Point site since the 1950s. A 26-inch line was constructed first, beginning in 1952, and a 30-inch pipeline was constructed between 1965 and 1967.[2] Maximum allowable operating pressures (MAOPs) for the 26-inch and 30-inch lines are 674 psig and 750 psig, respectively. The 26-inch pipeline is isolated and not in active service, but it is being maintained and could be returned to service if needed.[3]

In this report, these pipelines are referred to as the "preexisting pipelines," in contrast to the Algonquin Incremental Market (AIM) 42-inch pipeline that was constructed after the units began operating (see Section 1.2 of this report). The preexisting pipelines run closer to Unit 3 than to

[2] Algonquin Incremental Market application, Resource Report 10, Section 10.5.3. https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13473930.
[3] Operational information obtained from Enbridge on April 3, 2020.

Unit 2, but in both cases are outside the security owner-controlled area (SOCA), hundreds of feet away from safety-related plant equipment.

Appendix A presents background information on how these preexisting pipelines were evaluated by the licensee and the NRC from initial licensing through 2015.

1.2. Algonquin Incremental Market Project

In February 2014, Algonquin Gas Transmission, LLC (a subsidiary of Spectra Energy[4]) applied to the Federal Energy Regulatory Commission (FERC) for a Certificate of Public Convenience and Necessity and related authorizations for the AIM Project.[5] The AIM Project, as described in the original application, would include installing 37.6 miles of pipeline and related facilities in New York, Connecticut, and Massachusetts; adding compression capability at stations in New York, Connecticut, and Rhode Island; and modifying or constructing multiple metering and regulating stations. Figure 3 in this report provides an overview of the AIM pipeline.

The new pipeline facilities included:

> … 20.1 miles of 42-inch diameter pipeline that will replace certain segments of 26-inch diameter pipeline, including approximately 6.8 miles in Rockland County, New York, approximately 8.8 miles in Westchester County, New York, approximately 0.1 miles in Putnam County, New York and approximately 4.4 miles in Fairfield County, Connecticut (including horizontal directional drills of 0.7 miles crossing the Hudson River and 0.7 miles crossing I-84/Still River)…
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> … Installation of a new 42-inch [mainline valve], cross over piping and a 26-inch receiver facility at MP 5.48 (Stony Point to Yorktown Take-up and Relay) in Westchester County, New York…
>
> … Replace the existing 26-inch valve with a 42-inch valve equipped with Remote Control Valve (RCV) capability and install cross over piping at existing MLV 15 at MP 11.0 (Stony Point to Yorktown Take-up and Relay) in Westchester County, New York…

Algonquin's application also addressed concerns regarding Indian Point that had been identified in an October 2013 letter from Entergy to the FERC.[6] (Entergy's submittal was part of a FERC prefiling review, which included environmental scoping.) The relevant discussion is in Section 10.5.3 of Resource Report 10, "Hudson River Crossing Alternative."[7] Algonquin clarified in this section that none of the existing pipelines near Indian Point could be upgraded to a higher pressure, and that

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[4] In 2018, Spectra Energy was acquired by Enbridge Inc. Uses in this report of Algonquin, Spectra, and Enbridge are interchangeable. https://www.enbridge.com/media-center/news/details?id=123526&lang=en&year=2018.

[5] Submitted February 28, 2014; publicly available initial submittal files accessible at https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14190856, with other documents retrievable via FERC's Docket Search for CP14-96.

[6] Submittal dated October 14, 2013, responding to a September 13, 2013, FERC request for scoping comments on a planned environmental impact statement for the AIM pipeline; https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13369875. This submittal is part of the prefiling review docket PF13-16. Entergy's submittal notes that the potential for increased safety risks need to be evaluated before the pipeline begins operating. Entergy posed multiple questions regarding the construction and operations of the new pipeline.

[7] Dated February 2014; https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13473930

the existing pipelines needed to be retained for reliability. Algonquin evaluated Hudson River crossings using a northern route (along the existing right of way through the Indian Point site) and a southern route (farther away from Indian Point). Algonquin decided to use the southern route because it presented less risk and a higher likelihood of construction success. The figure showing these alternatives is reproduced in this report as Figure 4.

As part of its review, the FERC issued a draft environmental impact statement in August 2014.[8] The FERC docket shows multiple comments from Entergy, the NRC, and interested stakeholders regarding the potential impacts of the AIM pipeline on Indian Point. The Entergy comments discussed the design enhancements that Algonquin had committed to for the pipeline along the southern route, the evaluation that it had to conduct for Indian Point, the NRC's ongoing inspection of this evaluation (see Section 1.2.2), and its decision not to oppose the FERC approval of AIM following the southern route.[9] The NRC comments referenced the NRC's inspection and a planned future interaction with the FERC, as discussed in Sections 1.2.2 and 1.2.3.[10]

The FERC issued its final environmental impact statement in January 2015.[11] Multiple sections of the final environmental impact statement, beginning with the executive summary, address Indian Point. The alternatives section (Chapter 3) of the environmental impact statement discusses the northern (not selected) and southern (selected) route and their effects on Indian Point. The land use section (4.8) discusses Indian Point, including comments received and actions taken by Entergy and the NRC. Algonquin noted that it would coordinate all construction activities with Entergy's Indian Point site manager.

The section on reliability and safety (4.12) notes the enhanced mitigation measures for construction near Indian Point "exceed the most stringent Class 4 requirements,"[12] in a passage related to the nearby Buchanan-Verplanck Elementary School. The FERC further noted that this section of the pipeline would be designated a high consequence area, which means it would be included in Algonquin's integrity management program under the requirements of the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA) in 49 CFR 192, Subpart O, "Gas Transmission Pipeline Integrity Management (IM)."[13] This section also addresses Entergy's comments on the pipeline routing, pipeline design enhancements, construction impacts on Indian Point, and overpressure protection, as well as the results of Entergy's and the NRC's related activities.[14]

A summary of the FERC's relevant findings and bases can be found at the end of Section 4.13 of the final environmental impact statement on cumulative impacts:

> As a result of consultation between Algonquin and Entergy, Algonquin has agreed to additional design and installation enhancements along approximately 3,935 feet of the AIM Project pipeline where it would lie closest to [Indian Point] (i.e., 0.5 mile from [Indian Point's] security barrier). These measures are described in section 4.12.3. Entergy has concluded that, based on the proposed routing of the 42-inch-diameter pipeline further from safety-related equipment at [Indian Point], and accounting for the substantial design and installation enhancements agreed to

[8] Issued August 6, 2014; https://www.ferc.gov/industries/gas/enviro/eis/2014/08-06-14-eis.asp.
[9] Dated September 29, 2014; https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14255369.
[10] Dated September 30, 2014; https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14255780.
[11] Issued January 23, 2015; https://www.ferc.gov/industries/gas/enviro/eis/2015/01-23-15-eis.asp.
[12] 49 CFR 192.5, "Class locations"; https://www.law.cornell.edu/cfr/text/49/192.5.
[13] https://www.law.cornell.edu/cfr/text/49/part-192/subpart-O
[14] See pp. 4-276 to 4-279 of the final environmental impact statement.

> by Algonquin, the proposed AIM Project poses no increased risks to [Indian Point] and there would be no significant reduction in the margin of safety at the facility. The NRC conducted its own, independent review assuming a catastrophic pipeline failure, and concurred with these findings. As such, we find there would not be any significant cumulative impacts on safety or reliability associated with the proximity of the pipeline to the [Indian Point].

The FERC issued its approval order in March 2015.[15] Paragraphs 106 and 107 of the order address Entergy's and the NRC's activities regarding Indian Point and the FERC's conclusion that "the project will not result in increased safety impacts" at Indian Point. Spectra Energy placed the AIM Project into service in November 2016.[16]

1.2.1. Entergy Actions

Entergy was aware of Algonquin's plans to construct a 42-inch pipeline near the Indian Point site, in addition to the preexisting pipelines. This change meant that Entergy needed to consider under 10 CFR 50.59, "Changes, tests, and experiments," whether there would be effects on Indian Point needing NRC approval.[17]

Entergy voluntarily submitted its evaluation results to the NRC in August 2014, referencing the AIM pipeline application and draft environmental impact statement.[18] Entergy noted its plans to comment on the FERC draft environmental impact statement and concluded its letter with this passage:

> Entergy has determined that there are no increased risks to Indian Point and, pursuant to 10 CFR § 50.59, has concluded that prior NRC review and approval is not required. In our submittal to FERC we plan to point out that as part of the routine inspection program NRC always has the right to review and challenge any analysis done pursuant to 10 CFR 50.59. Unless NRC chooses to perform such a review we cannot guarantee that they would ultimately concur with our position. Therefore we will suggest that prior to approving the Project, FERC should consider conferring with the NRC before reaching a conclusion regarding the potential hazards posed by the AIM project on [Indian Point] and whether any additional mitigation is necessary. Accordingly, we are forwarding to the NRC the enclosed Safety Evaluation and Hazards Analyses and are prepared to answer any questions NRC may have on the Analyses or support inspections of the same.

Entergy, in its 10 CFR 50.59 evaluation, described earlier evaluations of the preexisting pipelines (all of which are discussed in Appendix A to this report), the routing and design of the planned AIM pipeline, and actions that the pipeline operator would take in the event of a rupture.[19] Entergy

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[15] Issued March 3, 2015; https://www.ferc.gov/CalendarFiles/20150303170720-CP14-96-000.pdf.

[16] https://www.eia.gov/todayinenergy/detail.php?id=29032

[17] https://www.nrc.gov/reading-rm/doc-collections/cfr/part050/part050-0059.html

[18] Submitted August 21, 2014. The letter and 10 CFR 50.59 evaluation are publicly available at ADAMS Accession No. ML14245A110. Enclosure 2 to the letter (the Risk Research Group hazards analyses) is available to the NRC staff at ADAMS Accession No. ML14245A111.

[19] This discussion of rupture isolation (sheets 7 to 8 of the 10 CFR 50.59 evaluation) is the first identification of the "3-minute assumption" discussed multiple times in this document. Specifically, the evaluation states (emphasis added) that: "[t]he existing pipeline automation and control system, which will be used for the proposed new 42 inch pipeline near [Indian Point], does not provide for an automatic isolation of the closest

discussed application guidance in Regulatory Guide 1.70 and staff review guidance in Standard Review Plan Section 2.2.3 for considering design-basis events external to the plant, as well as guidance in Regulatory Guide 1.91 for evaluating postulated failures at nearby facilities and transportation routes.[20] Entergy used this guidance to evaluate the exposure rates (likelihood) of pipeline failures and effects (consequences) of such events. The analysis resulted in a list of distances from the pipeline beyond which damage was *not* postulated:

- 1,266 feet to withstand heat flux from jet fires (at 12.6 kW/m^2)
- 1,155 feet to withstand detonation of a vapor cloud (at 1 psi overpressure)
- 900 feet to withstand missiles generated by the rupture (based on the maximum distance observed)

Entergy then evaluated structures and equipment that were closer to the pipeline than these distances (both to the enhanced pipeline running near the site and the non-enhanced pipeline farther away). The switchyard and fuel oil storage tank for the Units 2 and 3 emergency diesel generators, which are just over 100 feet from the nearest approach of the 42-inch pipeline, could be destroyed because of a pipeline rupture. Entergy clarified that the loss of offsite power that would result had already been analyzed and is a relatively high probability event for other reasons. The fuel oil storage tank is a source of fuel to the diesel generators beyond the onsite "day tanks" to ensure they have an overall 7-day supply of fuel. Offsite fuel could be obtained and provided to the site through alternative access routes. Entergy noted that it would move an associated tanker truck, and the team confirmed that it was moved to a distant location onsite. Other equipment and structures were either significantly further away or had backup capability. Of note, the SOCA fence (which bounds all safety-related equipment onsite) is at least 1,580 feet away from the pipeline. Figure 5 shows views of the AIM pipeline right of way from near Indian Point to provide perspective on the distance and terrain.

Entergy also assessed the frequency of a pipeline explosion "using industry data and correlating it to more recent data." The resulting rupture frequencies for generic pipeline and enhanced pipeline were 1.32×10^{-5} per year per mile and 1.98×10^{-6} per year per mile, respectively.[21] Entergy also estimated associated probabilities of jet fires, explosions, and missiles at various equipment locations.

Entergy concluded that the potential for increased risk to the public was acceptably low because no safety-related structures, systems, or components (SSCs) or security features would be damaged by a pipeline rupture, the effects on other SSCs from ruptures would not have a significant effect on plant safety, and the frequency of damage to such SSCs would generally preclude consideration of

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upstream and downstream mainline valves upon the detection of a pipeline rupture. The two closest actuated valves are located at mile post 2.61 on the west side of the Hudson River and at mile post 5.47 just east of [Indian Point]. They would require an operator to take action to close these valves. The system, however, is monitored 24 hours a day and an alarm would immediately alert the control point operator, located in Houston, Texas, of an event and isolation would be initiated. This would result in all the gas between these valves at the time of closure being able to vent or burn. **The estimated time to respond to the alarm (less than one minute) and the closure time of the valves (about one minute) was used as the basis for an assumed closure time of 3 minutes for the analysis performed in the attached report** [Enclosure 2]" (emphasis added).

[20] This guidance did not exist at the time the applications were submitted for Indian Point; see note 187.

[21] In the 2015 Entergy submittal (see note 22), these frequencies were updated to 1.25×10^{-5} per year per mile and 1.87×10^{-6} per year per mile for generic pipeline and enhanced pipeline, respectively.

such. Entergy used these evaluations to answer the questions associated with 10 CFR 50.59 and determined that prior NRC approval was not needed to address these issues.

In April 2015, Entergy submitted a revised 10 CFR 50.59 evaluation to the NRC.[22] This revision reflected "additional tie-in details for certain limited above-ground segments of the gas pipelines" that Algonquin had shared with Entergy. Only a portion of the 26-inch pipeline is above ground at that location, where it ends at a receiving pig trap,[23] and no portions of the 30-inch or 42-inch main pipelines are above ground. Several smaller-diameter pipe segments for valve actuators, equalizing lines, and pig tie-ins are above ground at that location. Figure 6 shows views of this above-ground area.

In the 2014 analysis, Entergy had considered a sabotage event or rupture at an above-ground portion of the pipeline and concluded that this area was sufficiently far away from all important equipment not to pose a risk. In the 2015 analysis, Entergy reevaluated a rupture of all above-ground components during pigging of the 26-inch pipeline. The heat flux and overpressure were less than in the previous calculation, so Entergy concluded that its previous conclusions regarding 10 CFR 50.59 remained valid.

Entergy updated the final safety analysis reports (FSARs) for Units 2 and 3 to reflect the analyses of the new 42-inch pipeline.[24]

1.2.2. NRC Response to Entergy Actions

The NRC conducted an inspection of Entergy's 10 CFR 50.59 evaluation using Inspection Procedure 71111.18, "Plant Modifications."[25] The NRC documented the results in a November 2014 quarterly inspection report for Indian Point.[26] As part of the inspection, NRC staff reviewed the Entergy documentation, walked down the proposed pipeline routing, and independently analyzed the potential hazards associated with failure of the proposed pipeline. These staff members prepared additional documentation to support the summary that was included in the inspection report.[27] The NRC concluded in the inspection report that "Entergy had appropriately concluded

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[22] Submitted April 8, 2015. The letter and 10 CFR 50.59 evaluation are publicly available at ADAMS Accession No. ML15104A660. Enclosure 2 to the letter (the Risk Research Group hazards analyses) is available to the NRC staff at ADAMS Accession No. ML15104A661.

[23] "Pigs" are devices that the pipeline industry uses to clean the insides of their piping systems, in a process called "pigging." At the end of a line, pigs are removed into a receiver referred to as a "pig trap." Modern inspection tools are also run through pipelines to measure and record irregularities such as corrosion or cracking; these inline inspection tools are generally referred to as "smart pigs." PHMSA fact sheet on In-Line Inspections, dated July 23, 2014; https://primis.phmsa.dot.gov/comm/FactSheets/FSSmartPig.htm?nocache=1315. RBN Energy post titled "'WOOO – PIG – SOOIE!' – The Business of Pipeline Integrity," dated October 3, 2013; https://rbnenergy.com/taxonomy/term/1165.

[24] Submitted September 19, 2016, for Unit 2; ADAMS Accession No. ML16280A161. (Chapter 2 is publicly available at ADAMS Accession No. ML16280A162, and the Chapter 2 figures are publicly available at ADAMS Accession No. ML16280A163.) Submitted October 2, 2017, for Unit 3; ADAMS Accession No. ML17299A163. (Chapter 2 is publicly available at ADAMS Accession No. ML17299A180, and the Chapter 2 figures are publicly available at ADAMS Accession No. ML17299A183.)

[25] Current version issued November 26, 2019; ADAMS Accession No. ML19197A103. The version that was in effect at the time of the Indian Point inspection (issued December 21, 2010) is publicly available at ADAMS Accession No. ML101320542.

[26] Issued November 7, 2014; ADAMS Accession No. ML14314A052.

[27] The documentation of the NRC confirmatory analysis dated October 15, 2014, is available to the NRC staff at ADAMS Accession No. ML14329A189. A redacted version is publicly available at ADAMS Accession

that the proposed pipeline does not introduce significant additional risk to safety-related SSCs and SSCs important-to-safety at Indian Point Units 2 and 3; and, therefore, the change in the design bases external hazards analysis associated with the proposed pipeline does not require prior NRC review and approval."

Since Entergy determined under 10 CFR 50.59 that NRC approval was not needed, and the NRC did not identify issues with this determination, the NRC did not conduct a licensing review or formally request additional information from Entergy (as might have been done in a licensing review).

1.2.3. NRC Coordination with FERC

Early in its review, the FERC offered the NRC the opportunity to participate formally with the FERC as a "cooperating agency" for the environmental review. Staff from both agencies discussed this option in April 2014 teleconferences.[28] As part of these interactions, the FERC shared public comments from the prefiling review and shared insights on the benefits of being a cooperating agency; the NRC explained Entergy's and the NRC's role in the process. The NRC determined that it did not intend to become a cooperating agency but would consider providing appropriate information, once available, on the impacts of the AIM Project.

The NRC commented on the FERC draft environmental impact statement in September 2014.[29] The NRC noted that its inspection of Entergy's hazards analysis was ongoing, with the results scheduled for issuance in mid-November 2014. The NRC recommended that it discuss the inspection findings with the FERC in October 2014 to allow more time for the FERC to prepare its final environmental impact statement.

This meeting occurred via teleconference on October 17, 2014.[30] In its meeting summary, the FERC made note of the Entergy and NRC analyses, as well as the additional mitigation measures that were part of the pipeline design. The FERC stated the following in the meeting summary:

> Based on its review, the NRC came to the same conclusion that Entergy did in its [10 CFR] 50.59 submission. Therefore, NRC finds Entergy's 50.59 submission acceptable and has determined that no prior approval from the NRC is needed. NRC also indicated that the existing pipelines have been studied extensively, including as recently as 2008.

1.2.4. 10 CFR 2.206 Petition

Coincident with its inspection of the 10 CFR 50.59 evaluation, the NRC received a 10 CFR 2.206 petition that raised issues with the 10 CFR 50.59 evaluation conducted by Entergy. The petitioner requested that the NRC take enforcement action against Entergy for violating regulations and raised concerns regarding the NRC's inspection, oversight, and handling of several portions of his petition. The NRC rejected this petition, citing prior reviews of the issues raised by the petitioner. Additional information on the petition and the NRC's handling of it is presented in Section 3 of this report.

No. ML15070A086. The regional inspection report "feeder" dated October 30, 2014, is publicly available at ADAMS Accession No. ML14307B748.

[28] Held April 2 and April 23, 2014; https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14209634.

[29] Submitted September 30, 2014; https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14255780.

[30] Dated October 17, 2014; https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14276308.

1.3. Event Inquiry and Expert Evaluation Team

On February 13, 2020, the NRC Office of the Inspector General (OIG) issued an Event Inquiry, "Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant" (Case No. 16-024).[31] In that report, the OIG raised concerns regarding (1) the NRC's safety analysis that supported the FERC determination to approve modifications to gas pipelines near Indian Point and (2) the NRC's response to a related 10 CFR 2.206 petition.

On February 24, 2020, the NRC Chairman directed the NRC staff to determine whether any immediate regulatory action was needed.[32] NRC staff promptly reviewed the OIG report and the technical aspects of the 42-inch gas line that runs near the Indian Point property. Based on this prompt review, the Executive Director for Operations (EDO) determined that there were no safety issues warranting immediate regulatory action at Indian Point.[33]

The staff was further directed to review whether any information in the OIG report demonstrates that the staff should revisit either the safety analysis or its response to the 10 CFR 2.206 petition, as well as to evaluate whether any modifications to agency practice or procedures are needed or appropriate based on the OIG report. On February 27, 2020, the EDO established an evaluation team to carry out the review directed by the NRC Chairman.[34] This report summarizes the results of that review.

The NRC publicly released the team's evaluation plan on March 9, 2020, including team membership.[35] The team was led by David Skeen (Deputy Director, Office of International Programs) and Theresa Clark (Deputy Director; Division of Rulemaking, Environmental, and Financial Support; Office of Nuclear Material Safety and Safeguards). NRC members were independent of prior reviews in this area. The team included experts in NRC engineering reviews and risk analysis. The team also obtained insights from external experts independent of the NRC's prior activities on this subject. A pipeline safety analysis expert from PHMSA reviewed the NRC and Entergy safety analyses. In addition, the NRC contracted for experienced researchers at Sandia National Laboratories (SNL) to provide expertise on natural gas modeling and fire risk; the results of SNL's efforts are presented in Appendix B. All team members were independent of prior reviews in this area. Biographies of the contributors, both NRC staff and those who provided external support, are included in Appendix F and Appendix G to this report.

As directed by the EDO, on March 18, 2020, the team identified some modifications that may be needed to agency practices or procedures.[36] The team noted that peer reviews should be strengthened, guidance for supporting inspections should be clarified, the structure for reviewing 10 CFR 2.206 petitions should be revisited, and interagency coordination should be strengthened. Section 4 of this report provides additional detail on process improvements recommended by the team.

The results of the team's activities are documented in the following sections of this report. The major activities of the team between February 27, 2020, and April 9, 2020, were:

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[31] Issued February 13, 2020; ADAMS Accession No. ML20056F095.
[32] Dated February 24, 2020; ADAMS Accession No. ML20057E265.
[33] Dated February 26, 2020; ADAMS Accession No. ML20058D088.
[34] Dated February 27, 2020; ADAMS Accession No. ML20058E354.
[35] Dated March 9, 2020; ADAMS Accession No. ML20069A759
[36] Dated March 18, 2020; ADAMS Accession No. ML20078L380

- Conducting one or more interviews each with:
    - 15 NRC staff and managers in Office of Nuclear Reactor Regulation (NRR) and Region I who were directly involved in the NRC's inspection, analysis, and petition review
    - 3 Entergy staff members who were involved in evaluations of pipeline hazards
    - 2 members of the public who had previously raised concerns with the NRC's handling of these issues [37]
    - 2 PHMSA staff members from the accident investigation division
    - 2 New York State pipeline safety program staff members
- Reviewing numerous public and non-public documents, as referenced in the chronology that the team assembled (Appendix I) and the footnotes to this report.
- Visiting the Indian Point site to directly observe pipeline locations, plant safety systems, and equipment and structures that could be affected by a pipeline rupture
- Conducting various risk and consequence analyses for pipeline ruptures, as discussed further in this report (notably Section 2, Appendix B, Appendix A, and Appendix D)
- Coordinating with NRC experts in the Office of Nuclear Regulatory Research and NRR to understand the bases for equations and references in Regulatory Guide 1.91 [38], the structural capabilities of buildings at Indian Point, and electrical cable routing.

During the team's review, the team or external parties identified additional issues separate from those included in the Chairman and EDO taskings. While the team remained vigilant for issues that could pose an immediate safety concern for Indian Point, most of the additional issues raised could not be addressed within the scope or timeframe provided to the team. Section 6.3 of this report captures these issues for further consideration by the NRC, as appropriate.

[37] Transcripts available at ADAMS Accession Nos. ML20087M164 and ML20087M178.
[38] Revision 2 issued April 2013; ADAMS Accession No. ML12170A980.

2. Conclusions Regarding Safety Analysis

Throughout its work, the team remained focused on the safety of Indian Point and whether new information revealed the need to take immediate regulatory action. The team did not identify any concerns that met this threshold. This section of the report describes how the team considered the safety of Indian Point in proximity to the AIM pipeline, from three perspectives: the likelihood of a pipe rupture and blowdown that could affect Indian Point, the consequences of a pipeline explosion (overpressurization and missiles), and the consequences of a pipeline-rupture-related fire (heat impacts). The team considered historical experience and conducted its own analyses of dynamic gas behavior following a pipe rupture and the risk of subsequent impacts at Indian Point. The subsections below address these topics in detail.

2.1. Pipe Rupture and Blowdown Likelihood

2.1.1. Design and Construction Enhancements

The team obtained information from Enbridge (the AIM pipeline owner and operator) regarding the enhanced design and construction of the AIM pipeline near Indian Point. Similar information had been provided to Entergy, in support of its 10 CFR 50.59 evaluation, and other requesting parties. The measures taken by Enbridge have been found to meet or exceed the applicable Department of Transportation requirements under 49 CFR Part 192, "Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards." For example, the enhanced protections for the pipeline adjacent to Indian Point include:

- A more stringent design factor, higher-grade pipe[39], and deeper burial than required
- Fusion-bonded epoxy coatings for corrosion control outside the pipe, an abrasive resistant overlay outside the pipe, and no coating on field weld joints that could cause pipe metal cracking, such as shrink sleeves or tape coatings
- 100-percent non-destructive examination of all girth welds; 100-percent inspection of all welding, coating, and backfilling activities; and pigging after construction to identify and remediate any dents exceeding code limitations
- Hydrostatic testing before placing the pipeline segment into natural gas service, at over 1.5 times MAOP for 8 hours

Enbridge also placed fiber-reinforced concrete slabs and warning tape above the pipeline near Indian Point to reduce the likelihood of construction digging or other activities inadvertently reaching and damaging the pipeline.

In general, these enhancements reduce the likelihood of a pipeline rupture due to known risk factors such as welding flaws, corrosion, and incidental damage. The team's peer reviewer confirmed this reduction when reviewing the team's event frequency estimate discussed in

[39] Spectra (now Enbridge) informed Entergy that the pipe would have 0.72-inch wall thickness and be X-70 piping with 70,000 psi yield strength and 82,000 psig minimum tensile strength. The pipe would be procured from vendors who have passed a stringent quality audit, and full-time mill inspection would be performed by Algonquin Gas Transmission during pipe production. Specifications would require additional quality testing and integrity requirements beyond normal standards. These enhancements were discussed in a Spectra Energy (Algonquin Gas Transmission) memorandum to Energy regarding Response to Entergy Document entitled "Pipeline Enhancements Being Evaluated to Mitigate a Pipeline Failure," dated July 29, 2014. This memorandum is not publicly available, but Entergy made it available to the team.

Section 2.4 and Appendix C, finding that the uncertainty in the estimate is likely to be in the direction of making the team's estimate much higher than the true rupture frequency of that pipeline segment. The full peer review comments are presented in Appendix E.

The team did not attempt to quantify a reduced pipeline rupture frequency for the AIM pipeline near Indian Point, given the uncertainties. In the team's view, optimistic estimates of failure *frequencies* (one in a million per year or less) often lead the licensee or the NRC to assess failure *consequences* in less detail. Therefore, the team continued with its analysis with a more general failure frequency.

2.1.2. Ongoing Evaluations

After construction, pipeline operators continue to assess and mitigate the risks to their pipelines through "integrity management" programs. For high consequence areas,[40] the relevant requirements are in 49 CFR 192, Subpart O. The AIM pipeline near Indian Point is identified as being in a high consequence area, so these requirements apply. Relevant requirements for this case are discussed in the following subsections.

2.1.2.1. Integrity Management

The Department of Transportation requires pipeline operators to have an integrity management program (49 CFR 192.911, among others). These programs include identification of high consequence areas, plans for various assessments of integrity threats to the pipeline, processes for continual evaluation, and certain procedures. Operators must continually improve their programs.

The team obtained information from Enbridge verifying that it has an integrity management program and risk assessment process that manages, monitors, and addresses various types of corrosion, defects in the pipeline, third-party damage, operations issues, and weather. Enbridge's program manual lays out the general approaches taken by Algonquin Gas Transmission.[41]

2.1.2.2. Risk Assessment

The Department of Transportation also requires pipeline operators to assess threats to the pipeline and take actions to mitigate the risks (49 CFR 192.917 and 192.935, among others). "Threats" for purposes of this assessment include those listed in the American Society of Mechanical Engineers and American National Standards Institute (ASME/ANSI) Standard B31.8S,[42] such as corrosion, construction defects, third-party damage, and human error. Operators use this standard to assess the risks associated with each threat and prioritize what baseline assessments and reassessments are needed, as well as what preventive and mitigative measures will be taken. Preventive and mitigative measures are based on the risk assessment and can include installing remote control valves, replacing pipe segments with pipe of heavier wall thickness, and operating below 30 percent of the specified minimum yield strength.[43]

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[40] Defined in 49 CFR 192.103; https://www.law.cornell.edu/cfr/text/49/192.903.

[41] Spectra Energy, "Integrity Management Program (IMP) Manual," 09-0000, Revision 11, dated October 10, 2019. This manual is not publicly available, but Enbridge made it available to the team.

[42] "Managing System Integrity of Gas Pipelines," published in 2018. Publicly available from https://www.asme.org/codes-standards/find-codes-standards/b31-8s-managing-system-integrity-gas-pipelines. The team had access to this standard through the NRC's subscription service.

[43] Specified minimum yield strength is defined in 49 CFR 192.3, "Definitions," https://www.law.cornell.edu/cfr/text/49/192.3. For the AIM pipeline near Indian Point, Enbridge specified that the piping would have a 70,000-psi yield strength.

As noted in Section 2.1.1, measures like these were taken in the design of the 42-inch AIM pipeline near Indian Point. In addition, Enbridge sent the team an assessment conducted by an outside consultant in August 2014 to address the threat of third-party damage that could puncture the AIM pipeline.[44] The report concludes that the force needed to puncture the pipeline could only be exceeded by an excavator weighing over 125 tons. Only about 0.07 percent of the excavators existing in the United States are heavier than this weight, so the consultant concluded that it was unlikely that an excavator with the capacity to damage the pipeline would be used. The consultant also calculated the size of a puncture that would be needed to cause a rupture.

The team also obtained information from Enbridge about the risk assessments conducted under its integrity management program. Enbridge uses a widely-used software package that integrates information on pipeline operations, maintenance, inspections, threats, and consequences to help plan activities. Enbridge conducts these risk assessments annually using a qualitative approach and is developing a more quantitative approach. The threats assessed include different types of corrosion and defects, third-party damage, equipment failure, and incorrect operations. Enbridge identified various design, construction, and operational provisions that address each threat.

2.1.2.3. Baseline and Continuous Pipeline Assessments

Finally, the Department of Transportation requires pipeline operators to conduct a baseline assessment of their pipelines, as well as continuous assessments (49 CFR 192.921, 192.937, and 192.939, among others). As appropriate for the pipeline segments, the operator conducts internal inspections to detect corrosion or other threats, pressure tests in accordance with 49 CFR 192, Subpart J, "Test Requirements,"[45] and direct assessments for corrosion. Operators must conduct this baseline assessment within 10 years from the date a pipeline is installed. Operators must continue to assess the pipeline, with a reassessment occurring no more than 7 years after the baseline assessment. The reassessments, similarly, can also include inline inspection, pressure tests, or direct corrosion assessments (49 CFR 192.921(a)).

The hydrostatic pressure test required under 49 CFR 192, Subpart J, which is conducted before placing the pipeline into natural gas service, is a valid way to satisfy the requirement for a baseline assessment (49 CFR 192.921(a)(2)). The team verified with Enbridge that a hydrostatic test was conducted on the new 42-inch AIM pipeline in October and December 2016. The test applied a pressure of over 1.5 times MAOP for 8 hours. Enbridge plans to conduct a multi-purpose inline inspection in May 2020.

2.1.2.4. Additional Evaluations

The team verified through PHMSA that the New York State Department of Public Service, which acts as an agent for PHMSA to inspect the AIM pipeline, had not issued any violations on these subjects in the years since the AIM pipeline was approved. One inspection report discussed a probable violation related to the AIM pipeline, but this related to the requirement for an emergency shutdown system near the gate of the Southeast Compressor Station in Brewster, NY—not a programmatic issue or a segment near Indian Point. The New York State Department of Public Service confirmed that they are not aware of any portions of the pipeline near Indian Point that do not meet the current 49 CFR Part 192 requirements for design, construction, and operations,

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[44] "Final Report on Puncture Assessment for Algonquin Pipeline to Spectra Energy Company," dated August 27, 2014. Kiefner and Associates, Inc. This report is not publicly available, but Enbridge made it available to the team.

[45] https://www.law.cornell.edu/cfr/text/49/part-192/subpart-J

including integrity management. They are also not aware of any outstanding 49 CFR Part 192 safety inspection findings or enforcement issues for the 42-inch AIM pipeline.

The team also gained access to a risk assessment contracted by the State of New York to assess infrastructure near the AIM pipeline and the risks of damage to the pipeline.[46] The risk assessment was based on experts' judgment and did not quantify probabilities and consequences of specific scenarios. This evaluation considered risks to pipeline integrity such as corrosion and other material issues, excavation and other sources of damage, as well as equipment and operational failures. All risks specific to Indian Point were categorized as "unlikely." Mitigation and emergency response strategies were identified for each, including actions that the New York State Department of Public Safety would take. The appendix on Indian Point pipeline impacts summarized publicly available analyses related to the preexisting and AIM pipelines, including those by the NRC and licensees.

Collectively, these ongoing evaluations and mitigative measures provided the team with further confidence that a pipeline rupture is unlikely, though the team did not attempt to quantify the risk reduction from such activities.

2.1.3. Isolation of a Pipeline Rupture

If a rupture occurs on the 42-inch AIM pipeline near Indian Point, the potential impacts on the nuclear power plant would depend on the volume of gas released as a result of the rupture. The volume of gas released is a function of (1) the speed with which the pipeline operator isolates the ruptured pipeline and (2) the length of pipeline that would need to be isolated. This volume of gas could then be able to feed a fire or cause other consequences. Entergy and the NRC made different assumptions regarding these variables to estimate the volume of gas. The team obtained updated information from Enbridge on the methods that the pipeline operator would use to isolate a rupture of the 42-inch AIM pipeline in order to clarify the time it would take to isolate the ruptured pipeline and the length of pipe that would be isolated.

Enbridge informed the team that the 42-inch AIM pipeline is continuously monitored from a gas control center in Houston, TX. The control center monitors pressures, flows, and compressor station status (including discharge and suction pressures). The Supervisory Control and Data Acquisition (SCADA) system is used to detect ruptures and was specifically enhanced to include a schematic screen to expedite evaluation and isolation of the pipeline. Alarms include a rate-of-change alarm that detects a pressure drop on the line. If the data indicates a rupture requiring valve closures, gas controllers have the authority, autonomy, and ability to close valves to isolate the pipeline. They are also trained to isolate other affected facilities including shutting down the compressor station across the Hudson River, if necessary.

Enbridge has procedures for emergency notification, emergency response, alarm management, and response to abnormal operations that it would apply in these cases. The procedures indicate that the operator may have enough information from the data system, alarms, and trends to enable emergency response actions. If the data is not clear, the operators can also use reports from outside sources such as emergency services or public officials to justify isolating a line. However, the controller is not required to have such verification to isolate the line if the data is clear.

[46] "Algonquin Incremental Market Pipeline Risk Analysis Report," transmitted from several New York State agencies to the FERC Chairman on June 22, 2018 (see note 135 for a related letter). The report is marked privileged and confidential and may contain Critical Energy Infrastructure Information, as designated by the FERC. This report is not publicly available, but the FERC made it available to the team.

The mainline valves for the 42-inch pipeline are remote-operated from the Houston control center. The control center can also monitor pressures on the upstream and downstream sides of the valves. **Based on tabletop training and operating experience, Enbridge estimated that it would likely take 3 to 8 minutes to identify a rupture using the SCADA system, confirm that the valves need to be closed, and close the valves. Enbridge noted that 3 minutes (previously referenced by Entergy) would be a "best-case" scenario.** The team confirmed with the New York State Department of Public Service, which has inspection authority for the pipeline, that state inspectors observed remote operation of the valves that would isolate the pipelines near Indian Point on three occasions in 2018 and 2019. From the time the controller in Houston initiated the closure, the valve took about 30 seconds to close. The inspectors witnessed this both from the Houston control room and at the valve location near Indian Point and did not identify any issues.

Data from actual accident experience, as discussed in Section 2.4, indicates that it can take minutes to several hours to isolate ruptured pipelines. Some of the very long isolation times represent situations very different from the AIM pipeline. Manually operated valves would require operators to travel to the valve location. Accident experts also told the team that pipeline operators may want to keep gas flowing for safety reasons (e.g., in extreme cold) and may allow gas to release and burn off from a break for hours in some cases where there is no safety concern.

The team obtained schematics showing the location of mainline isolation valves near Indian Point. As has been stated in multiple other evaluations, the nearest remote-controlled valves to Indian Point are about 2.8 miles apart. The next closest downstream valve—which is also remote controlled—is about 5.6 miles downstream. The next closest upstream valve is associated with the Stony Point compressor station, about 2.5 miles further upstream. Based on the PHMSA team member's experience and confirmed by Enbridge, in some cases the pressure drop from a pipeline rupture may make it challenging to close the nearest valve to a rupture, and operators may need to close a valve further from the rupture. Enbridge confirmed that the valve operators use power gas from either side of the valve to move a hydraulic actuator. If a pipeline were punctured, the nearest remote-controlled valve could be closed quickly. If a full guillotine rupture occurred, the pressure at the nearest remote-controlled valve would likely drop below the pressure required to activate the valve operator. In this case, the next downstream valve would be closed. **The team concludes that the minimum pipeline length that could be isolated is about 2.8 miles. For a full guillotine rupture, the pipeline length would more likely be 8.4 miles (assuming the operator closed the next closest downstream valve).**

As a result of this new information, the team recommends that Entergy reevaluate its assumptions of a 3-minute pipeline isolation time and a gas volume based on approximately 3 miles of isolated pipe, as discussed in Section 2.6, to determine if changes to these assumptions would materially change its original external hazard evaluation related to the 42-inch AIM pipeline. The OIG finding related to this issue is also discussed in Section 5.1.5.

2.2. Pipe Rupture Consequences – Overpressurization and Missiles

Regulatory Guide 1.91 states that "[a] demonstration that the rate of exposure to a peak positive incident overpressure in excess of 1.0 psi (6.9 kPa) is less than 10^{-6} per year when based on conservative assumptions, or 10^{-7} per year when based on realistic assumptions, is acceptable." Additionally, the guide states that if the "criteria cannot be met, then the applicant may show through analysis that the risk to the public is acceptably low on the basis of the capability of the safety-related structures to withstand blast and missile effects associated with detonation of the potentially explosive material."

In the 10 CFR 50.59 evaluations performed in 2014 and 2015,[47] Entergy found that the frequency of a peak overpressure may be more than 10^{-6} per year, so a detailed evaluation was needed to illustrate that the safety-related structures could withstand blast and missile effects. For missile effects, Entergy noted that 900 feet is the greatest distance noted in the literature, which is less than the distance to any plant systems within the SOCA. For blast effects, Entergy calculated that a vapor cloud explosion would not damage important-to-safety SSCs within the SOCA.

The NRC staff's inspection report[48] stated that:

> The staff determined that the impacts to the SSCs important-to-safety outside the SOCA from the proposed new pipeline are bounded by the impacts from low probability events of extreme natural phenomena (including seismic activity, tornado winds, and hurricanes) which have been previously assessed and are addressed in the Indian Point Units 2 and 3 [updated FSARs].

The team could not verify the NRC staff's determination that the Unit 2 and Unit 3 updated FSARs bounded the impacts for missiles. Additional information on this assumption is provided in Section 5.2.2. However, for missiles, the team found that the largest reported distance that a pipe fragment has been thrown is approximately 600 feet. (According to PHMSA, the 900 feet reported by Entergy for one incident was an initial estimate by accident investigators, but the final established distance was 554 feet, which is about 1.1 times the potential impact radius for this pipeline, as explained in Section 2.3.)

For overpressurization, the team was not able to determine by analysis that there would be no impact to SSCs required for safe shutdown. Therefore, the team conducted a probabilistic risk assessment to determine the increased risk to the plant that could be caused by overpressurization of plant equipment or structures. Section 2.4 provides more information on this risk assessment, which concluded that the increase in risk was very small. Furthermore, Section 2.5 discusses real-world experience with large pipeline ruptures, which indicates that pressure-related effects have not been observed in structures or equipment beyond the boundary of the impact area related to heat and missiles generated by the rupture.

At the team's request, experts from SNL performed a more detailed analysis to evaluate whether the models specified in Regulatory Guide 1.91 were used appropriately, determine whether the NRC analytical model results could be validated, and perform a preliminary vapor cloud dispersion simulation. In replicating prior NRC analyses, SNL determined that certain assumptions made by the NRC may not be valid. The two major assumptions challenged by SNL's analysis relate to immediate positive buoyancy of the methane cloud and the use of the trinitrotoluene (TNT) equivalency model for this scenario. The team recommends that Regulatory Guide 1.91 be updated to account for these findings, which would apply to detailed analyses conducted when the safe-distance criterion in the guide is not met. Section 4.4 has more details on recommended changes to Regulatory Guide 1.91 to provide clearer expectations for detailed analyses.

In the preliminary vapor cloud dispersion simulation (see Appendix B), SNL showed that a dense methane cloud could form and travel far distances. These distances are consistent with PHMSA's

[47] See notes 18 and 22.
[48] See note 26.

document for vapor cloud dispersion,[49] which is typically only applied to nonflammable gases.[50] Based on these findings, the team consulted with PHMSA pipeline accident investigators. They noted that rich gases such as butane or propane, which are heavier than air, may form gas vapor clouds. However, they were unaware of any large natural gas (methane) transmission pipeline ruptures that have resulted in delayed vapor cloud explosions. They agreed that methane gas under high pressures could initially be heavier than air when being released after a pipeline rupture. In their experience, however, although the dense methane gas might initially pool in the crater resulting from the rupture, as the methane gas expands and leaves the crater, it would become lighter than air. The team did not find any record of dense methane gas clouds, such as that observed in Figure 7, igniting or exploding at a location away from the initial pipe rupture.

The team reviewed an Oak Ridge National Laboratory study performed for PHMSA.[51] Oak Ridge prepared the report to evaluate the benefits of automatic and remote-controlled isolation valves. When discussing the scope of the report, Oak Ridge noted:

> Blast, overpressure, shrapnel, and earthquake-type effects resulting from an unintended natural gas or hazardous liquid pipeline release are hazards that can adversely affect humans, property, and the environment. However, these effects are beyond the scope of this study because they occur immediately after the break and [remote-controlled valves] and [automatic shutoff valves], which typically require several minutes to close, cannot mitigate these hazards.

While Oak Ridge did not expand further on the statement that blast and overpressure effects "occur immediately after the break," the team includes it here because it is consistent with the accident experience noted above and described in Section 2.5. The team notes that ignition sources associated with the rupture itself (e.g., from portions of the ruptured pipe striking rocks, gravel or other materials in the soil around it) may contribute to these early effects.

In the team's interview with an independent gas pipeline expert, he made similar statements.[52] For example, he noted that the first five minutes after a pipeline rupture were "the most dangerous" because of the high heat radiation, and that "the massive heat flux, with possible explosions and high thermal radiation, probably [occurs] in the first five or ten minutes." After discussing the effects of local topography on blast forces, he acknowledged that, not knowing the details, that heat radiation was the "real threat." These heat flux impacts are described further in Section 2.3.

As noted in the analysis assumptions in Appendix B, the SNL preliminary evaluation of vapor cloud transport and dispersion did not quantify potential plant impacts or overpressures that may be experienced, if the cloud exploded or caught fire. SNL did not consider local terrain in this simplified analysis, assuming a flat plane instead. The local elevation change, river valley

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[49] TTO-14, "Derivation of Potential Impact Radius Formulae for Vapor Cloud Dispersion Subject to 49 CFR 192," dated January 2005; https://www.phmsa.dot.gov/pipeline/gas-transmission-integrity-management/derivation-potential-impact-radius-formulae-vapor.

