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

EVENT INQUIRY