[50] "PHMSA Gas Integrity Management Inspection Manual: Inspection Protocols with Supplemental Guidance," dated January 1, 2008; http://www.viadata.com/pipeliner/library_docs/GasIMP%20Protocols%20With%20Guidance%20(8%201%202008)%20w%20disclaimer.pdf. PHMSA lists its inspection protocols individually at https://primis.phmsa.dot.gov/gimdb/prolist.gim.

[51] "Studies for the Requirements of Automatic and Remotely Controlled Shutoff Valves on Hazardous Liquids and Natural Gas Pipelines with Respect to Public and Environmental Safety," ORNL/TM-2012/411, dated October 31, 2012; https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/16701/finalvalvestudy.pdf

[52] See, for example, p. 33 of the transcript dated March 19, 2020; ADAMS Accession No. ML20087M164.

meteorology, and surface roughness would impact vapor cloud dispersion and would be expected to preclude dispersion toward the plant. If a vapor cloud traveled toward the plant, several ignition sources appear to exist between the pipeline and plant, such as the Buchanan switchyard.

Given the accident experience from PHMSA, input from the independent pipeline expert, local terrain effects, and the presence of ignition sources, the team concludes that there is reasonable assurance that the safety-related equipment at Indian Point would enable the reactors to be shut down and remain safely shut down, providing for adequate protection of public health and safety.

2.3. Pipe Rupture Consequences – Jet or Cloud Fires

Department of Transportation regulation 49 CFR 192.903, "What definitions apply to this subpart?" defines terms including "potential impact radius." The potential impact radius "means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property." This impact radius is based on the premise that thermal radiation from a jet or trench fire is the dominant hazard.[53] The equation included in the regulation is:

$$r = 0.69\sqrt{p * d^2}$$

In this equation, r is the potential impact radius (ft), p is the MAOP of the pipeline (psi), and d is the pipeline diameter (in). This equation is associated with the heat-affected area,[54] as described further in the notice issuing the rule[55] and the technical basis provided in C-FER report prepared for the Gas Research Institute.[56]

Based on the input from the team's PHMSA member and the team's interview with an independent gas pipeline expert, the potential impact radius is the radius for a person to get out of the area within 30 seconds and is not meant to be used to determine the survivability of buildings. They recommended multiplying the calculated potential impact radius by 1.5 to 2 as a "rule of thumb" to determine a safe distance for buildings.[57] This aligns with the Oak Ridge National Laboratory report[58] that evaluated the thermal impacts of double-ended guillotine breaks of pipelines. That report noted that severe damage could occur within 1.5 to 1.7 times the potential impact radius. This conclusion is also consistent with the risk assessment performed by New York State.[59]

Using this formula for the 42-inch, 850-psig gas pipeline at Indian Point results in a potential impact radius of 845 feet. Doubling this number results in an expanded impact radius of 1,690 feet. This radius would extend into the SOCA; however, it would not impact any safety-related structures.[60]

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[53] TTO 13, "Potential Impact Radius Formulae for Flammable Gases and other Natural Gases"; https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/gas-transmission-integrity-management/65311/tto13potentialimpactradiusfinalreportjune2005.pdf.

[54] Regulatory Guide 1.91 does not include any guidance on calculating heat fluxes associated with blasts. The guide assumes that overpressurization is the limiting scenario.

[55] 68 FR 69778, issued December 15, 2003; https://www.govinfo.gov/link/fr/68/69817. Additional information on this rule can be found in the docket folder at https://www.regulations.gov/docket?D=PHMSA-RSPA-2000-7666.

[56] Dated October 2000; https://www.regulations.gov/document?D=PHMSA-RSPA-2000-7666-0049.

[57] See pp. 25-26 of the transcript dated March 19, 2020; ADAMS Accession No. ML20087M164.

[58] See note 51.

[59] See note 46.

[60] To provide further perspective, the team calculated a modified impact radius using the same methodology (see note 53) but based on the lowest heat flux that would cause wooden structures to burn, applying a constant of 1.09 rather than 0.69. The resulting impact radius was approximately 1,335 feet. The team

Entergy found that at the SOCA fence, heat fluxes would be below 10 kW/m^2, and that the heat flux at 2,028 feet (a location inside the SOCA fence but not impacting safety-related systems) is only 5 kW/m^2.[61]

NUREG/CR-3330[62] discusses the survivability of reinforced concrete at various heat fluxes for varying points inside a wall, the closest point being six inches inside the wall. At Indian Point Unit 3, the diesel generator building has the thinnest walls of all safety-related buildings at 24 inches.[63] The thinnest point of containment is 42 inches,[64] and the thinnest point of the auxiliary building above ground is 30 inches.[65] NUREG/CR-3330 notes that at a heat flux of 15 kW/m^2, it will take 11.6 hours for temperature at six inches inside the wall to exceed 350 degrees Fahrenheit (177 degrees Celsius) and 5 hours if the heat flux was 50 kW/m^2.

The team's independent analysis based on calculations in NUREG/CR-3330 found that heat fluxes at the closest safety-related structure would be 11 kW/m^2 for a mass flow rate of 1940 kg/s. For a bounding flow rate of 4,000 kg/s, the heat flux would be 21 kW/m^2. Even at this bounding flow rate, the structure could withstand the heat flux for over eight hours, which greatly exceeds the estimated time it would take for the gas pipeline to be shut off; therefore, the heat flux would have no impact on safety-related structures. An appendix to the SNL report (included as Appendix B to this report) presents this analysis in more detail.

These methods of analysis give the team confidence that the robust concrete structures housing safety-related equipment inside the Indian Point SOCA, over 2,300 feet from the 42-inch AIM pipeline, would continue to function to safely shut down the plant and maintain it in a safe state. Therefore, a jet or cloud fire would not be expected to affect safe shutdown of the Indian Point reactors.

2.4. Pipe Rupture Risk Assessment

The NRC uses a variety of methods to determine the safety significance of postulated events. Two of these methods use the insights from probabilistic risk assessments. One method is the significance determination process,[66] which uses risk insights, where appropriate, to help the NRC determine the safety significance of inspection findings. The other method is described in Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis."[67]

Both approaches use the metric of change in core damage frequency resulting from the situation to assess an inspection finding or a licensing basis change. These approaches define a very small change to be less than one in a million years (1×10^{-6}). The NRC uses the agency's independent risk models to evaluate the change in core damage frequency. The team, with support from experts at the Idaho National Laboratory, modified the NRC's Indian Point risk models to postulate a failure of the 42-inch AIM pipeline and conducted a risk analysis. The team assumed that a pipeline failure

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includes this information because wooden structures would be damaged much more easily than the seismic Category I structures at the Indian Point site. Furthermore, the seismic Category I structures are well outside this distance.

[61] See note 22.

[62] Published September 1983; ADAMS Accession No. ML062260290.

[63] Response to a Request for Additional Information regarding Order EA-12-049 and Order EA-12-051, dated December 2, 2016; ADAMS Accession No. ML16350A103.

[64] Indian Point Unit 3 Individual Plant Examination, dated June 1994; ADAMS Accession No. ML110320477.

[65] Submitted September 26, 1997; ADAMS Accession No. ML11227A102.

[66] IMC-0609 issued January 2019; ADAMS Accession No. ML18187A187.

[67] Revision 3 issued January 2018; ADAMS Accession No. ML17317A256.

would cause an unrecoverable loss of the Buchanan switchyard and cause loss of the city water tank. Based on these analyses, the team found that the change in core damage frequency for both plants was an increase of one in 63 million years (1.6×10^{-8} per year), which is well below the agency's defined threshold for a "very small" change in risk of one in a million years.

Because of the uncertainty associated with the consequences of overpressurization from an explosion, the team also performed a sensitivity analysis. This analysis assumed that all equipment not housed in a seismic Category I structure (i.e., not located in the primary auxiliary building, diesel generator building, or reactor containment) was lost upon the pipeline rupture. These Category I structures are robust concrete structures. For example, as discussed in Section 2.3, the minimum thickness of the walls for the auxiliary building is 30 inches. They are also designed to resist internal pressurization from design-basis events, which in the case of the Indian Point containments includes a design pressure of 47 psi above the atmospheric pressure. According to structural engineering experts at the NRC, it is a good starting assumption that these structures will be capable of withstanding the pressures from an explosion associated with a rupture of the 42-inch AIM pipeline.[68] The team primarily evaluated Unit 3 for this sensitivity, since it is closer to the pipeline and would experience the most severe impacts. The change in core damage frequency for this scenario was one in 5.7 million years (1.75×10^{-7} per year). Again, this is below the agency's threshold for a "very small" change in risk of one in a million years.

The team was also concerned that PHMSA's pipeline rupture data provided a national pipeline mileage that included all diameters of pipes, not just large pipes, which could be non-conservative if used to calculate an event frequency. The team independently reviewed publicly available pipeline data.[69] Using the last ten years' worth of data, the team determined Class 2, 3, or 4 carbon steel transmission lines with pipe diameters greater than or equal to 20 inches and maximum operating pressures greater than or equal to 300 psig rupture with a frequency of 2.4×10^{-5} per mile per year. The team recalculated the change in core damage frequency using this higher frequency and concluded that the change in risk remained below the agency's threshold for a "very small" change in risk. More information on the team's risk assessment and the PHMSA data can be found in Appendix A and Appendix D, respectively.

Even after the Indian Point reactors shut down permanently, spent fuel will still be onsite and could be a source of additional risk. The agency's independent risk models only consider reactor risk, so the spent fuel pools and the dry fuel storage location were considered separately. The spent fuel storage pit for Indian Point Unit 3 is also a robust concrete seismic Category I structure like the auxiliary building and diesel generator building, and the spent fuel is below grade. Given this rugged construction and the input from structural experts, the team concludes that a pipeline rupture would not negatively affect the spent fuel pit. Indian Point Units 2 and 3 use the Holtec HI-STORM 100 dry cask storage system for storage of fuel after removal from the spent fuel pools.[70] The HI-STORM 100 dry cask storage system is also designed for the same conditions as other

[68] A more detailed structural analysis would consider (1) the credible blast or deflagration loads from the pipeline accident; (2) the structural properties of the structures such as the thickness, spans and reinforcements of their walls and roofs; and (3) the details of relevant design loads such as the tornado design missiles and high wind pressure loads. The team did not pursue such an analysis given the conclusions it drew from the accident experience presented in Section 2.5.
[69] From PHMSA Gas Distribution Incident Data, January 2010 to present (ZIP); https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data.
[70] 77 FR 41454, issued July 13, 2012; https://www.govinfo.gov/content/pkg/FR-2012-07-13/pdf/2012-17110.pdf.

Category I buildings. The team also concludes that the dry fuel storage location, which is much farther from the 42-inch AIM pipeline than the other structures evaluated, would not be negatively affected by a pipeline rupture.[71]

2.5. Historical Pipe Rupture Experience

To provide perspective for the team's analytical results, the team obtained information from PHMSA's accident investigation division on some actual pipeline ruptures. This information is summarized in Table 1. While this table provides a relatively small sample, it provided important background information to the team. In the table, the "impacted area" refers to the distance away from the pipeline where investigators found impacts as a result of the pipeline rupture. Impacted areas are generally an ellipse with a length parallel to the pipeline (and longer in the direction that had more compressed gas available) and a shorter width perpendicular to the pipeline. Most of these impacts were within or near the potential impact radius defined in Department of Transportation regulations, with none further than about 1.1 times the potential impact radius. Isolation times can be relatively long in certain circumstances, such as when valves need to be locally operated or when shutting off the pipeline could have more significant consequences (e.g., for customers who need heating in the winter) than letting the fire burn, if it is an isolated area. PHMSA staff stated that fires do not ignite in all cases, as both a spark and the correct atmospheric conditions are needed to ignite the gas vapors.

Table 1. PHMSA pipeline accident data showing pipe diameter and allowable pressure, calculated potential impact radius (PIR), impacted area, distance pipe was ejected, time to isolate the line, and duration of fire. "NR" is shown where data was not reported, and "N/A" is shown where the event did not occur. "TBD" is included where the accident investigation is not complete.

Year	Location	Pipe Dia. (in.)	MAOP (psi)	PIR (ft.)	Impacted Area Length (ft.)	Impacted Area Width (ft.)	Pipe Ejected (ft.)	Isolation Time (h:mm)	Fire Duration (h:mm)
1985	Beaumont, KY	30	936	633	700	500	NR	NR	NR
2003	Viola, IL	24	975	517	not reported (NR)		554	8:48	11:55
2008	Appomattox, VA	30	800	585	566	200	N/A	NR	NR
2010	San Bruno, CA	30	375	401	375	160	100	1:35	2:35
2017	Dixon, IL	20	800	390	365	163	N/A	0:31	3:06
2018	Batesville, OH	24	1,440	628	50	50	N/A	0:00	1:04
2018	Moundville, OH	36	1,440	943	250	250	100	0:25	3:05
2018	Hesston, KS	26	899	538	400	200	254	0:02	2:44
2018	Buffalo, OK	26	765	496	110	60	170	1:09	N/A
2018	Woodruff, UT	20	918	418	143	90	430	1:21	N/A
2018	Dixon Springs, TN	22	773	422	30	20	75	0:38	N/A
2019	Caldwell, OH	30	936	633	500	500	N/A	1:35	14:05
2019	Mexico, MO	30	900	621	437	286	125	1:12	1:31
2019	Hot Springs, AR	30	1,000	655	252	114	306	2:12	N/A
2019	Artesia, NM	20	1,000	436	100	60	360	3:23	N/A

This experience, which is mostly from the last few years after PHMSA formed its accident investigation division, is generally consistent with earlier information included in the C-FER report.[72] The C-FER report collected information on incidents from 1969 to 1995 and compared actual incident outcomes to the proposed hazard area model—which became the potential impact radius under 49 CFR Part 192. Figure 8 shows the comparison of distances that was included in the

[71] FSAR for HI-STORM 100; ADAMS Accession No. ML081350153.

[72] See note 56.

C-FER report. In all but one case, the potential impact radius was larger than the burn area or distance where any injuries was seen. Where the burn area was larger (NTSB-PAR-71-1), it was about 1.1 times the potential impact radius.

Figure 9 shows four examples of pipeline ruptures, including those with and without fires. The elliptical nature of the most severe impacts is demonstrated in the two left-hand images, fire and debris damage can be seen in the bottom-right image, and a rupture crater is shown clearly in the top-right image.

The team discussed pipeline ruptures with the PHMSA accident investigation staff who prepared the more recent data. The PHMSA staff confirmed that, in their experience, that they had never seen explosions from natural gas clouds occurring away from the initial rupture site.

2.6. Recommendation – Ask Entergy to Revisit its 10 CFR 50.59 Evaluation

Although the team did not conclude that immediate regulatory action is needed regarding Indian Point, the team does recommend further work be done by Entergy to show that its prior conclusions remain valid. **Based on concerns raised by external parties and substantiated by the team, the team recommends that the NRC request that Entergy evaluate the impact of Enbridge's updated information that a 3 minute closure time for the isolation valves is a "best-case" scenario, and that the pipe length that may need to be isolated could be greater than 3 miles.** Entergy should either revisit its analysis by applying updated assumptions or provide a basis for why the updated information does not significantly impact the results of the conclusions previously presented.

During the NRC's review of the October 2014 petition referenced in Section 1.2.4, the petitioner raised a concern that Entergy provided inaccurate or incomplete information contrary to the requirements in 10 CFR 50.9, "Completeness and accuracy of information."[73] The petitioner also asserted that the licensee may have violated 10 CFR 50.5, "Deliberate misconduct."[74] The petitioner's concern centered on whether it was appropriate to model the 42-inch AIM pipeline being isolated in 3 minutes.[75] To this day, the petitioner continues to assert that Entergy knew that the isolation times were inaccurate and material to the NRC determination.[76]

For purposes of addressing the issue raised by the petitioner the requirements in 10 CFR 50.5 state, in relevant part, that licensees may not:

> (a)(1) Engage in deliberate misconduct that causes or would have caused, if not detected, a licensee or applicant to be in violation of any rule, regulation, or order; or any term, condition, or limitation of any license issued by the Commission; or
>
> (a)(2) Deliberately submit to the NRC, a licensee, an applicant, or a licensee's or applicant's contractor or subcontractor, information that the person submitting the information knows to be incomplete or inaccurate in some respect material to the NRC.
>
> (c)…deliberate misconduct by a person means an intentional act or omission that the person knows: … Would cause a licensee or applicant to be in violation of any

[73] https://www.nrc.gov/reading-rm/doc-collections/cfr/part050/part050-0009.html.
[74] https://www.nrc.gov/reading-rm/doc-collections/cfr/part050/part050-0005.html.
[75] See pp. 14 and 16 of the PRB transcript dated July 15, 2015; ADAMS Accession No. ML15216A047.
[76] The petitioner raised this issue during his interview with the team, as well in multiple instances of correspondence with the NRC.

> rule, regulation, or order; or any term, condition, or limitation, of any license issued by the Commission; or … Constitutes a violation of a requirement, procedure, instruction, contract, purchase order, or policy of a licensee, applicant, contractor, or subcontractor.

Similarly, 10 CFR 50.9 states, in relevant part, that:

> Information provided to the Commission … by a licensee … shall be complete and accurate in all material respects.

The team did not identify any information showing that Entergy misled the NRC, so the team does not recommend referring the issue to an Allegation Review Board. Entergy's prior submittals, as described in Section 1.2.1, were based on its understanding of information received from Spectra at the time. The team received updated information from Enbridge indicating that the assumptions Entergy made represent a "best-case" scenario—but not an impossibility. Although the team recommends that Entergy revisit its analysis to determine whether these assumptions were material to its conclusions (as shown in Section 2.6), the team does not recommend that a violation be pursued under 10 CFR 50.9 at this time.

3. Conclusions Regarding 10 CFR 2.206 Petition

In October 2014, a member of the public submitted a 10 CFR 2.206 petition regarding the new 42-inch AIM pipeline near Indian Pont.[77] The petitioner requested that the NRC take enforcement action against Entergy for violating regulations at 10 CFR 50.9, "Completeness and accuracy of information," 10 CFR Part 50, Appendix B, "Quality Assurance Requirements," and 10 CFR 50.59. As part of the petition, the petitioner also raised concerns regarding the NRC's inspection, oversight, and the precise handling of several portions of his petition.[78] In January 2015, the petitioner met with the Petition Review Board (PRB) and presented his concerns.[79] Over the course of several months, the petitioner continued to supplement his petition with additional information and pursue additional insights through requests for agency documents.

In April 2015, the petitioner received documents from the NRC that, in his view, supported the petition's assertion that a materially false statement was made with respect to Enbridge's ability to close the AIM pipeline isolation valves in 3 minutes. During a July 2015, PRB meeting, the petitioner and PRB discussed this additional information and agreed that the petitioner would submit any remaining concerns in writing.[80] The petitioner submitted 39 questions later in July 2015.[81] In September and November 2015, the NRC rejected the 2.206 petition and provided responses to the 39 questions, respectively.[82]

3.1. Summary of the Current 10 CFR 2.206 Process

The 2.206 petition process allows the public and other interested stakeholders to request enforcement action against NRC licensees and license activities.[83] The current implementation of the 2.206 petition process is established in Management Directive 8.11.[84] Additional guidance is available in a desktop guide.[85] Overall process flowcharts from the desktop guide are reproduced as Figure 10 and Figure 11 of this report.

Under most circumstances, a 10 CFR 2.206 petition review begins with a written request submitted to the EDO. The written request identifies the licensee, the activity, the enforcement action requested, and supporting evidence.[86]

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[77] Submitted October 15, 2014; ADAMS Accession No. ML14294A751.
[78] Concerns with issues related to the petition that were handled in other NRC processes are addressed in Section 5 of this report. This section focuses on the 10 CFR 2.206 petition process.
[79] A transcript of the January 28, 2015, meeting is available ADAMS Accession No. ML15044A459.
[80] A transcript of the July 15, 2015, meeting is available at ADAMS Accession No. ML15216A047.
[81] Submitted July 27, 2015; ADAMS Accession No. ML15251A050.
[82] Petition rejection issued September 9, 2015; ADAMS Accession No. ML15251A023. Response to 39 questions issued November 6, 2015; ADAMS Accession No. ML15287A257.
[83] Enforcement Petition Process brochure dated March 2019; ADAMS Accession No. ML19070A037.
[84] Management Directive 8.11, "Review Process for 10 CFR 2.206 Petitions," issued March 1, 2019; ADAMS Accession No. ML18296A043.
[85] "Desktop Guide: Review Process for 10 CFR 2.206 Petitions," effective March 1, 2019; ADAMS Accession No. ML18176A147.
[86] Unsupported assertions, general opposition to nuclear power, the identification of safety issues without seeking enforcement action fall outside the 10 CFR 2.206 petition process. Other processes that could be triggered include allegation reviews or investigations by the NRC Office of Investigations or OIG.

Then, the NRC establishes a PRB to review the petition. The PRB is generally composed of a chairperson (a Senior Executive Service manager), the office 2.206 petition coordinator,[87] a petition manager, cognizant management and staff, a regional representative (branch chief or higher), a representative from the Office of Enforcement, and a representative from the Office of the General Counsel.[88] The PRB or the petition manager initially determines whether immediate action is necessary based on the safety or security issue raised by the petitioner; if so, the NRC pursues that action before taking further action to disposition the petition. If immediate action is not necessary, the PRB will prepare for an initial meeting that will include (1) a discussion of the safety significance, (2) a discussion of immediate actions taken (or needed, if new information has arisen since the initial determination), (3) a recommendation concerning referral for investigation, and (4) a proposed schedule.[89] At the initial meeting, the PRB also assesses whether the petition meets the acceptance criteria in Management Directive 8.11, could be consolidated with other petitions, or should be held in abeyance.[90]

In determining whether a petition should be accepted, the NRC first determines whether the petition specifies facts that support the requested action.[91] Second, the NRC determines whether the petition raises an issue that was previously resolved in a facility-specific or generic review. If the issue had been raised before, the PRB must determine (to accept the petition) that the specific issue was not resolved, the resolution does not apply to the current facts, or the petition provides significant new information[92] that was not previously considered. After evaluating the petition against the acceptance criteria, the PRB will inform the petitioner of its assessment prior to a meeting and offer the petitioner an opportunity to meet with the PRB.[93]

Should the petitioner decide to meet with the PRB, the meeting will normally be conducted as a public meeting.[94] The meeting is an opportunity for the petitioner to provide any relevant additional explanation and support, considering the PRB's initial assessment. During the petitioner's presentation, the PRB members may ask questions to help clarify the assertions and concerns. The licensee is invited to participate and may also ask clarifying questions. The licensee does not formally present.

After considering any new information, the PRB will make an initial determination to either accept or reject the 2.206 petition. If the petition is rejected (as was the case for the October 2014 petition), the PRB issues a closure letter to the petitioner that explains why the petition was not

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[87] The office coordinator is selected from the NRC office responsible for regulating the licensee (e.g., NRR for an operating reactor).
[88] The PRB may include a representative from the Office of Investigations and a cognizant office enforcement coordinator.
[89] Desktop Guide, Appendix B, Section III.C (see note 85).
[90] Desktop Guide, Appendix B, Section III.C – III.D (see note 85).
[91] Desktop Guide, Appendix B, Section III.D.1.a (see note 85).
[92] "Significant" information means that the information is sufficiently great or important to be worthy of attention and that the information is real and not speculative. The information must also be "new" in that the NRC staff has not previously received and/or evaluated the information in response to the issue raised in the petition (which includes any prior resolutions of the issue). The term "significant new information" means that the information is both significant and new. Desktop Guide, Appendix B, Section III.D.1.b.n.1 (see note 85).
[93] The PRB chairperson informs the office director or designee of its initial assessment.
[94] Some limited exceptions to the public meeting requirement may apply. See Management Directive 3.5, "Attendance at NRC Staff-Sponsored Meetings," issued December 4, 2019; ADAMS Accession No. ML19350A643.

accepted, acknowledges the petitioner's efforts in bringing issues to the staff's attention, explains any immediate actions taken, notifies the petitioner if the issue is being referred to another NRC program or process, and responds to the issues raised in the petitioner's request.[95] If the petition is accepted, a letter is sent informing the petitioner, and the petition review proceeds to a Director's Decision.[96] On its own initiative, the Commission may review the Director's Decision within 25 days of the date of the decision.[97]

3.2. Observations on October 2014 Petition Review

In his October 2014 request for enforcement action against Entergy, the petitioner asserted that Entergy's assumption regarding the time to isolate the new 42-inch natural gas transmission pipeline was mistaken.[98] He further asserted that the agency should not have accepted this 3-minute closure time and that Entergy knew the information was materially inaccurate or incomplete. The petitioner also challenged the licensee's and NRC's use of the Areal Locations of Hazardous Atmospheres (ALOHA) modeling software to model a postulated pipeline explosion.[99] The petitioner raised concerns regarding the use of Regulatory Guide 1.91 and what he viewed as the staff's deviation from the guidance. The petition questioned the quality assurance process used by the agency for its analysis of the AIM pipeline hazard.

During the NRC's evaluation of the petition, the PRB met with the petitioner twice to discuss the underlying facts, and the petitioner's concerns. Ultimately, the PRB determined the petition could not be accepted because the NRC had previously evaluated the concern.[100] To reach that conclusion, the PRB requested technical staff to conduct additional analysis.[101] The additional analysis was not thoroughly documented (Figure 12 and Figure 13 in this report are examples of handwritten sketches and results). As a result, the results were difficult for the PRB to review or verify, as indicated in interviews the team conducted with PRB members.

The team observes that the timing of the petition closure appears to be unusual, with the petition rejection occurring in September 2015 while the petitioner still had questions and concerns outstanding. The PRB promised to provide a response to his concerns later and did so in November 2015.

3.3. Team's Conclusion on 10 CFR 2.206 Petition Review Decision

The PRB's determination that the petitioner's concerns had been resolved in a prior staff review (i.e., the inspection report) met the criterion for rejecting a petition. Based on the guidance that was

[95] Desktop Guide, Appendix B, Section III.H.3 (see note 85).
[96] A Director's Decision is the official agency response to a 2.206 petition that is accepted for review. The Director's Decision may grant, partially grant, or deny the action requested by the petitioner. In most cases, the staff prepares a proposed Director's Decision, which is transmitted to the petitioner and licensee for comment. After receiving any comments, the staff dispositions the comments and revises the Director's Decision as appropriate. The director's decision is then issued, and a notice of issuance is subsequently published in the Federal Register. Desktop Guide, Appendix B, Section V (see note 85).
[97] Desktop Guide, App. B, p.2 (see note 85). The Commission will not entertain a request for review of the office director's decision.
[98] See note 77.
[99] PRB transcript, p.23; see note 75. For a comparison of the ALOHA calculations with the analysis performed by Sandia National Laboratories as part of this team's activities, refer to Section 2 and Appendix B.
[100] See note 82.
[101] A security-related summary of this analysis is available to the NRC staff at ADAMS Accession No. ML15078A067. Images of portions of the analysis are included in this report as Figure 12 and Figure 13.

used to conduct the 10 CFR 2.206 petition review, the team concludes that the PRB appropriately dispositioned the petitioner's concerns. Under the NRC's petition review guidance[102], a petition could be rejected because:

> The petitioner raises issues that already have been the subject of NRC staff review and evaluation either on the cited facility, other plant facilities, or on a generic basis, for which a resolution has been achieved, the issues have been dispositioned, and the resolution is applicable to the facility in question.

Therefore, the team concluded that the PRB appropriately dispositioned the petitioner's concerns, based on the information available and the guidance in effect at the time. As noted in Section 2.6, however, the team subsequently identified concerns with Entergy's assumptions regarding the time needed to isolate the pipeline and the gas volume that could flow from a ruptured pipeline.

The team recommends that Entergy be asked to update its 10 CFR 50.59 evaluation. Assuming this action is pursued (e.g., under 10 CFR 50.54(f)), then the team does not view it as necessary to reopen the 10 CFR 2.206 petition.

Nonetheless, the team observes that the PRB process could have been more rigorous, questioning, and well-informed about prior agency reviews. The OIG Event Inquiry identified some areas of concern with respect to the agency's analysis and communications with the petitioner. Recommendations to improve the 10 CFR 2.206 process are presented in Section 4.3.

[102] Part II, p. 9 of the Directive Handbook for Management Directive 8.11 (see note 85). Similar criteria for rejecting a petition continue to appear in the current guidance for evaluating 10 CFR 2.206 petitions.

4. Conclusions Regarding NRC Processes

During the review of the NRC's safety analysis, the 10 CFR 50.59 inspection, and the 10 CFR 2.206 petition, the team identified several areas where processes could be improved. Four recommended areas for improvement concern internal NRC processes and procedures, and one concerns NRC interactions with outside entities. For the four internal issues, the agency should (1) improve certain NRC technical work products, including peer reviews; (2) clarify guidance for regional inspection support by headquarters; (3) improve and clarify the 10 CFR 2.206 petition review process; and (4) update guidance for pipeline hazard analysis. In addition, a procedure should be developed to guide coordination between the NRC and other agencies to ensure clear documentation, communication, and consideration of each agency's needs.

4.1. Recommendation – Improve Certain NRC Technical Work Products, Including Peer Reviews

In March 2020, NRR revised its office instruction ADM-405, "NRR Technical Work Product Quality and Consistency." [103] This office instruction provides guidance for technical work products to meet expectations for quality. It specifies when peer reviews should be conducted, the qualifications for staff performing per reviews, the time and effort needed to perform an adequate peer review, and how to resolve peer review comments. The team identified these areas as weaknesses during interviews with those involved in the peer reviews of the NRC's analyst's two main calculations for the technical analysis that supported the NRC's 10 CFR 50.59 inspection and 10 CFR 2.206 petition review. It appeared that the first peer reviewer was identified almost by accident and was given little direction on what was expected of the peer review. The resulting reviews were brief and, in the first instance, much more focused on the licensee's analysis than the NRC's analysis, given the responsibility of the licensee under 10 CFR 50.59.

The NRC staff and supervisors interviewed by the team uniformly expressed a lack of familiarity with the previous versions of this office instruction. Therefore, the team recommends that the roll-out of the newly revised office instruction have a robust communication plan to ensure that technical staff and supervisors are familiar with the requirements. The team noted that training slides have already been prepared to accompany the issuance of the guidance. [104] **The team recommends that NRR consider how this guidance will be reinforced for new staff or supervisors who did not participate in training when the guidance was updated.** The team also notes that this guidance is specific to NRR. **Other NRC offices may want to consider whether their peer review procedures provide for appropriate scope, process, and qualifications. The agency should also consider implementing continuing training requirements for branch chiefs, other supervisors, and senior leaders on technical work product quality and consistency.** Continuing training requirements would help promote consistency in technical work products. Continuing training would also support NRC leaders as they transition to new positions and may become responsible for technical staff who provide independent or confirmatory analysis for NRC regulatory decisions.

Finally, the team observed that the ways the NRC staff documented their analyses of Entergy's 50.59 evaluation opened the door to later challenges. For example, calling an assumption "conservative" or "bounding" can be refuted if the basis for that claim is not well documented. It may be advantageous to make realistic or reasonable assumptions and document the basis appropriately. In addition, some NRC analysis documents related to the review were undated or did

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[103] Issued March 18, 2020; available to the NRC staff at ADAMS Accession No. ML20066J085.
[104] Training slides are available to the NRC staff at ADAMS Accession No. ML20070M965.

not designate who conducted the analysis. Applying more rigor and consistency in documenting NRC technical analysis would provide a lasting record of the work performed, in case questions about the analysis arise at some time in the future. Additional discussion on documenting decisions under the 10 CFR 2.206 process is provided in Section 4.3.4.

4.2. Recommendation – Clarify Guidance for Regional Inspection Support by Headquarters

The analyses that became the focus of the OIG Event Inquiry originated in a request for technical support from Region I. The regional inspection staff knew that this 10 CFR 50.59 evaluation would be of high interest and made, in the team's view, an appropriate decision in selecting it as a sample for their baseline plant "modifications" inspection. The onsite inspections and document reviews appear to have been thorough and reasonable. Furthermore, the team views favorably the region's decision to request technical support from headquarters to help review the licensee's unusually complex 10 CFR 50.59 evaluation related to the proposed 42-inch pipeline.

In hindsight, given the amount of effort that was expended by technical staff, it would have been beneficial for Region I to document its request for headquarters support more formally through a Task Interface Agreement.[105] The relevant NRR office instruction clarifies when such agreements are suitable, as well as identifying when an informal teleconference or email with headquarters technical staff would suffice.[106] While the full Technical Interface Agreement process is not warranted in all cases when inspectors need technical support from headquarters, the team concluded that a better explanation of the Region's request and more formal documentation of the technical staff's response would result in a more consistent process.

Regions should provide the headquarters technical experts who support inspections the appropriate context for their review. The team heard from multiple individuals that the focus of inspections is to determine whether the licensee violated regulations and whether significant issues are found in the licensee's technical basis supporting changes to the plant. When regions ask for technical support from headquarters, they are not requesting a full technical review and endorsement of all aspects of a licensee's technical evaluation. (In the case of a 10 CFR 50.59 inspection, the conclusion being sought is whether the licensee appropriately determined that no prior NRC review is needed before implementing a change to the plant.) This approach contrasts with the more detailed licensing reviews typically performed by NRC technical reviewers to make an affirmative finding that a request from a licensee or applicant meets NRC requirements. Technical experts who are used to performing licensing reviews may benefit from additional dialogue on the difference between a licensing review and the region's need for a technical review of a licensee's 50.59 evaluation to support an inspection. Inspectors can help the headquarters technical expert by identifying specific focus areas for the technical review. The inspector may also want to pose specific licensing or technical questions to the technical expert. The inspector may also identify concerns or uncertainties with specific aspects of a licensee's analysis that should be checked by confirmatory calculations. Reproducing a full licensee analysis is likely not necessary to make the conclusions expected during an inspection. The inspector should define the expected level of effort, timeframe, and response format at the beginning of the activity.

Therefore, **the team recommends that the NRC develop guidelines and good practices for inspectors and technical experts to use in arranging formal and informal technical support**.

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[105] NRR-COM-106, issued November 20, 2015; ADAMS Accession No. ML15219A174.

[106] In the case of the 10 CFR 50.59 inspection for Indian Point, the inspector recalled the analyst taking a couple of months to respond. This level of effort probably warranted a Task Interface Agreement.

Such guidelines would also be referenced whenever technical support is needed, so that the inspector and the technical expert can reach agreement on expectations.

4.3. Recommendation – Improve and Clarify the 10 CFR 2.206 Petition Review Process

The team identified several areas where the 10 CFR 2.206 process should be further enhanced, as described in the subsections below. These enhancements should be included in the next update to the process guidance (either the Management Directive or the desktop guide).

4.3.1. Modernize Petition Review Boards

The team recommends that PRBs be improved by designating standing members for certain roles. Under the current process, membership in PRBs is an ancillary duty for each participant. PRB members interviewed by the team indicated that this process can lead to inconsistencies in the expertise, ownership, and experience level of those serving on the PRB. Under the current process, a separate PRB is established for each petition. For example, one office rotates PRB chair responsibilities among senior managers. This rotation of leadership and participation can mean that leadership and staff do not necessarily develop a deep understanding of the process. This may result in some PRB members feeling bound by the process and reticent to challenge assertions made or exercise the appropriate questioning attitude.

Efficiency may be particularly harmed if key PRB members are conducting the process for the first time or relearning the process if it has been a long time since they served on the PRB. This may result in the PRB member tending to focus on strictly applying the process in a way that discourages creative approaches to a petitioner's request, even when warranted. If PRB members do not understand why certain procedures are in place and when procedures should be modified or are unnecessary, they are unlikely to suggest improvements to the process.

4.3.2. Provide for Independent Petition Reviews

The team recommends that, to the extent practicable, PRB members and support staff be independent from any previous substantive work on the issues raised in the petition. One criterion for rejecting a petition is that the issue raised by the petitioner has been previously resolved on a facility-specific or generic basis. The desktop guide states that "[o]ffice management should avoid potential conflicts of interest when assigning staff and a chair to the PRB."[107] Several PRB members and supporting technical staff associated with the review of the October 2014 petition were involved in the recently completed inspection of the licensee's 10 CFR 50.59 evaluation. This included the technical reviewer and the petition manager. The guidance and process applicable to that petition did not specify that conflicts of interest should be avoided, but it did stress the importance of conducting an independent technical review.[108]

In this case, the technical reviewer was effectively tasked with determining whether the issues raised by the petitioner had been previously resolved through a facility-specific review. The petition was ultimately dispositioned based on a previous resolution that relied on the previous work of the technical reviewer. Because he was tasked with reviewing the petitioner's assertion, he faced an intractable conflict of interest. If he determined that the petitioner raised a valid issue, he would have had to determine that he erred in his earlier work. Simultaneously, the petition

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107 Desktop Guide on 2.206, Appendix B, p. 8 (see note 85).

108 The petition manager "[b]riefs the petition review board on the petitioner's request(s), any background information, the need for an independent technical review, and a proposed plan for resolution, including target completion dates." Part II, p. 4 of the Directive Handbook for Management Directive 8.11 (see note 84).

manager also served as the licensing project manager for Indian Point Units 2 and 3. He also would have had some familiarity with the licensee's 10 CFR 50.59 analysis and the NRC inspection. He, also, would have needed to determine that his prior involvement had failed to identify a problem with the licensee's actions.

This petition review also exposed the fact that for certain skill sets, such as external hazard analysis, limited expertise is available internally to the agency. This weakness limits the agency's ability to assign staff as peer reviewers of agency calculations and to conduct independent reviews of prior agency decisions. The team's recommendations on peer reviews are presented in Section 4.1.

The lack of independence and depth may cause concerns among petitioners, members of the public, and other interested stakeholders. Petitioners may remain concerned that petition reviews are not sufficiently rigorous. Licensees may worry that an issue will be raised over and over, occupying increasing resources and time by the NRC.

To the extent practicable, the NRC should select PRB members and support staff who are independent of any previous facility-specific or generic disposition of the issues related to a petitioner's concerns.

4.3.3. Conduct Detailed Reviews after Petition Acceptance

After reviewing the events for this petition and interviewing many of the members and participants in this PRB, the team found that, given the amount of effort expended in reviewing the petitioner's concerns, a majority believed that it might have been better to accept the petition and proceed to a Director's Decision. Most, however, indicated that at the time it was difficult to foresee how much additional work and analysis would be needed. The process proceeded iteratively with the petitioner supplementing the original petition and seeking additional information from the staff. As a result, the PRB may have perceived at each iteration that only a little extra work was needed. In hindsight, the PRB performed a significant volume of work to determine that the petition would not be accepted.

During the team's evaluation, a theme developed with respect to the staff perception of the 10 CFR 2.206 process and the level of effort required for different aspects. The staff considers the work necessary to effectively participate in the 2.206 petition review process to be considerable. That level of effort increases if a petition is accepted and proceeds to a Director's Decision. Despite this additional effort, a prior NRC staff analysis found that many 10 CFR 2.206 petitions *are* accepted and *do* result in NRC action, even if the specific actions requested by the petitioner are not taken.[109] Between 1975 and 2012, the NRC granted or took related action on about 37 percent of 10 CFR 2.206 petitions.

The team recommends that PRBs accept petitions for review if detailed analysis will be needed to review the issues raised. If a PRB needs staff to conduct a new analysis or needs to engage in lengthy discussions to decide whether to accept a petition, it may be appropriate to accept the petition and do the extra work needed to prepare a Director's Decision. This approach would support proper documentation of the analysis, as discussed in the next section.

4.3.4. Document Analysis Supporting Petition Decisions

The team recommends that any staff analysis or calculations used to support a 10 CFR 2.206 petition decision should be rigorously documented. This documentation is particularly important when it is relied on in a decision to reject or deny a petition.

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[109] Filing dated June 15, 2012; ADAMS Accession No. ML12167A524.

In the case of the October 2014 petition, the calculations used by the PRB to make its decision appear to consist of print-outs of ALOHA runs and hand calculations, with only one analysis being documented in a short undated summary that included scanned sketches and handwritten notes. These calculations appear largely to have been retained only by the technical reviewer, who later provided a copy to the OIG during its event inquiry.[110] Because these calculations formed the basis of the PRB's justification to reject the 10 CFR 2.206 petition, it would have been prudent to more formally document the calculations and provide the basis for the variables used. Calculations need to be appropriately performed, documented, and reviewed. The work needs to be retained in a retrievable form and drafted in a manner that would support a full understanding of the calculations that were performed, including any assumptions and engineering judgment.

4.4. Recommendation – Update Guidance for Pipeline Hazard Analysis

The team recommends that the NRC review and update Regulatory Guide 1.91 to address several technical issues that the team identified and to enhance the review process for pipeline hazards. Regulatory Guide 1.91 was updated in 2013 to reflect gas pipeline hazards for the first time, based on approaches that the NRC staff had previously found acceptable. Regulatory Guide 1.91 should be revisited in an independent review to ensure its guidance reflects generically acceptable approaches for evaluating gas pipelines near nuclear power plants. The team reviewed other licensee or applicant analyses that referenced Regulatory Guide 1.91 and found that, in general, assumptions were made that maximized the potential hazard. The team considers that those conclusions would likely remain valid even if Regulatory Guide 1.91 were updated to account for these issues.

As discussed in Section 5.1.6 of this report, Regulatory Guide 1.91 provides a formula to calculate the minimum safe distance by evaluating a potential explosion at the source based on the amount of explosive in terms of TNT equivalent. Beyond the minimum safe distance, no adverse effect would be expected to occur. That safe distance is proportional to the cube root of the mass of the explosive in the equation (in this case, the mass of flammable gas vapor released). Regulatory Guide 1.91 assumes equipment failures at specific levels of overpressure (1 psia). The guide recommends a detailed analysis if this safe-distance criterion is not met. The guide, however, provides no suggestions for how this analysis should be conducted. As discussed in Sections 2.2 and 2.3, presented in more detail in Appendix B, detailed calculations conducted by SNL raised concerns with some of the assumptions made when considering vapor cloud explosions, particularly buoyancy and dispersion of the natural gas. The team recommends that the NRC provide clear expectations for detailed calculations that would be conducted if the safe-distance criterion is not met, such as those seen in References 8 and 9 of Regulatory Guide 1.91.

A key element in the minimum safe-distance calculation is the mass of gas released following the postulated pipeline rupture. The team observed a significant disparity in the calculated potential impact distance when different assumptions were used (e.g., how to account for the duration of gas release, the affected pipeline length, and the use of a yield factor as listed in Table 1 of the regulatory guide). The current revision of Regulatory Guide 1.91 does not provide clear guidance for determining the mass release. As a result, the guidance can produce different results, based on different assumptions for the mass release. Therefore, more guidance on what assumptions are valid to make when determining the values to be used in the Regulatory Guide 1.91 formula would be beneficial.

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[110] Copies of the ALOHA runs and hand calculations were returned to the technical reviewer during the team's review.

The comment response associated with the draft Revision 2 to Regulatory Guide 1.91 discusses how the guide was changing from mass equivalence to energy equivalence and states that an energy equivalence (yield) "between 20 [percent] and 40 [percent] is recommended for hydrocarbons."[111] Specific values were not provided for different chemicals. This additional detail on appropriate yield values would be a beneficial addition to the guide. The team also noted that Reference 9 of the guide does not include information about different classes of unconfined vapors. Therefore, the team recommends that additional guidance be provided on how vapors should be classified.

The team also recommends updating the TNT-equivalent equation in Regulatory Guide 1.91 to revert to the 4,500 kJ/kg value that had been included in the draft Revision 2, as discussed in Section 5.1.6.

Finally, Regulatory Guide 1.91 provides no guidance on heat flux, which is the subject of Department of Transportation regulations and, according to some pipeline experts, may be the controlling issue for potential nuclear power plant impacts. This aspect should be addressed in an update to Regulatory Guide 1.91.

4.5. Recommendation – Formalize Coordination with Other Agencies

4.5.1. Documentation of Coordination

The team recommends that the NRC improve documentation of its interactions with other agencies, particularly when NRC expertise or decisions will be cited by another agency.

As noted in Section 1.2.3, the NRC shared the results of its 10 CFR 50.59 inspection with FERC staff in an October 2014 teleconference.[112] The team interviewed several staff that the FERC identified as participating in that meeting. Only one staff member recalled details of the teleconference which was consistent with the OIG Event Inquiry statement that the NRC "did not provide calculations to FERC but talked them through the inspection report." The team reached out to the FERC and found that the FERC engineer who participated in the meeting had subsequently left the agency and the environmental contractor how participated in the meeting was no longer under contract. Also, the team's interviews with NRC staff indicated that the NRC licensing project manager for Indian Point had additional informal telephone conversations with FERC representatives, though the team could not find documentation of these conversations and did not interview the now-retired project manager.[113]

The team, therefore, developed its views on the NRC-FERC interactions based on what is in the public record. The NRC appears not to have provided any formal correspondence to the FERC beyond the September 2014 comment on the draft environmental impact statement. The OIG Event Inquiry states that "two FERC headquarters-based engineers assigned to the AIM Project revealed that FERC used NRC's November 7, 2014, inspection report for its [environmental impact statement] and FERC's Commission relied heavily on NRC's expertise to determine if [Indian Point]

[111] "Staff Responses to Public Comments on Regulatory Guide 1.91, Revision 2," issued April 26, 2013; ADAMS Accession No. ML12170A987.
[112] See note 30.
[113] Given the short timeframe for the team's activities, the team decided not to review any NRC staff who were involved with these issues but had subsequently retired. OIG interviewed some of these individuals, including the licensing project manager referenced as "NRC's primary communicator with FERC."

could be safely shut down in the event of a pipeline accident, for approval of the portion of the AIM Project that crossed [sic] [Indian Point] property."[114]

It is unclear whether the NRC provided any regulatory context for its review to the FERC in the October 2014 teleconference. The team views that the FERC would have benefited from a clearer understanding of the findings Entergy was making in its 10 CFR 50.59 analysis, the findings the NRC was making in its inspection report, and how those findings differed from what might be done in a full licensing review. The FERC may also have benefited from a richer understanding of the analyses of the preexisting pipelines (which were mentioned in the October 2014 teleconference).

The team is not suggesting that the FERC would have made different conclusions in this case as a result of better understanding the information provided by the NRC, but the NRC and FERC positions could have been made clearer to interested stakeholders if their interactions were well documented.

4.5.2. Formalization of Coordination

The team recommends that the NRC clarify guidance for when it should participate as a cooperating agency in other agencies' environmental reviews, as well as how it should engage with Federal or state agencies more generally.

The NRC policy for intergovernmental consultation[115] applies to "major interagency agreements, major organizational changes, major rules and regulations, statements of policy, guides, and standards, and major studies that may have a significant state or local impact." It specifically excludes "[c]onsultation with state officials and Federal agencies on individual licensing and enforcement decisions." The team did not identify guidance applicable to the NRC-FERC interactions described in this report.

For its own environmental reviews, the NRC considers during the scoping period whether there should be cooperating agencies.[116] Based on discussions with the environmental center of expertise, the team found that a memorandum of understanding is usually developed to describe the respective responsibilities, jurisdictional authorities, and expertise of each agency within the context of the applicable review. The memorandum also establishes a schedule and deliverables for the environmental review. The NRC's document database includes multiple formal letters between the NRC and other agencies, inviting one party or another as cooperating agencies and accepting such invitations. For example, the NRC and the U.S. Army Corps of Engineers executed a memorandum of understanding in 2008 that establishes the Corps as a cooperating agency for NRC environmental reviews related to the issuance of authorizations to construct and operate power reactors.[117]

No such formality appears to have been applied to the FERC review of AIM pipeline. As noted in Section 1.2.3, the NRC declined to be a cooperating agency in FERC's environmental review and communicated this decision in an April 2014 teleconference between the FERC and NRC environmental and intergovernmental liaison staff. It is unclear what the basis was for the NRC's decision since there was no written documentation. In an interview with the team, the manager

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[114] The team observes that the AIM pipeline does *not* cross Indian Point property. See Figure 4 for an overview of the AIM pipeline in yellow.
[115] Management Directive 5.1, issued April 5, 1993; ADAMS Accession No. ML041770442.
[116] 10 CFR 51.29(a)(7); https://www.nrc.gov/reading-rm/doc-collections/cfr/part051/part051-0029.html.
[117] 73 FR 55546, published September 25, 2008; https://www.federalregister.gov/documents/2008/09/25/E8-22528/notice-of-availability-of-memorandum-of-understanding-between-us-army-corps-of-engineers-and-us

responsible for the intergovernmental liaison function at the time did not recall the exact reason. The team observes that a more formal coordination such as a memorandum of understanding or cooperating agency status could have prompted both agencies to engage in the formal communications recommended in the previous section of this report. Such a structure could also be beneficial in ensuring that critical design or operational aspects are appropriately documented.

Therefore, the team concludes that additional guidance for interactions with both Federal and state agencies on specific matters would be beneficial to the NRC staff.

5. Review of Key OIG Findings

5.1. Key Findings Related to NRC Analysis

The team reviewed key aspects of the OIG findings related to prior NRC analyses as described in the subsections below. Many of these subjects are also addressed elsewhere in the report, but they are collected here for ease of reading, with cross-references to other sections.

5.1.1. Was use of ALOHA inappropriate?

The "Findings" section of the OIG Event Inquiry stated that "NRC's underlying independent analysis was conducted using a computer program that the National Oceanic and Atmospheric Administration (NOAA), which developed the program, said it was not designed for." OIG also noted that the staff did not conduct a verification and validation of the ALOHA code.

ALOHA performs calculations for chemical source terms and resulting downwind concentrations. Source term calculations determine the rate at which the chemical material is released to the atmosphere, release duration, and the physical form of the chemical upon release.

The ALOHA code allows for modeling the accident scenarios for gas release from a pipe source. The pipe source configuration represents gas discharges from a long pipe either (1) connected to a very large (infinite, for analytical purposes) reservoir or (2) isolated at its unbroken end. The analyst must specify a gas temperature and pressure, along with pipe length and diameter and whether the surface is smooth or rough.

ALOHA uses the pipe length to predict the discharge rate from a ruptured pipeline. The length-to-diameter ratio of the pipe must be at least 200. The rupture area may be a size up to the cross-sectional area of the pipe.

ALOHA can model two different types of scenarios for a gas pipeline failure. The two types of scenarios differ in the state of the unbroken end. For the isolated scenario, a finite amount of gas is in the pipeline section. As gas is discharged at the broken end, the pressure drops, and the discharge rate slows over time. The release occurs over a finite time. For the infinite-reservoir scenario, pressure and discharge rate remain essentially constant, and the release can be modeled to continue for up to 60 minutes.

In using ALOHA, the source duration is specified as either instantaneous or continuous. A continuous release refers to any duration lasting longer than a minute. ALOHA assumes an instantaneous release to last one minute. For an instantaneous release, the total quantity (mass or volume) released into the air is the residual gas mass in the pipeline (i.e., until the finite length of pipeline is emptied). For a continuous release, the mass or volumetric release rate is specified as well as the duration in minutes. The allowable input range for the duration is between 1 and 60 minutes. ALOHA calculates time-dependent release rates for up to 150 time steps. ALOHA then averages the release rates from the individual time steps over one to five averaging periods, each lasting at least one minute. The five averaging periods are selected to most accurately portray the peak emissions. ALOHA provides several results, including a 1-minute maximum release rate of mass and a total release of mass.

The team agrees with the OIG comment that ALOHA does not have the capability to model the scenario of remote closure of the isolation valves within 3 minutes. In addition, ALOHA cannot directly model a double-ended break where the pipe has broken in the middle and is leaking from both broken ends. The model can calculate the release from one side of the pipeline, but not both sides together. In addition, ALOHA does not model supercritical flow which is applicable to this pipeline rupture release scenario.

Therefore, the team agreed that there are concerns with using ALOHA as the main tool to assess a scenario as complex as the Indian Point postulated pipeline rupture. With support from experts at the SNL, the team conducted an analysis to assess the postulated 42-inch pipeline rupture scenario that revealed concerns with some of the NRC's analysis methods, including ALOHA's ability to model supercritical flow and topography. (That analysis is discussed more in Section 2 and Appendix B.) As discussed in Section 4.4, the team recommends improving the NRC's guidance in Regulatory Guide 1.91 for detailed analyses of pipeline ruptures.

Furthermore, the team agreed that analysts should provide an appropriate technical justification for using an analysis code for a situation outside of its original scope. This justification may or may not need a full verification and validation. The team recommends that this be considered as part of the recommended update to Regulatory Guide 1.91.

5.1.2. Was the correct area analyzed?

The "Findings" section of the OIG Event Inquiry stated that "the majority of NRC's independent analysis described the impact of a potential rupture on an above ground point on [Indian Point] property that NRC believed presented the most credible risk due to its exposure; however, ultimately the as-built 42-inch pipeline does not come above ground anywhere on [Indian Point] property but does traverse the [Indian Point] property."

During multiple interviews with the review team staff, the analyst stated that he performed calculations for breaks postulated at two locations on the 42-inch pipeline: (1) at the above-ground "tie-in" east of Indian Point and (2) an underground middle section at the closest location to safety-related SSCs on site. The analyst also stated that he presented the results of the first case in his report, because he determined that it was the bounding case for assessing the postulated pipeline failure at Indian Point site.

The team determined that these locations were appropriate for evaluation. The difference between below-ground and above-ground breaks would not alter the effects of the pipeline explosion according to the team's PHMSA member and the team's interview with an independent gas pipeline expert. Additionally, the change in location of the above-ground portion of the pipeline was only 21 feet, which would not have altered the conclusions of either Entergy or the NRC analyst.[118]

The team observes that the NRC did not reinspect or reanalyze the 2015 revision to Entergy's 10 CFR 50.59 evaluation. Since the change was relatively minor, the team considers that this was a reasonable approach.

5.1.3. Were analyses documented properly?

The "Findings" section of the OIG Event Inquiry stated that managers had "differing understandings of the assumptions and factors driving the analysis" and that the analyst "did not have a basis" for engineering judgments and "did not document a basis or a methodology in [the analyst's] report."

The analyst prepared a 6-page summary to document his original calculation in October 2014, and Region I used it as a feeder to the inspection report issued in November 2014.[119] The analyst assumed a pipe rupture equivalent to the diameter of the pipe at a maximum operating pressure of 850 psig. The pipeline rupture was assumed to occur at the far end of the pipeline where the

[118] See note 22.
[119] See note 26.

pipeline rises above ground, releasing the full volume of gas within the 3-mile length of pipeline between the nearest isolation valves. Also, the analyst assumed that the isolation valves would be closed in 3 minutes. The ALOHA calculation for this scenario resulted in a maximum sustained methane release rate of 256,000 lb_m/min and estimated a total release amount of 354,651 pounds averaged over 9 minutes. The analyst assumed the maximum release over 1 minute (256,000 pounds of methane) and determined the TNT-equivalent (W_{TNT}) amount with a yield factor of 0.05. By using the Regulatory Guide 1.91 formula, the analyst determined that the minimum safe distance—beyond which there would be a less than 1 psi overpressure—was 2,351 feet. The analyst noted that the pipeline at the far end (above ground) is located over 2900 feet from the nearest safety-related SSCs within the SOCA. In addition, the analyst noted that some SSCs designated as important to safety outside the SOCA were closer to the pipeline than 2,351 feet, so those SSCs may could experience greater than 1 psi overpressure and would be impacted. Furthermore, the analyst noted that a detailed discussion of the impact of these important-to-safety SSCs, which was reviewed by NRC inspectors, is included in the licensee's August 2014 10 CFR 50.59 evaluation.[120]

Subsequently, during the 10 CFR 2.206 petition review in 2015, there were concerns about whether remote pipeline operators would be able to recognize that a pipeline rupture occurred and then take timely actions to close the nearest pipeline isolation valves within 3 minutes. As a result, the analyst performed additional ALOHA modeling was performed as a sensitivity study to determine the significance of valve closure times.[121] (Section 4.3.4 of this report provides additional information on the documentation of these calculations.) The original scenario assumed a maximum 1-minute release in determining the minimum safe distance and the potential heat flux due to a jet fire. In the infinite-source scenario, the analyst assumed that the pipeline isolation valves do not close, and gas continues to flow as if there was an infinite source for 60 minutes. The analyst stated that the maximum calculated release of natural gas determined by the ALOHA model for the infinite-source scenario only slightly varied from the prior analysis, and the calculated results were marginally changed. The distance that would be subject to a 1 psi overpressure increased, but the distance remained lower than the distance to the most limiting SSC inside the SOCA boundary. Therefore, the analyst concluded that pipeline isolation valve closure times were inconsequential. He continued to support the original conclusion that the 42-inch AIM pipeline at the Indian Point site does not represent an undue risk and that the plant could safely shut down following a postulated pipeline rupture.

The team noted that the analyst stated that it was conservative to use the 1-minute maximum gas release rate (rather than total mass released over the assumed duration) from ALOHA for both the 3-minute scenario in 2014 and the 60-minute infinite-source scenario in 2015. However, the analyst did not provide a thoroughly documented technical basis to justify the conservatism of that assumption in either the 2014 or 2015 analyses. Therefore, the team agrees that the basis for using the 1-minute maximum gas release was not well documented.

5.1.4. Were pipeline enhancements credited appropriately?

The “Findings” section of the OIG Event Inquiry referenced statements that the “use of credit for enhanced piping was inappropriate.”

During multiple interviews with the team, the analyst stated that he only considered credit for the enhanced pipeline during his thought process for assessing the impact from postulated pipeline failures near Indian Point. He noted that at the closest point to the plant, the pipeline is thicker, is

[120] See note 18.
[121] See note 101.

buried deeper, and is physically protected by reinforced concrete mats. (The team notes that these are only some of the enhancements associated with this pipeline being in a high consequence area subject to the requirements of 49 CFR 192, Subpart O.) Nevertheless, the analyst stated that he did not credit any pipeline enhancements in the calculation documented in his report. Therefore, the team did not substantiate the OIG finding related to inclusion of piping enhancements in the analyst's calculation.

5.1.5. How was the time needed to isolate the pipeline considered?

The "Findings" section of the OIG Event Inquiry raised issues with the assumption that pipeline isolation would occur in 3 minutes, noting that the pipeline operator "estimated it would take at least 6 minutes after the detection of a leak to close the valves." OIG noted inconsistencies in the understanding of the amount of gas that would be released.

The analyst originally assumed that the isolation valves for the pipeline could be closed in 3 minutes. As noted in Section 5.1.3, however, the analyst performed a sensitivity study to support the 10 CFR 2.206 petition review. In the second scenario, the analyst assumed that following a complete pipeline rupture, the pipeline provides an infinite source of natural gas and the pipeline isolation valves do not close for an hour.

The team verified that ALOHA does have the capability to assess 60 minutes of gas release from an infinite source, as well as the gas released in the first minute. However, the team noted that analyst used the 1-minute maximum gas release rate (rather than total mass released over the assumed duration) from ALOHA for both the 3-minute scenario and the 60-minute scenario assessed. As discussed in Section 5.1.3 of this report, the analyst did not provide a documented technical basis to justify the appropriateness or conservatism for that assumption. Therefore, the team was not able to confirm the validity of the conclusion that the pipeline closure times only minimally changed the peak overpressure calculation and the heat flux calculation.

As discussed in Section 2.1.3, the team found conflicting information on the time it would take to isolate the ruptured pipeline and the length of pipe that would need to be isolated. As a result, as noted in Section 2.6, the team recommends that the NRC ask Entergy to revisit its 10 CFR 50.59 evaluation to apply an appropriate isolation timeframe or justify why the timeframe is not relevant.

5.1.6. Was Regulatory Guide 1.91 used correctly?

The "Findings" section of the OIG Event Inquiry stated that "NRC used a draft regulatory guide in lieu of the final, approved version (which had been issued approximately 2 years prior) and deviated from the approved version in a manner that was less conservative and had an impact on the analysis outcome."

The OIG Event Inquiry referenced the analyst's use of 4,500 kJ/kg instead of 4,420 kJ/kg for the denominator in Equation 4 of Regulatory Guide 1.91. The team found that the denominator used in the reference[122] where this equation originated is 4,500 kJ/kg. In further discussions with fire experts in the Office of Nuclear Regulatory Research, the team verified that this 4,500 kJ/kg value is appropriate and consistent with fire and explosion literature (this was also noted by SNL in their calculations). It appears that the more precise value may have come from conversions between English and metric units, but it is not applied elsewhere in the literature. Therefore, the team found the analyst's use of this value acceptable, even though it did not match the latest revision of

[122] Zalosh, R.G., *SFPE [Society of Fire Protection Engineers] Handbook of Fire Protection Engineering*, 2nd Edition, "Explosion Protection," SFPE, Boston, MA, June 1995.

Regulatory Guide 1.91. The team recommends that a future update to Regulatory Guide 1.91 should revisit the change made in that denominator.

Additional recommended improvements to Regulatory Guide 1.91 are discussed in Section 4.4.

5.2. Key Findings Related to NRC Processes

5.2.1. Did the FERC approval represent the NRC analysis appropriately?

The "Findings" section of the OIG Event Inquiry stated that "NRC's independent analysis was incorrectly portrayed in FERC's approval document as significantly more conservative than it actually was."

The FERC issued its approval order for the AIM pipeline in March 2015.[123] Section k.2. of this order addressed safety issues related to Indian Point, and in paragraph 107, the FERC described the NRC's review. The team considered the accuracy of the FERC's approval order paragraph 107 as follows.

- **"The NRC reviewed the site hazards analysis performed by Entergy and performed an independent confirmatory analysis of the blast analysis as well."** The team agrees with this statement (while acknowledging the analysis could have been conducted differently, as discussed elsewhere in this report), and it is consistent with the NRC inspection report.
- **"The NRC's analysis did not account for the additional pipeline design measures identified by Entergy and committed to by Algonquin …"** The team agrees with this statement. As discussed in Section 5.1.4, the NRC analyst did consider the pipeline enhancements but did not use them in his pipeline rupture consequence calculation.
- **"[The NRC's analysis …] assumed a pipeline catastrophic failure."** The FERC uses a term "catastrophic" that is not included in the original October 2014 NRC analysis or November 2014 NRC inspection report. The term appears to have been introduced in the October 2014 NRC-FERC meeting summary.[124] The team considers that given the discussion in that analysis of a "hole equivalent to the diameter of the pipe" (i.e., a full guillotine break), the failure itself could be described as catastrophic for the pipeline. The team does not view this use as implying a catastrophe in terms of consequences.
- **"The review covered everything within the [SOCA], which encompasses everything inside the outermost fenced area of the facility including the area with the spent fuel rods."** This description of the SOCA, which also appeared in the October 2014 NRC-FERC meeting summary, may represent a misunderstanding of the portion of the Entergy property that is bounded by the SOCA fence for security purposes. Entergy owns property outside the SOCA, which is also bounded by a fence. The SOCA encompasses a smaller area that includes, among other things, the safety-related equipment, the spent fuel pools, and the spent fuel dry storage area. The Entergy and NRC analyses did consider equipment both inside and outside the SOCA, as well as equipment outside Entergy property (such as the Buchanan switchyard). Therefore, although the statement is slightly inaccurate, the team considers this statement to be acceptable, since it does not have a significant impact.
- **"The NRC concluded that a breach and explosion of the proposed 42-inch-diameter natural gas pipeline would not adversely impact the safe operation of the Indian Point**

[123] See note 15.
[124] See note 30.

facility." This phrasing is less nuanced than the October 2014 meeting summary[125] and uses language that the NRC had used in the November 2014 inspection report in the context of Entergy's analysis, not the NRC's.[126] In this light, the statement could be viewed as partially inaccurate. The team determined that, the NRC focused on (a) whether Entergy complied with 10 CFR 50.59 in deciding NRC review was not needed (as concluded in the inspection report) and (b) that Indian Point could safely shut down and remain shut down after a pipeline rupture. "Safe operation" might be misconstrued as meaning continued full-power operation of the reactors after a pipeline rupture, which was *not* what the NRC assumed. The team, however, does not view this distinction as distorting the overall Entergy or NRC conclusions in 2014-2015 about the ability safety of Indian Point reactors to safely shutdown in the event of a rupture of the 42-inch pipeline.

The FERC used this information to support a statement that **"the final [environmental impact statement] concludes that the project will not result in increased safety impacts at the Indian Point Facility."** This language asserting "[no] increased safety impacts" does not appear in the final environmental impact statement passages described in Section 1.2. The FERC did state the following in Section 4.13 of the final environmental impact statement: "Entergy has concluded that … the proposed AIM Project poses no increased risks to [Indian Point] and there would be no significant reduction in the margin of safety at the facility. The NRC conducted its own, independent review assuming a catastrophic pipeline failure, and concurred with these findings."

Entergy's 2014 10 CFR 50.59 evaluation (the one completed at the time of the FERC environmental impact statement) includes this statement: "based on the proposed routing of the 42-inch pipeline further from safety related equipment at IPEC and accounting for the substantial design and installation enhancements agreed to by AGT, the proposed AIM Project poses no increased risks to IPEC and there is no significant reduction in the margin of safety. Accordingly, as documented in the enclosed 10 C.F.R. § 50.59 Safety Evaluation, Entergy has concluded that the change in the design basis external hazards analysis associated with the proposed AIM Project does not require prior NRC approval." Therefore, the FERC accurately characterized Entergy's conclusions in its environmental impact statement. The team observes that "no increased risk" is not a standard imposed by 10 CFR 50.59, which does not mention risk or margins. The NRC must review proposed changes that would result in "more than a minimal increase" in the frequency or consequences of accidents previously evaluated or the likelihood or consequences of equipment malfunctions previously evaluated, as well as changes that would create "a possibility for" different types of accidents or different results of equipment malfunctions.

The NRC's 2014 inspection report concluded that "safety-related SSCs inside the SOCA would not be exposed to conditions exceeding the threshold for damage" and that "Entergy's conclusions … are reasonable and acceptable, and are also comparable with the staff's conclusions." The NRC's summary of Entergy's evaluation stated that Entergy concluded that the AIM pipeline "poses ***minimal or*** no increased risk to the safe operation of Units 2 and 3" (emphasis added). Entergy had used the "minimal" terminology in Enclosure 1 to its evaluation, which specifically addressed the

[125] The meeting summary conclusion is: "Based on its review, the NRC came to the same conclusion that Entergy did in its 50.59 submission. Therefore, NRC finds Entergy's 50.59 submission acceptable and has determined that no prior approval from the NRC is needed."

[126] The November 2014 NRC inspection report concludes that "**Entergy's conclusions** involving the potential rupture of the proposed pipeline near [Indian Point] poses **no threat to safe operation of the plant or safe shutdown of the plant**, are reasonable and acceptable, and are also comparable with the staff's conclusions" (emphasis added). Other NRC documents, including the response to the petitioner's 39 questions in November 2015 (see note 82), did include looser uses of "safe operation."

criteria in 10 CFR 50.59. The NRC did not identify any violation of Entergy's application of those criteria.

Based on this information, the team concludes that the FERC's statement that the pipeline "will not result in increased safety impacts" is similar to the conclusions drawn by Entergy but more definitive than the conclusions drawn by the NRC. Because this language is not attributed to the NRC or relate to the NRC analysis, the team does not agree with OIG that the FERC portrayed the NRC analysis as "significantly more conservative than it actually was."

Section 4.5 includes the team's recommendations on how the NRC can interact better with other agencies, including how the context of an NRC inspection or review could be described better.

5.2.2. Was the NRC inspection report accurate?

The "Findings" section of the OIG Event Inquiry stated that "NRC's inspection report contained inaccuracies suggesting additional analysis had been conducted, when this was not the case." The OIG Event Inquiry noted that (1) the analyst did not calculate missile generation though Regulatory Guide 1.91 suggested it, and (2) the analyst believed that effects on important-to-safety SSCs were being "bounded by more severe accidents … already evaluated" in Indian Point's FSAR.

The team notes that Regulatory Guide 1.91 is not clear as to the scope of SSCs that should be evaluated for missiles. The guide makes a general statement that "[t]he effects of blast-generated missiles would be less than those associated with the blast overpressure levels considered in this guide." Therefore, missiles generally need not be evaluated where the overpressure levels are not exceeded—which would include all safety-related equipment inside the SOCA, in the case of the NRC analyst's results for Indian Point.

The guide goes on to state that if "SSCs important to safety" are closer to the hazard than the 1 psi overpressure threshold distance, "the applicant may show through analysis that the risk to the public is acceptably low on the basis of the capability of the safety-related structures to withstand blast and missile effects associated with detonation of the potentially explosive material." The team read this passage as stating that if safety-related equipment (for these purposes, the equipment needed to safely shut down the reactor and maintain it in a safe state) [127] can be shown to be protected against blasts and missiles, the risk can be considered acceptably low. In the NRC analysis, this is the case—safety-related equipment is outside the 1-psi overpressure zone, so missiles would not be expected there. [128] Therefore, the team does not agree with OIG that a missile analysis was necessary or omitted in this case.

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[127] 10 CFR 50.2: "*Safety-related structures, systems and components* means those structures, systems and components that are relied upon to remain functional during and following design basis events to assure: (1) The integrity of the reactor coolant pressure boundary[;] (2) The capability to shut down the reactor and maintain it in a safe shutdown condition; or (3) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to the applicable guideline exposures set forth in § 50.34(a)(1) or § 100.11 of this chapter, as applicable." https://www.nrc.gov/reading-rm/doc-collections/cfr/part050/part050-0002.html.

[128] The reference to "important to safety" SSCs in Regulatory Guide 1.91 complicates matters somewhat. The guide's intent is not clear for this reference. The NRC does not define important to safety in its requirements, other than in the general statement in the introduction to 10 CFR Part 50, Appendix A, "General Design Criteria": "structures, systems, and components that provide reasonable assurance that the facility can be operated without undue risk to the health and safety of the public"; https://www.nrc.gov/reading-rm/doc-collections/cfr/part050/part050-appa.html. There has been significant discussion of this definition and how it differs from (is broader than) the definition of "safety-related" over the decades since this regulation was

Regulatory Guide 1.91 compares explosions to other natural hazards: drag pressure effects would be "much smaller than those resulting from the wind loading assumed for the design-basis tornado" and ground motion from overpressure "should be less than the vibratory ground motion associated with a safe-shutdown earthquake." The reader might draw the conclusion that these issues have been addressed uniformly for all facilities. The NRC analyst "believed" that extreme natural phenomena had already been evaluated for Indian Point and therefore, did not verify the statement that pipe ruptures would be bounded by such phenomena. Every facility, however, has a unique licensing basis depending on when it was licensed, what requirements applied at that time, and what later requirements were imposed by the NRC.[129] The team agrees with the OIG that the analyst should not have referred to prior analyses of the facility—especially if they were not important to the conclusions—without verifying the scope and results of those analyses. As noted in Section 2.1, the team could not verify that prior analyses in fact bounded potential pipeline impacts.

5.2.3. Were quality standards applied appropriately?

The "Findings" section of the OIG Event Inquiry referenced remarks that the NRC does "not have a quality assurance program for these calculations, but [that] a peer review by a qualified NRC engineer was performed on NRC's independent analysis and follow-up analysis." OIG noted deficiencies with the peer review.

As discussed in Section 4.1, the team identified that several NRC personnel were unfamiliar with the internal guidance for conducting high-quality analysis and calculations, including the criteria for peer reviews As discussed in Section 4.3.4, documentation of confirmatory analyses and peer reviews is fundamental to assuring that calculations and peer reviews use appropriate standards, are effectively and efficiently reviewed, and support the agency's determination. The team does not consider a formal "quality assurance program" to be necessary to provide this assurance. However, given the lack of staff familiarity with the quality standards that *do* exist at the NRC, the calculations analyzing the licensee's 10 CFR 50.59 analysis and supporting the PRB's decision to reject the 10 CFR 2.206 petition, the team agrees that appropriate standards were not fully applied in this case.

The team recommends that the agency consider additional training regarding the technical work product quality and consistency guidance, as noted in Section 4.1.

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issued (after the construction permits were issued for Indian Point Units 2 and 3). Licensees have taken individual approaches to defining important-to-safety SSCs for their facilities. In its 2015 final 10 CFR 50.59 evaluation, Entergy listed "important to safety" equipment or structures that could be affected by pipeline ruptures: the switchyard, diesel fuel tank, meteorological tower, and emergency operations facility. The team did not question Entergy's classification of these as "important to safety," but the team did not follow up on whether Entergy treats all of these as such (e.g., analyzing them against dynamic effects under General Design Criterion 4) or is required to depending on the Indian Point licensing basis. The team agrees, however, with Entergy's conclusion that loss of these, while not ideal, is either analyzed (in the case of the switchyard, which would cause a loss of offsite power) or could be mitigated by backups (the diesel fuel tank has a tanker truck backup, and the meteorological tower and emergency operations facility that both have backup facilities). These SSCs could be analyzed for missile impacts, but since they were already considered lost because of overpressure or heat flux, that does not seem necessary.

[129] For example, tornadoes at Indian Point Unit 2 were not evaluated in detail at initial licensing, but were considered in the hearings discussed in Section A.4 of Appendix A to this report. The Commission determined that only a wind evaluation of certain equipment and structures was needed.

6. Conclusion and Recommendations

6.1. Summary of Conclusions Regarding Safety and Processes

The team determined that, even though Entergy (the plant owner) and the NRC made some optimistic assumptions in analyzing potential rupture of the 42-inch natural gas transmission pipeline, the Indian Point reactors remain safe. The team drew two key conclusions related to this statement.

- **A rupture of the newly installed 42-inch natural gas transmission pipeline that runs near Indian Point is unlikely.** This pipeline was installed using modern techniques, stringent quality standards, and construction precautions that limit the likelihood of later pipeline damage. This stretch of pipeline was designated as a high consequence area under Department of Transportation requirements, meaning that additional inspection, integrity threat assessment, pipe remediation, and documentation requirements apply. Given the remaining operating life of Units 2 and 3 (mere weeks to a year, respectively), the risk of a pipeline rupture affecting the reactor units is very small.

- **If a rupture occurred on the stretch of 42-inch pipeline near Indian Point, the nuclear power plant would remain protected.** The plant's safety systems are all far from the pipeline. They are two or more times the "potential impact radius" that the U.S. Department of Transportation designates for protecting people from pipeline ruptures and also far outside the distance where heat flux would be high enough to affect wooden structures, let alone the robust concrete structures that house the plant's safety equipment. The potential impact radius bounds most pipe rupture impacts observed in real-life accidents. In a more detailed transient analysis, the team found that the robust concrete structures housing the plant's safety-related equipment, spent fuel pool, and fuel storage containers would withstand the heat and pressure impacts of an explosion or fire that could follow a pipeline explosion. The safety-related equipment would be able to safely shut down the reactors and maintain them in a safe shutdown condition. Equipment or structures outside these buildings could be affected, but these serve as backups or alternatives to the safety-related equipment. The team also conducted a risk assessment to consider the uncertainties of the events that could unfold at Indian Point and found that the risk of serious consequences from a postulated pipeline rupture was very small.

6.2. Summary of Recommendations

The team recommends that Entergy be **asked to revisit the assumptions it made regarding the consequences of a postulated rupture of the 42-inch pipeline.** While the team is confident in its independent safety conclusions, Entergy's analysis used assumptions that do not appear to be accurate. Specifically, Entergy assumed a highly optimistic timeframe to isolate the pipeline. Entergy may also have been optimistic about how close to the postulated rupture the pipeline could be isolated, meaning that a smaller than realistic amount of gas was analyzed. Entergy should be asked to assess the importance of these assumptions to its original conclusions and update its analysis, if needed.

The NRC also needs to improve its processes and practices for technical reviews, inspection support, petition reviews, pipeline analysis, and coordination with other agencies. Separate from the technical matters, the team substantiated many of the OIG report's procedural findings. The team identified several areas where the NRC could improve its processes. Highlights of these findings are:

- **NRC staff peer reviews need to be done more rigorously and consistently**. Recently updated guidance concerning the expected quality of NRC technical products should help achieve this goal, if staff and managers are properly trained on its use.
- **Inspectors and technical experts need better guidelines for arranging formal and informal technical support to inspections**. Understanding and documenting expectations up front, then providing clear responses to the initial queries, will make NRC inspections more effective.
- **The NRC needs to improve its petition review processes even more**. While the process was recently updated, the team still found weaknesses in the consistency and independence of reviews, documentation of decisions, and level of detail reviewed at each stage.
- **The NRC needs to improve how it supports other agencies' reviews.** When the NRC's expertise or decisions will be cited by another agency, the NRC should follow practices it already has in place for its own environmental reviews, formalizing and documenting the interactions across agencies. This approach would provide for a mutual understanding of each agency's objectives and regulatory context.

6.3. Future Analysis and Activities

During the team's review, the team or external parties identified issues separate from those included in the Chairman and EDO taskings, particularly issues related to the preexisting pipelines discussed in Appendix A. While the team remained vigilant for issues that could pose an immediate safety concern for Indian Point, most of the issues raised could not be addressed within the scope or timeframe provided to the team. NRC management should consider whether further action by the NRC, other agencies, or Entergy is warranted to address these subjects. The team observes that, with respect to reactor safety, such decision-making should reflect the remaining plant operating time (mere days for Unit 2; about a year for Unit 3). A longer timeline would apply to the spent fuel, though the location of the dry fuel storage location makes it unlikely that there would be pipeline-related impacts at that site.

- On March 26, 2020, two representatives of the New York State Public Service Commission wrote to the team leads.[130] This letter included several recommendations for the team's activities, notably: (1) analysis and peer review by neutral, third-party experts (e.g., the National Academy of Sciences) and (2) a site-wide analysis of reactors and spent fuel at Indian Point that considers both the preexisting and AIM pipelines and uses updated seismic analyses. The team obtained independent membership and peer review to the extent feasible within 45 days, and its scope was focused on issues raised by the OIG regarding the 42-inch AIM pipeline. The team recommends that NRC management review the team's report and consider whether a broader analysis may be appropriate.
- On March 23, 2020, Paul Blanch (the petitioner for the October 2014 petition discussed in Section 3) wrote to the team lead with comments on the team's scope of review.[131] Mr. Blanch emphasized that a risk analysis under 49 CFR 192.917 needed to be done for the AIM pipeline. (Section 2.1.2 provides information on this risk analysis.) He also indicated that the team should

[130] ADAMS Accession No. ML20086L280.

[131] ADAMS Accession No. ML20086L164.

address concerns he had previously raised to OIG, including NRC's use of its procedures, potentially false statements made by Entergy, processing of a prior allegation, and NRC's inspections and communications to the FERC. Mr. Blanch supported calls from New York State for an independent risk analysis reviewed by the National Academy of Sciences. Aspects of these requests were addressed by the team's activities and recommendations, as documented in this report. The team recommends that NRC management review the team's report and consider whether further evaluation is needed.

- On March 19, 2020, the Office of the Attorney General of the State of New York wrote to the NRC Chairman, FERC Chairman, and PHMSA Administrator asking for a joint evaluation of the AIM pipeline and Indian Point.[132] Specific to the NRC, this letter recommended that PHMSA and other pipeline safety experts assist the NRC in assessing the risk profile of the AIM pipeline and its proximity to Indian Point, that the NRC analyze both the preexisting and AIM pipelines and their proximity to the reactor and spent fuel, and that the NRC require a 10 CFR 50.59 review of all three pipelines. Aspects of these requests were addressed by the team's activities and recommendations, as documented in this report. The team recommends that NRC management review the team's report and consider whether further response to these questions is needed.

- On March 13, 2020, U.S. Representative Nita Lowey wrote to the NRC Chairman requesting a personal briefing and public meeting on the OIG report and the NRC's response.[133] The team recommends that NRC management review the team's report and respond appropriately.

- On March 11, 2020, several members of the New York State Legislature wrote to the NRC Chairman expressing concern about the Event Inquiry by the OIG.[134] The letter requested that the NRC explain its past and future actions and retract prior analyses used by the FERC. The team recommends that NRC management review the team's report and consider what response to this letter is needed.

- On March 9, 2020, the Chief Executive Officer of the New York State Department of Public Service wrote to the NRC Chairman and FERC Chairman expressing concern about the Event Inquiry by the OIG.[135] The letter requested that the agencies respond to issues raised in a June 2018 letter.[136] The June 2018 letter included questions regarding the Indian Point spent fuel pools, use of ALOHA and Regulatory Guide 1.91 to evaluate pipelines including the preexisting pipelines, the status of security reviews, the conclusions of the 2008 evaluation of pipelines, and whether seismic analyses were conducted of the pipelines. Several of these questions are addressed by this report. The team recommends that NRC management review the team's report and consider whether further response to these questions is needed.

- As noted by then-Chairman Burns in a November 2015 letter,[137] the Advisory Committee on Reactor Safeguards formed a working group to evaluate external man-made hazards (such as pipelines) at nuclear power plants. Based on a discussion with the Executive Director and

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[132] Not yet publicly available at the time this report was finished; available to the NRC staff at ADAMS Accession No. ML20090B533.
[133] Not yet publicly available at the time this report was finished; available to the NRC staff at ADAMS Accession No. ML20084M363.
[134] Not yet publicly available at the time this report was finished; available to the NRC staff at ADAMS Accession No. ML20087M278.
[135] Not yet publicly available at the time this report was finished; available to the NRC staff at ADAMS Accession No. ML20071F306.
[136] Dated June 22, 2018; ADAMS Accession No. ML18176A367.
[137] Dated November 30, 2015; ADAMS Accession No. ML15258A242.

Chairman of the Advisory Committee on Reactor Safeguards, the team understands that this work is ongoing. The NRC should remain apprised of the progress and results of this activity.

Appendix A. Historical Information on Preexisting Gas Pipelines

This appendix presents background information on how these preexisting pipelines were evaluated by the licensee and the NRC. This team's primary scope of work relates to the later-installed 42-inch AIM pipeline that is the main subject of this report. Some of the analyses for the 42-inch AIM pipeline referenced prior analyses of the preexisting pipelines. Reevaluating prior conclusions on the 26-inch and 30-inch preexisting pipelines is not within the scope of the team's work. The team summarizes this information for context without passing judgment on the prior conclusions.

A.1. Initial Licensing (1960-1973)

This section summarizes information readily available to the team in the Agencywide Documents Access and Management System (ADAMS) regarding the initial licensing of Indian Point Units 1, 2, and 3. It does not represent a comprehensive review of the licensing bases of these reactors. The summary, however, shows that the AEC and NRC were aware of and, in some cases, explicitly evaluated the preexisting gas transmission lines as part of the initial licensing of the facilities.

Indian Point Unit 1

In November 1960, as part of its operating license application, Consolidated Edison submitted a map of the area around Indian Point showing public utilities as Exhibit H-13.[138] This map shows the Algonquin gas transmission line as a dashed black line, crossing the Hudson River and passing within about 1,000 feet (the map scale is not precise) of the centerline of Indian Point Unit 1. A section of the map is reproduced in this report as Figure 14.

Consolidated Edison also submitted Exhibit H-14, a scale plot plan of the site showing the 26-inch gas main and the Algonquin right of way. A section of the plot plan is reproduced in this report as Figure 15. Consolidated Edison submitted Exhibit H-14, Revision 1, in September 1962 to add some details related to offices, material storage, and vehicle storage and maintenance, as well as removal of the "caretaker's house" and a temporary construction building.[139]

In February 1962, the Commission ordered the AEC staff to issue a provisional license for Indian Point Unit 1.[140] Paragraph 43 of that order stated that:

> Paragraph A-3 of Appendix A to the license as approved above limits more than the applicant would have it to do the utilization at the reactor site of Consolidated's natural gas facilities. The applicant proposed to include as site activities the transmission and distribution of natural gas, with no bulk storage there and no pressure above 50 psig within 600 feet of the reactor building. Cogent reasons for adopting the staff position have heretofore been discussed. Upon this point it has been shown that use of the natural gas facilities at the reactor site <u>as described in the application</u> is not inimical to public health and safety and constitutes no threat to the integrity and safety of the reactor facilities and utilization. Other now unknown and unevaluated possible uses of natural gas or natural gas installations at the site might portend hazards to reactor safety. Accordingly, the technical specification appropriately should limit the natural gas facilities and utilizations at

[138] The "amended and substituted application" submitted on December 5, 1960, is the likely source of this map. It is available to the NRC staff at ADAMS Accession No. ML110690359. Exhibit H-13 is separately available at ADAMS Accession No. ML093220861.
[139] Available to the NRC staff at ADAMS Accession No. ML110590360.
[140] Issued February 21, 1962; available to the NRC staff at ADAMS Accession No. ML111510462.

> the site to those which have been described and which consequently have been weighed in deriving the safety judgments herein expressed.

This paragraph in the order refers to Section A.3 of the technical specifications, which are in Appendix A to the provisional license.[141] Section A.3 states:

> The principal activities carried on within the exclusion area shall be the generation, transmission and distribution of steam (except by gas-fired power plant); the generation, transmission and distribution of electrical energy; and associated service activities. Such activities, among others, shall include in the case of the facility, the subject of this license, activities relating to the controlled conversion of the atomic energy of fuel to heat energy by the process of nuclear fission and the storage, utilization and production of special nuclear, source and byproduct materials. Transmission and distribution of natural gas shall be through the use of facilities located as described in the application.[142, 143]

The "exclusion area" was defined in Section A.2 of the original technical specifications as the area surrounding the facility for which access was under the full control of Consolidated Edison, approximately 1/3 of a mile.

Consolidated Edison reported to the AEC in October 1964, that—consistent with the provisions in its license for changes it could make to the facility—Consolidated Edison was permitting the Algonquin Transmission Company to widen its right of way to install an additional gas transmission

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[141] DPR-5 issued on March 26, 1962; available to the NRC staff at ADAMS Accession No. ML100330629.

[142] By 1965, this paragraph had been revised to include "as amended" at the end (submittal dated May 6, 1965; available to the NRC staff at ADAMS Accession No. ML110480269). Later, the proposed technical specifications for the full-term operating license were even more explicit: "The transmission and distribution of natural gas shall be through the use of facilities located as described in U.S. Atomic Energy Commission Docket No. 50-3, Exhibit H-14" (submittal dated September 30, 1969; available to the NRC staff at ADAMS Accession No. ML100601013).

[143] Additional context for this paragraph can be found in the transcript of the Commission hearing (hearing held January 3, 1962; available to the NRC staff at ADAMS Accession No. ML100082152). Dr. Bryan of the AEC Division of Licensing and Regulation was asked about changes the applicant made regarding activities on the site. He stated that "[i]n the application, the only description of activities connected with the use of handling of natural gas had to do with the transmission of natural gas through a line which traverses the site. We have not had any, we have not had presented to us any evaluation of the hazards that might be involved in utilization, in any further utilization of such facilities than that described in the application." The focus of the discussion appears to be on the potential hazards of "distribution and utilization" of natural gas onsite (e.g., if the licensee wanted to use the natural gas to supply a power plant onsite), not the transmission pipeline itself that the AEC staff was aware of and on which it was making its findings.

Also, the AEC staff sent a brief that provided input for the licensing order (dated February 5, 1962; available to the NRC staff at ADAMS Accession No. ML111510466). In this brief, the staff noted that it had proposed an amendment to technical specifications Section A.3 "in order to assure that any expansion of such activities [related to natural gas], not presently in the application will be subject to Commission review under the change procedure set forth" in the license. This change procedure was similar to 10 CFR 50.59, "Changes, tests, and experiments," which did not become effective until July 1962 (27 FR 5491). It enabled the licensee to make certain changes to the Hazards Summary Report (analogous to the FSAR) if they did not involve an unreviewed safety question—i.e., if the probability of occurrence of an analyzed accident did not increase, if the consequences of an analyzed accident did not increase, and if the change did not create a credible probability of a different type of nuclear accident than those analyzed. If the change would affect the technical specifications (Appendix A of the license) then AEC approval would be needed.

pipeline (i.e., the 30-inch line).[144] Consolidated Edison noted that the total right of way would increase from 30 to 65 feet, but the minimum distance between the pipelines and the restricted area of the facility would be unchanged because the new pipeline would be farther away from the present pipeline. Consolidated Edison provided a new Exhibit H-14 (Revision 2).[145] A section of the plot plan is reproduced in this report as Figure 16. There are no records showing that the AEC disagreed with the licensee's determination that it could make this change without prior approval.

In November 1969, Consolidated Edison provided supplementary information that the AEC needed to authorize a full-term (rather than provisional) operating license.[146] The AEC had requested that Unit 1 be compared to the General Design Criteria that had been published in 1967 as a proposed amendment to the AEC's regulations.[147] Specific to proposed Criterion 2 on withstanding forces from local site effects, Consolidated Edison analyzed gas pipeline accidents.

Consolidated Edison clarified the pipelines that were near the site at the time: "The first pipeline [26-inch] was installed in Indian Point in 1952; the second line [30-inch] in 1965. Both pipes are made of 52,000 psi minimum yield strength steel, conforming to the American Petroleum Institute Specification 5LX52."

The licensee discussed the American Standard Code and New York State Safety Code, noting that a small percentage of failures and fires of pipelines reported by the Federal Power Commission occurred in states with stringent safety requirements. The licensee also reported on the inspection procedures and operating history of the Algonquin Transmission Company. The licensee described the design, operation, and maintenance of the pipelines, noting that "conditions which might lead to a pipeline failure have either been provided for in the design of the pipes, or do not exist at the Indian Point site."

The licensee also considered a postulated pipeline failure, including the potential for explosions that could create missiles, as well as the potential for fire damage caused by burning gas and secondary fires. The evaluation of fires assumed that the "primary fire would be of short duration since automatic shut off valves would isolate the ruptured section of the main within 4 minutes." The valves were located on both banks of the Hudson River to the west of Indian Point and in Yorktown, NY, about 10 miles east of Indian Point. The licensee noted that it had already been concluded (as noted in the next section) "that the gas transmission lines pose no danger to the safe operation of Unit No. 3." Since Unit 1 was north of Unit 3, the pipelines were further away "and therefore pose no problem."

In December 1973, the AEC's Directorate of Licensing completed the Section 2 (Site Safety) safety evaluation input for the Unit 1 full-term operating license.[148] This section has only a short passage on the pipelines: "Two natural gas lines cross the Hudson River and pass about 750 feet from the Indian Point 1 containment structure. Based on previous staff reviews, failures of these gas lines will not impair the safe operation of Indian Point 1." The details of these "staff reviews" could not be found.

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[144] Dated October 23, 1964; available to the NRC staff at ADAMS Accession No. ML110590225.
[145] Dated October 26, 1964; available to the NRC staff at ADAMS Accession No. ML110490188.
[146] Dated November 10, 1969; available to the NRC staff at ADAMS Accession No. ML100080840.
[147] The General Design Criteria now appear as Appendix A to 10 CFR Part 50 and are part of the application requirements for reactor licenses. At the time, they existed as a proposed rule (32 FR 10213).
[148] Available to the NRC staff at ADAMS Accession No. ML111370488.

The analysis effectively became moot in October 1974. Unit 1 shut down at that point when a variance issued regarding emergency core cooling systems at the facility expired and did not resume operating.[149]

Indian Point Unit 2

In December 1965, Consolidated Edison applied to the AEC for a construction permit to expand its Indian Point facility with Unit 2.[150] Section 1.2.3, "Site Ownership and Control," of the preliminary safety analysis report includes the following text:[151]

> The Algonquin Gas Transmission Co. has a right-of-way running east to west through the property, 3500 feet long and 65 feet wide. The proposed reactor is 1450 feet north of the Algonquin 26-inch gas main.

The 65-foot width is consistent with the widening noted in the 1964 Unit 1 document. That wider right of way would have accommodated the 30-inch pipeline, for which construction began in 1965. This chapter also included figures like those provided for Unit 1. Portions of these, dated August and November 1965, are reproduced in this report as Figure 17 and Figure 18, respectively.

The FSAR submitted to support the Unit 2 operating license application provides similar information on the pipeline right of way:[152]

> The Algonquin Gas Transmission Company has a right-of-way running east to west through the property, 2840 feet long and 65 feet wide. Unit 2 is 1450 feet north of the 26 inch Algonquin gas main.

The 1970 safety evaluation for the Unit 2 operating license does not reference the pipelines or any other nearby industrial facilities.[153]

Indian Point Unit 3

In April 1967, Consolidated Edison applied to the AEC for a construction permit to expand its Indian Point facility further with Unit 3.[154] Section 1.2.3, "Site Ownership and Control," of the PSAR includes the following text:[155]

> The Algonquin Gas Transmission Co. has a right-of-way running east to west through the property, 3500 feet long and 65 feet wide. The proposed reactor is 700 feet north of the Algonquin 26-inch gas main.

Because Unit 3 is southwest of Units 1 and 2, the pipeline right of way is several hundred feet closer to Unit 3 than to Units 1 and 2. This PSAR chapter also includes a site plot plan similar to those

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[149] A 1979 petition from the Union of Concerned Scientists resulted in NRC action that effectively (if not formally) revoked the Unit 1 operating license. Section A.3 has more information on this petition.
[150] Submitted December 16, 1965; ADAMS Accession No. ML093520917 (transmittal letter; PSAR chapters are in separate documents).
[151] Dated June 1, 1966; ADAMS Accession No. ML102460284.
[152] Dated November 12, 1970; ADAMS Accession No. ML073240146. The second page of this document notes that it reflects the October 1968 submittal through Supplement 15 in November 1970, with certain sensitive information redacted.
[153] Dated November 16, 1970; ADAMS Accession No. ML072260449.
[154] Submitted April 26, 1967; ADAMS Accession No. ML100250264 (transmittal letter; PSAR chapters are in separate documents).
[155] Submitted April 26, 1967; ADAMS Accession No. ML093480188.

provided for Units 1 and 2. A section of the plot plan, dated April 1967, is reproduced in this report as Figure 19.

As part of the construction permit review, the AEC asked Consolidated Edison to analyze the ability of the facility to accommodate the consequences of an explosion or fire in the pipelines. In 1968, Consolidated Edison responded with an analysis that was very similar to what Consolidated Edison would provide for Unit 1 in 1969. [156] This evaluation led the applicant to conclude that the presence of the lines "does not endanger the safe operation of Unit #3."

This information was not specifically discussed in the AEC's safety evaluation for the Unit 3 construction permit.[157]

The FSAR submitted to support the Unit 3 operating license application provides information on the pipeline right of way very similar to that for Unit 2, without clarifying information on the Unit 3 location:[158]

> The Algonquin Gas Transmission Company has a right-of-way running east to west through the property, 2840 feet long and 65 feet wide. Unit 2 is 1450 feet north of the 26 inch Algonquin gas main.

In the 1973 safety evaluation for the Unit 3 operating license, the AEC stated that "two natural gas lines cross the Hudson River and pass about 620 feet from the Indian Point 3 containment structure. Based on previous staff reviews, failures of these gas lines will not impair the safe operation of Indian Point 3."[159] As for Unit 1, the details of these "staff reviews" could not be found.

A.2. Licensee FSAR Updates (1980-2014)

Initially, the NRC did not require licensees to maintain and resubmit the FSARs submitted as part of their operating license applications. In 1980, the NRC issued a rule—10 CFR 50.71(e)—requiring licensees to submit an updated FSAR within 2 years and annual updates thereafter.[160]

Indian Point Unit 2

In July 1982, Consolidated Edison submitted Revision 0 of the updated FSAR for Indian Point Unit 2.[161] The 26-inch gas pipeline was mentioned in Section 2.2.3, "Site Ownership and Control": "The Algonquin Gas Transmission Company has a right-of-way running east [to] west through the property, 2840 feet long and 65 feet north of the 26 inch Algonquin gas main." The 30-inch gas main (which is located farther away from Unit 2 and within the same right of way) was not specifically mentioned. Chapter 2 of the FSAR did not present further analysis of the natural gas pipelines or any other nearby industrial facilities.

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[156] Submitted August 30, 1968; ADAMS Accession No. ML093480204. The evaluation begins on p.253 of the file: Item 7 of Supplement 1 to the Indian Point Unit 3 PSAR. The PSAR is part of the application to the AEC for a construction permit.
[157] Dated February 20, 1969; ADAMS Accession No. ML100261033.
[158] This quotation is from Amendment 13 to the FSAR, submitted December 4, 1970, available to the NRC staff at ADAMS Accession No. ML093480359.
[159] Dated September 21, 1973; ADAMS Accession No. ML072260465.
[160] Dated February 26, 1981; ADAMS Accession No. ML031080517.
[161] The FSAR was submitted on July 22, 1982. It is not publicly available but is available electronically to the NRC staff; Chapter 2 is ADAMS Accession No. ML100350907.

Revision 0 omitted some words from the original FSAR, which had been clear that the right of way was 65 feet wide and lay 1,450 feet south of Unit 2. Consolidated Edison corrected the FSAR error in Revision 2, restating this passage as: "The Algonquin Gas Transmission Company has a right-of-way running east to west through the property, 2840 ft long and 65 ft wide. Unit 2 is 1450 ft north of the 26-in. Algonquin gas main." [162]

This text was substantially unchanged until 2008, when Entergy submitted Revision 21 to the Indian Point Unit 2 FSAR.[163] This revision included updated text in Section 2.2.3 (highlighted in gray below) associated with the pipelines, as well as a new Figure 2.2-3. No further analysis was included in Chapter 2. Section A.4 of this report describes analyses conducted by Entergy in 2008 that may have triggered this update.

> Entergy owns the Indian Point Units 1 and 2 Nuclear Power Plants. As shown in Figure 2.2-3, the Algonquin Gas Transmission Company has a 24 inch gas mainline and a 30 inch loop line on a 65 foot wide right-of-way running east to west through the property. Unit 2 is 1450-ft north of the 24-in. Algonquin gas mainline.
>
> The Georgia-Pacific Corporation has an easement, 1610-ft long and 30-ft wide, through the southerly part of the Indian Point site. The Georgia-Pacific easement is used for overhead electrical power and telephone lines and underground gas, water, and sewer lines. These easements permit Entergy to determine all activities within the right-of-way in order to ensure safe operation of the units.

This revision changed the diameter of the pipeline, added the figure included in this report as Figure 20, and clarified Entergy's ability to determine activities within the easements to ensure safe operation of the units.

Entergy revised the FSAR in October 2010 to correct and clarify the sizes of the preexisting pipelines, as shown in the highlighted text:[164]

> As shown in Figure 2.2-3, the Algonquin Gas Transmission Company has a 26 inch gas mainline and a 30 inch gas mainline on a 65 foot wide right-of-way running east to west through the property. Unit 2 is 1450-ft north of the 26-in. Algonquin gas mainline. One 30 inch main and 2-24 inch mains pass under the river to a pipeline facilities station on the easement near the river. One 24 inch main is available as a bypass alternative and ends in the pipeline facilities station while the other two continue as the 30 inch and 26 inch mains.

There were no further substantive changes to Chapter 2 of the FSAR regarding the pipelines until analysis of the AIM 42-inch pipeline was included, as discussed in Section 1.2 of this report.

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[162] The FSAR was submitted in July 20, 1984. It is not publicly available but is available electronically to the NRC staff; Chapter 2 is ADAMS Accession No. ADAMS Accession No. ML100431991.
[163] The October 20, 2008, transmittal letter is publicly available at ADAMS Accession No. ML083390108. The FSAR is not publicly available but is available electronically to the NRC staff. (Chapter 2 is ADAMS Accession No. ML083390226 and the Chapter 2 figures are ADAMS Accession No. ML083390227.)
[164] The October 6, 2010, transmittal letter is publicly available at ADAMS Accession No. ML11280A140. The FSAR is not publicly available but is available electronically to the NRC staff. (Chapter 2 is ADAMS Accession No. ML11280A135 and the Chapter 2 figures are ADAMS Accession No. ML11280A136.)

Indian Point Unit 3

In July 1982, the Power Authority of the State of New York submitted Revision 0 of the updated FSAR for Indian Point Unit 3.[165] The 26-inch gas pipeline was mentioned in Section 2.2.2, "Site Ownership and Control":

> …the Algonquin Gas Transmission Company has a 26 inch gas main on a right-of-way (approximately 1350 feet long and 65 feet wide) running east to west through the Authority's property. … These easements permit the Authority to determine all activities within the right-of-way in order to ensure safe operation of the unit.

The 30-inch gas main (which is located farther away from Unit 3 and within the same right of way) was not specifically mentioned. Chapter 2 of the FSAR did not present analyses of the natural gas pipelines or any other nearby industrial facilities.

This text was substantially unchanged until the 2009 update to the Indian Point Unit 3 FSAR.[166] This revision included updated text in Section 2.2.2 (highlighted in gray below) associated with the pipelines. The referenced FSAR Figure 2.2-2 is like Figure 19 included in this report. Section A.4 of this report describes the referenced analysis.[167]

> As shown in Figure 2.2-2, the Algonquin Gas Transmission Company has a 24 inch gas mainline and a 30 inch loop line on a right-of-way (approximately 1350 feet long and 65 feet wide) running east to west through Entergy's property. The threats posed by the rupture of these pipelines and the release of natural gas (essentially methane) from them were addressed in Item 7 of Supplement 1 to the original FSAR. The September 21, 1973 SER concluded the failure of these gas lines would not impair the safe operation of the plant.
>
> A subsequent evaluation in 2008, (Reference 1), discussed the consequences of a pipeline rupture and the potential impact of that event on the sites Protected Area, Vital Areas, the Security Plan, safe shutdown, and other non-safety related structures, such as the waterfront warehouse. The hazards created by a breach and explosion of the pressurized above ground portions of the pipeline include:
>
> a. potential missiles,
>
> b. an over-pressurization event,
>
> c. a vapor cloud or flash fire,
>
> d. a hypothetical vapor cloud explosion, and
>
> e. a jet fire.
>
> A simultaneous rupture and ignition of both gas mains at the above ground locations inside the owner controlled area (OCA) is postulated to be the worst case scenario

[165] The July 14, 1982, transmittal letter is publicly available at ADAMS Accession No. ML093380878. The FSAR is not publicly available but is available electronically to the NRC staff. (Chapter 2 is ADAMS Accession No. ML20055A765.)
[166] The October 13, 2009, transmittal letter is publicly available at ADAMS Accession No. ML093430690. The FSAR is not publicly available but is available electronically to the NRC staff. (Chapter 2 is ADAMS Accession No. ML093430729 and the Chapter 2 figures are ADAMS Accession No. ML093430731.)
[167] FSAR Reference 1: IP-[RPT]-08-00032, "Consequences of Fire and Explosion Following the Release of Natural Gas from Pipelines Adjacent to Indian Point", by David Allen, Risk Research Group, August 2008.

> since this event will result in the most significant release of gas volume and have the potential to contribute to the largest potential fire. An attempt to uncover, breach and ignite a buried portion of the pipeline was not considered feasible. The report concluded that the event would not damage any safety related structure and there are no adverse effects on the gas pipeline event on vital areas, safe shutdown equipment, [Indian Point] Security Plan, or essential personnel. Some damage to non-vital structures or non-essential personnel in the area of the pipeline may occur.

Entergy next changed this section in the 2015 update to the Indian Point Unit 3 FSAR (highlighted in gray below).[168] Section A.4 of this report describes a 2015 analysis that was likely the trigger for this update.

> A subsequent evaluation in 2008 (Reference 1) discussed the consequences of fire and explosion due to a pipeline rupture. … An attempt to uncover, breach and ignite a buried portion of the pipeline was not considered feasible. The report concluded that the rupture of the natural gas pipelines that cross the Indian Point site and subsequent ignition of the methane released will result in a jet fire and injury or death to any people exposed to flames or intense thermal radiation. It will not, however, damage any safety related structure. Even in the unlikely event of a hypothetical vapor cloud explosion, structural damage to buildings other than the waterfront warehouse adjacent to the pipelines will not occur. A flammable vapor cloud fire that engulfs the plant is improbable because the turbulent momentum with which the methane exits the pipeline will confine flammable methane concentrations to the point of release.

There were no further substantive changes to Chapter 2 of the FSAR regarding the pipelines until analysis of the AIM 42-inch pipeline was included, as discussed in Section 1.2 of this report.

A.3. Indian Point Hearings (1979-1985)

In September 1979, the Union of Concerned Scientists petitioned the NRC to decommission Indian Point Unit 1 and suspend operation of Units 2 and 3. In February 1980, the Director of the NRC Office of Nuclear Reactor Regulation (NRR) issued his decision on the petition (referred to as a Director's Decision).[169] The Director's Decision granted a portion of the petition regarding Unit 1 (as noted at the end of the Unit 1 discussion in Section A.1). The Director's Decision, however, denied the request to suspend operation of Units 2 and 3, given the issuance of confirmatory orders to the licensees that required multiple important interim safety measures. While the Director's Decision did not address the gas pipelines near Indian Point, the extensive follow-up activities did include additional analysis of the pipelines.

[168] The FSAR was submitted on October 1, 2015. It is not publicly available but is available electronically to the NRC staff. (Chapter 2 is ADAMS Accession No. ML15293A108 and the Chapter 2 figures are ADAMS Accession No. ML15293A109.)

[169] Issued February 11, 1980; available to the NRC staff (without enclosures) at ADAMS Accession No. ML100290756.

After reviewing the Director's Decision and considering public comments, the NRC Commission in May 1980 announced a "four-pronged approach" to resolve issues raised by the petition:[170]

- Holding an adjudication on the safety issues for Units 2 and 3, with the Atomic Safety and Licensing Board making findings and recommendations for a Commission decision
- Holding an informal proceeding to determine the issues to be pursued in the adjudication
- Considering generically the question of reactors in areas of high population density
- Establishing a staff task force to review data and give the Commission information to decide the status of Units 2 and 3[171]

The Commission was interested in the risks of serious accidents at Indian Point Units 2 and 3, including accidents not considered in the plants' design bases. This topic was identified in the Commission's May 1980 order and amplified in additional orders issued later in 1981.[172]

The Atomic Safety and Licensing Board issued its findings and recommendations in October 1983.[173] This document does not refer specifically to the natural gas pipelines near Indian Point, other than noting that externally initiated events are the principal contributors to risk at Indian Point. In coming to its conclusions, however, the Board considered evaluations that do address the pipelines, including:

- The Indian Point Probabilistic Safety Study, prepared by the licensees
- "Letter Report on Review and Evaluation of the Indian Point Safety Study" by Sandia National Laboratories (SNL)

The subsections below describe these evaluations in more detail.

The Commission issued its decision in May 1985, addressing the risk of Indian Point—including ways to reduce risk and how the risk compared to other plants—as well as emergency planning and other topics.[174] The Commission considered the licensee and SNL analyses, as well as other information, but did not explicitly reference the natural gas pipelines as a hazard or accident initiator. The Commission concluded that neither the shutdown of Units 2 and 3, nor imposition of additional remedial actions beyond those implemented voluntarily by the licensees, was warranted. As a result, the NRC rescinded some aspects of the confirmatory order that had been issued to the licensees for Units 2 and 3 in February 1980.[175] The Commission found that the risk reduction effect of those measures was "not sufficient to be termed substantial," and that they should not be

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[170] Issued May 30, 1980; available to the NRC staff at ADAMS Accession No. ML100150748.
[171] The task force issued its results as NUREG-0715, "Task Force Report on Interim Operation of Indian Point," in August 1980 (available to the NRC staff at ADAMS Accession No. ML19344F216), concluding that was the overall risk of the Indian Point reactors was about the same as the typical reactor on a typical site. The task force report does not mention the natural gas pipelines. This report supported a Commission decision that the units could continue to operate during the adjudicatory proceeding, but the Commission noted that it would not "turn a decision on interim operation into a final decision on the long-term acceptability [of] the Indian Point site."
[172] Dated January 8, 1981, and September 18, 1981; available to the NRC staff at ADAMS Accession Nos. ML19340E920 and ML20039A702, respectively.
[173] Available to the NRC staff at ADAMS Accession No. ML20081A330.
[174] CLI-85-06, issued May 7, 1985; legacy ADAMS Accession No. 8505090592 (not available electronically).
[175] Dated July 5, 1985; ADAMS Accession No. ML003778131.

imposed unless they were needed to fulfill generic requirements applicable to similar types of reactors or to meet other license requirements for Indian Point.

Indian Point Probabilistic Safety Study

The Indian Point licensees submitted the Indian Point Probabilistic Safety Study in March 1982 for use in the adjudicatory proceeding.[176] This was one of the earliest comprehensive risk assessments of a nuclear power plant. Based on the study's results, the licensees identified and implemented cost-effective risk reductions, including new tests and procedures and certain equipment and structural changes.

Volume 11 of the study, Section 7.7.4, documents the licensees' evaluation of the gas transmission lines near Indian Point.[177] The evaluation is not significantly more detailed than those submitted in 1968-1969 for initial licensing (in fact, it references a United Engineers and Constructors[178] analysis from April 1968 that likely was the input for those submittals), but it does include data and estimates in addition to the prior qualitative assessments. The licensees had also obtained additional information from the Algonquin Gas Transmission Company in February 1981. Several key assumptions and results from this section are:

- ***Probability of pipeline failure:***
  - The 26-inch and 30-inch pipelines had been successfully hydrostatically tested in 1952 and 1965, respectively, to at least 92 percent of yield stress. Preventive maintenance included a twice-weekly aerial survey, a twice-yearly foot patrol with leak survey equipment, a monthly vehicle patrol, and weekly inspection of cathodic protection.
  - Data from the U.S. Department of Transportation and information from the Algonquin Gas Transmission Company were used to determine the failure frequency for large transmission lines. Only 30 percent of known failures (excluding the 70 percent resulting from damage by outside forces) were assumed to apply to these pipelines.
  - The estimated pipeline failure probability was approximately 5×10^{-7} per year. This estimate considered transmission line failures in the United States, length of pipe near site, fraction of failures that were large, fraction of time wind would blow toward the plant, fraction of failures due to original construction and corrosion, and fraction of leaks going undetected.
- ***Consequences of pipeline failure:***
  - Automatic shutoff valves were located at the east side of the Hudson River and in Yorktown, NY (10 miles away). They would isolate the 10-mile section passing near the plant. Gas would empty out in a little over an hour, supporting combustion for a total of 15 to 20 minutes.
  - If a fire occurred, destroying the offsite power lines, the plant could be shut down using diesel generator or gas turbine power.
  - Missiles had been found as far as 351 feet from a Louisiana pipeline explosion. Such missiles would "pose little threat" to the Unit 3 facilities at least 400 feet from the pipelines

[176] Submitted March 5, 1982; ADAMS package Accession No. ML093430890.
[177] Submitted March 5, 1982; ADAMS Accession No. ML102520202 (part of package referenced in note 176).
[178] United Engineers and Constructors was the principal subcontractor to Westinghouse as the architect-engineer of Indian Point.

or the Unit 2 facilities "which might be more vulnerable, but which are located 1,000 feet from the line and which are protected by a number of other structures."

  - The possibility of a gas line fire leading to a core melt is "extremely small."

- ***Other issues:***
  - Smaller leaks were determined not to jeopardize the plant; the probability of wind blowing toward the plant was cited as 0.14. This was considered in the pipeline failure probability but could also be used in considering other consequences of pipeline leaks.

Sandia National Laboratories Evaluation

In August 1982, SNL provided the NRC with a draft letter report documenting its review of the Indian Point Probabilistic Safety Study.[179] In Section 2.7.5 of the report, SNL commented on the thermal hazards from a pipeline fire:

> A fire from such a large leak would have to burn for several hours before safety related concrete structure might be threatened. Such long exposures to high heat fluxes do not result in catastrophic failure of structures, but rather in the (conservative) thermal design criteria for reinforced concrete structures being exceeded.
>
> Thus, the probability of 5 x 10-7/year developed in [Indian Point Probabilistic Safety Study] Section 7.7.5 is a very conservative estimate for the loss of safety-related equipment. Based on this probability, the contribution to the risk arising from the failure of these exposed pumps due to offsite fires would be expected to be less than that due to tornado hazards. An expected probability of exceeding Part 100 exposure guidelines or of a core melt would be much smaller.
>
> In summary, the probability of thermal fluxes from large fires endangering the safety related structures and equipment is bounded by the failure of this equipment by tornado hazards. The already low probabilities of [occurrence] of the fires would be very conservative estimates of the probabilities for exceeding Part 100 guidelines or for core melt.

This letter report was followed by a formal NUREG report completed in December 1982.[180] The purpose of the review was to search for areas in the licensees' analysis where omissions and critical judgments were made that could impact the quantitative results. This report addressed pipeline accidents from two perspectives.

- **Thermal hazards.** The evaluation in the final report had the same conclusions as the draft report—that there would not be catastrophic failure of structures or a significant impact on the Indian Point plant damage states or risk.

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[179] Submitted August 25, 1982; available to the NRC staff at ADAMS Accession No. ML100200464. (This version is marked as a draft.)
[180] NUREG/CR-2934, "Review and Evaluation of the Indian Point Probabilistic Safety Study," dated December 1982. ADAMS Accession No. ML091540534.

- **Blast hazards.** The evaluation noted that pipeline fragments, which could be propelled about 350 feet, would pose minimal risks to reinforced concrete structures. They would penetrate only a very small distance compared to design-basis tornado missiles.

Atomic Safety and Licensing Board Hearing

The Atomic Safety and Licensing Board considered these pipeline evaluations in during a February 1983 hearing. Specifically, Dr. Robert Budnitz,[181] a consultant who supported the NRC and SNL reviews, provided written and oral testimony.[182]

In his written testimony, Dr. Budnitz stated that he accepted most of the licensees' basic data, but he had reservations about the estimates for large leak fraction and small leak growth. He noted that the NRC staff had produced its own analysis, with which he agreed, resulting in a value of about 8×10^{-5} per year per mile of pipeline for large leaks. He identified three issues of concern that were not analyzed in the Indian Point Probabilistic Safety Study:

- **Damage to the site electrical system from a pipeline accident.** Dr. Budnitz stated that it was conceivable that a pipeline rupture and large fire could compromise offsite power, since the transmission lines pass over the pipeline. Using the NRC staff's value of 8×10^{-5} per year per mile of pipeline, even if offsite power were compromised every time, this rate of failure of offsite power would be acceptably small. Dr. Budnitz indicated that the actual probability of power loss was probably much smaller.[183] Accordingly, he concluded that this problem was not an important contributor to risk.

- **Gas flowing toward the plant prior to ignition, being taken up in plant systems, and then igniting.** Dr. Budnitz identified two possible scenarios: (1) an unusual wind pattern could blow gas toward the site, overcoming the normally high buoyancy of natural gas, or (2) the high buoyancy of gas could be reduced because of expansion cooling during its escape from the pipeline, making its density higher than air. While Dr. Budnitz admitted this effect had not been quantified, he noted that the small orifice needed for significant expansion cooling was "probably very small compared to a size that could produce large volumes of gas." He also indicated that it was not likely that the gas could remain cold and dense (without mixing with air) while traveling several hundred feet to safety equipment at the reactor. Therefore, while the analysis "to allay this concern fully" had not been done, the issue seemed unlikely to produce a "major incremental risk."

- **Isolation valve failure that would lead to continuous pumping of natural gas out of the break, causing a much larger fireball.** Dr. Budnitz found that this issue could also be "bounded acceptably." Even if the valves failed in every pipeline break, such fireballs would occur based on the staff estimate "only every 12,000 years or so." Dr. Budnitz noted that the fire would "in all likelihood be localized to the region near the pipeline, with little chance of

[181] Dr. Budnitz was an expert in the area of probabilistic risk assessment. He had served for two years as the director of the NRC Office of Nuclear Regulatory Research. Among other activities as an independent consultant, he was part of an independent advisory body to the NRC that reviewed the pioneering WASH-1400 Reactor Safety Study to describe how risk assessment methodology could be used in the NRC review process.

[182] Written testimony submitted January 24, 1983; available to the NRC staff at ADAMS Accession Nos. ML20070N197. Hearing held February 10, 1983; transcript available to the NRC staff at ADAMS Accession No. ML20064N013.

[183] During the hearing, Dr. Budnitz was asked if he was aware that there was a 13.8 kilovolt underground cable from the Buchanan substation to the plant that was extrinsic to those power sources; he said he was not. Presumably this line was perceived by the Board as a backup to the overhead transmission lines.

spreading to the plant except under the most unusual wind conditions." He stated that the overall threat seems "to be sufficiently infrequent that its contribution to overall risk can be considered small."

Dr. Budnitz concluded overall that the core-melt risk to Indian Point from gas pipeline failures was considerably less than the risks from other sources, and that omitting a full-scale quantitative risk analysis for pipelines at Indian Point was acceptable. In his hearing testimony, Dr. Budnitz acknowledged that there was not a realistic numerical analysis of the probability of core damage that would make him "comfortable by itself," but that he felt comfortable with the pipeline bounding analysis.

A.4. Additional Licensee Evaluations of Preexisting Pipelines (1980-2015)

Control Room Habitability Report

In 1980, as part of the response to the accident at Three Mile Island (TMI) Unit 2, the NRC issued NUREG-0737, "Clarification of TMI Action Plan Requirements." [184] Item III.D.3.4 of NUREG-0737 stated, in part, that licensees needed to assure that control room operators would be adequately protected against the effects of accidental release of toxic or radioactive gases. In response, the Power Authority of the State of New York submitted a control room habitability report. [185] It included the following text related to the preexisting natural gas pipelines:

> The Algonquin Gas right-of-way passes approximately 0.3 miles from the Indian Point Unit 3 Control Room Air Intake. Two pipelines carrying natural gas (96% methane, 2.5% ethane, 0.5% propane) are installed in the right-of-way. Methane is not a toxic chemical. The pipelines are, therefore, deleted from further consideration in this study.

This information is not explicitly addressed in the relevant input to the NRC safety evaluation on this topic. [186]

Individual Plant Examination of External Events

In the late 1980s and early 1990s, the NRC assessed issues and guidance that were not within the licensing scope for facilities licensed before 1976 (including Indian Point Units 2 and 3). [187] In

[184] Published November 1980; ADAMS Accession No. ML051400209.
[185] Dated July 20, 1981; ADAMS Accession No. ML093430606.
[186] The team could only find an internal input to the safety evaluation (available to the NRC staff at ADAMS Accession No. ML093450337). The transmittal letter for the final safety evaluation (available to the NRC staff at ADAMS Accession No. ML093430874) did not include the safety evaluation itself.
[187] For example, the following guidance documents issued after the initial licensing of the Indian Point units address natural gas pipelines in various ways. Regulatory Guide 1.70 on format and content for safety analysis reports (reactor license applications) was not issued until 1972 (ADAMS Accession No. ML13350A353). This document standardized the format of applications submitted after that time. Section 2.2.3 of Regulatory Guide 1.70, Revision 0, states "[i]f large natural gas pipelines cross, or pass close to the nuclear plant, explosions from this source should be evaluated." The NRC staff's review of later applications was conducted under the Standard Review Plan, issued for the first time in 1975 (ADAMS Accession No. ML081510817). Sections 2.2.1 and 2.2.2 of the Standard Review Plan noted that "[t]he problems of pipeline rupture and other flammable gas releases are reviewed on an individual case basis by evaluating analyses provided by the applicant, and may also involve independently checking the gas cloud size and TNT equivalency derived by the applicant." The AEC provided related guidance to applicants and licensees in Regulatory Guide 1.91, "Evaluation of Explosions Postulated To Occur on Transportation Routes

particular, in June 1991, licensees were asked to conduct an Individual Plant Examination for External Events (IPEEE).[188] The NRC concluded in 1993 that the IPEEE would address hazards posed by industrial facilities located near nuclear power plants licensed before 1976.[189]

Unit 2

In December 1995, Consolidated Edison submitted the IPEEE for Unit 2.[190] The licensee considered earthquakes that could damage the gas pipelines, as well as pipeline accidents in general.

The licensee noted several measures that enhanced the quality of the pipelines: stronger construction, random joint x-rays, recent inspection of the 26-inch line with smart pigs, a coating and cathodic protection to prevent corrosion, and frequent surveys. The licensee also noted that there were manual shutoff valves located by the river crossing, and that a SCADA system provides instant flow and pressure information, so that a leak could be quickly detected.

In the seismic assessment, the licensee cited multiple construction features that would support the pipelines and prevent slope failures. In one location 1,200 feet from the nearest Unit 2 structures, the licensee identified a slope that it could not screen out of its assessment. To address this location, the licensee considered three potential failure impacts.

- **Fires at the pipeline.** These were determined not to impact Indian Point Unit 2 given the 100-foot-wide firebreak around the plant.
- **Explosions.** The licensee referenced "extensive studies by the [U.S.] Bureau of Mines and others" demonstrating that natural gas does not detonate unless confined, so a severe shock wave was deemed not credible.
- **Transport of a vapor cloud and fire at the plant site.** The licensee noted that natural gas readily disperses into the atmosphere, and it was unlikely that weather conditions would support a gas cloud that could travel 1,200 feet from the pipeline to Unit 2 and still support combustion or asphyxiation.

The licensee estimated a frequency of an earthquake that could cause the pipeline to fail, combined with wind in the direction of Unit 2, with the gas cloud not igniting until it reached critical safety systems and structures. This frequency was 6×10^{-7} per year. Since this was below the screening

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Near Nuclear Power Plant Sites," issued in January 1975 (ADAMS Accession No. ML12298A133). The introduction of the 1975 edition was clear that it was focused on materials carried over transportation routes "not including gases." The NRC revised the guidance in February 1978 (ADAMS Accession No. ML003740286) to be even more clear about its scope: "This guide is limited to solid explosives and hydrocarbons liquified under pressure and is not applicable to cryogenically liquified hydrocarbons, e.g., LNG. It considers the effects of airblasts on highway, rail, and water routes but excludes pipelines and fixed facilities." This Revision 1 does not reference gases at all. Not until 2011 did the NRC issue draft guidance (DG-1270) that addressed pipeline explosions specifically (ADAMS Accession No. ML110390554). This guidance was finalized in 2013 as Revision 2 to Regulatory Guide 1.91 (ADAMS Accession No. ML12170A980).

[188] Generic Letter 88-20, Supplement 4, "Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities - 10CFR 50.54(f)," dated June 28, 1991. https://www.nrc.gov/reading-rm/doc-collections/gen-comm/gen-letters/1988/gl88020s4.html

[189] SECY-90-343, "Status of the Staff Program to Determine How the Lessons Learned from the Systematic Evaluation Program Have Been Factored into the Licensing Bases of Operating Plants," dated October 4, 1990. Available to the NRC staff at ADAMS Accession No. ML19324H923.

[190] Submitted December 6, 1995; ADAMS Accession No. ML11227A100.

criterion of 10^{-6} per year, the scenario was screened from further analysis and the gas pipelines were determined not to be aseismic vulnerability.

The licensee evaluated gas pipeline accidents in general as well. The licensee contacted the Algonquin Gas Transmission Company for updated information on the performance and service history of the pipelines since the Indian Point Probabilistic Safety Study was conducted. The licensee noted that:

- The 26-inch pipeline was retested after installation.
- Pressure relief valves had been replaced with line pressure monitors, and automatic shutoff controls had been removed from all valves given a history of false closures.[191] Quick response to line breaks was expected because of the emergency response plan in place and the use of a SCADA system.
- Vehicle patrols were weekly rather than monthly as noted in the Indian Point Probabilistic Safety Study.

The licensee concluded that the analysis from the Indian Point Probabilistic Safety Study (estimating a 5 x 10^{-7} per year failure frequency) remained applicable, and the event could be screened out.

The NRC documented its review of the Indian Point Unit 2 IPEEE in May 1999.[192] The reviewers summarized the information on seismically induced failures without noting any objections. For pipeline accidents in general, the reviewers noted that hazard frequency arguments were used to screen these events from further consideration. The natural gas pipeline accident analyses, with a failure frequency of about 5 x 10^{-7} per year, were considered reasonable.

Unit 3

In September 1997, the Power Authority of the State of New York submitted the IPEEE for Unit 3.[193] The licensee referenced the Unit 2 IPEEE seismic analysis, making the same conclusion for Unit 3 that the pipelines could be screened as a seismic vulnerability. The licensee then noted that a pipeline explosion could result in damaging overpressures at Unit 3.

The assessment considered factors that reduced the likelihood failures of the pipelines that come within 400 feet of safety-related equipment for Unit 3. The licensee provided background on hydrostatic testing of the pipelines, internal inspections conducted every 3 years, pressure monitoring, and surveys used to detect leaks and possible threats. The licensee considered that overpressure failures were unlikely to pose significant risks given these design features and the distance to the plant (greater than the 351-foot distance missiles were thrown in a Louisiana pipeline failure). The licensee also stated that the pipelines were buried in a wide, clear, and well-marked right of way on site, so they were unlikely to be damaged by careless construction or excavation.

To consider pipeline failure consequences, the licensee examined a catastrophic event caused by a pipeline rupture and a vapor cloud explosion. The licensee estimated initial discharge rates from both pipelines and the jets that could be produced. Explosion of methane in those jets could result

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[191] The team reviewed 10 CFR 50.59 annual reports from 1980 through 1997 for Indian Point Units 2 and 3 and could not find a disposition of this change with respect to docketed correspondence for Units 1 and 3 (see notes 146 and 156).
[192] Memo dated May 14, 1999; ADAMS Accession No. ML090130608.
[193] See note 65.

in a 1-psi overpressure at distances that “may cause major damage” to Unit 3. Formation of a plume of buoyant methane could create a flammable vapor cloud. If the entire contents of the 10-mile pipeline length between valves were included in the cloud and an explosion occurred, “a 1-psi overpressure may engulf” Unit 3.

The licensee, however, concluded that these vapor cloud explosions could be eliminated as a source of concern. Referencing data from a 1994 risk analysis text, the licensee estimated a failure frequency of large diameter pipelines: about 1.2 x 10^{-4} per year for the 5 miles of pipeline around Indian Point Unit 3. Assuming a 0.01 probability of a vapor cloud explosion following a pipeline failure and a 0.1 conditional probability of core damage, the resulting core damage frequency contribution was less than the 10^{-6} screening value.

The NRC documented its review of the Indian Point Unit 3 IPEEE in December 2000.[194] This review noted that the licensee did not estimate the core damage frequency from nearby facility incidents (which includes pipelines) to be greater than 10^{-6} per year. The NRC observed that the analyses “were done only to the level of detail needed to screen out” the event and concluded that the licensee appeared to have identified the significant initiating events. There was no discussion specific to the pipelines.

2008 Entergy Analysis

In March 2008, the NRC expressed a concern to Entergy regarding a potential security vulnerability associated with the preexisting natural gas lines. In two security-related responses submitted in April and September 2008, Entergy provided the NRC with information about the referenced location.[195] Entergy referenced an analysis of pipeline incidents by Dr. David J. Allen of the Risk Research Group, a consultant who also prepared the analyses of nearby facility hazards for the Indian Point Unit 3 IPEEE and conducted later analyses for Entergy discussed in this report.

The consultant noted that the Indian Point Unit 3 IPEEE did not assess the consequences of a natural gas release in detail given the predicted frequency of spontaneous ruptures. Considering instead intentional and malicious activity, it became necessary to reevaluate the consequences of natural gas releases. The consultant noted that a large line break would result in a remote low-pressure alarm (in Houston, TX) and pushbutton isolation of about 6.5 miles of pipeline. Using the BREEZE and ALOHA codes, the consultant analyzed jet fires, vapor cloud fires, and hypothetical vapor cloud explosions (though they were deemed unlikely) from a point near Unit 3.

The resulting heat flux from jet fires, which could burn for over an hour depending on the scenario, was found to be low enough not to damage equipment except in the immediate vicinity of pipelines, with no major damage to facilities. (The next subsection provides additional detail on heat flux calculations.) Vapor cloud fires were determined not “to be a real possibility” given the turbulence and high velocity with which the natural gas would exit the pipeline (making jet fires more likely). Vapor cloud explosions were found to be “most unlikely” given the little confinement near the pipelines. Assuming some confinement from nearby trees, the consultant calculated overpressures that would not damage safety-related structures on site.

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[194] Memo dated December 15, 2000; available to the NRC staff at ADAMS package Accession No. ML003780825.

[195] Letters dated April 23, 2008, and September 30, 2008, are not in ADAMS but were made available to the team. The September letter included a security-related enclosure dated August 14, 2008, that is available to the NRC staff at ADAMS Accession No. ML103140627. This is the same analysis that was referenced in the 2009 revision to the Indian Point Unit 3 FSAR (see Section A.2 of this report).

The consultant noted that these results "differ at first sight from the conclusions drawn in the original IPEEE … about a vapor cloud explosion or flammable vapor cloud engulfing the plant." The consultant offered the following explanation:

> The re-evaluation of the consequences of this event and, in particular, the recognition of the effect of turbulent mixing as the methane exits the pipeline and of the fact that vapor cloud explosions involving methane do not occur in uncongested or semi-open spaces, leads us to conclude that the hypothetical engulfment of the plant in a vapor cloud explosion or vapor cloud fire is improbable. That said, a jet fire, ignored in the IPEEE, is likely to occur in the event a gas pipeline is ruptured. Such a fire might well endanger plant staff who are unable to shelter; it would not, however, damage safety structures or equipment.

2015 Entergy Analysis

In August 2015, the NRC expressed a concern to Entergy regarding the 2008 consultant report, particularly the heat flux calculations and the location where the rupture was assumed. The NRC also asked Entergy to provide details on the plant's licensing basis with respect to the pipelines.

In a security-related response provided to the NRC in October 2015, [196] Entergy clarified that the rupture location in the 2008 analysis was based on the issues raised by the NRC. Entergy also clarified that no time had been assumed in 2008 for isolation of the ruptured line because the duration did not affect the peak values calculated for overpressure and heat flux. The analysis assumed that the remaining gas would burn for a period after isolation. Entergy also noted that the Unit 2 IPEEE had referenced the change from automatic to remote (not automatic) isolation of the valves on the gas pipeline. Entergy determined that, since the most significant effects of a pipeline rupture are at the beginning of a release, "the timing of valve closure is not considered relevant" and no new analysis was needed to amend the licensing basis.

Entergy also noted that certain plant equipment had not been accounted for in the heat flux calculations in 2008, and these were addressed in the updated analysis. The 2015 analysis was conducted by the same consultant who performed the 2008 analysis, but it was independently reviewed by another individual not employed by Entergy. The consultant considered jet fires, delayed-ignition cloud fires, vapor cloud explosions, missile generation, and smoke. The 2015 analysis documented heat flux over 12.6 kW/m^2 and overpressure over 1 psi that could negatively affect certain safety-related or important-to-safety equipment or structures for Unit 3. The analysis concluded that the following important equipment could be affected, but that backup equipment would allow for safe shutdown of the plant. Other equipment was less important to the facility or unaffected because of shielding or distance. [197]

- **Emergency diesel generators (based on heat flux at the outside air louvers).** Also, some shielding is provided by other buildings and the downhill slope toward the plant.
- **Several tanks with exposed instruments within the protected area.** The level instruments were assumed to be lost based on heat flux, which could result in required actions under the plant technical specifications, but the tanks could still be used.

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[196] Letter dated October 15, 2015, is not in ADAMS but was made available to the team. The referenced "2015 Report" was not available to the team but was discussed in detail in the attachment to the letter.
[197] For example, Entergy states that the metal siding on the Unit 3 fuel storage building could be damaged by the heat flux, but the building has been evaluated for the effects of siding damage and fires, and the reinforced concrete spent fuel pool would not be affected.

- **Equipment in the 138-kV yard.** The analysis discusses multiple ways to restore power, as well as alternative sources that could be manually aligned (which the plant has analyzed).
- **Offsite electrical switchyard and transmission lines.** Loss of the switchyard is postulated for certain rupture locations, and loss of offsite power (an analyzed event) is assumed.
- **Diesel fuel oil storage tank and tanker trailer.** Entergy noted that the tanker trailer, relatively close to the pipeline, was needed to move fuel from the storage tank (which was less likely to be affected) onto the site. Separately, the team verified that the tanker trailer was later moved much farther away from the pipeline and, combined with day tanks onsite, provides significant fuel oil supply for the emergency diesel generators.
- **City water tank.** This water supply provides cooling or backup cooling to various important plant equipment. Entergy noted that other water sources would be available in the scenarios that would affect this tank, though manual alignment may be needed.

Entergy concluded that "the highly unlikely—but assumed—loss of [the] adversely affected SSCs … would not prevent the safe shutdown of the plant." Entergy also stated that "exposure rates are sufficiently low to justify a conclusion that the original licensing basis (i.e., the gas line will not impair the safe operation of [Unit 3]) is met."

A.5. Additional NRC Evaluations of Preexisting Pipelines (2003-2015)

2003 Security-Related Review

At an NRC meeting in March 2003, a member of the public raised concerns about the safety and security implications of the natural gas pipelines that pass through the Indian Point site. In response, NRC staff reviewed prior evaluations of the pipelines and assessed the risks of large releases of natural gas, including through intentional acts.[198]

In assessing intentional acts, the NRC staff acknowledged that it was not valid to consider the pipe rupture frequency, but rather the pipeline failure had to be assumed as an initial condition. Postulating this rupture, the NRC staff considered the consequences of a major pipe rupture and the likelihood of detonation of an unconfined gas cloud.

First, using the 1 psi overpressure distances included in the Indian Point Unit 3 IPEEE, the NRC staff calculated the mass of the vapor cloud that could create such an overpressure. Using the IPEEE-referenced discharge rates, the NRC staff observed that a vapor cloud that could cause this overpressure could form within a minute. Another equation also indicated that a vapor cloud could form in a short time. (A prior study had shown a mean time between rupture and ignition of 6-7 minutes.) The NRC staff considered the peak overpressure capacities for the fuel handling building and diesel generator building and found that overpressures of 1 psi or less would not pose a significant threat, though higher pressures could pose damage.

The NRC staff noted multiple references showing that unconfined vapor clouds of natural gas are not easily detonated. In the IPEEE, the likelihood of detonation given a large rupture was estimated to be 0.01. Entergy and its contractor informed the NRC that more recent information would support an even lower likelihood.

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[198] Memo dated April 25, 2003; ADAMS Accession No. ML11223A040. The non-public enclosure is available to the NRC staff at ADAMS Accession No. ML031210213.

The NRC staff also estimated radiant heat fluxes using the methodology from NUREG/CR-3330, "Vulnerability of Nuclear Power Plant Structures to Large External Fires."[199] This report estimated an equilibrium flow rate from a rupture in a 36-inch, 1,000 psig pipeline, which the NRC staff viewed as an upper bound since pipeline isolation would decrease the discharge rate over time. Using IPEEE discharge rates and calculations for the radiant heat from a resulting fireball, the NRC staff concluded that at least several hours of fire exposure would be needed to have detrimental effects on safety-related concrete structures. Some wood ignition and personnel injury would be expected depending on the distance.

The NRC staff used this information to suggest that intentional ruptures may be an impractical and unlikely choice for those seeking nuclear power plant damage. The staff recommended that a "definitive evaluation of this aspect" be conducted as a safeguards review.

2010 Petition Review

In October 2010, a member of the public submitted a petition under Title 10 of the *Code of Federal Regulations* (10 CFR), Section 2.206, "Requests for action under this subpart."[200] This petition raised issues with the preexisting pipelines on the Indian Point site. The NRC staff, in considering the petition, reviewed historical information regarding the pipeline, as well as publicly available technical data.[201] The historical references reviewed by the staff have all been described elsewhere in this appendix. A compiled report containing safeguards information was produced as a record of the review. In addition, the security staff developed questions for the licensee that were shared with regional security inspectors to address at the next baseline inspection.

The NRC staff also used the ALOHA modeling software to assess both the conclusions of the 2008 Entergy analysis (Section A.4) and the conclusions of the 2003 NRC evaluation (Section A.5). While details of the ALOHA calculations were not included in the summary memo, the NRC staff asserts in the memo that the 2003 and 2008 conclusions remained valid.

Considering all of this information, the NRC staff did not identify any violations of NRC regulations or any new information that would change the staff's previous conclusion that the pipelines do not endanger the safe or secure operation of Indian Point Units 2 and 3. The NRC did not accept the 10 CFR 2.206 petition for further review, stating that the issues raised had been previously resolved.[202]

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[199] See note 62.

[200] Submitted October 25, 2010; ADAMS Accession No. ML103020293. The non-public version is available to the NRC staff at ADAMS Accession No. ML102990527.

[201] An internal memo dated March 23, 2011, referencing these reviews is publicly available at ADAMS Accession No. ML11223A041. Detailed information is available to the NRC staff at ADAMS Accession Nos. ML110750113 (March 23, 2011, memo) and ML110700162 (March 7, 2011, input memo), as well as in a safeguards report that the team reviewed.

[202] Letter dated March 31, 2011; ADAMS Accession No. ML110890309.

Appendix B. Pipeline Rupture Analysis Results

The following pages show the letter report from Sandia National Laboratories that documents the analyses its staff conducted in support of the evaluation team's activities. (Note: Page numbering resumes with Appendix C, accounting for the length of this report.)

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March 31, 2020

To: Suzanne Dennis
U.S. Nuclear Regulatory Commission

Subject: ***Review of NRC confirmatory analysis regarding fire and explosion for Algonquin gas transmission line at Indian Point nuclear power plant***

The following provides a review of dispersion and explosion hazard analysis conducted by staff at the U.S. Nuclear Regulatory Commission (NRC) [1] regarding a 42" diameter natural gas pipeline next to the nuclear power plant, Indian Point Energy Center (IPEC) near Buchanan, New York.

This review includes:

- Evaluation of whether the models specified in the US NRC regulatory guide 1.91 [2] were used appropriately.
- Verification of the results using the models used in the analysis.
- Preliminary vapor cloud dispersion simulation using Computation Fluid Dynamics (CFD).
- Summary of review.

The following provides further description of each of these items as well as results and discussion thereof. Note that the request by NRC was urgent and required that Sandia provided the review within three weeks. Because of the limited time available the independent analysis performed by Sandia is considered preliminary for reasons discussed in section 3.

Additionally, appendix A provides a calculation of incident heat flux seen at IPEC safety related reinforced concrete structures. The calculation is based on NUREG/CR-3330 which provides an analysis on the amount of time nuclear safety related concrete structures can withstand various incident heat fluxes [A.1].

Sandia National Laboratories is a multimission laboratory managed and operated by National Technology and Engineering Solutions of Sandia, LLC, a wholly owned subsidiary of Honeywell International Inc., for the U.S. Department of Energy's National Nuclear Security Administration under contract DE-NA0003525.

1. Evaluation of the appropriate use of models:

a. Model Description

As specified in the US NRC regulatory guidelines 1.91, the NRC analysis uses the recommended ideal blast wave TNT equivalency method to determine the blast overpressure from a vapor cloud explosion. This method is described in a guideline document by Factory Mutual (FM) [3] cited in the NRC regulatory guidelines 1.91. The Factory Mutual document provides yield factors (or efficiency numbers) and heat of combustion values required as inputs into the model and discussion regarding the appropriate use and limitations of the model.

The equations used in the model are the following.

$$E = \alpha \Delta H_c m_f \quad (1)$$

$$W_{TNT} = \frac{E}{H_{detonation\ TNT}} \quad (2)$$

$$R_{min} = Z * W_{TNT}{}^{1/3} \quad (3)$$

where

E = blast wave energy
α = yield or efficiency number
ΔH_c = theoretical net heat of combustion
m_f = mass of vapor released
$H_{detonation\ TNT}$ = heat of detonation of TNT
R_{min}= distance from explosion where peak positive overpressure equals 1.0 psi (6.9 kPa)
Z = scaled distance (45 ft/lb$^{1/3}$or 18 m/kg$^{1/3}$)
W_{TNT} = TNT equivalent mass

b. Model inputs

<u>Mass of vapor released</u>
The NRC analysis considered the release from one side of the rupture and uses ALOHA to determine the mass of the vapor cloud. The scenario evaluated is of a full-bore above-ground release. Such a scenario was realized in the natural gas pipeline accident in Carlsbad, New Mexico as described in the National Transportation Safety Board report [4] in which a 49-ft section of corroded pipe was blown off through the soil leaving a large crater.

The pipeline is assumed to have manual closure of the isolation valves within 3 minutes where the distance between isolation valves is 3 miles. Thus, for a release from one pipe end rather that two, both isolation valves would have to be closed and the release would occur at one end of the 3-mile section or next to one of the isolation valves. Based on this distance, the pipe length was entered as 3 miles in ALOHA and the closed option selected which means the pipe is closed off at one end. ALOHA uses equations for choked flow assuming an ideal gas in which the flow rate decreases over time due to the pressure drop and closed end of the pipe. The analysis considers a release over 1 minute using the maximum sustained average flow rate. An explosion calculation was also performed by NRC using ALOHA which calculates overpressure distances using the Baker-Strehlow-Tang method which incorporates general factors for obstacles that are not site specific.

The NRC guidelines 1.91 cite reference [5] for methods of estimating the mass of the vapor cloud. The reference provides a range of possible models to use from integral to CFD-based models and ALOHA is among those listed which is considered an integral-based model. ALOHA is not capable of modeling topography and geometry that reflects congestion at a particular site. It also does not have models for supercritical releases which will be discussed in section 3. The NRC guidelines does state:

> *"For releases of vapor clouds at offsite location or pipelines, plume modeling based on site topography and meteorological conditions should be evaluated. The atmospheric transport of released vapor clouds should be calculated using dispersion or diffusion models that permit temporal as well as spatial variations"*

Since ALOHA cannot model topography and temporal variations, it is not appropriate for use if the above guideline is to be followed. It also does not model supercritical fluids which require models for real gases since it assumes the ideal gas law.

Yield factor

The parameter, α, in equation 1 is the yield factor or efficiency number which indicates the fraction of available combustion energy participating in blast wave generation.

As stated in the FM guideline document,

> *"It cannot be overemphasized that assigning of an explosion efficiency number to a potential gas release incident is, with current technology, and entirely arbitrary exercise"*

This is a key point because as discussed in the FM guideline a release in a congested area such as dense vegetation, vehicles, and buildings can result in significantly higher overpressures. The congestion will result in a range of yield values which is not accounted for by the TNT equivalency method. It is also noted that the method represents the explosion as a point source which is not representative of the pressure signature of vapor cloud explosions which tend to have greater pressures in the far field and of longer duration than predicted from the model. Due to the point-source representation of the model, overpressures are overpredicted in the near field and underpredicted in the far field and are of shorter duration than vapor cloud explosions [3]. Lower overpressures of longer duration have the potential to be more damaging to structures than higher overpressures of short duration. It is further noted in the FM guideline that the method despite its drawbacks is often used to provide an approximate evaluation and that when very specific design basis building siting is required the method is inappropriate.

Related to the discussion provided in the FM guideline is the following statement provided in the NRC guideline 1.91:

> *"A detailed analysis of possible accident scenarios for particular sites, including consideration of the actual amount of potentially explosive material, potential release, site topography, and prevailing meteorological conditions, should be used to justify a value for the yield. However, for establishing safe standoff distances independent of site conditions, the use of a conservative estimate for the yield is prudent"*

The NRC guidelines 1.91 refers to the FM guideline for recommendations regarding the yield factor. The FM guideline recommends a yield factor of 0.05 for a Class I material such as natural gas based upon historical evidence which has indicated yields of 0.01 to 0.05 for typical hydrocarbons, though yields as high as 50% have been recorded and even very low estimated yields (~0.001) have caused extensive damage [3]. Thus, it's difficult to determine what value is considered conservative.

The NRC analysis used the recommended yield factor of 0.05 but did not account for site-specific conditions such as congestion and surrounding topography. A key question is whether the site surrounding the pipeline can result in much higher yields than 0.05 given the congestion as shown in Figure 1. The pipeline shown in Figure 1 is between IPEC and Buchanan or approximately 1600 ft from IPEC. It is evident that the surrounding area is highly congested with vegetation, structures, and vehicles indicating that more detailed analysis would be warranted based on recommendations in both guidelines. The FM guidelines recommends the TNO Multi-Energy Model for congested sites and is discussed in that document. The main assumption of the NRC analysis is that the since the vapor cloud is buoyant will rise and rapidly disperse above the surrounding vegetation and structures. This validity of the assumption will be discussed in section 3.

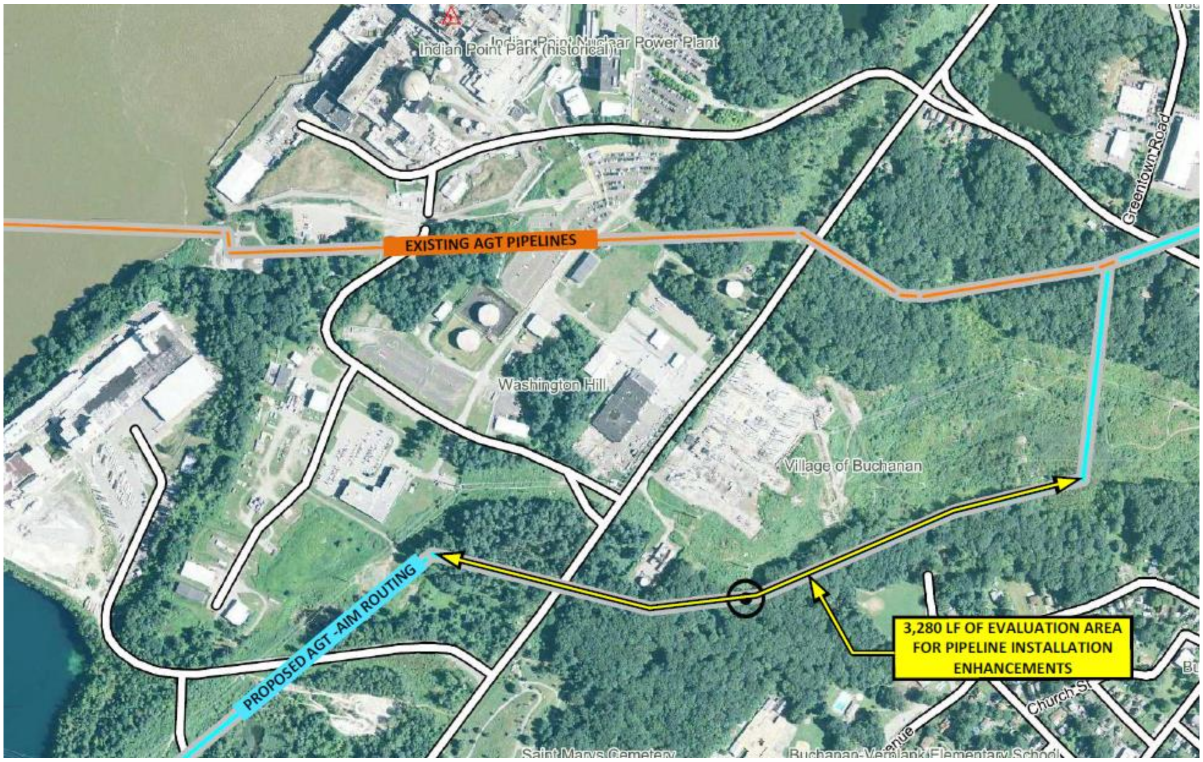


Figure 1: Indian Point Energy Center and Buchanan, NY.

Heat of Combustion

The NRC guidelines 1.91 refers to either NUREG-1805 [6] or the FM guidelines for the heat of combustion, though the FM guidelines does not specify the value for methane or natural gas. In ref. [6] the heat of combustion for liquefied natural gas composed mostly of methane is provided as 50,000 kJ/kg. The NRC analysis used a value of 50,030 kJ/kg for methane. This results in a higher blast wave energy, though of an insignificant amount (0.06%) compared to using a value of 50,000 kJ/kg.

Heat of Detonation

In equation (2) the denominator, that is the heat of detonation, is given as 4420 kJ/kg (1900 BTU/lb_m) in the NRC guidelines 1.91 where reference [7] is cited as the source for the value. The reference [7] source provides a value of 4500 kJ/kg (1935 BTU/lb_m) rather than 4420 kJ/kg. To check the validity of these values, a resource by a recognized expert in the field of explosives [8] was used. Reference [8] states that the heat of detonation can be determined using three approaches, two theoretical approaches and experimentally. From a theoretical approach using the thermodynamic work function the value is 4853 kJ/kg and that using the hydrodynamics work function the value is 4519 kJ/kg. Experiment has indicated a value of 4686 kJ/kg. Thus, among these values the most conservative is 4519 kJ/kg which is above 4500 kJ/kg indicating that 4500 kJ/kg is a reasonable value to use. It is uncertain as to where the value 4420 kJ/kg was obtained in the NRC guidelines.

Duration of release

The amount of mass of vapor used in equation 1 is determined by the duration of the release. Based upon discussion via teleconference with the author of the NRC analysis, a key assumption of the

NRC analysis is that the vapor cloud will be buoyant and disperse within the first minute and thus only considered the mass released over 1 minute. The full release duration is never considered whether the release is 3 minutes or 60 minutes thereby making the time at which the isolation valves are closed irrelevant. There is no evidence or justification presented for this assumption. Note that it is recommended in the FM guideline document that for a pipeline release it should be assumed that the pipeline is completely severed, and the duration of discharge should be 10 minutes flowing from both ends of the severed pipe even if automatic or manual block valves are present. An exception to this recommendation is not made for methane in the FM guideline.

2. Verification of the results

a. *Explosion*

The results of the explosion calculations by the NRC analysis and verification by Sandia National Laboratories (SNL) are provided in Table 1. Note that the pipeline pressure is 850 psig and in ALOHA the absolute pressure should be entered which would be 864 psia. Based on this verification, the NRC analysis appeared to have used 850 psia which does provide a flow rate of 256,000 lbs/in. If 864 psia is used, the average flow rate would increase to 261,000 lbs/min and the resulting distance to an overpressure of 1 psi is 2365 ft which is not a significant different than the distance of 2351 ft obtained from the NRC analysis. Note that in Table 1 the distance verified by Sandia is using a pressure of 850 psia to determine if the NRC results could be reproduced.

The NRC analysis used the maximum average flow rate obtained from ALOHA from a closed-end 3-mile pipeline, considering a release for 1 minute before the cloud is ignited. The NRC analysis used both the TNT equivalency method and ALOHA to calculate the blast overpressure distance to 1 psi. The delay time that was used for the ALOHA calculation for the 1-minute release was not specified in the NRC analysis. SNL could only reproduce the results approximately if a delay time of 8 minutes is specified providing a distance of 3057 ft. If the delay time is not specified, but is chosen by ALOHA the distance is much greater, providing 9504 ft. The distance calculated by NRC using ALOHA for this case was discounted as mentioned in the report that vapor dispersion in a congested area is not credible because the methane cloud is buoyant and will quickly rise and disperse rapidly.

The NRC analysis also considered a 60-minute release using ALOHA to calculate the maximum average sustained flow rate of 311,000 lbs/min. The mass released over the first minute was considered and not the total mass released over 60 minutes. The NRC analysis assumes that since the cloud will be buoyant it will disperse within 1 minute and thus an explosion will occur during the first minute independent of release duration and thus uses a mass of 311,000 lbs for the TNT equivalency calculation. If the cloud is not immediately buoyant, then for a 60-minute release using the total mass calculated by ALOHA the result in 8872 ft or 1.7 miles. The assumption of whether the vapor cloud is immediately buoyant or if it behaves as a dense gas which will greatly extend the time before the cloud is diluted below the lower flammability limit is discussed in section 3a.

Table 1: Results of explosion calculation for NRC analysis and SNL verification

Scenario	Pipe distance	Mass released	Distance to 1 psi blast overpressure	Results of verification by SNL using same methods
Explosion from one side of full-bore rupture release	3 miles (distance between isolation valves)	256,000 lbs for 1 minute using 'closed' end of pipe option in ALOHA	2351 ft (TNT) 3054 ft (ALOHA, with congestion)	2349 ft (TNT) 9504 ft (ALOHA, with congestion)
Explosion from one side of full-bore rupture release	3 miles (distance between isolation valves)	Release over 60 minutes using 'infinite source' option in ALOHA. • 311,000 lbs/min maximum average sustained flow rate • Total amount released 13,785,499 lbs	2509 ft (TNT - mass released for first minute)	2507 ft (TNT – mass released for first minute) 8872 ft (TNT – total mass released)

3. Computational fluid dynamics simulations

A preliminary simulation was performed to determine the extent of the vapor cloud using two Computation Fluid Dynamics (CFD) codes, namely ANSYS Fluent for supercritical pipe flow and Fire Dynamics Simulator (FDS) for dispersion. The results from the pipe flow simulation is used to provide an approximate boundary condition for the natural gas release in FDS. Two separate simulations were performed because the pipe flow involves very high-speed flow which requires very small timesteps which would greatly increase the dispersion calculation if both the pipe and dispersion flow were coupled in a single simulation. Thus, pertinent values for the pipe flow simulation were assessed several diameters from the pipe exit where velocities are much lower than near the exit. FDS was chosen to perform the dispersion simulation instead of ANSYS Fluent because FDS has been validated for dense-gas dispersion [9], though ANSYS Fluent has the pertinent physics to model dispersion.

It is highly stressed that the simulations are considered preliminary because a simulation study involves validation, evaluation of parameter sensitivity, and evaluation of grid independence to evaluate the level of uncertainty in predictions. Additionally, the accuracy of the real-gas equation of state used has not been evaluated. Other models specifically for natural gas have been recently developed [10] [11] but require extensive effort to implement into ANSYS Fluent which would not allow for this review to be completed in the timeline required. Also due to the limited time available to perform this analysis, the actual topography of the site is not included in the dispersion calculation and the simulation assumes a flat plane.

a. Pipe simulation

The flow of natural gas in the 42" diameter pipe is supercritical at 850 psi for temperatures 200 K and greater shown in Figure 2. Thus, a real-gas equation of state is used rather than the ideal gas equation. The flow is under-expanded choked flow in which the Mach number is 1 at the exit. Specifications provided in Table 2 and the domain shown in Figure 3 were used for the simulation.

Results from this simulation are shown in Figures 4 through 7. Figure 4 shows an axisymmetric contour plot of the Mach number which indicates choked flow. Figure 5, showing an axisymmetric contour plot of velocity, indicates that the velocity at the exit of the pipe is about 375 m/s and that a downstream shock wave occurs which has a velocity of about 970 m/s. Especially significant to this review are the temperature and density contour plots shown in Figure 6 and Figure 7, respectively, since the statement has been made in the NRC analysis that the vapor cloud will immediately become buoyant. The results indicate that the region just before the shock wave would result in condensation of the methane and in regions after the shock would condense water allowing for the cloud to be visible. Note that the simulations did not include multiphase flow but would be required for a detailed analysis.

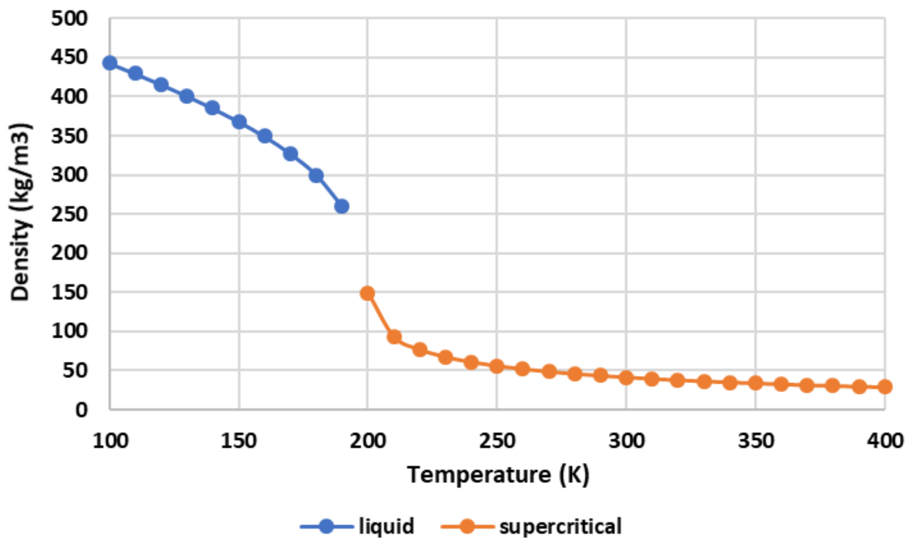


Figure 2: Temperature versus density of methane at 850 psi (https://webbook.nist.gov/chemistry/fluid).

Table 2: Specifications for pipe flow simulation

Specification	Value
Pipe diameter	1.07 m
Pipe length	100 m
Length, height of region beyond the pipe	50 m, 25 m
Fluids	methane, air
Equation of State	Soave-Redlich-Kwong
Inlet temperature	283 (K) (50ºF)
Inlet pressure	5.861 (MPa) (850 psi)

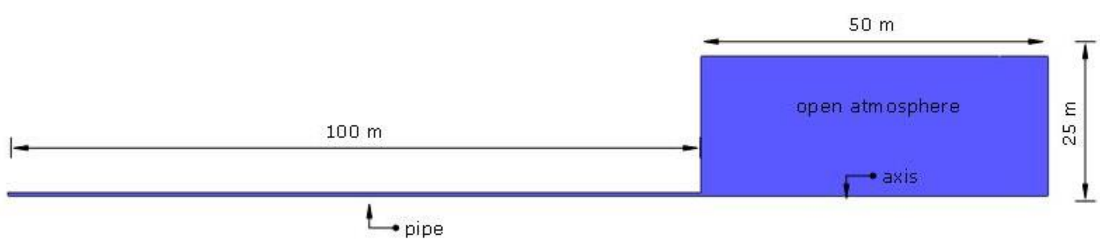


Figure 3: Domain for pipe simulation.

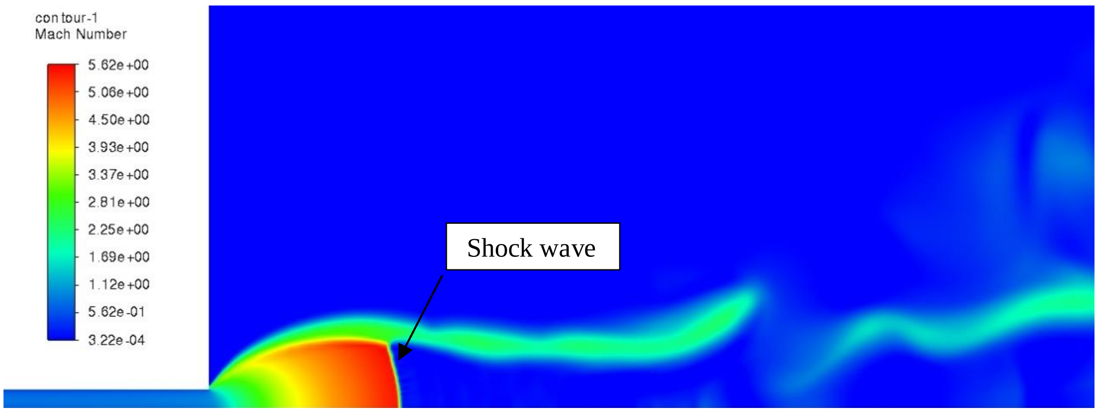


Figure 4: Axisymmetric view of Mach number contours.

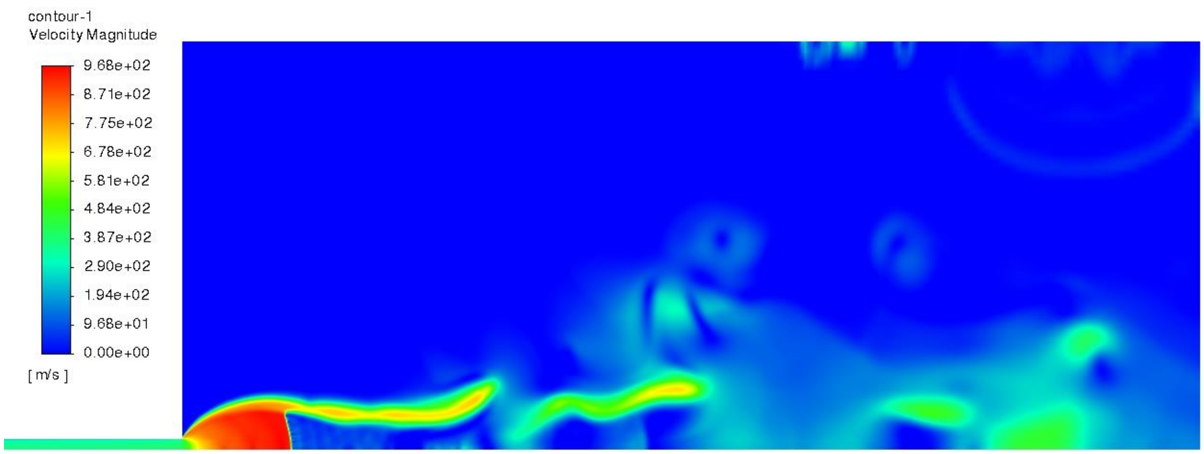


Figure 5: Axisymmetric view of velocity contours.

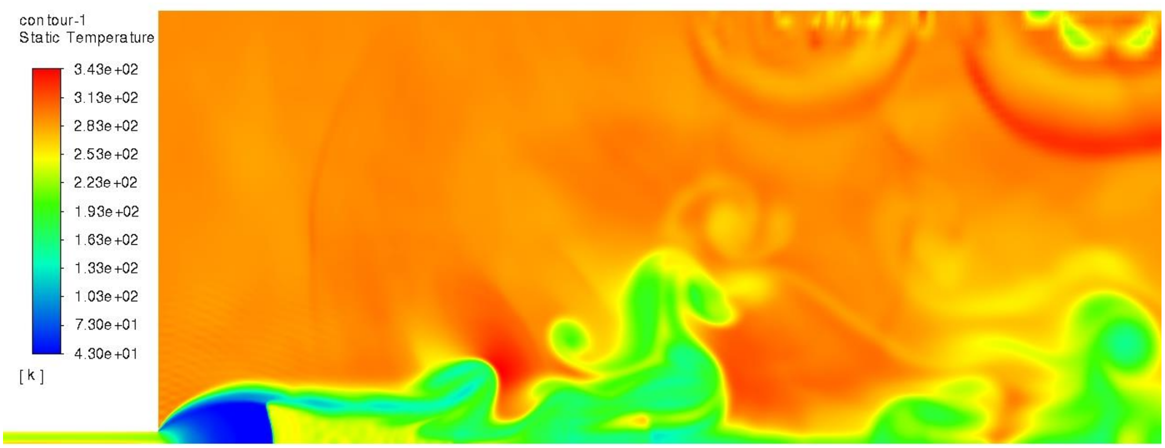


Figure 6: Axisymmetric view of temperature contours.

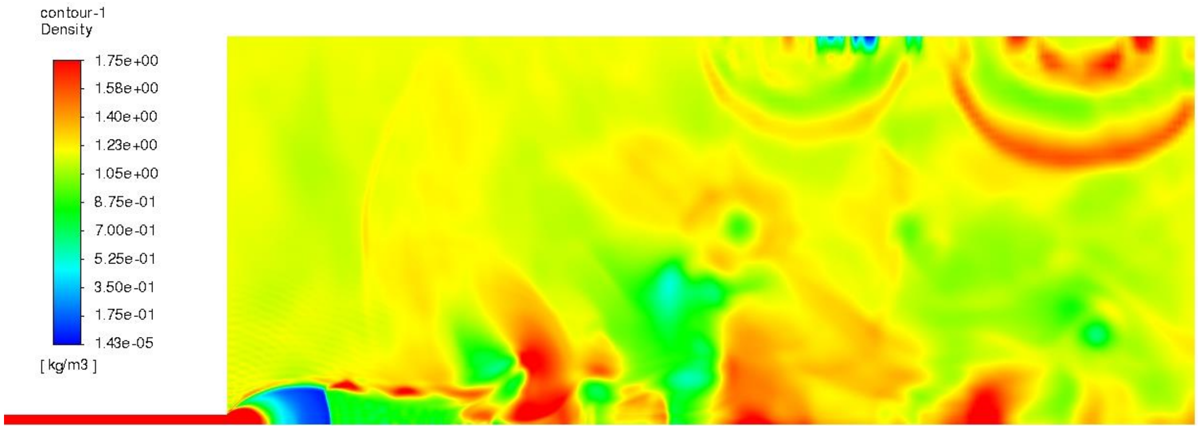
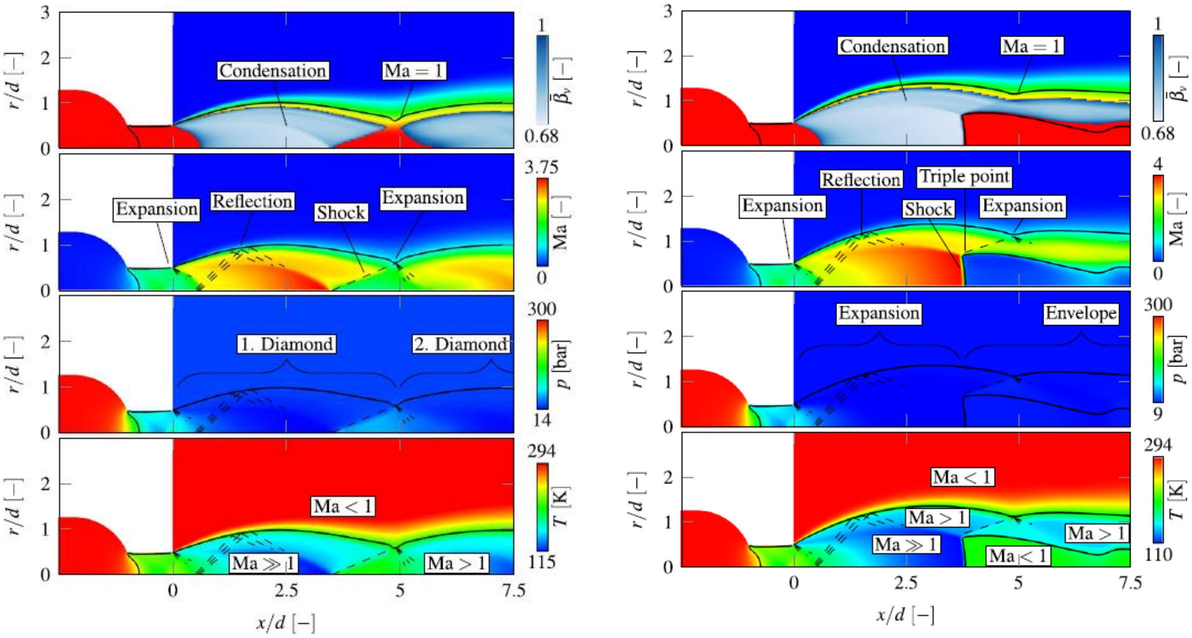


Figure 7: Axisymmetric view of density contours.

Under-expanded compressible flow can produce a series of progressively weaker shock waves that form a diamond pattern. The pattern will not continue indefinitely but will be diffused from viscous effects and will no longer maintain their pattern. The pattern formed will depend on the exit pressure which for this simulation was approximately 350 psi (2.3 MPa or 24 bar). Illustration of variation of patterns is shown in Figure 8 which are simulation results taken from reference [12] of under-expanded methane jets for two different exit pressures, 20 bar (290 psi) and 12 bar (174 psi). Notable is that both cases results in regions of condensation. The pattern of the simulation results presented in Figures 4 through 7 are closest to the exit pressure of 12 bar shown in Figure 8b. Though this should be caveated with the understanding that this is a preliminary simulation and that additional investigation is needed to improve accuracy for the reasons noted previously. For instance, the region beyond the pipe exit uses a stretched mesh in which cell sizes become increasing larger further away from the exit. It was necessary to use a relatively coarse mesh in this region in order to reduce computational run time to meet the project's timeline. Since the flow may not be sufficiently resolved past the initial shock wave, potential subsequent shocks forming the diamond pattern may not be captured. Also, due to the under resolution, the turbulence viscosity was artificially high which resulted in enhanced mixing. It is anticipated more detailed structure similar to reference [12] would be captured as the mesh is refined possibly showing additional regions of condensation.



(a) **(b)**

Figure 8: Simulation results of underexpanded methane jet for exit pressure of (a) 20 bar and, (b) 12 bar. Figure taken from Banholzer, M, et al., "Numerical investigation of the flow characteristics of underexpanded methane jets", Phys. Fluids, 2019 [12].

The results from the present simulation and from reference [12] indicate that the vapor cloud would be a dense gas initially and not be immediately buoyant. Furthermore, the NRC analysis provides additional supporting evidence to the above that the issuing gas would be heavier than air. The NRC analysis uses a flow rate of 256,000 lbs/min (1939 kg/s) and a methane density issuing from the pipe exit of 0.67 kg/m^3 which is less dense than air. Given the area of the pipe (0.89 m^2), the resulting exit velocity would be 3,961 m/s for this assumed density which would not be choked flow. To satisfy choked flow with an exit velocity of about 375 m/s, the density would have to be around 6 kg/m^3.

This has significant consequences for explosion hazards since dense gas vapor clouds in stable atmospheric conditions can travel significant distances [13] and will persist much longer than 1 minute. Additionally, the dense vapor cloud would travel through the surrounding vegetation and other infrastructure to provide an environment for a deflagration to detonation transition (DDT). Particularly since the natural gas is not 100% methane but can have up to 5% of other hydrocarbons such as ethane and propane. Small additions of these hydrocarbons can increase the sensitively of the gas to detonation [13].

Thus, it is recommended that the TNT equivalency model not be used but rather use a model that can include the effects of congestion such as the TNO multi-energy method [3]. And, if using ALOHA for explosion hazard assessment it is recommend that the 'congested' option be used. For a 256,000 lbs/min released from one end of the pipe for either 1 minute or 10 minutes using ALOHA with the congestion option, distances to 1 psi overpressure of 1.8 miles and 5 miles are predicted, respectively. As noted previously, ALOHA calculates overpressure distances using the Baker-Strehlow-Tang method which incorporates general factors for obstacles which are not site-specific and thus isn't considered as accurate as the TNO multi-energy method.

b. Dispersion simulation

The simulation of the vapor cloud dispersion assumes that the safety valves could be shut in 12 minutes, doubling the time provided in the report by the Office of Inspector General of the NRC [14] from an interview with the Enbridge Energy Corporation, owners of Algonquin, which stated that it would take a minimum of 6 minutes to shut the isolation valves. For this preliminary simulation, the same flow rate as used by the NRC analysis of 256,000 lbs/min (1939 kg/s) was assumed for a double-sided full-bore release. This is because the release rate depends on the pipe length and the simulation of the pipe used a length of 100 m rather than a length of 3 miles due to computational run time. For any future investigation, flow rate as a function of pipe length should be evaluated. Note that for the pipeline, given the much greater range of operating pressures above atmospheric, the flow will be in a thermodynamic state to result in a gas density that is heavier than air. Thus, within the potential flow rates arising from the range of operating pressures, the gas will be denser than air. Based on the findings from the pipe simulation, the density of the gas is specified as 1.5 kg/m^3 by evaluating regions beyond the shock wave. Thus, the gas will be heavier than air and will persist and spread much further than if the cloud was lighter than air. Since the CFD code, FDS, used to model the vapor dispersion is designed for low Mach number flows, that is, Mach numbers up to about 0.3 a release velocity of 50 m/s is used which is about Mach 0.15, well below the limits of FDS. To use this velocity and match the mass release rate of (1939 kg/s), the area of the release had to be increased relative to the pipe diameter, that is, from 1.1 m to 6.6 m. Thus, the details of the dispersion will not be representative of the actual pipe near the release but will be representative of the vapor cloud in the far field providing an estimate of the extent of dispersal. The release is also above ground, but it is anticipated that the vapors would fill and eventually overflow a crater formed from a release. The specifications used in the simulation is provided in Table 3.

Table 3: Specifications for dispersion simulation

Specification	Value
Duration of release	12 minutes
Diameter of release	6.6 m
Mass release rate	1939 kg/s (256,000 lbs/min) from two horizontal full-bore releases directed towards each other placed 15 m (50 ft) apart
Fluids	methane, air
Density of methane	1.5 kg/m^3
Atmospheric conditions	Stable (Monin-Obhukov relations), wind speed 1.5 m/s, temperature 293 K
Number of elements	80 M
Element size	0.2 m
Number of processors	168

The computational run time was much longer than typical dispersion simulations because of the relatively high release velocity (50 m/s vs. ~1 m/s). Typically, dispersion simulations will take about 1-2 days to complete depending on the number of elements required. For this dispersion simulation it took about a day to complete 200 seconds of real time. With an ending time of 1800 seconds, it would take about 9 days to complete. The simulation was terminated unexpectedly from the high-performance compute cluster, possibly due to high demand, at almost 500 seconds of real time and was not restarted in order to meet the project's timeline. At almost 500 seconds the vapor cloud reached the lower flammability limit (LFL – 5% vol.) at a distance of about 950 m (3,100 ft) from the release point. Since the release doesn't terminate until 720 seconds (12 minutes), it is anticipated that the distance would increase if the simulation was continued. Also, even after the release is terminated, the cloud will drift downwind and take several minutes to dissipate resulting in greater distances to the LFL. Given the above, it is anticipated that the distance would extend beyond 1,600 m (5,248 ft) since the cloud is propagating in the downwind direction at a speed of about 100 m/min. Figure 9 through Figure 16 shows a temporal sequence of the development of the vapor cloud from 1-8 minutes by plotting contours of methane volume fractions at the upper flammability limit (UFL – 15% vol.) and LFL . If the cloud reaches an ignition point within the flammability region an explosion can occur. Note that the cloud in the lateral extent is propagating beyond the computational domain indicating that for any future investigation the domain should be increased in the lateral extent.

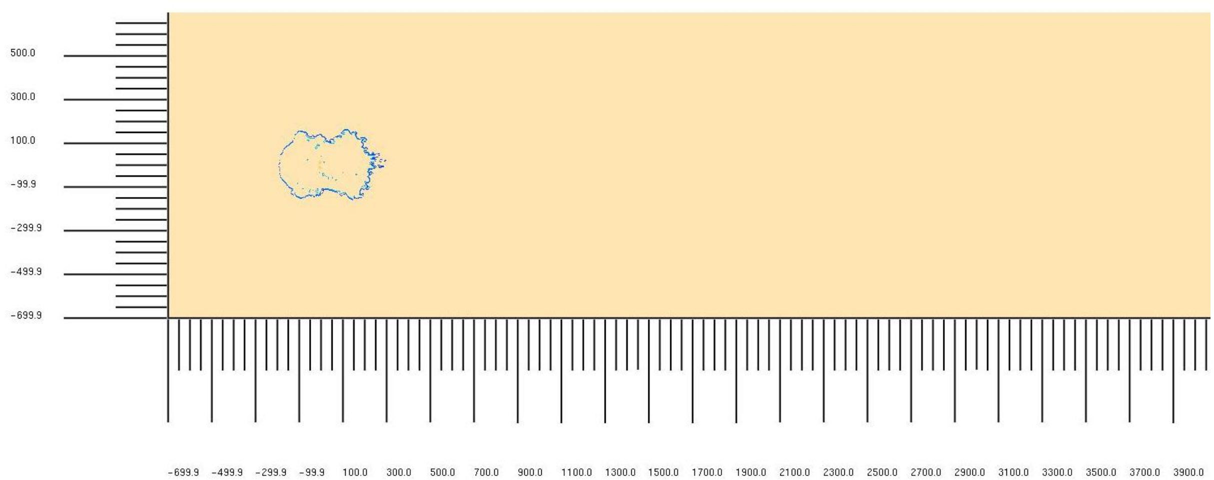


Figure 9: Top-view image of UFL (light blue) and LFL (dark blue) contours 1 minute after release. Distances are in meters.

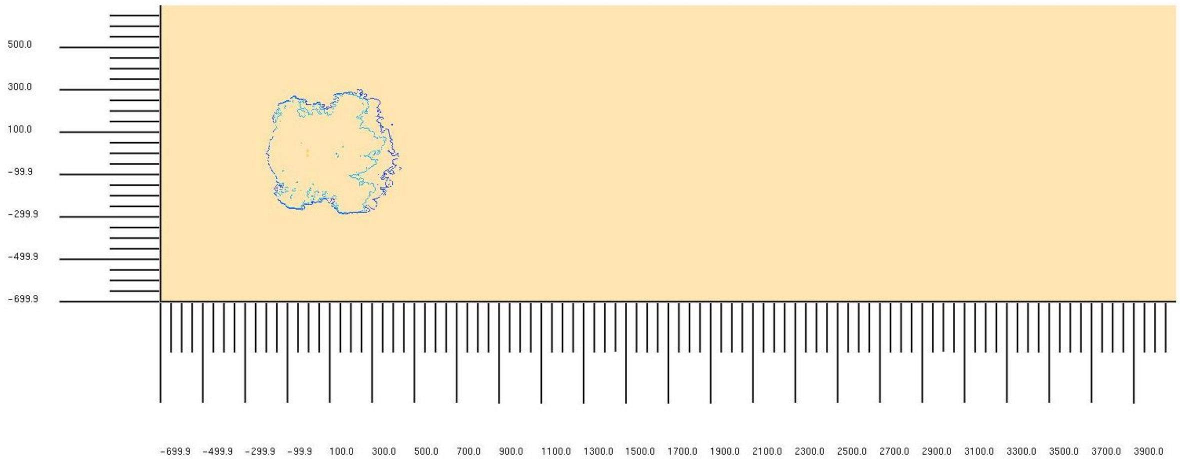


Figure 10: Top-view image of UFL (light blue) and LFL (dark blue) contours 2 minutes after release. Distances are in meters.

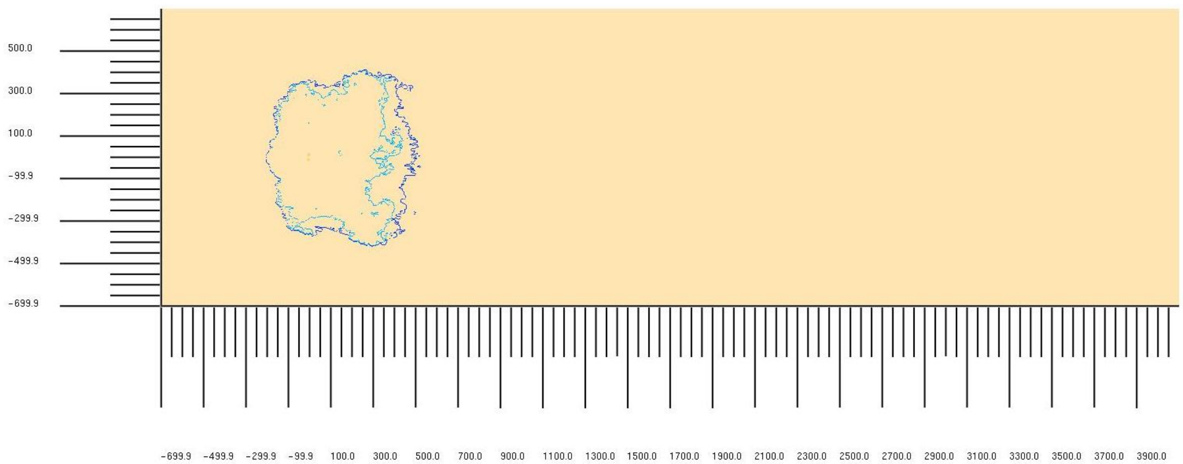


Figure 11: Top-view image of UFL (light blue) and LFL (dark blue) contours 3 minutes after release. Distances are in meters.

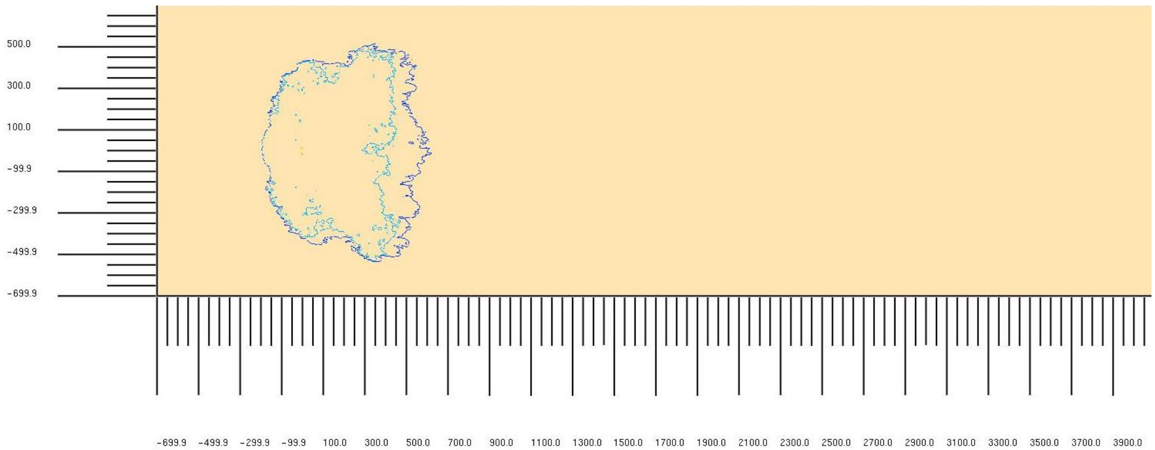


Figure 12: Top-view image of UFL (light blue) and LFL (dark blue) contours 4 minutes after release. Distances are in meters.

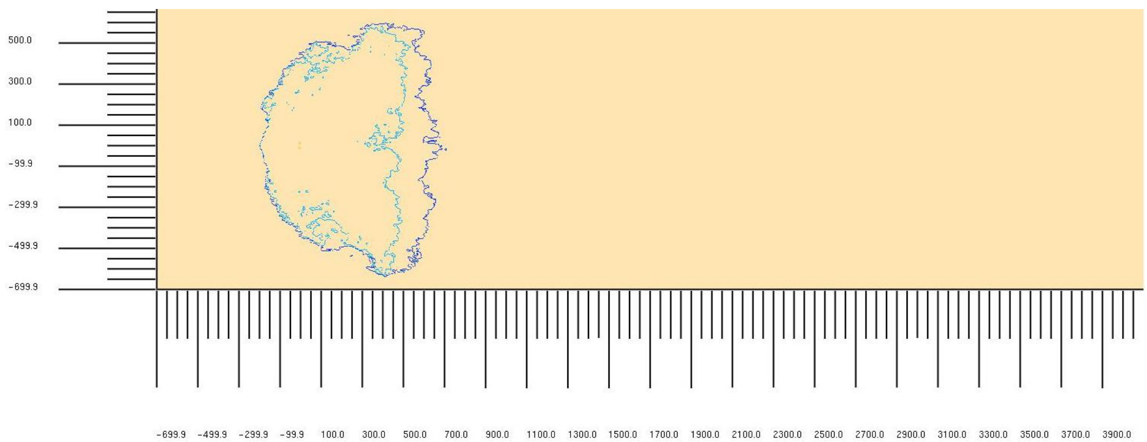


Figure 13: Top-view image of UFL (light blue) and LFL (dark blue) contours 5 minutes after release. Distances are in meters.

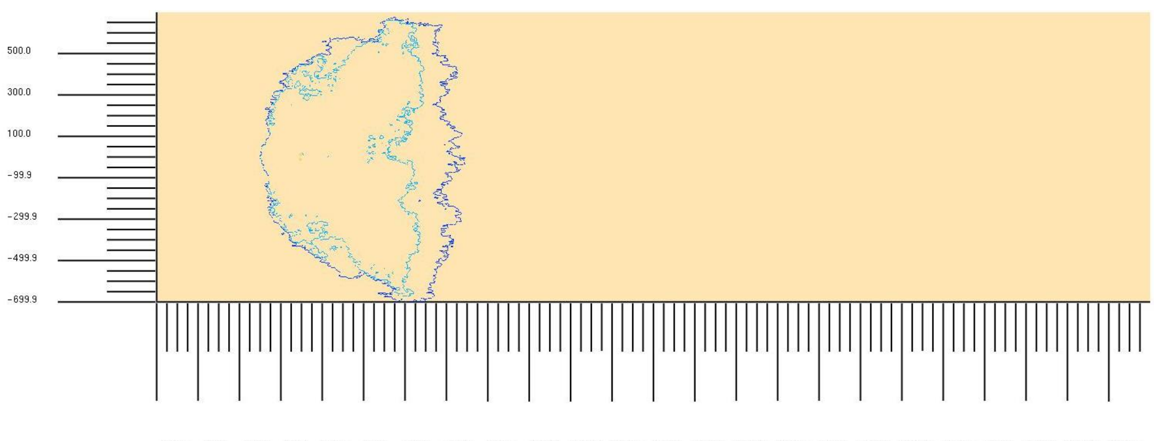


Figure 14: Top-view image of UFL (light blue) and LFL (dark blue) contours 6 minutes after release. Distances are in meters.

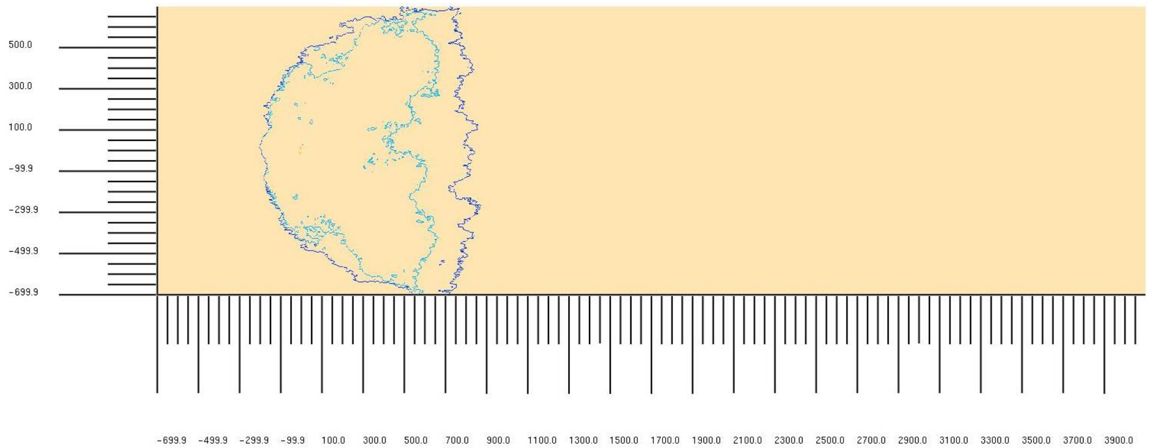


Figure 15: Top-view image of UFL (light blue) and LFL (dark blue) contours 7 minutes after release. Distances are in meters.

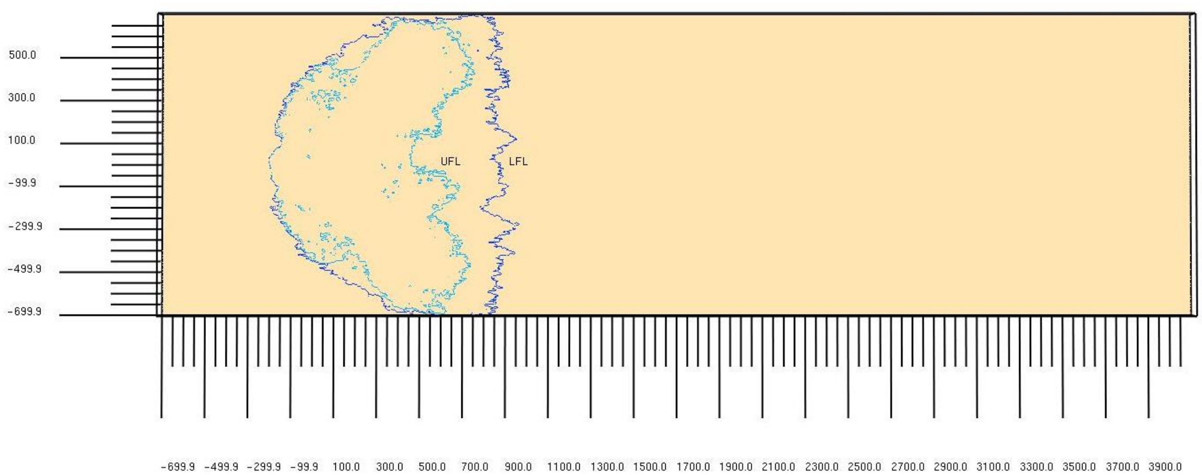


Figure 16: Top-view image of UFL (light blue) and LFL (dark blue) contours 8 minutes after release. Distances are in meters.

Figure 17 shows a centerline side view of the vapor cloud at 8 minutes indicating that it has not risen like a buoyant cloud but rather displays dense gas behavior by keeping relatively close to the ground. The highest point of the vapor cloud is near the source with a height of about 50 m then decreases to about 20 m for downwind distances. Note that the vertical extent of the domain is 100 m. Along the pipeline's route its elevation is lower than that of the IPEC, ranging from 20 ft to about 100 ft. Given this difference in height and the height of the cloud, the cloud can migrate over the hills if the wind direction is towards the IPEC. Since the wind can be in any direction, the dispersion calculation assumes the wind direction is towards the SOCA.

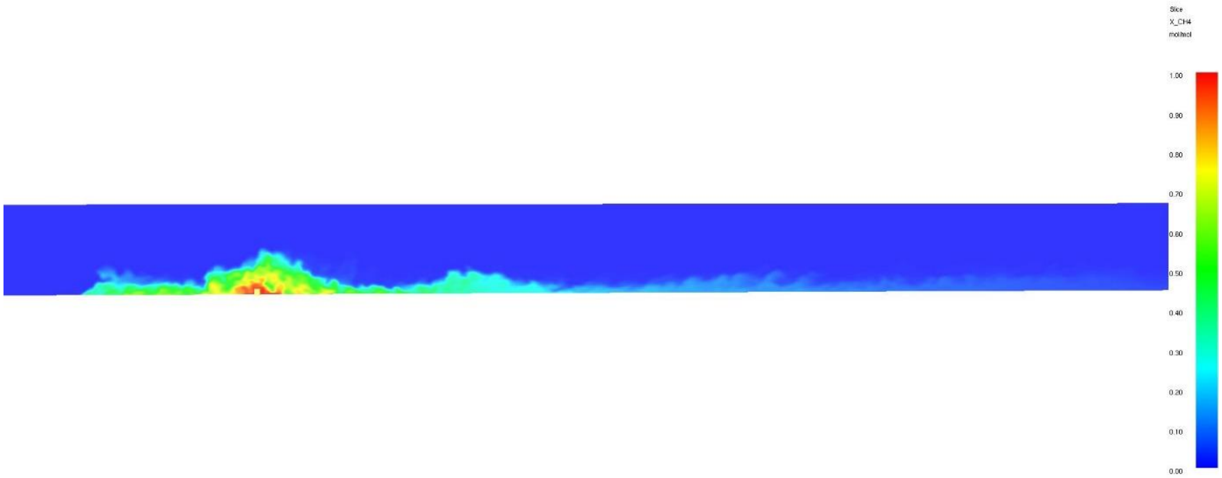


Figure 17: Centerline side view of vapor cloud showing contours of methane volume fraction at 8 minutes.

This dense gas behavior has implications with regards to explosion hazards since the vapor cloud would travel through vegetation and persist for a sufficient amount of time to result in potential ignition which can lead to a deflagration to detonation transition due to the congestion or have overpressures that exceed 1 psi from a deflagration explosion. The vapor cloud region between the flammability limits is roughly 1/3rd the cloud volume and if the cloud encounters an ignition source in congested areas, significant overpressures can result. At approximately 6 to 7 minutes after release the flammability region of the vapor cloud will be either near or begin to engulf the SOCA and can result in an explosion with a high likelihood of exceeding an overpressure of 1 psi at the SOCA if ignited within the flammability region. The furthest point downwind distance within the flammability region is about 950 m (3,100 ft) at 8 minutes which is greater than any distance from the pipeline route to the SOCA (Security Owner Control Area) which varies from about 1580 ft to 2363 ft. At 8 minutes the flammability region would surround the SOCA. The results from this simulation indicate that for this release scenario explosion overpressures of greater than 1 psi at the SOCA would most probably occur given the surrounding congestion. Instances of natural gas pipeline accidents in which the natural gas was not immediately ignited at the release point and indicated that the cloud was not immediately buoyant can be found in references [15] [16].

4. Summary of review

The following are the key findings from this review:

1. Evaluation of models used:
   - Correct heat of detonation value was used;
   - ALOHA does not model supercritical flow and topography which is applicable to this release scenario.
   - TNT equivalency model is inadequate for the release scenario.

2. The major assumptions of the NRC analysis that results in an underprediction of distances to an overpressure of 1 psi are:
   - The cloud will become immediately buoyant and disperse below the flammability limits within 1 minute regardless of when the pipeline can be closed. Thus, only the mass released over 1 minute is considered in the TNT equivalency calculations.
   - The cloud will not propagate through vegetation and congested areas since its density will be less than air.

3. The major findings from the preliminary SNL analysis are:
   - The vapor cloud will be heavier than air which will cause it to disperse near the ground and will persist after the pipe has been closed.
   - The dense-gas vapor cloud will propagate through the vegetation and congested areas which increases the likelihood of a deflagration to detonation transition.
   - Simulation results indicate that at approximately 6 to 7 minutes after release the flammability region of the vapor cloud will be either near or begin to engulf the SOCA and at 8 minutes the flammability region would surround the SOCA. Thus, if the cloud is ignited within the flammability region, the explosion would have a high likelihood of exceeding an overpressure of 1 psi at the SOCA.

It is highly stressed that the simulations are considered preliminary because a simulation study involves validation, evaluation of parameter sensitivity, and evaluation of grid independence to evaluate the level of uncertainty in predictions. Also, the accuracy of the real-gas equation as not been evaluated for the pipe simulation and the actual topography and infrastructure of the site is not included in the dispersion simulation.

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[1] Rao Tammara, US Nuclear Regulatory Commission, "Safety Review and Confirmatory Analysis, Entergy's 10 50.59 Safety Evaluation, Algonquin Incremental Market (AIM) Project, Indian Point Energy Center (IPEC)," October 16, 2014, also supplementary analysis undated.

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[3] Factory Mutual Global's Property Loss Prevention Data Sheets 7-42, "Guidelines for Evaluating the Effects of Vapor Cloud Explosions Using a TNT Equivalency Method," May 2008.

[4] National Transporation Safety Board, "Natural Gas Pipeline Rupture and Fire Near Carlsbad, New Mexico, August 19, 2000," NTSB/PAR-03/01, 2003.

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[13] A. Luketa-Hanlin, "A review of large-scale LNG spills: Experiments and modeling," *J. Haz. Mat.,* vol. A132, pp. 119-140, 2006.

[14] Office of the Inspector General, U.S. Nuclear Regulatory Commission, "Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant," Case No. 16-024, February 13, 2020..

[15] National Transportation Safety Board, "Rupture of Florida Gas Transmission Pipeline and Release of Natural Gas, May 4th, 2009," NTSB/PAB-13/01.

[16] K. Mishra and K. Wehrstedt, "Underground gas pipeline explosion and fire: CFD based assessment," *J. Natural Gas Sci. Eng.*, vol. 24, pp. 526-542, 2015.

Appendix A: NUREG/CR-3330 Calculation

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NUREG/CR-3330 provides an example calculation of a fire accident scenario for a high-pressure natural gas pipeline. In the sample calculation a discharge from a 36-inch pipeline operating at 1000 psig [A.1]. From 3-1 the average flow rate of 1700 kg/s from the range of 1400-2100 kg/s was applied to the calculation.

Using the equations provided in the NUREG the results can be replicated and applied to the AIM pipeline situation. There are three main steps in calculating the incident heat flux applied to the reinforced concrete safety related structures.

Step 1: Calculate the radiated power (PR), using Equation 3.1
Step 2: Calculate the radius and diameter of the spherical flame
Step 3: Calculate the incident radiation at various distances using Equations 4.1 and 4.2[1]

Applying this methodology to the AIM pipeline the same variable assumptions were made, except for the mass flow rate of the 42-inch pipeline operating at 850 psig. According to the NRC's Review and Confirmatory Analysis the mass flow rate for the pipeline is 1935 kg/s [A.2]. The value was rounded to 1940 kg/s for the sake of this calculation and is referred to as the Nominal Case.

According to Table 3-1 of the NUREG a pipeline of 42-inch diameter would have a mass flow rate between 2000-3200 kg/s. To illustrate the impact of a pipeline of larger mass flow rate on incident heat flux a value of 4000 kg/s was used to calculate the last set of values this referred to as the Bounding Case.

Below in Table A-1 the results of incident heat flux on reinforced safety related concreate structure are shown for distances of 482, 500, 700, 1000, and 1500 meters. The Security Owner Control Area (SOCA) fence is 482 meters away. Buildings that house Emergency Diesel Generators (EDGs) are approximately 700 meters from the pipeline.

[1] For Transmissivity in Step 3, the 20% Relative humidity Curve on Figure 3-2 in NUREG/CR-3330 was used.

Table A-1: Incident Radiation at Various Distances and Mass Flow Rates

Case	Distance (m)	Mass Flow Rate (kg/s)	Radiated Power (kW)	Fire Diameter (m)	Transmissivity	Incident Radiation (kW/m^2)
Sample	482	N/A	N/A	N/A	N/A	N/A
	700	N/A	N/A	N/A	N/A	N/A
	500	1700	4.09E+07	295	0.7	19.6
	1000				0.63	4.6
	1500				0.57	2.0
Nominal	482	1940	4.57E+07	312	0.7	23.6
	500				0.7	22.1
	700				0.65	10.9
	1000				0.63	5.3
	1500				0.57	2.2
Bounding	482	4000	9.61E+07	452	0.7	44.1
	500				0.7	41.5
	700				0.65	21.4
	1000				0.63	10.7
	1500				0.57	4.4

Using the bounding mass flow rate of 4000 kg/s the incident heat flux on safety related structures if located at 482 meters would be 44 kW/m^2. Note that the same parameter assumptions were made as were made in the sample calculation; combustion efficiency, fraction of excess entrained air, and flame temperature may affect the results.

NUREG/CR-3330 states in Table 2-1 that the reinforced safety related structure would last 5 hours with an incident heat flux of 50 kW/m^2 applied. This is based on the criterion 1 which is ‘Temperature at the first rebar location does not exceed 177°C (350°F)’. Since the first rebar location does not exceed this temperature, the interior temperature does not exceed this value either.

References

[A.1] U.S. Nuclear Regulatory Commission, NUREG/CR-3330, “Vulnerability of Nuclear Power Plant Structures to Large External Fires”, Washington, DC, August 1983.

[A.2] Rao Tammara, US Nuclear Regulatory Commission, "Safety Review and Confirmatory Analysis, Entergy's 10 50.59 Safety Evaluation, Algonquin Incremental Market (AIM) Project, Indian Point Energy Center (IPEC)," October 16, 2014.

Appendix C. Indian Point Risk Significance Analysis Results

C.1. Executive Summary

Plant Name / Unit Number: Indian Point Energy Center, Units 2 & 3	**Summary Title:** Gas pipeline failure
EA Number (if applicable): N/A	**Result:** Very low safety significance (~10^{-8} ΔCDF)

On February 13, 2020, the U.S. Nuclear Regulatory Commission (NRC) Office of the Inspector General (OIG) issued an Event Inquiry, "Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant" (Case No. 16-024). In that report, the OIG raised concerns regarding (1) the NRC's safety analysis that supported the Federal Energy Regulatory Commission's (FERC's) determination to approve modifications to gas pipelines at Indian Point and (2) the NRC's response to a petition filed under Title 10 of the Code of Federal Regulations (10 CFR), Section 2.206 on this topic.

On February 24, 2020, the NRC Chairman directed the NRC staff review whether any information in the OIG report demonstrates that the staff should revisit either the safety analysis or its response to the 10 CFR 2.206 petition, as well as to evaluate whether any modifications to agency practice or procedures are needed or appropriate based on the OIG report. As part of this review, the staff initiated a risk assessment of gas pipeline rupture at both Indian Point Unit 2 and Unit 3.

During the review of the previous safety analyses, the team noted that risk was used numerous times, by both the licensee and the NRC to judge that there was negligible safety concern. The pipeline rupture failure probabilities reported by the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) are higher than those listed in Entergy or NRC reports. This discrepancy pushes the gas pipeline rupture frequency higher than screening values (1×10^{-6} per year when based on conservative assumptions, or 1×10^{-7} per year when based on realistic assumptions) in Regulatory Guide 1.91.

C.2. Analysis Results

The risk analysis considers the additional risk associated with the gas pipeline rupture. This evaluation only considers the impact for internal events with the reactor at-power.

Change in Core Damage Frequency: The estimated increase in core damage frequency (ΔCDF) for this event is 1.6×10^{-8} per year.

Dominant Sequence: Given the low risk contribution, the dominant accident sequences for the overall model are unchanged. The dominant accident sequence for the gas pipeline failure is simultaneous common-cause failure of all emergency diesel generators to run and failure of the operators to recover the diesels.

C.3. Risk Analysis Details

Analysis Type: An expert at Idaho National Laboratory created an event tree modeling effects of a pipeline rupture. Initiating event frequencies were generated based on data from PHMSA. The analysis also includes the likelihood and impacts of a pipeline rupture in response to all other modeled internal events during the 24-hour mission time.

Model Used: Indian Point Unit 2 Standardized Plant Analysis Risk (SPAR) Model, Version 8.59 and Indian Point Unit 3 SPAR model, Version 8.56

Software Used: SAPHIRE Software, Version 8.2.1

Exposure Time and/or Date of Occurrence: The analyst used the full 1-year exposure time.

Key Modeling Assumptions: The following modeling assumptions and associated basic event modifications were applied for this event analysis:

- **Failure mode:** A gas pipeline rupture causes an unrecoverable loss of switchyard and loss of city water. These failures were based on the results of the initial blast analysis done by Entergy.

- **Initiating event frequency:** The failure data provided by PHMSA (see Appendix D) shows that from 2002-2018, 15 ruptures occurred of pipe that (1) has a diameter greater than 20 inches; (2) has a maximum operating pressure of greater than 300 psig; and (3) is a Class 2, 3, or 4 pipeline. The initiating event frequency was calculated by using the bounding assumption that all 15 of these pipe ruptures resulted in detonation. The data shows that ignition only occurs approximately 50 percent of the time. Additionally, the data is for pipes greater than 20"; since 2002, no ruptures of onshore 42-inch-diameter pipes have been reported (one 42-inch inch pipe ruptured offshore during Hurricane Ike). Furthermore, the initiating event frequency assumes that one mile of pipeline is affected; however, there is only 3,935 feet (0.75 miles) of pipeline that would have an impact on the facility. Using these assumptions, the initiating event frequency is calculated to be 1.9×10^{-5}.

- **Seismic failures:** Seismic failure of the gas pipeline was not explicitly modeled.

- **FLEX:** FLEX equipment was not credited for these calculations; however, implementation of FLEX procedures and equipment would be beneficial in furthering reducing the risk impacts of a pipeline rupture, as the pipeline rupture could cause an extended loss of offsite power.

- **Ex-vessel core damage:** The analyst did not account for the impact of the performance deficiency on ex-core sources, such as spent fuel in the pool, dry fuel storage, or other sources. These sources are outside of the scope of the SPAR models. This risk has been evaluated in Section 2.4 of the report.

- **Human reliability analysis:** The gas pipeline rupture and detonation are expected to have minimal impact on the human failure events that are required to mitigate the accident, given the distance from the blast of the locations where these actions would be taken.

Uncertainty: The analyst performed an uncertainty quantification for the pipeline failure event tree using Monte Carlo sampling with 5,000 random samples. Table 2 presents the results. It should be noted that even the tails of the uncertainty analysis are below actionable levels.

Table 2. Uncertainty quantification for risk assessment.

	Unit 2	**Unit 3**
Number of samples	5,000	5,000
Events	177	196
Cutsets	917	846
Point estimates	1.6×10^{-8}	1.6×10^{-8}
Mean value	2.2×10^{-8}	2.0×10^{-8}
5th percentile	5.4×10^{-11}	3.9×10^{-11}
95th percentile	8.6×10^{-8}	8.3×10^{-8}
Median value	6.7×10^{-9}	4.9×10^{-9}

C.4. Sensitivity Studies

Two sensitivity studies were performed for this analysis: one on the consequences of overpressurization and the other on the initiating event frequency.

Overpressurization Study

Because of the uncertainty associated with the consequences of overpressurization from an explosion, the team conducted an analysis assumed more equipment and structural failures. Specifically, the team assumed that all equipment not in a seismic Category I structure (i.e., not located in the primary auxiliary building, diesel generator building, or reactor containment), such as balance of plant systems and the Appendix R diesels, was lost upon the postulated pipeline rupture. Based on the input from NRC structural experts, the team assumed that the overpressurization will not damage these Category I buildings.

For Unit 2, the change in core damage frequency for this scenario was 1.6×10^{-8}. This remains well below the agency's threshold for a "very small" change in risk of one in a million years.

For Unit 3, the change in core damage frequency for this scenario was 1.7×10^{-8}. This remains well below the agency's threshold for a "very small" change in risk of one in a million years.

Frequency Study

Based on PHMSA's data listed in Table 4 (Appendix D), the team was concern that the calculated frequency was based on a mileage that included all diameters of pipes, not just large pipes, and may be non-conservative. The team performed an independent data analysis based on PHMSA's publicly available incident-report data.[203] For the last 10 years, the team determined that the failure frequency for ruptures in Class 2, 3, or 4 carbon steel transmission lines having pipe diameters greater than or equal to 20 inches and maximum operating pressure greater than or equal to 300 psig is 2.4×10^{-5} per mile per year. The failure data show that, over a period of 10 years, 26 ruptures occurred across 45501.75 miles of pipeline, and 42 percent of these ruptures occurred on pipes that were larger than 20 inches.

The risk results are still well below the agency's threshold for a very small change.

C.5. Summary

The analysis shows that the risk of a gas pipeline rupture is of very low safety significance both as defined in the significance determination process and based on the definitions in Regulatory Guide 1.174. The results for each model can be seen in Table 3.

[203] See note 69.

Table 3. Results of sensitivity studies.

Model	**Δ CDF (per year)**
Unit 2 base case	1.6×10^{-8}
Unit 2 frequency sensitivity	2.0×10^{-8}
Unit 2 overpressure sensitivity	1.6×10^{-8}
Unit 3 base case	1.6×10^{-8}
Unit 3 frequency sensitivity	2.0×10^{-8}
Unit 3 overpressure sensitivity	1.7×10^{-8}

Analyst: Suzanne Dennis Date: March 28, 2020
Reviewed By: Jeffery Wood Date: March 30, 2020

Appendix D. Pipeline Rupture Data from PHMSA

Table 4 presents onshore gas transmission incident data for 2002-2019 obtained from the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), as of March 3, 2020. The selected incidents are leaks or ruptures in Class 2, 3, or 4 piping having pipe diameters greater than or equal to 20" and maximum operating pressure greater than or equal to 300 psig. From 2002 to 2019, incidents were categorized as pipeline ruptures in the body of the pipe or pipe seam. From 2010 to 2019, incidents were categorized as pipeline ruptures in the pipe body, pipe seam, or girth weld.

Table 4. Pipeline rupture incidents obtained from PHMSA.

Year	LEAK	RUPTURE	LEAK or RUPTURE
2002	3	1	4
2003	1	1	2
2004	4	1	5
2005	2	0	2
2006	2	1	3
2007	2	2	4
2008	0	1	1
2009	2	0	2
2010	0	2	2
2011	1	0	1
2012	2	1	3
2013	0	0	0
2014	3	3	6
2015	0	0	0
2016	0	0	0
2017	1	1	2
2018	1	1	2
2019	0	0	0

Based on 2018 information (the most recent available), there were a combined 45,501.75 miles of pipeline in the United States categorized as Class 2, 3, and 4 piping, with a ratio of stress at maximum allowed operating pressure to specified minimum yield strength of greater than 30 percent. Pipelines of a diameter greater than 20" in diameter, as included in the incidents in Table 4, would be subset of this mileage. (See Section C.4 for a sensitivity study related to this data.) PHMSA does not have data on mileage of specific piping classes and diameters combined.

Appendix E. Peer Review of This Report

The evaluation team requested a peer review of this report by Dr. Peter Riccardella, a member of the NRC's Advisory Committee on Reactor Safeguards. Dr. Riccardella has more than 45 years' experience working on the structural integrity of nuclear power plant components. He is an authority in the application of fracture mechanics to nuclear pressure vessels and piping and has made significant contributions to the diagnosis and correction of materials degradation concerns at operating plants. He has been a principal investigator on Electric Power Research Institute projects and served more than 20 years as a member of the American Society of Mechanical Engineers Subcommittee on Nuclear Power Plant Inservice Inspection. Dr. Riccardella earned his bachelor's, master's and doctorate degrees in mechanical engineering from Carnegie Mellon University, and is a Fellow and Life Member of the American Society of Mechanical Engineers.

Dr. Riccardella reviewed the entire report, and the team incorporated his comments into the final version of this report. Dr. Riccardella also provided the following general comments for inclusion in this appendix, focused on the risk assessment of the AIM pipeline addressed in Section 2, Appendix C, and Appendix D.

The risk assessment consisted of:

- **An estimate of the rupture frequency of the AIM pipeline.** The evaluation team estimated this frequency to be 1.94×10^{-5} (per year per pipeline mile) based on PHMSA pipeline rupture data during the period from 2002 to 2019 (Table 4 in Appendix D). They also performed sensitivity analyses of this value, based on an independent review of publicly available pipeline data for the last ten years. The review resulted in a slightly increased frequency of 2.4×10^{-5} for Class 2, 3, or 4 carbon steel transmission lines with pipe diameters greater than or equal to 20 inches and maximum operating pressures greater than or equal to 300 psig.
- **A probabilistic risk assessment analysis of the conditional core damage probability assuming AIM pipeline rupture as the initiating event.** The team, with support from experts at the Idaho National Laboratory, modified the NRC's Indian Point risk models to postulate a failure of the 42-inch pipeline and conduct a risk analysis. They assumed, as a nominal case, that a pipeline failure would cause an unrecoverable loss of some equipment near the pipeline. The team also performed a sensitivity analysis of this study, assuming as a worst case, that all equipment not housed in a seismic Category I building was lost upon the pipeline rupture.

The product of these two results is the change in core damage frequency (ΔCDF) associated with installation and operation of the new 42-inch AIM pipeline. The resulting ΔCDF estimates range from 1.6×10^{-8} per year for the nominal case to 2.2×10^{-7} per year under the sensitivity study assumptions. The team determined that these values are well below the acceptable limits for small changes cited in Regulatory Guide 1.174.

The method used to estimate the initiating event frequency, although based on actual pipeline rupture data, does not have a high degree of statistical confidence or relevance to the AIM pipeline. The data are a limited sample, and there were likely different causes and conditions associated with each of the rupture events reported in the PHMSA database. Furthermore, these conditions are not directly applicable to the subject AIM pipeline. Review of the PHMSA rupture data reveals that ~80 percent of the ruptures were in pipelines installed prior to 1980, and around half of them used seam welding processes known to be inferior to current fabrication techniques used for the AIM piping.[204] These legacy pipes were also likely subjected to many years of in service degradation due

[204] Electric resistance welding, electric fusion welding, or lap welds.

to corrosion, stress corrosion cracking and/or metal fatigue. These conditions and potential failure mechanisms have limited applicability to the 42-inch AIM pipeline in general, and especially to the approximately 4000 feet of the AIM pipeline that are in closest proximity to Indian Point, which has been enhanced as described in Section 2.1.1. Therefore, although there is a high degree of uncertainty in the assumed initiating event frequency, it is likely that this uncertainty is in the direction of making the team's estimates much higher than the true rupture frequency of that pipeline segment.

To quantify this judgment, the peer reviewer performed a set of Monte Carlo probabilistic fracture mechanics calculations[205] based on the methodology described in a recent American Society of Mechanical Engineers paper.[206] The analysis started with a typical legacy pipeline base case having a rupture frequency like that derived from the PHMSA database.

- **Baseline Case:** a 24-inch X-60 pipe with an electric resistance welding (ERW) seam weld, operating at MAOP of 1,200 psig and operating for ten years following an inline inspection in which detected anomalies were repaired in accordance with PHMSA guidelines. The analysis assumed a fracture toughness distribution for pre-1970 ERW seam welds and a strength distribution for X-60 grade piping.
- **Enhanced Case:** the same 24-inch pipe with modern seam weld technology (double submerged arc welded or improved ERW), and with pressure reduced to result in stresses equal to the same percentage of X-70 yield strength as would be experienced in the enhanced AIM 42-inch pipe at MAOP (35.4%). This pipe was assumed to have a 1.5xMAOP hydrotest at time zero with the hydrotest pressure reduced to that percentage of yield experienced by the enhanced section during the preoperational hydrotest that was performed (53.1%).

Both cases assumed a flaw distribution and flaw density (per mile) observed in legacy ERW seam welds. They also assumed fatigue cycling over the ten-year interval typical of relatively severe cyclic duty for gas pipeline service. The resulting rupture frequencies are reported in the following table.

Table 5. Resulting rupture frequencies (per mile per year) from probabilistic fracture mechanics analyses during the 10-year evaluation interval.

Baseline	Enhanced
1.84×10^{-5}	3.38×10^{-7}

These results show an expected improvement in the rupture frequency for the enhance segment of AIM pipeline of about factor of 50 relative to the frequency estimates obtained from the PHMSA database.

There are, of course, other pipeline failure mechanisms of concern besides the low-toughness seam weld issue addressed in the foregoing analyses. These include corrosion (including stress corrosion cracking), excavation and other outside force damage, equipment failures, and incorrect operation.

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[205] Structural Integrity Associates calculation package.

[206] Riccardella, P. et al, "Evaluation of Crack Growth and Material Toughness Effects on Probability of Pipeline Failure," ASME 2018 International Pipeline Conference, IPC2018-78691. https://asmedigitalcollection.asme.org/IPC/proceedings/IPC2018/51869/V001T03A075/276721.

Figure 21 provides a summary of the causes of serious incidents since 2005 (not exclusively pipe ruptures, but all incidents that have led to fatalities or injuries).[207]

A total of 59 serious incidents occurred during this 15-year period. Thus, the estimated frequency of such events over the entire 300,000 miles of gas transmission pipelines in the United States is approximately 1.31 x 10^{-5}, which is not largely different from the initiating event frequency for ruptures estimated by the team. The bulk of these were associated with external force damage due to excavation or other forces (e.g., vehicular damage). Such external force damage would likely lead to a puncture of the pipeline, rather than a rupture, but if that puncture were large enough, it might lead to similar consequences to Indian Point equipment as a rupture. It is noteworthy that the enhancements implemented in the AIM pipeline segment nearest to the plant include fiber-reinforced concrete slabs and warning tape above the pipeline that should greatly reduce the possibility of an external force event. Nonetheless, even if the above serious incident frequency were added to the team's estimated initiating event frequency, it would still not cause the ΔCDF to exceed the Regulatory Guide 1.174 limit for very small changes.

In conclusion, the peer reviewer found that the evaluation team has performed an acceptable risk analysis of the potential for damage to the Indian Point plant and equipment, conservatively demonstrating that the risk imposed by the AIM pipeline is small and within applicable agency limits.

The team agrees. As noted in Appendix A, the initiating event frequency used by the team is likely higher than a more detailed realistic data analysis would show. As the risk numbers are much lower than the agency's threshold for action, the team did not perform a detailed data analysis to estimate a lower pipeline failure frequency.

[207] The team observes that excavation damage represents a relatively high fraction of the incidents shown in Figure 21. In the most recent year's data for gas transmission lines, third-party damage has been reduced to a smaller percentage given damage prevention efforts.

Appendix F. NRC Contributors

David Skeen (team lead) is a member of the Senior Executive Service and has served as the Deputy Director of the Office of International Programs since June 2014. From 2011 to 2014, he served as the Director of the Japan Lessons-Learned Directorate leading the agency's response to the Fukushima Dai-ichi accident. He first joined the NRC in 1991 as a reactor systems engineer and served in progressively responsible technical, policy, and management positions at the staff and Commission staff levels. Prior to joining the NRC, Mr. Skeen worked in the electrical construction industry for 15 years on large industrial projects, including both fossil and nuclear power plants. Mr. Skeen received a bachelor's degree in electrical engineering from West Virginia University.

Theresa Clark (deputy team lead) has served as the Deputy Director of the Division of Rulemaking, Environmental, and Financial Support since November 2017. She is a member of the NRC's Senior Executive Service Candidate Development Program. Ms. Clark joined the NRC in 2004 and has served in progressively responsible positions, including as an Executive Technical Assistant providing technical and policy advice to the agency's senior executives, the chief of the Mechanical Engineering Branch in the Office of New Reactors, and a reliability and risk analyst. Ms. Clark earned bachelor's and master's degrees in materials science and engineering from the University of Maryland.

Dr. Yueh-Li (Renee) Li is a senior mechanical engineer in the NRC's Office of Nuclear Reactor Regulation. She is an agency expert in the review of piping design and pipe break hazard analysis for new nuclear power plants. Dr. Li joined the NRC in 1980 as a mechanical engineer. Prior to joining the NRC, Dr. Li was a senior stress analyst and senior nuclear staff at Bechtel Power Corporation for four years. She earned a Ph.D. degree in mechanical engineering and a master's degree in nuclear engineering from The Catholic University of America and a bachelor's degree in nuclear engineering from National Tsinghua University in Taiwan.

Suzanne Dennis is a Risk and Reliability Engineer in the Office of Nuclear Regulatory Research. She joined the NRC in the Office of New Reactors as a Risk and Reliability Analyst in 2009 and has developed specialized expertise in the area of external hazard risk analysis. She holds a bachelor's degree in nuclear engineering from Missouri University of Science and Technology and a master's degree in reliability engineering from the University of Maryland.

Brian Harris, Esq. is the Deputy Assistant General Counsel for Reactor and Materials Rulemaking and was previously the Acting Assistant General Counsel for Operating Reactors. Mr. Harris joined the NRC in 2009 as a staff attorney and was the lead legal advisor for the agency's response to the accident at the Fukushima Dai-ichi nuclear power plant. Before joining the NRC, he was an associate at Townsend, Townsend & Crew and Pillsbury Winthrop Shaw Pittman. Mr. Harris's previous work experiences include the U.S. Navy as a nuclear-trained surface warfare officer and as part of the Joint Staff for the J-2, Director of Intelligence. Mr. Harris earned a law degree from the University of Richmond School of Law and bachelor's degree in chemical engineering from Brigham Young University.

Appendix G. External Support

The NRC obtained expert support on pipeline construction, operations, and accidents from the Pipeline and Hazardous Materials Safety Administration (PHMSA), part of the U.S. Department of Transportation. Insights that resulted from this support are included in multiple sections of this report.

- **Steve Nanney** has worked for the past 15 years in PHMSA's Engineering and Research Division. Mr. Nanney has worked on the development and implementation of his agency's integrity management program, rulemakings, special permits, stakeholder outreach, and pipeline research programs. He previously worked in industry for 29 years, including operations, design, construction, and marketing of gas and liquid pipelines. His industry experience also includes U.S. offshore drilling and gas production operations and several years of greenfield development of gas pipelines outside the United States. Mr. Nanney has a bachelor's degree in civil engineering from the University of Mississippi and a master's degree in petroleum engineering from the University of Houston. He is a registered professional engineer in Texas.

The NRC also contracted with Sandia National Laboratories to provide expertise on natural gas modeling and fire risk. The results of the efforts by Sandia National Laboratories are included in Appendix B and referenced in the body of the report. Insights from the Sandia experts about fire risk were also used in preparing the team's report.

- **Dr. Chris LaFleur** is the program lead for Hydrogen Safety, Codes, and Standards at Sandia National Laboratories in Albuquerque, NM, where she is responsible for the fire risk program activities and conducting research on the fire risks of emerging energy technologies. Before joining Sandia, she worked at General Motors and Parsons Engineering Science. Dr. LaFleur earned bachelor's degrees in geology and mechanical engineering from the University of Rochester, a master's degree in fire protection engineering from the University of Maryland, and a doctorate of engineering in manufacturing engineering from the University of Michigan. She is a licensed professional engineer.
- **Dr. Anay Luketa** is a Principal Member of Technical Staff at Sandia National Laboratories in the Fire Science and Technology Department. She serves as test director of large-scale fire experiments and performs numerical analysis. Her area of expertise pertains to analysis, utilizing computational tools for applications that span turbulent reacting and non-reacting flow, solid mechanics, and shock-physics. Specific applications have involved pool fire, blast, and dispersion calculations for hazard analysis involving liquefied natural gas, as well as fires involving composites, propellants, and other hydrocarbons. She was the lead technical author of guidance reports addressing risk management of large liquefied natural gas carriers. She has bachelor's degrees in mathematics and in psychology from Seattle University, and a master's degree and Ph.D. in mechanical engineering from the University of Washington.
- **Jamal Mohmand** is a Member of the Technical Staff at Sandia National Laboratories. Mr. Mohmand has several years of experience of building fire risk models. In particular, Mr. Mohmand's expertise lies in plant partitioning, ignition frequency, fire scenario selection, quantification, uncertainty analysis, and model integration. Mr. Mohmand has helped build and maintain several fire risk models for plants across the country. Mr. Mohmand has participated in peer reviews, plant walkdowns, significance determination process responses, and safety reviews of probabilistic risk assessment models. He graduated from Texas A&M University with a Bachelor of Science in Radiological Health Engineering in 2017.

Appendix H. Figures

Figure 1. Aerial view of the Indian Point Energy Center on the east side of the Hudson River. This view shows the Unit 2 containment and turbine building on the left, the Unit 1 containment in the center, and the Unit 3 containment and turbine building on the right. (Some older aerial photos show a red and white stack associated with Unit 1; it has been removed and only the white base is showing to the left of Unit 1.)

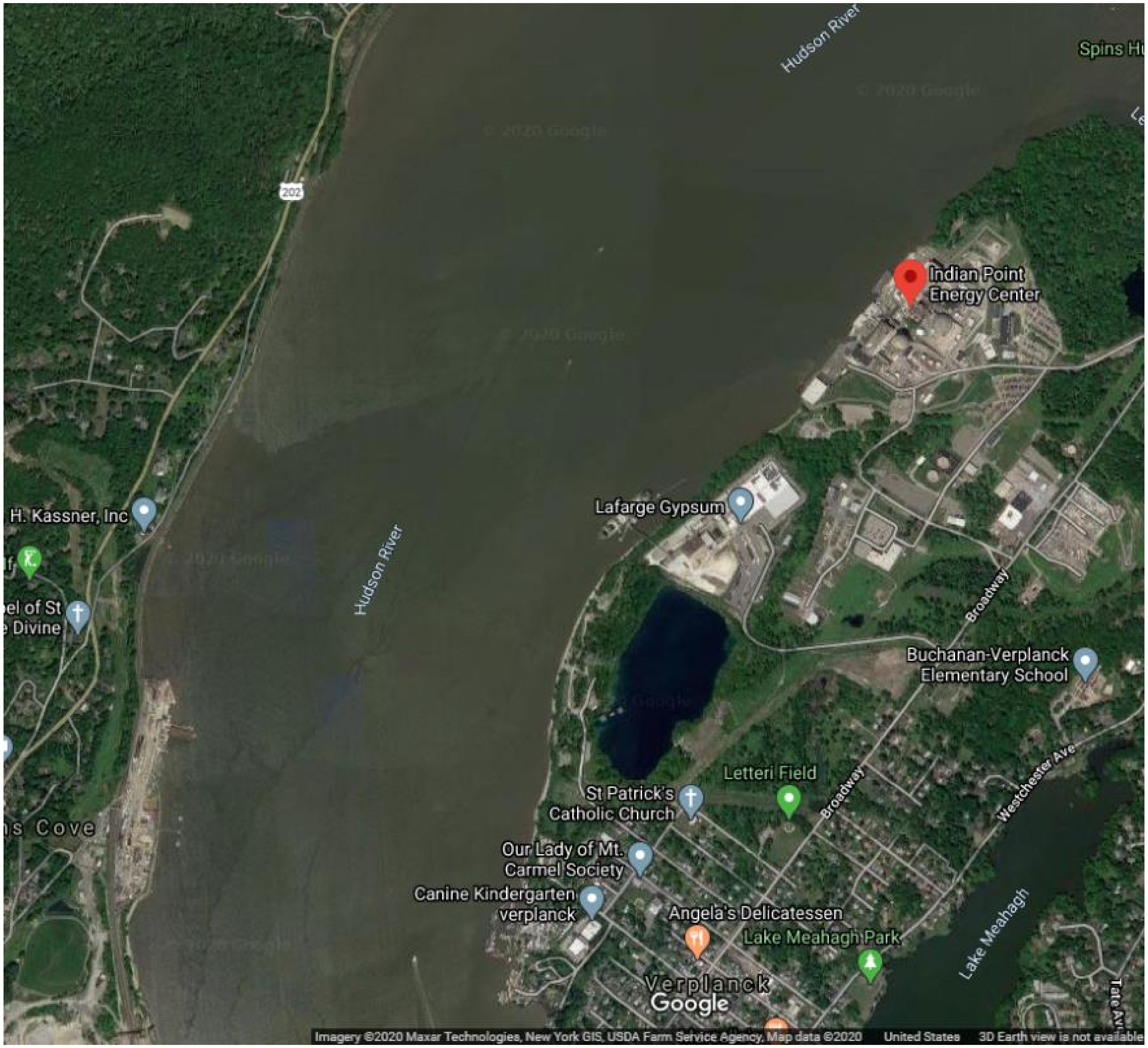


Figure 2. Satellite map view of Indian Point Energy Center (near top right). Southwest of the plant (marked Lafarge Gypsum) is a gypsum plant not associated with the nuclear power plant. (Imagery ©2020 Maxar Technologies, New York GIS, USDA Farm Service Agency, Map data ©2020 Google.)

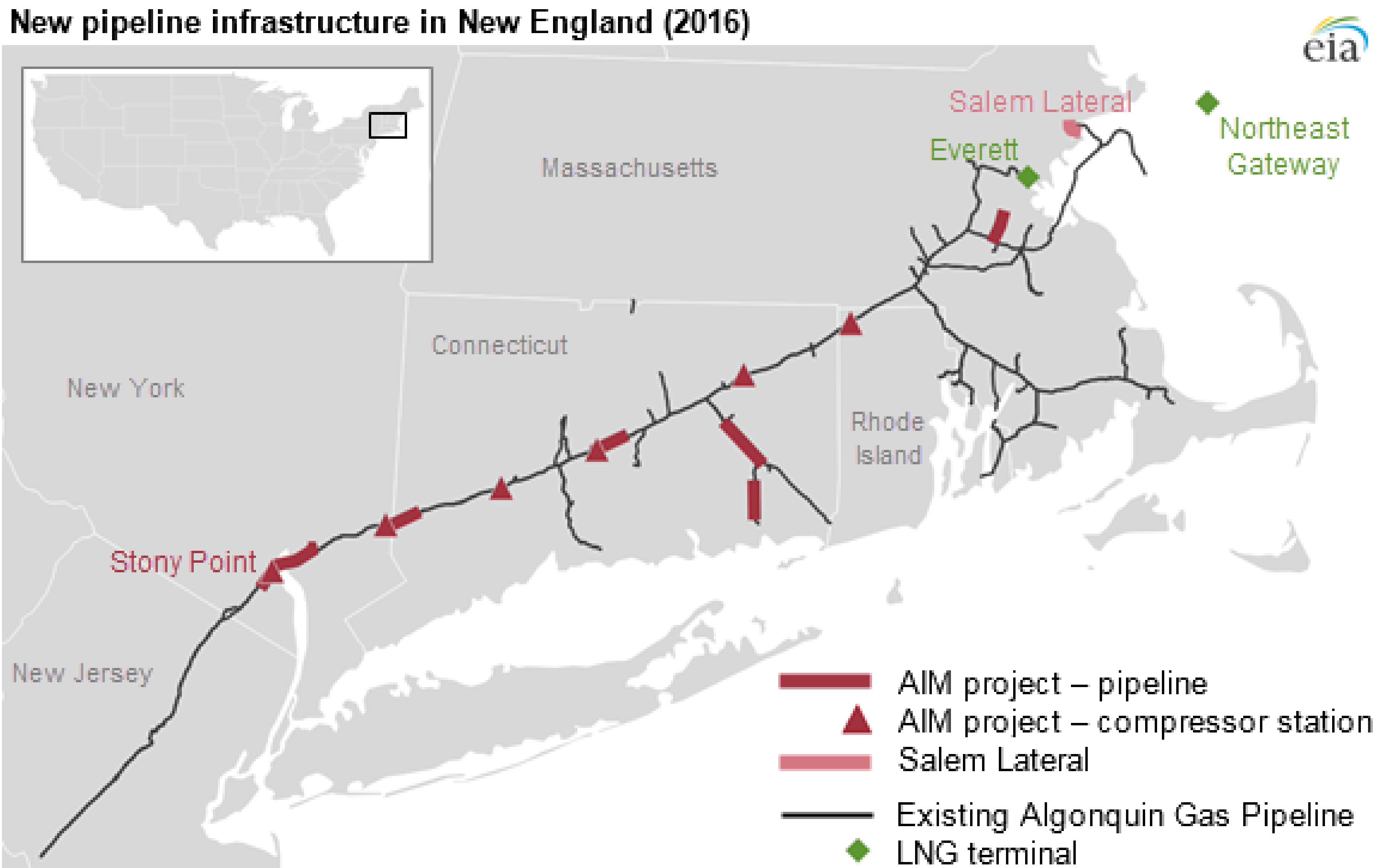


Figure 3. Overview of AIM pipeline infrastructure. Source: U.S. Energy Information Administration (https://www.eia.gov/todayinenergy/detail.php?id=29032).

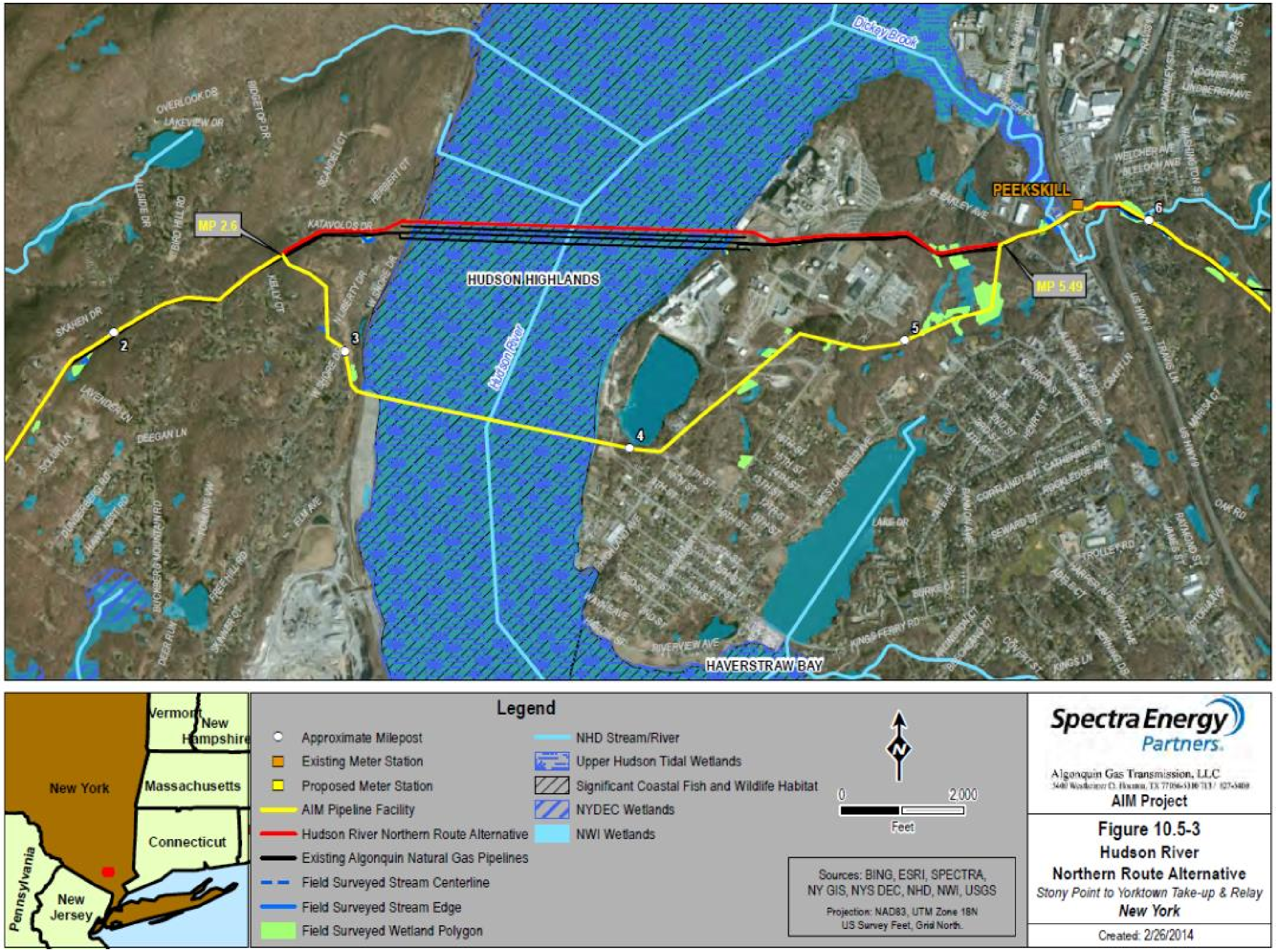


Figure 4. Figure 10.5-3 from the AIM application, showing the pipeline route in yellow and the alternative (not selected) for a northern route through the Indian Point site in red.

Figure 5. View of the 42-inch AIM pipeline from near Indian Point. At left is a view of the right of way from a location southeast of Indian Point. The pipeline area can be identified by the lighter grass beyond the trucks on the opposite side of the road (Broadway); the Indian Point SOCA is well outside the frame to the right; the red and white tower is the meteorology tower that Entergy assessed for pipeline rupture impacts. At center is a view of the right of way from within the Indian Point property. The pipeline area can be identified by the lighter grass beyond the fence (behind the white items); the Indian Point SOCA is well behind the viewer and to the left of the frame. The photos show the hilly terrain near the site, with the pipeline in a low area. The image at right shows the Indian Point site near the top, blue dot with the location where the center photo was taken, and cemetery in the clear area near the bottom right. The pipeline area can be identified by the clear-cut through the trees; the Buchanan switchyard is just to the right of the frame where the road (Broadway) intersects the edge of the image. The photos were taken by the team on March 12, 2020. (Right image: Imagery ©2020 Maxar Technologies, New York GIS, USDA Farm Service Agency, Map data ©2020 Google.)

Figure 6. Images of above-ground connections where the 26-inch, 30-inch, and 42-inch pipelines connect, east of Indian Point. These photos were taken by the team on March 12, 2020.

Figure 7. Aerial image of a dense methane cloud from a National Transportation Safety Board report.[208]

[208] National Transportation Safety Board, "Rupture of Florida Gas Transmission Pipeline and Release of Natural Gas, May 4th, 2009," NTSB/PAB-13/01; https://www.ntsb.gov/investigations/AccidentReports/Pages/PAB1301.aspx

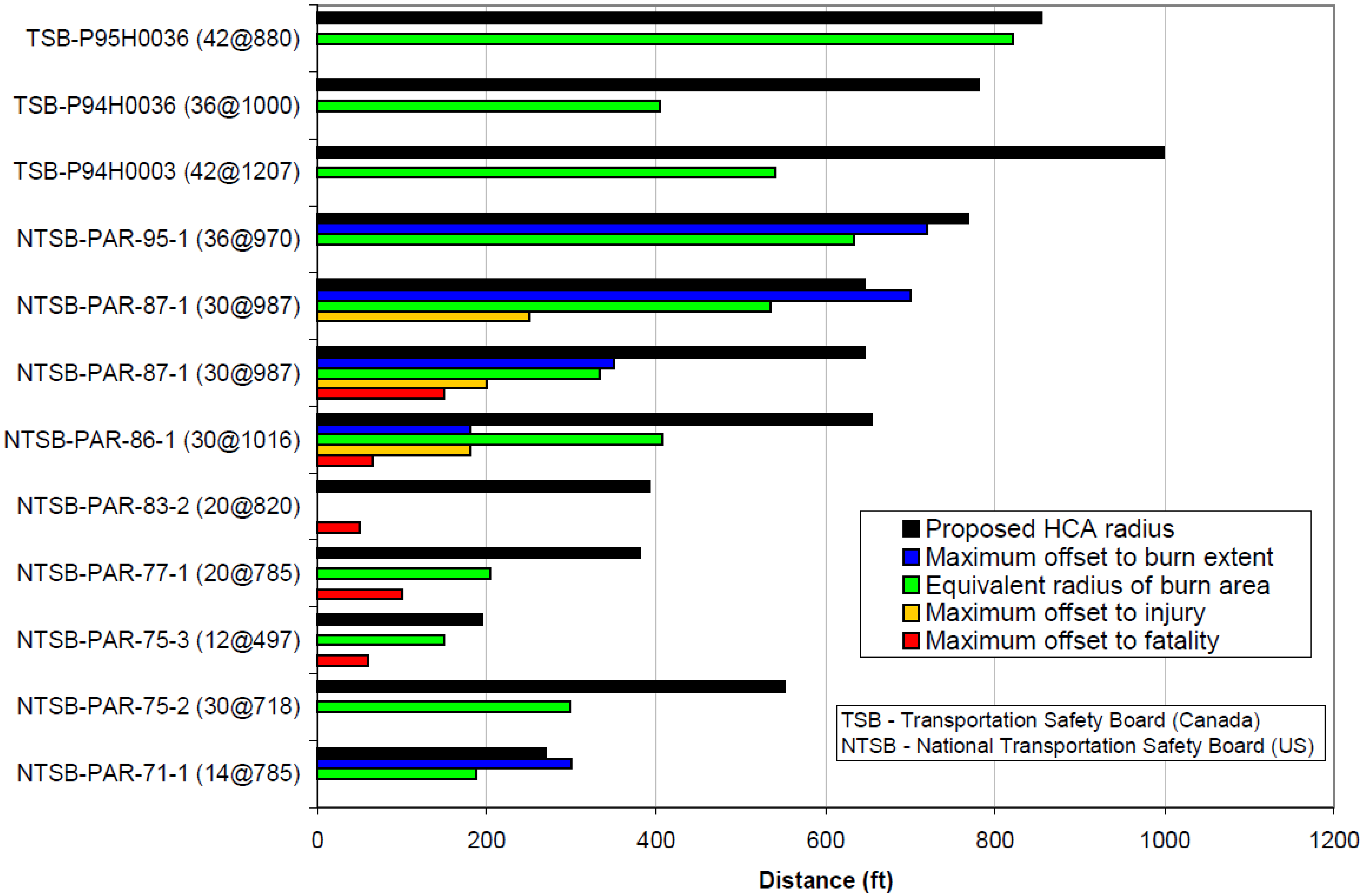
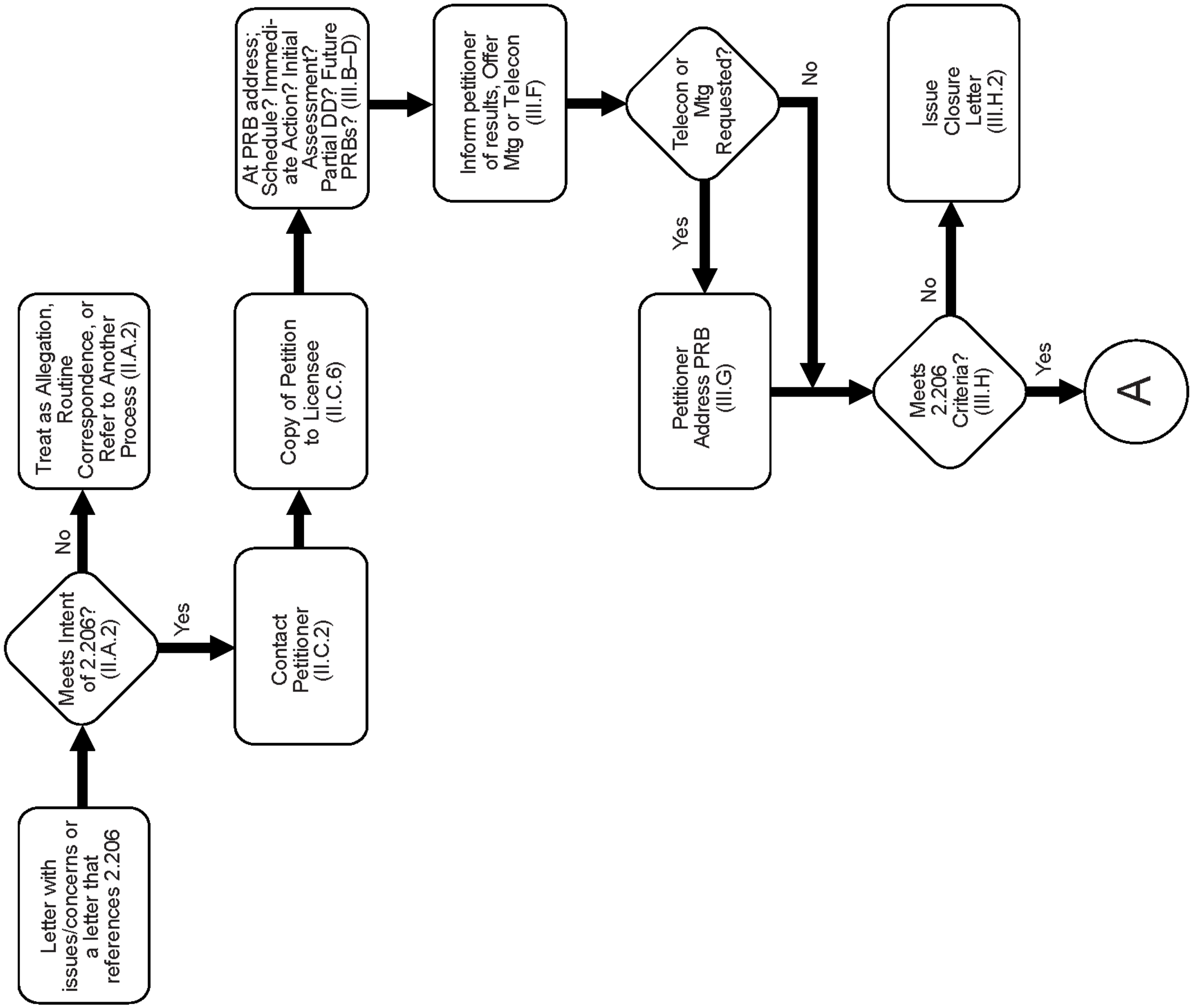


Figure 8. Figure 3.1 from Gas Research Institute / C-FER report comparing pipeline rupture damage areas to a proposed high consequence area (HCA) hazard area radius, which became the potential impact radius in Department of Transportation regulations.

Figure 9. Pipeline rupture accident images obtained from PHMSA. Accident sites are: (1) Appomattox, VA in 2008, (2) Artesia, NM in 2019, (3) Mexico, MO in 2019, and (4) Moundville, OH in 2018.



1. Parenthetical Information is associated Guide paragraph number

Figure 10. Simplified process flowchart (1 of 2) from NRC desktop guide on 10 CFR 2.206 petition reviews (Exhibit 1).

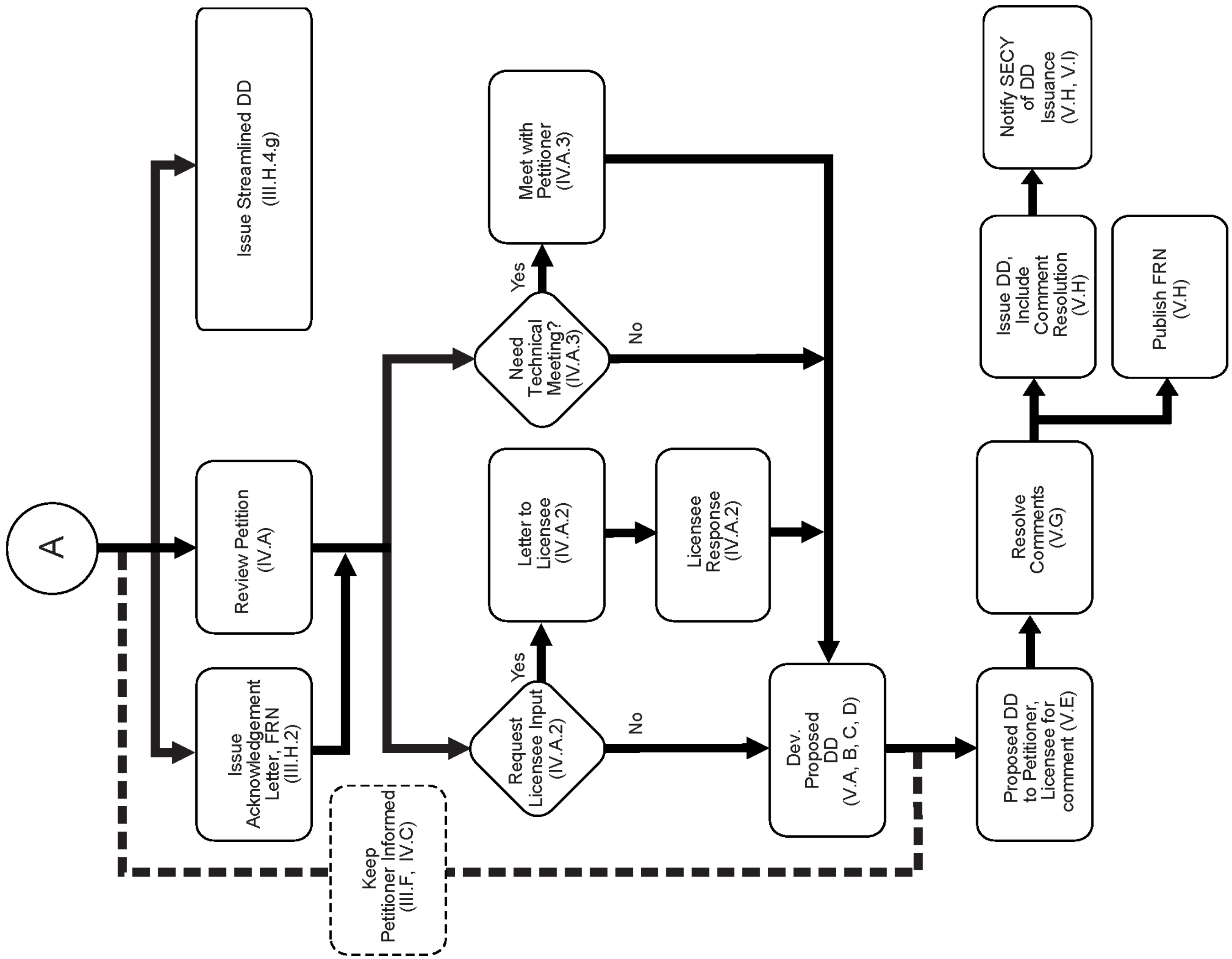


Figure 11. Simplified process flowchart (2 of 2) from NRC desktop guide on 10 CFR 2.206 petition reviews (Exhibit 1).

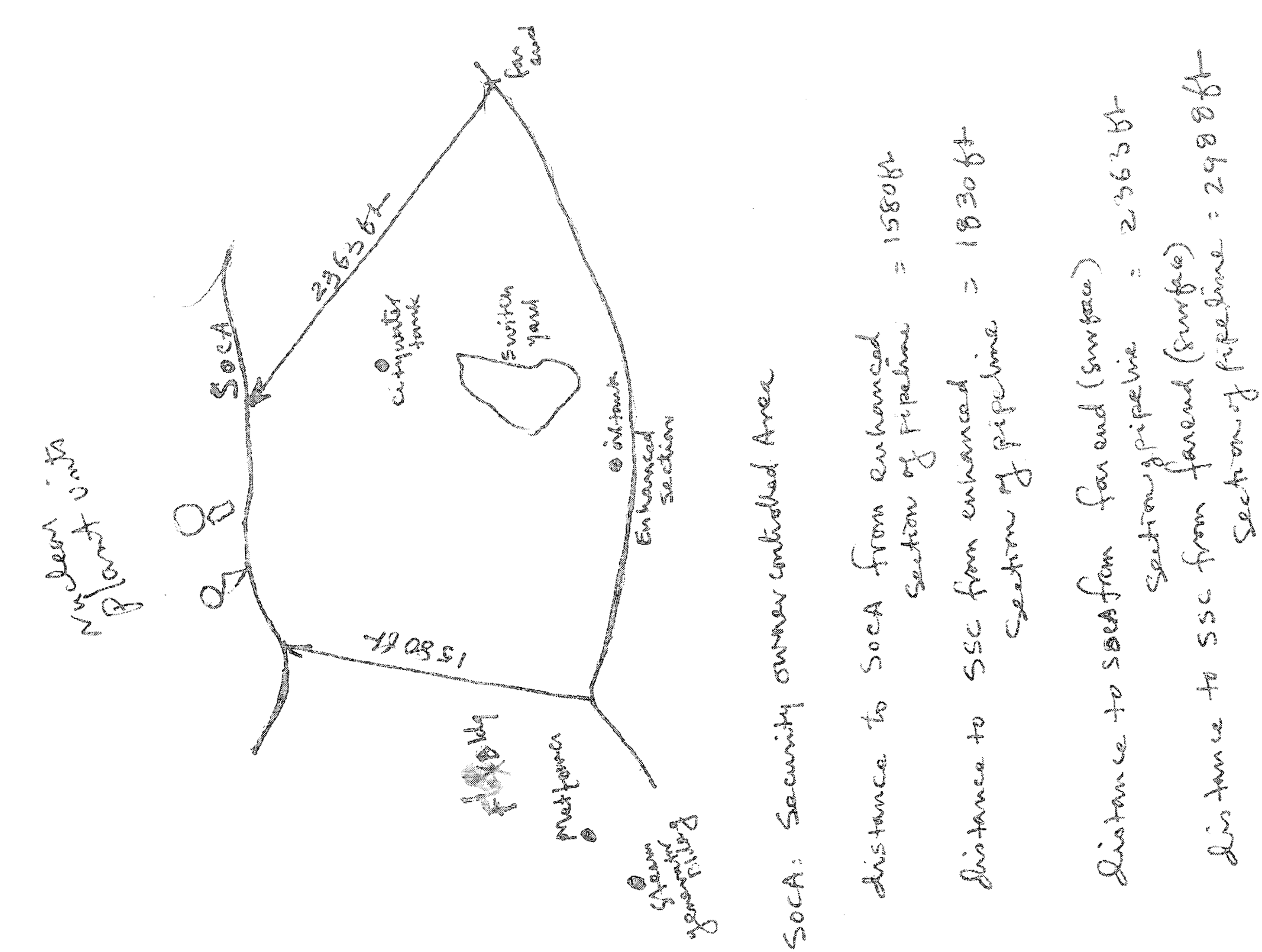
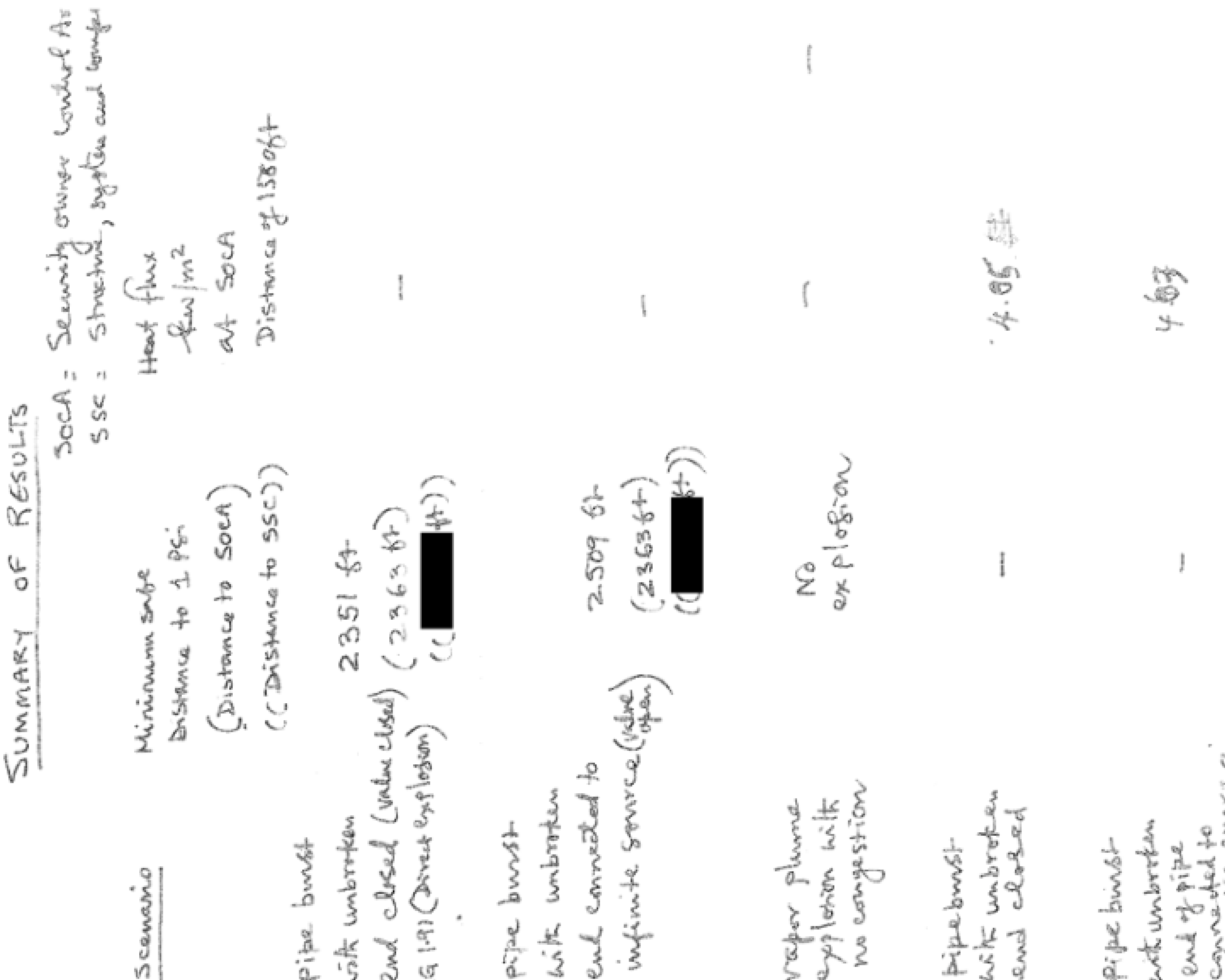


Figure 12. Sketch prepared by NRC analyst in conducting sensitivity study for PRB on 3-minute isolation valve closure time for AIM pipeline.



SUMMARY OF RESULTS

SOCA: Security owner control Area
SSC: Structure, system and component

Scenario	Minimum safe Distance to 1 psi (Distance to SOCA) ((Distance to SSC))	Heat flux kw/m² at SOCA Distance of 1580 ft
Pipe burst with unbroken end closed (valve closed) RG 1.91 (Direct explosion)	2351 ft (2363 ft) (([redacted] ft))	—
Pipe burst with unbroken end connected to infinite source (valve open)	2509 ft (2363 ft) (([redacted] ft))	—
Vapor plume explosion with no congestion	No explosion	—
Pipe burst with unbroken end closed	—	4.85
Pipe burst with unbroken end of pipe connected to infinite source	—	4.8[illegible]

Figure 13. Image showing handwritten results of sensitivity study conducted by NRC analyst at the request of the PRB. The team redacted the "distance to SSC" as potentially security-related information, though similar information may exist in other documents.

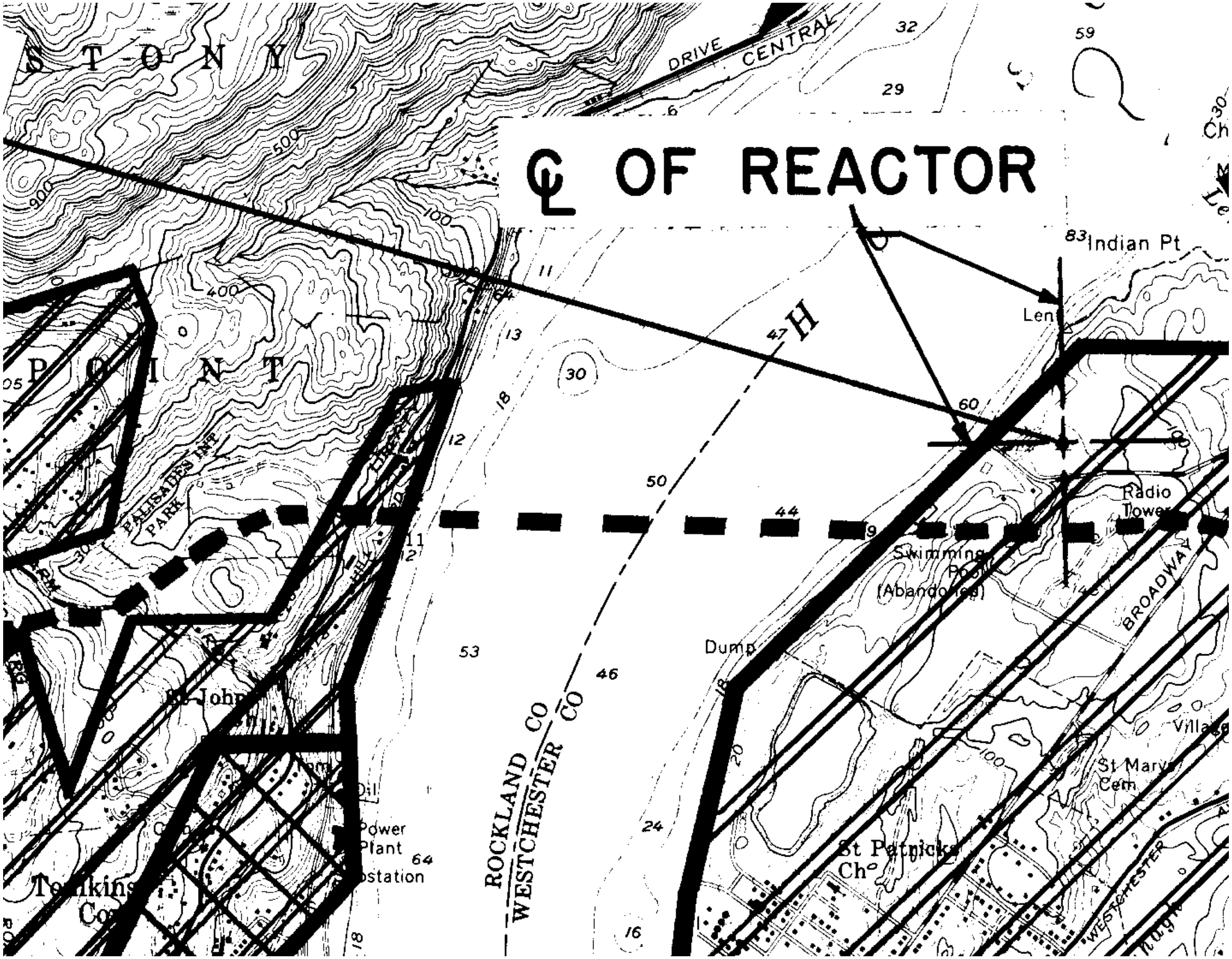


Figure 14. Selection from 1960 map of Indian Point Unit 1 vicinity, including public utilities. The preexisting 26-inch pipeline is shown as a dashed line.

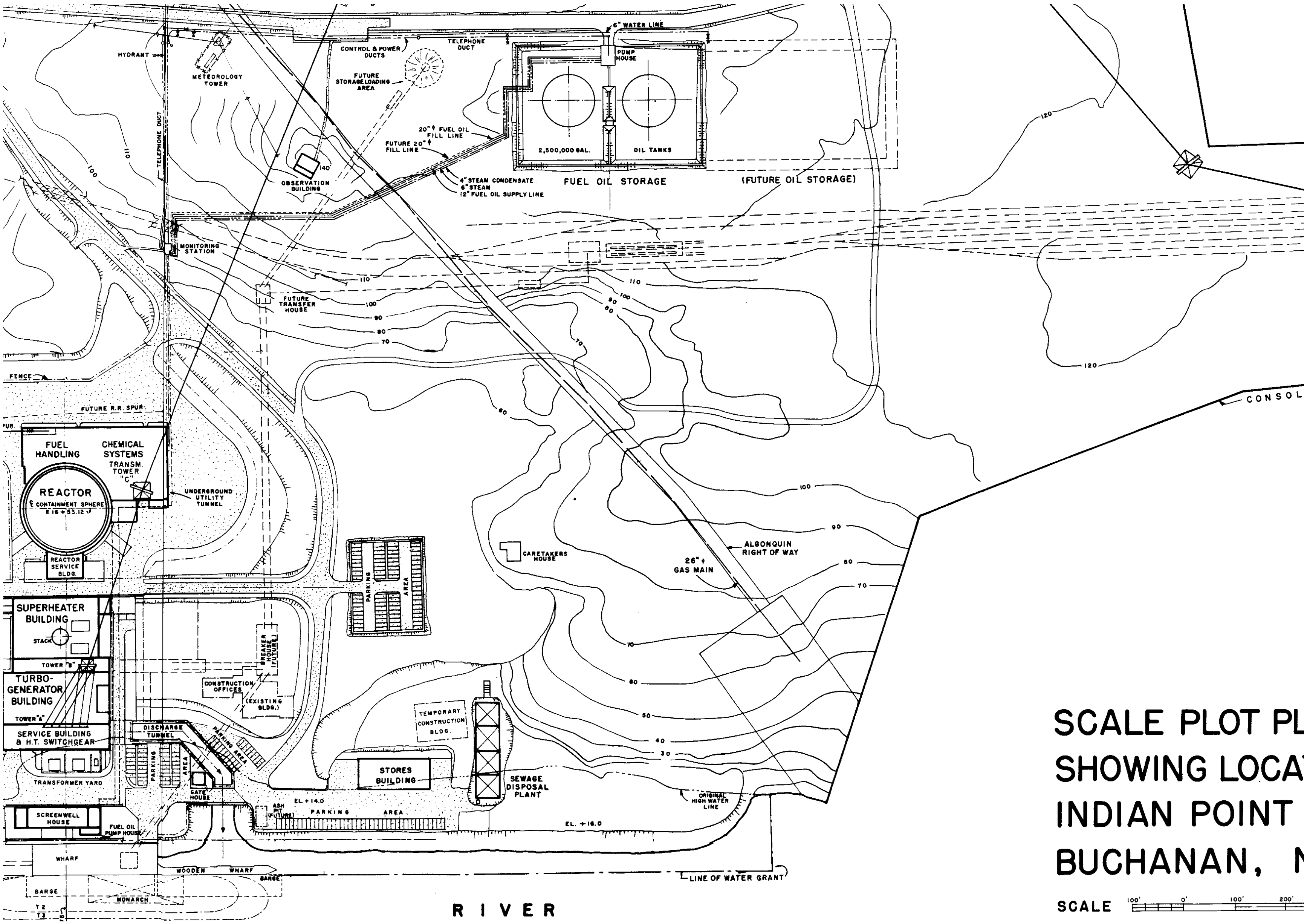


Figure 15. Scale plot plan of Indian Point Unit 1 (Exhibit H-14), showing reactor and Algonquin right of way for the preexisting 26-inch gas main.

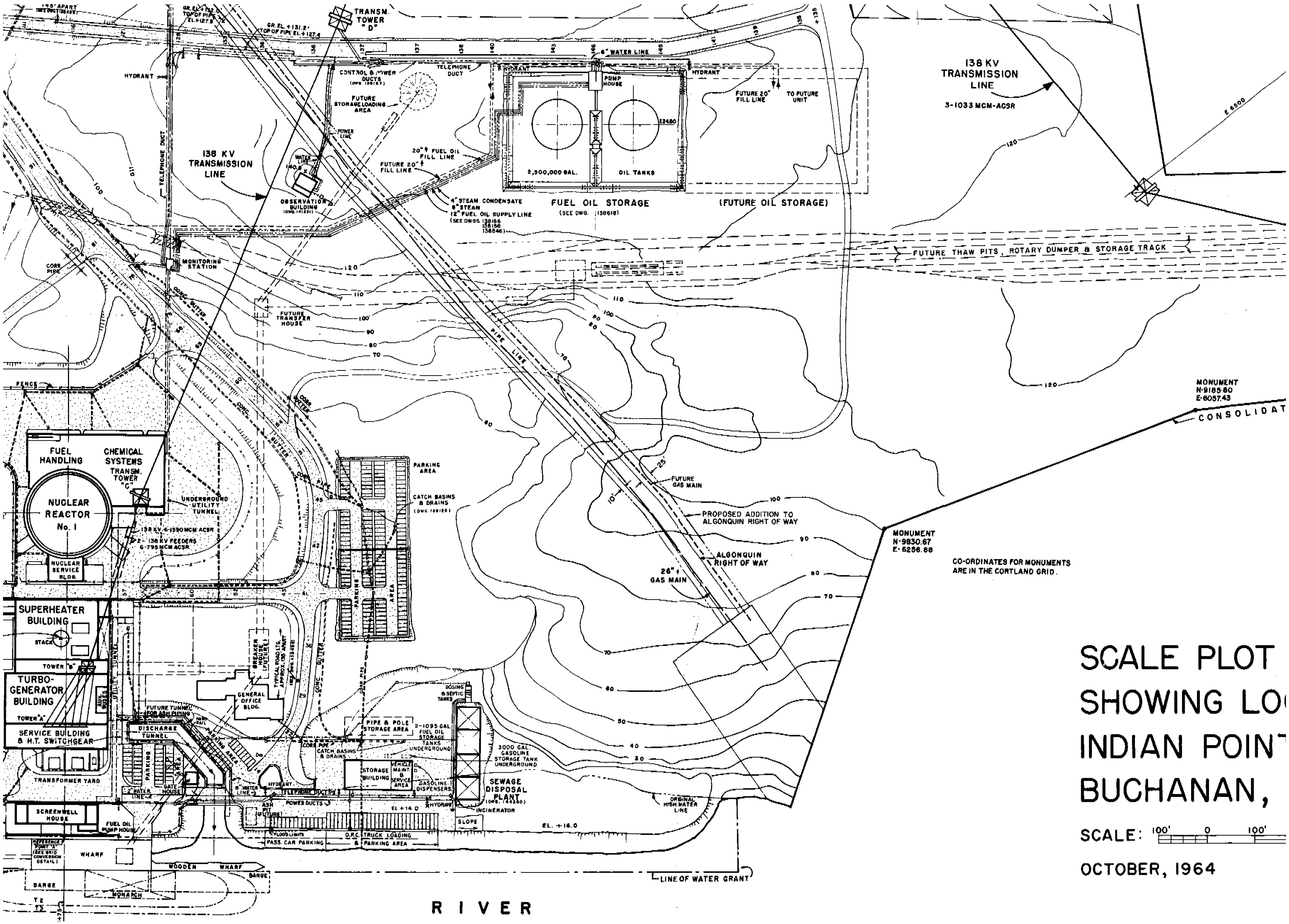


Figure 16. Scale plot plan of Indian Point Unit 1 (Exhibit H-14, Revision 2), showing right of way for the 26-inch gas main and the proposed 30-inch line.

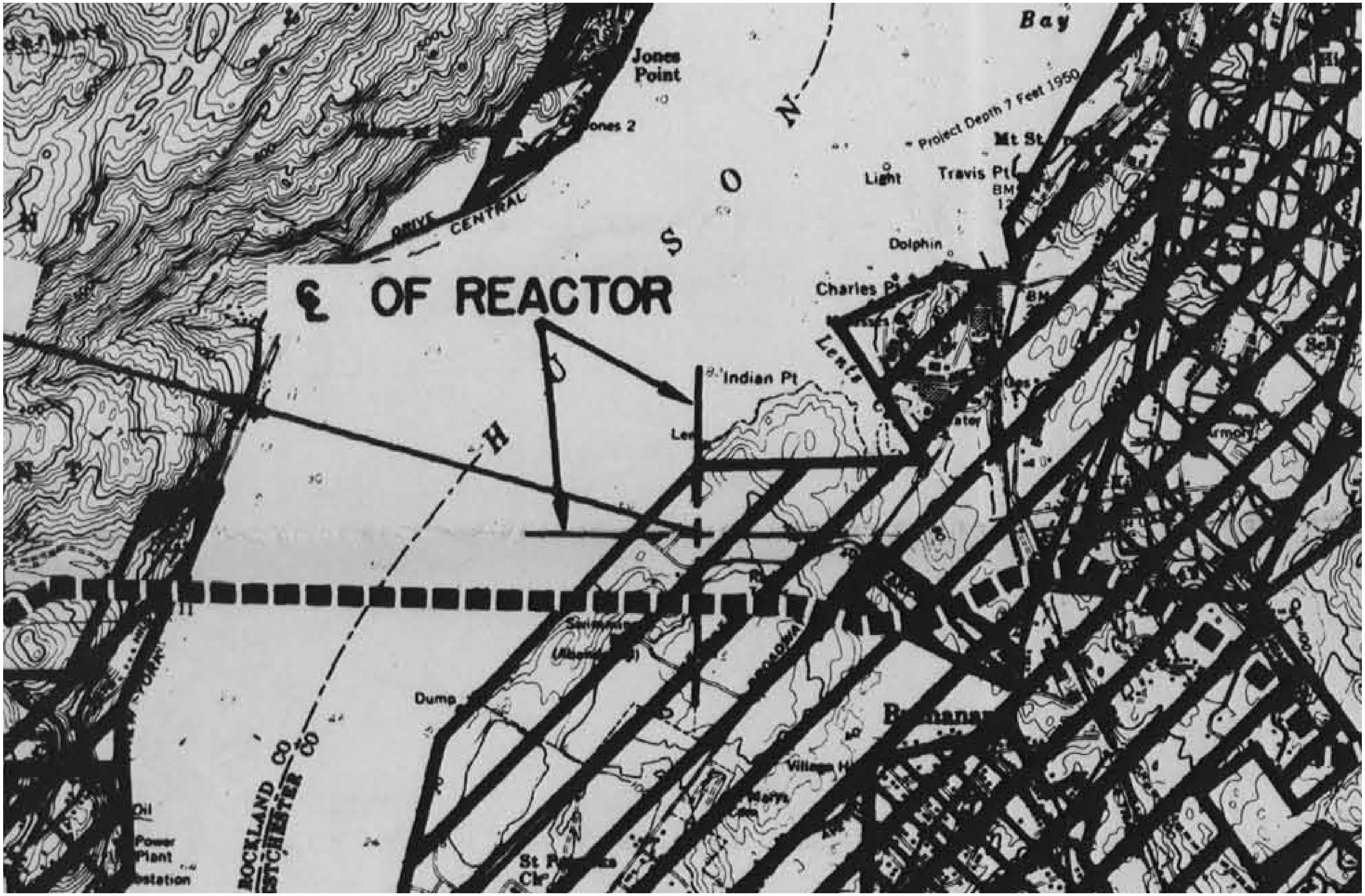


Figure 17. Portion of Indian Point Unit 2 PSAR Figure 1.4-4, showing reactor and Algonquin gas transmission lines (two) designated by dashed black line.

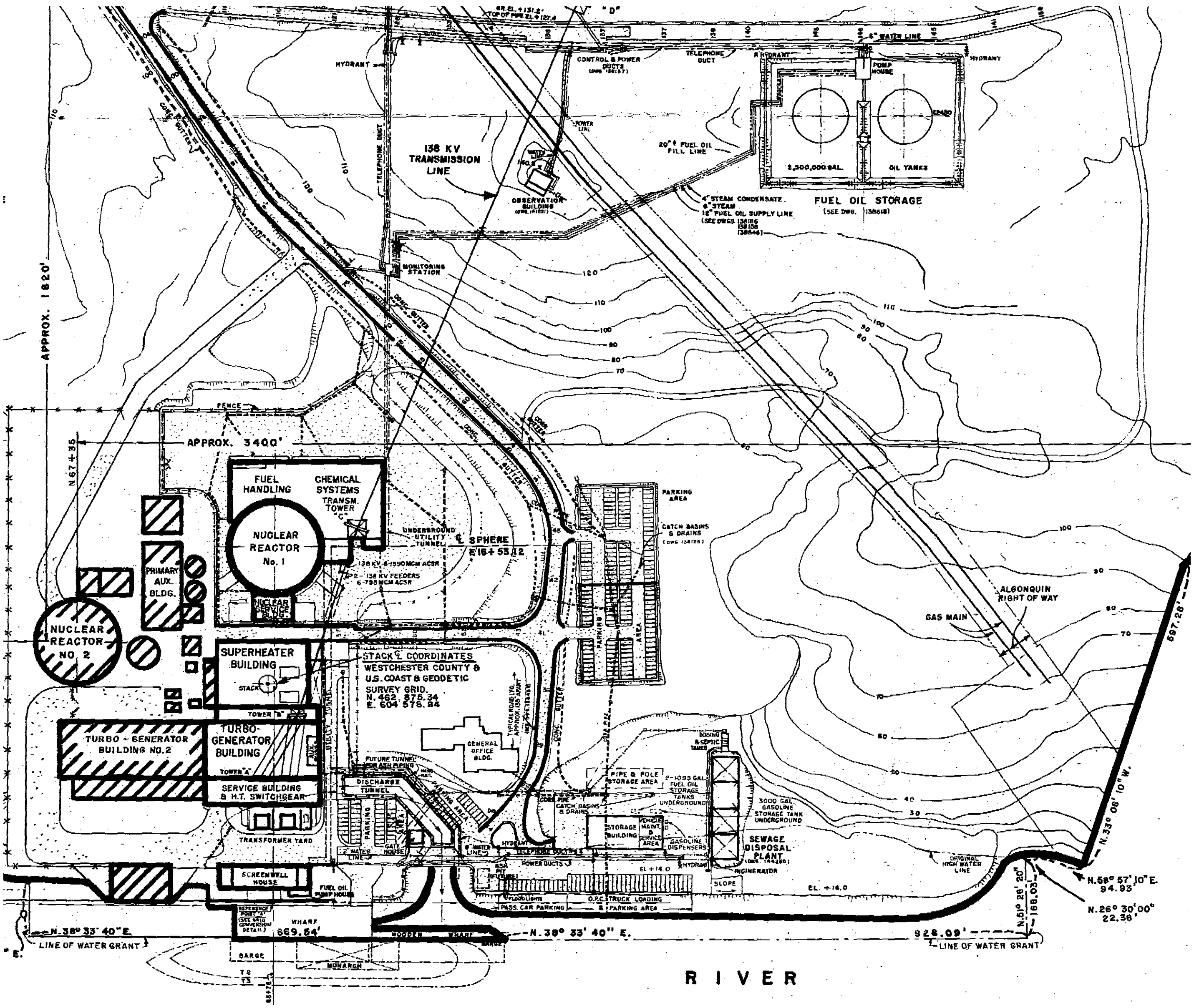


Figure 18. Section of Indian Point Unit 2 PSAR Figure 1.2-2, showing Units 1 and 2 and the Algonquin right of way.

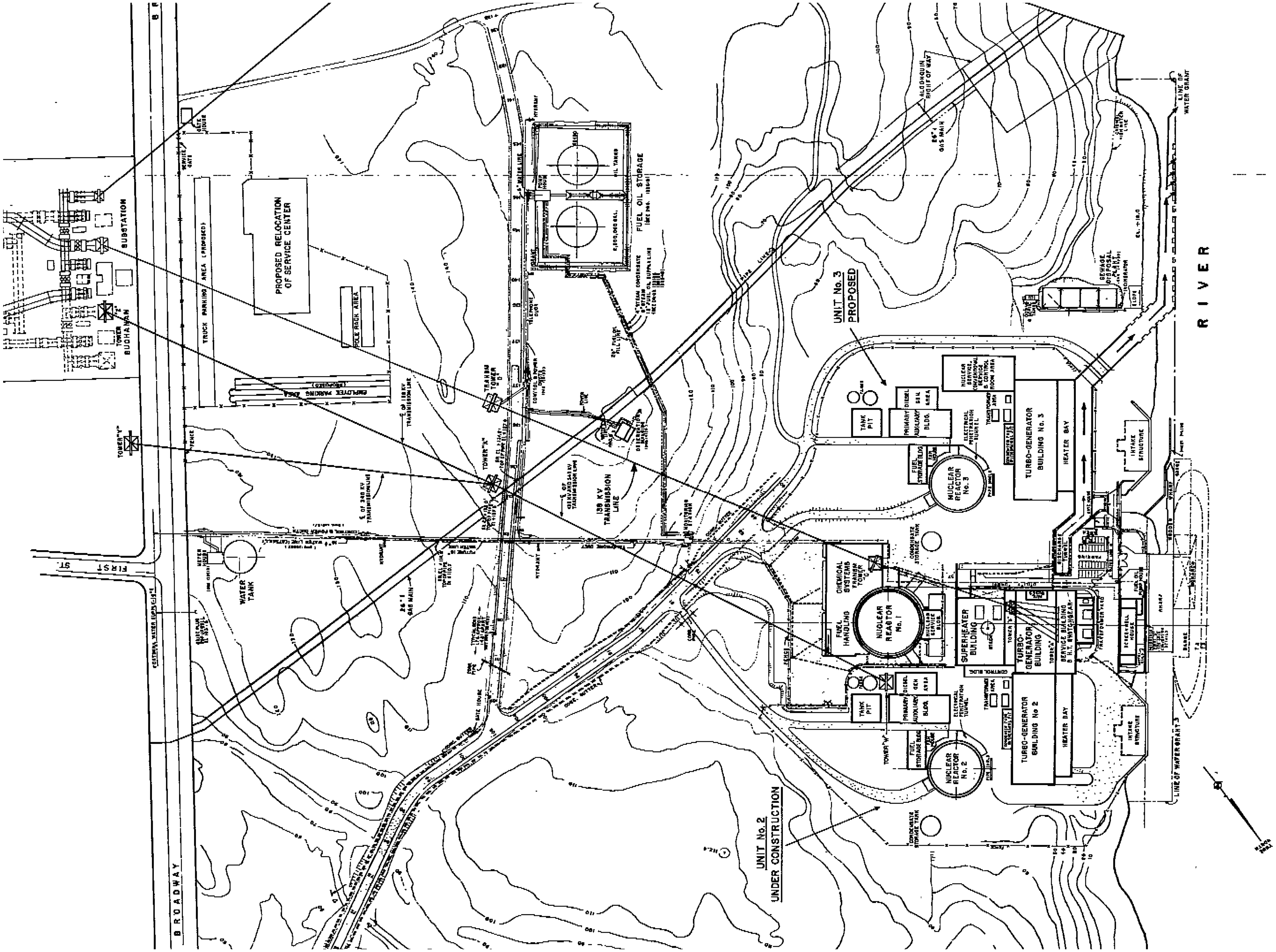


Figure 19. Section of Indian Point Unit 3 PSAR Figure 1.2-2, showing all three reactors and the Algonquin right of way (rotated counterclockwise from Unit 1 and 2 images).

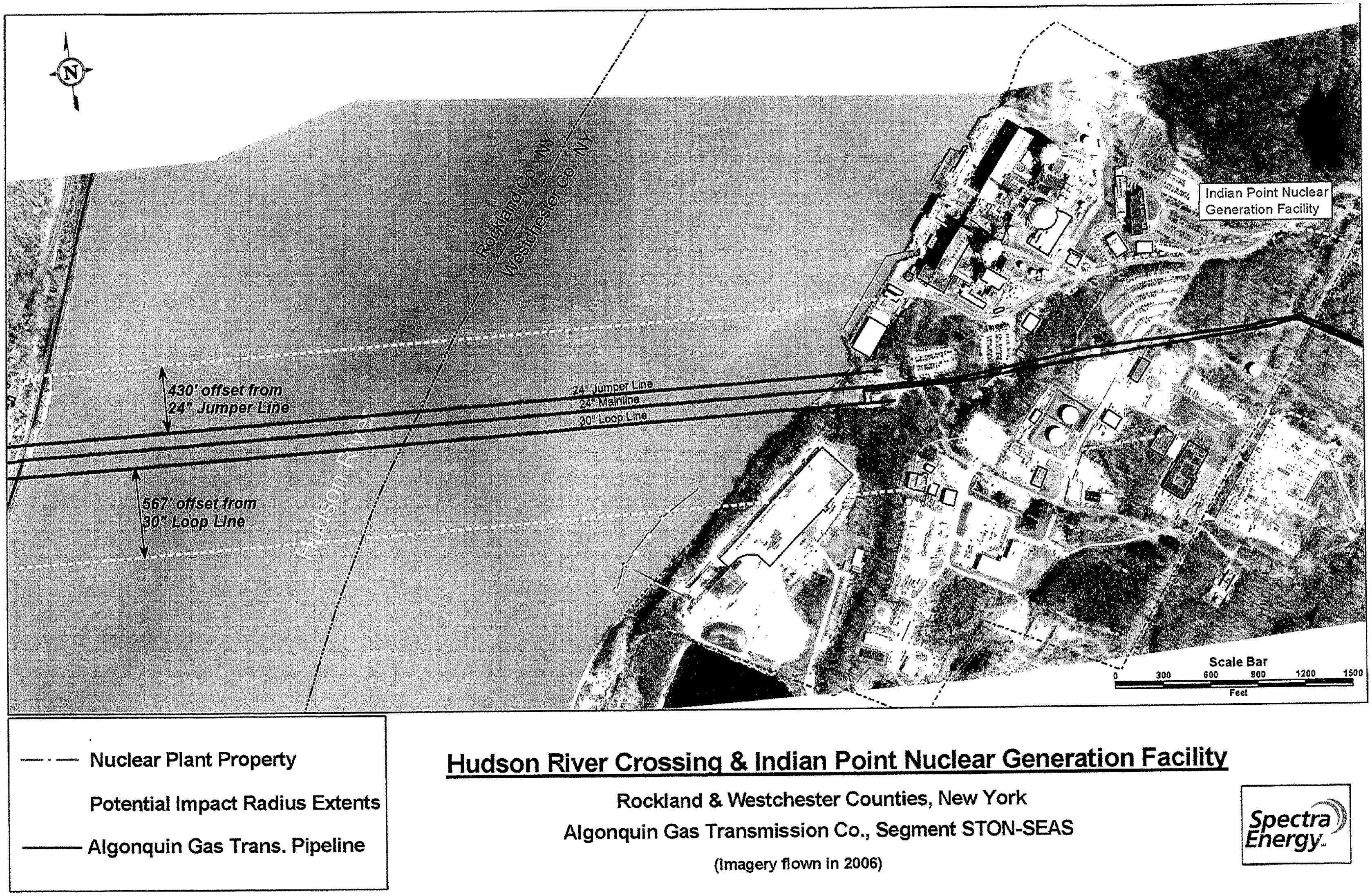


Figure 20. Section of Indian Point Unit 2 Updated FSAR Figure 2.2-3, showing the Hudson River crossing of the preexisting pipelines, the potential impact radius extent in white dotted lines, and the Indian Point facility north of the pipelines. Potential impact radius" is defined in DOT regulations at 49 CFR 192.903 as the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. The potential impact radius is determined by the formula $r = 0.69* \sqrt{(p*d^2)}$, where "r" is the radius of a circular area in feet surrounding the point of failure, "p" is the MAOP in the pipeline segment in pounds per square inch and "d" is the nominal diameter of the pipeline in inches. The 0.69 constant is the applicable value for natural gas.

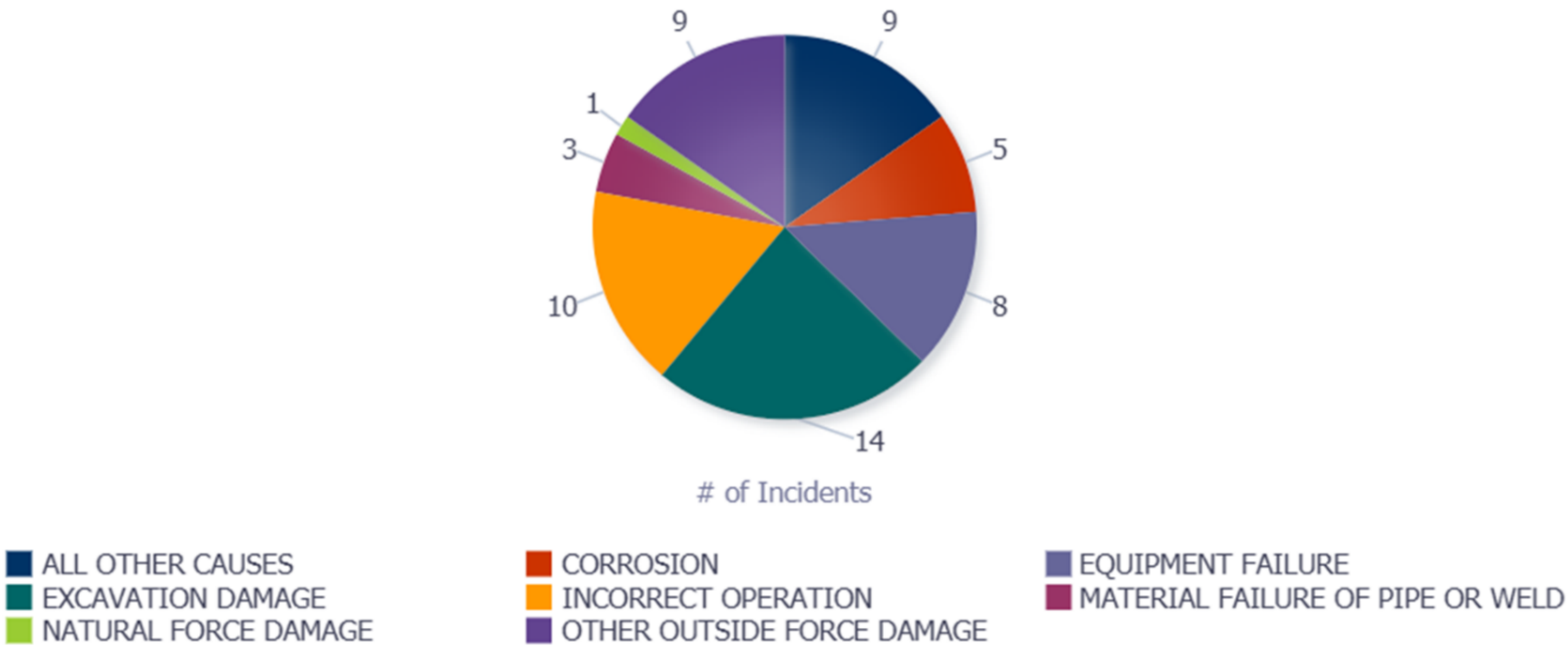


Figure 21. Summary of serious pipeline incident causes (from 2005 to present) from PHMSA database. Serious incidents include a fatality or injury requiring overnight inpatient hospitalization.

Appendix I. Chronology of Events and Documents Related to Indian Point Pipeline Review

Date	Category	Activity	Reference
1968-08-30	Licensee Review / Analysis	Consolidated Edison concludes in Indian Point Unit 3 preliminary safety analysis report Supplement 1 that pipeline fire will not endanger Unit 3, references 4-minute automatic isolation	ML093480204
1973-09-21	NRC Review / Analysis	AEC concludes in Indian Point Unit 3 operating license safety evaluation report that pipeline failure will not impair safe operation	ML072260465
1975-01-31	NRC Guidance	NRC issues Revision 0 to Regulatory Guide 1.91	ML12298A133
1978-02-28	NRC Guidance	NRC issues Revision 1 to Regulatory Guide 1.91	ML003740286
1982-03-05	Licensee Review / Analysis	Power Authority of the State of New York and Consolidated Edison submit Indian Point Probabilistic Safety Study to NRC	ML093430890
1982-12-31	NRC Review / Analysis	NRC completes review of Indian Point Probability Safety Study (NUREG/CR-2934), including heat flux and missiles from pipeline explosions/leaks	ML091540534
1983-01-21	Licensee Review / Analysis	Power Authority of the State of New York and Consolidated Edison submit Amendment 1 to Indian Point Probabilistic Safety Study to NRC, updating several analyses (but not pipeline)	ML093431170
1984-04-02	Licensee Review / Analysis	Consolidated Edison and Power Authority of the State of New York submit Amendment 2 to Indian Point Probabilistic Safety Study to NRC, updating several analyses (but not pipeline)	ML100321844
1995-12-06	Licensee Review / Analysis	Consolidated Edison screens pipeline failure out of Indian Point Unit 2 IPEEE based on low frequency, notes that automatic shutoff valves had been removed	ML11227A100
1997-09-26	Licensee Review / Analysis	New York Power Authority screens pipeline vapor cloud explosion out of Indian Point Unit 3 IPEEE based on low frequency	ML11227A102
1999-05-14	NRC Review / Analysis	NRC issues safety evaluation of IP2 IPEEE, noting that natural gas pipeline accidents were screened based on frequency	ML090130608
2000-10-25	10 CFR 2.206	NRC updates Management Directive 8.11 on Title 10 of the *Code of Federal Regulations* (10 CFR) 2.206 petition reviews (most recent update before pipeline-related petitions)	ML041770328
2001-02-15	NRC Review / Analysis	NRC transmits Indian Point Unit 3 IPEEE safety evaluation to Entergy, noting evaluation and walkdowns of pipeline	ML11227A103

Date	Category	Activity	Reference
2003-04-25	NRC Review / Analysis	NRC documents review regarding safety hazard of exposed natural gas pipelines near the Hudson River shoreline	memo: ML11223A040 (public) enclosure: ML031210213 (non-public)
2007-02-28	NRC Guidance	U.S. Environmental Protection Agency and NOAA issue ALOHA User's Manual	https://nepis.epa.gov/
2008-03-12	NRC Review / Analysis	NRC issues Request for Information RI-2008-A-021 on gas pipelines	non-public (not in ADAMS)
2008-03-28	Licensee Review / Analysis	Entergy completes safeguards analysis for pipeline explosion near Indian Point Unit 3	NS107994 (non-public, safeguards)
2008-04-12	Licensee Miscellaneous	Entergy changes licensee-controlled documents to remove gas turbine references and add station blackout and Appendix R diesel for Indian Point Unit 2	ML090410062
2008-04-23	Licensee Review / Analysis	Entergy provides initial response to RI-2008-A-021 on gas pipelines	non-public (not in ADAMS)
2008-05-12	NRC Guidance	NRC/Office of Nuclear Reactor Regulation (NRR) issues office instruction ADM-405, "NRR Technical Work Product Quality and Consistency," Revision 1	ML072750452 (non-public)
2008-09-30	Licensee Review / Analysis	Entergy provides supplemental analysis to RI-2008-A-0021 on gas pipelines, enclosing 2008-08-14 Risk Research Group analysis	letter: (non-public, not in ADAMS) enclosure: ML103140627 (non-public)
2008-10-20	Licensee Miscellaneous	Entergy updates Indian Point Unit 2 final safety analysis report to correct references to gas pipelines	Chapter 2: ML083390226 (non-public)
2009-10-13	Licensee Miscellaneous	Entergy updates Indian Point Unit 3 final safety analysis report to include 2008 pipeline analysis information	Chapter 2: ML093430729 (non-public)
2010-04-12	Correspondence / Meetings	NRC responds to 2010-03-04 email from Paul Blanch re: Indian Point pipeline "unanalyzed condition," referencing 2008 and earlier analyses	ML101020487
2010-05-27	Licensee Miscellaneous	Entergy corrects description of pipelines in Indian Point license renewal application	ML101590515
2010-07-06	Correspondence / Meetings	NRC responds to 2010-06-08 email from Paul Blanch re: Texas pipeline incidents and applicability to Indian Point	ML101890929
2010-10-25	10 CFR 2.206	Paul Blanch submits 10 CFR 2.206 petition regarding preexisting gas pipelines	ML103020293 (public) ML102990527 (non-public)
2010-11-02	10 CFR 2.206	NRC holds PRB meeting regarding 2010-10-25 10 CFR 2.206 petition from Paul Blanch	ML103081077

Date	Category	Activity	Reference
2010-11-05	10 CFR 2.206	Paul Blanch supplements 10 CFR 2.206 petition re: hazard frequency and 10 CFR 50.59 review on change to non-automatic valves	ML103260134 (public) ML103160377 (non-public)
2010-11-09	10 CFR 2.206	NRC holds PRB meeting regarding 2010-10-25 10 CFR 2.206 petition from Paul Blanch	ML103190125
2011-03-03	10 CFR 2.206	NRC holds PRB meeting regarding 2010-10-25 10 CFR 2.206 petition from Paul Blanch	ML110680090
2011-03-03	10 CFR 2.206	Paul Blanch supplements 10 CFR 2.206 petition re: 10 CFR 50.59 review on change to non-automatic valves and Part 100 siting requirements	ML110630131
2011-03-04	NRC Review / Analysis	NRC/Office of Nuclear Security and Incident Response completes safeguards review of Indian Point gas pipelines (referenced in staff memos)	NS108076 (non-public, safeguards) 2011-03-07 memo: ML110700162 (non-public) 2011-0323 memo: ML11223A041 (public), ML110750113 (non-public)
2011-03-31	10 CFR 2.206	NRC rejects 2010-10-25 Paul Blanch petition, finding that issues had been previously resolved	ML110890309
2011-07-20	NRC Guidance	NRC issues draft Revision 2 to Regulatory Guide 1.91 (DG-1270) for public comment	ML110390554 76 FR 43356
2012-06-15	10 CFR 2.206	NRC staff responds to Atomic Safety and Licensing Board order re: 10 CFR 2.206 petitions	ML12167A524
2013-04-17	NRC Guidance	NRC issues Revision 2 to Regulatory Guide 1.91	ML12170A980
2013-12-23	NRC Guidance	NRC/NRR issues office instruction ADM-405, "NRR Technical Work Product Quality and Consistency," Revision 2	ML13337A212 (non-public)
2013-12-30	NRC Guidance	NRC/NRR issues office instruction COM-106, "Control of Task Interface Agreements," Revision 4	ML13300A002
2014-02-28	AIM / FERC	Algonquin Gas Transmission, LLC submits application to the FERC for AIM Project under CP14-96	https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14190856 https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14244199
2014-04-02	AIM / FERC	NRC and FERC meet to discuss whether to cooperate on FERC environmental impact statement for AIM pipeline	https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14209634
2014-04-30	AIM / FERC	Algonquin Gas Transmission, LLC submits info on Hudson River crossing, Indian Point location, and aerial view with measurements near Indian Point to the FERC	https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13532866 (see pp. 85 and 315)

Date	Category	Activity	Reference
2014-05-30	NRC Guidance	NRC/NRR issues office instruction LIC-504, "Integrated Risk-Informed Decision-Making Process for Emergent Issues," Revision 4	ML14035A143
2014-07-29	Licensee 50.59	Spectra sends information on AIM pipeline enhancements to Entergy (via Morgan Lewis) [Ref. 7 in 2014-08-21 10 CFR 50.59 evaluation]	obtained from Entergy through IP senior resident inspector
2014-08-06	AIM / FERC	FERC issues draft environmental impact statement for AIM pipeline	https://www.ferc.gov/industries/gas/enviro/eis/2014/08-06-14-eis.asp
2014-08-21	Licensee 50.59	Entergy submits 10 CFR 50.59 evaluation #1 for AIM pipeline	ML14245A110 (letter and Encl. 1) ML14245A111 (Encl. 2 non-public)
2014-09-07	AIM / FERC	Paul Blanch submits comments on FERC draft environmental impact statement	ML18177A401 (Enclosure 3)
2014-09-30	AIM / FERC	NRC submits comments on FERC draft environmental impact statement, referencing planned 10 CFR 50.59 inspection	https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14255780
2014-10-15	10 CFR 2.206	Paul Blanch submits 10 CFR 2.206 petition re: Entergy 10 CFR 50.59 evaluation	ML14294A751
2014-10-16	Licensee 50.59	NRC/Office of New Reactors (NRO) documents "safety review and confirmatory analysis" re: Entergy's 2014-08-21 10 CFR 50.59 evaluation	ML14329A189 (non-public) ML15070A086 (public, redacted)
2014-10-17	AIM / FERC	NRC and FERC meet to discuss NRC 10 CFR 50.59 inspection	https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14276308
2014-10-30	Licensee 50.59	NRC Region I Division of Reactor Safety completes 10 CFR 50.59 inspection feeder to quarterly inspection report for Indian Point	ML14307B748
2014-11-03	AIM / FERC	Rick Kuprewicz provides report on AIM pipeline to Town of Cortlandt, questioning 3-minute assumption and asking for safety/risk assessment (submitted as supplement to 2014-10-15 petition)	ML14352A397
2014-11-07	Licensee 50.59	NRC issues integrated inspection report including 10 CFR 50.59 inspection results	ML14314A052
2014-11-11	Correspondence / Meetings	Paul Blanch responds to 2014-11-06 email from Dori Willis re: corrosion of gas lines	ML15008A117
2014-12-12	10 CFR 2.206	Entergy (Prussman) provides information to NRC (McCarver) re: basis for 3-minute valve closure time	ML15168A042
2014-12-30	AIM / FERC	Rick Kuprewicz writes to the FERC re: need for transient analysis, risk assessment	enclosure in ML15027A419
2014-12-30	Correspondence / Meetings	NRC Chairman Macfarlane writes to Rep. Nita Lowey re: Entergy and NRC analyses	ML14343A934

Date	Category	Activity	Reference
2015-01-06	Correspondence / Meetings	Paul Blanch writes to Bill Dean (Region I Regional Administrator) re: 3-minute closure time and whether valves should be safety related	ML15008A119
2015-01-15	Correspondence / Meetings	Assemblywoman Sandy Galef writes to NRC Chairman Macfarlane re: independent risk analysis, Kuprewicz concerns	ML15027A419
2015-01-16	Licensee 50.59	Spectra sends Entergy updated (final) drawings for the tie-in between new and preexisting pipelines	obtained from Entergy through IP senior resident inspector
2015-01-23	AIM / FERC	FERC issues final environmental impact statement for AIM pipeline	https://www.ferc.gov/industries/gas/enviro/eis/2015/01-23-15-eis.asp
2015-01-28	10 CFR 2.206	NRC holds public PRB meeting regarding 2014-10-15 10 CFR 2.206 petition from Paul Blanch	ML15044A459
2015-02-24	10 CFR 2.206	NRC holds internal PRB meeting to discuss initial decision to reject 2014-10-15 10 CFR 2.206 petition	(no reference)
2015-02-26	10 CFR 2.206	Paul Blanch writes to Doug Pickett (project manager) re: source for 3-minute closure time	ML15057A530
2015-03-03	AIM / FERC	FERC issues approval order for AIM pipeline	https://www.ferc.gov/CalendarFiles/20150303170720-CP14-96-000.pdf
2015-03-13	Correspondence / Meetings	NRC (Evans) responds to Assemblywoman Sandy Galef re: 60-minute analysis, PRB process	ML15050A131
2015-03-17	Correspondence / Meetings	Paul Blanch writes to Commissioners re: delay in 10 CFR 2.206 acknowledgment letter, deficiencies in NRC analysis	ML15082A419
2015-03-27	Correspondence / Meetings	Paul Blanch writes to NRC Chairman Burns re: testimony before Rep. Lowey	https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13829121
2015-03-19	10 CFR 2.206	NRC/NRO documents sensitivity study regarding 3-minute isolation valve closure time on AIM pipeline	ML15078A067 Undated document; date estimated based on ADAMS addition.
2015-03-30	Licensee 50.59	NRC/NRR documents peer review of Entergy and NRC analyses re: 10 CFR 50.59	ML15331A342
2015-04-08	Licensee 50.59	Entergy submits 50.59 evaluation #2 for as-built AIM pipeline	ML15104A660 (letter and Encl. 1) ML15104A661 (Encl. 2 non-public)
2015-04-27	10 CFR 2.206	Dave Beaulieu emails PRB with background information on valve closure times (greater than 3 minutes)	ML15274A108
2015-04-28	10 CFR 2.206	Doug Pickett (project manager) emails Paul Blanch re: PRB's initial recommendation to reject petition, offers opportunity for second presentation	ML15124A027

Date	Category	Activity	Reference
2015-04-30	Correspondence / Meetings	NRC, FERC, and U.S. Department of Transportation hold government-to-government meeting with Assemblywoman Sandy Galef re: pipeline	mentioned in ML15251A372 slides received from Region I
2015-05-20	Correspondence / Meetings	Entergy writes to NRC responding to questions raised at 2015-04-30 government-to-government meeting, including Spectra procedures, inline inspections, and idle status of 26-inch pipeline	ML15182A235
2015-05-20	Correspondence / Meetings	NRC holds annual assessment meeting for Indian Point	https://www.nrc.gov/pmns/mtg?do=details&Code=20150737 summary: ML15152A076 Paul Blanch statement: ML15159A609
2015-06-13	Licensee Review / Analysis	Allegation submitted re: preexisting pipelines	ML15167A444
2015-06-24	Correspondence / Meetings	NRC Chairman Burns writes to Rep. Nita Lowey re: confidence in findings, worst case scenarios	ML15159A865 ML15176A589
2015-07-09	10 CFR 2.206	Paul Blanch supplements 10 CFR 2.206 petition re: failure probability of preexisting gas lines	ML15195A081
2015-07-15	10 CFR 2.206	NRC holds second PRB meeting regarding 2014-10-15 10 CFR 2.206 petition from Paul Blanch	ML15216A047
2015-07-27	10 CFR 2.206	Paul Blanch writes to Doug Pickett (project manager) with 39 questions to be addressed by PRB	ML15251A050
2015-08-04	Correspondence / Meetings	Assemblywoman Sandy Galef writes to NRC Chairman Burns requesting independent risk assessment including transient risk analysis	ML15232A212
2015-08-27	Licensee Review / Analysis	NRC (Scott) issues Request for Information (RI-2015-A-0074) on gas pipelines	non-public (not in ADAMS)
2015-09-09	10 CFR 2.206	NRC (Miller) rejects 2014-10-15 Paul Blanch petition, finding that issues had been previously resolved	ML15251A023
2015-09-10	Correspondence / Meetings	Paul Blanch meets with NRC Chairman Burns and Commissioners Baran and Ostendorff (September 10-11)	ML15259A047
2015-09-25	Correspondence / Meetings	NRC (Satorius) writes to Assemblywoman Sandy Galef re: conservative assumptions, 2015-04-30 meeting	ML15251A372
2015-10-07	Correspondence / Meetings	NRC (McCree) responds to Timothy Judson of Nuclear Information and Resource Service re: Entergy and NRC analyses	ML15253A007

Date	Category	Activity	Reference
2015-10-12	Correspondence / Meetings	Rick Kuprewicz writes to Sandy Galef re: 2015-09-25 letter to her, need for transient analysis	https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14016631
2015-10-15	Licensee Review / Analysis	Entergy responds to RI-2015-A-0074, enclosing 2008-09-30 and 2015-10-07 analyses by the Risk Research Group	non-public (not in ADAMS) - files on CD were not retained [additional safeguards material may exist]
2015-10-27	Correspondence / Meetings	Assemblywoman Sandy Galef writes to NRC (Satorius), attaching 2015-10-12 Rick Kuprewicz letter	https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14039741
2015-11-06	10 CFR 2.206	NRC (Miller) responds to Paul Blanch's 39 questions re: 2014-10-15 10 CFR 2.206 petition	ML15287A257
2015-11-20	NRC Guidance	NRC/NRR issues OI COM-106, "Control of Task Interface Agreements," Revision 5	ML15219A174
2015-11-30	Correspondence / Meetings	NRC Chairman Burns writes to David Lochbaum re: Regulatory Guide 1.91 and Advisory Committee on Reactor Safeguards man-made hazards working group	ML15258A242
2015-12-07	Correspondence / Meetings	NRC Chairman Burns meets with elected officials near Indian Point	referenced in ML15348A324
2015-12-07	NRC Review / Analysis	NRC/NRO completes confirmatory analyses related to 30-inch pipeline at Indian Point as allegation follow-up	ML16235A166 (pp. 12-15, 47-50,53-56, 59-62 of PDF for various copies of analysis documentation) ML16215A115
2015-12-14	10 CFR 2.206	Paul Blanch responds to Chris Miller re: 2015-11-06 "39 questions" letter	ML15348A324
2015-12-17	AIM / FERC	Paul Blanch contacts Pipeline and Hazardous Materials Safety Administration (PHMSA) administrator re: 49 CFR 192	https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14126329
2015-12-17	AIM / FERC	Paul Blanch contacts FERC Chairman re: 49 CFR 192	https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14081851
2016-01-07	Correspondence / Meetings	NRC Chairman Burns writes to Rep. Nita Lowey re: differences of opinion, lack of need for additional risk assessment	ML15355A409
2016-01-21	AIM / FERC	FERC responds to Paul Blanch Freedom of Information Act request re: PHMSA risk analysis (no records)	enclosure in ML16064A007 (non-public)

Date	Category	Activity	Reference
2016-01-21	Correspondence / Meetings	NRC Chairman Burns responds to Assemblywoman Sandy Galef re: planned meeting with Rick Kuprewicz	ML16013A181
2016-01-26	AIM / FERC	Paul Blanch emails PHMSA Administrator re: pipeline risk assessment (49 CFR 192)	https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14126330
2016-02-02	Correspondence / Meetings	NRC and PHMSA meet with Rick Kuprewicz re: pipeline; NRC provides follow-ups with plant information, 2014 10 CFR 50.59 evaluation	meeting summary: ML16036A347 (non-public) 2016-02-17 follow-up email: ML16048A097
2016-02-18	AIM / FERC	PHMSA replies to Paul Blanch re: NY DPS inspections of pipeline, risk analysis	(no reference)
2016-02-18	Correspondence / Meetings	NRC (Krohn) responds to Assemblywoman Sandy Galef re: 2015-12-28 letter requesting NRC staff meeting with Rick Kuprewicz (held 2016-02-02)	ML16042A488
2016-02-25	OIG Inquiry	Paul Blanch writes to NRC Office of the Inspector General (OIG) to request investigation of NRC staff not fulfilling its regulatory responsibilities	provided by Paul Blanch to Dave Skeen 3/8/2020
2016-02-29	AIM / FERC	NY State informs the FERC that the Governor directed an independent safety risk analysis of AIM pipeline near Indian Point	https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14166823
2016-03-11	AIM / FERC	Paul Blanch writes to PHMSA Administrator requesting risk analysis	(no reference)
2016-03-22	Correspondence / Meetings	NRC holds government-to-government meeting near Indian Point re: pipeline	slides received from Region I (date estimated)
2016-04-12	Correspondence / Meetings	Paul Blanch holds teleconference with PHMSA staff	https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14209383
2016-06-08	Correspondence / Meetings	NRC holds annual assessment meeting for Indian Point	ML16176A116
2016-09-12	AIM / FERC	Rick Kuprewicz completes filing (filed 2016-09-21) re: AIM pipeline in FERC court case (DC Circuit Docket No. 16-1081)	https://www.delawareriverkeeper.org/sites/default/files/Safety%20Threats%20Ignored%20Attachment%203%2C%20Declaration%20of%20Richard%20Kuprewicz%2C%20T....pdf
2016-09-16	AIM / FERC	Paul Blanch completes filing (filed 2016-09-21) re: AIM pipeline in FERC court case (DC Circuit Docket No. 16-1081)	http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B226348E4-8AA4-4E5F-B420-141915EE8C1F%7D

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2016-10-18	AIM / FERC	Spectra requests the FERC to authorize AIM to be placed in service using the preexisting Hudson River crossings	https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14379082
2016-11-30	Correspondence / Meetings	Paul Blanch emails Rao Tammara to request a meeting re: calculations	ML16336A729
2016-12-23	Correspondence / Meetings	NRC (Boland) responds to Paul Blanch request for meeting	ML16351A187
2018-02-08	NRC Guidance	NRC Commission holds public meeting on potential changes to the 10 CFR 2.206 petition review process	https://www.nrc.gov/reading-rm/doc-collections/commission/tr/2018/
2018-02-20	NRC Guidance	NRC issues Staff Requirements Memorandum re: Management Directive 8.11 updates (SRM-M180208)	ML18051A998
2018-06-22	AIM / FERC	NY State submits executive summary of risk analysis to the FERC	ML18176A367 http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B72A21EDA-B822-46D0-8C1E-E873D7F570E8%7D
2018-06-25	AIM / FERC	Paul Blanch writes to FERC Chairman asking for risk assessment required by 49 CFR 192.917	ML18177A401
2018-07-27	AIM / FERC	DC Circuit Court of Appeals issues ruling in City of Boston v. FERC re: AIM pipeline	https://www.ferc.gov/legal/court-cases/opinions/2018/16-1081CITYOFBOSTON.pdf
2018-08-02	AIM / FERC	Enbridge writes to the FERC re: New York State letter of 2018-06-22, pipeline safety	https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14992932
2018-08-16	AIM / FERC	Paul Blanch writes to New York Governor re: Enbridge's statements	https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=15000090
2019-03-01	NRC Guidance	NRC updates Management Directive 8.11 on 10 CFR 2.206 petition reviews	ML18296A043
2020-02-13	OIG Inquiry	NRC OIG issues Event Inquiry 16-024 on gas transmission lines near Indian Point	ML20056F095
2020-02-24	OIG Inquiry	NRC Chairman Svinicki tasks EDO in response to OIG Event Inquiry 16-024	ML20057E265
2020-02-26	OIG Inquiry	EDO writes memo to Commission re: no need for immediate regulatory action	ML20058D088

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2020-02-27	OIG Inquiry	EDO tasks David Skeen with leading expert evaluation team in response to OIG Event Inquiry 16-024	ML20058E354
2020-03-09	OIG Inquiry	NRC publicly releases evaluation team plan	ML20069A759
2020-03-09	OIG Inquiry	New York Department of Public Service writes to NRC and FERC re: NRC OIG report and 2018-06-22 letter	ML20071F306
2020-03-17	OIG Inquiry	Enbridge writes to FERC re: 2020-03-09 New York Senator Harkham letter, OIG report	https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=15486325
2020-03-19	OIG Inquiry	New York Attorney General's office writes to NRC, FERC, and PHMSA re: NRC OIG report	ML20090B533
2020-03-23	OIG Inquiry	Paul Blanch writes to NRC evaluation team leads	ML20086L164
2020-03-26	OIG Inquiry	New York State Public Service Commission writes to NRC evaluation team leads	ML20086L280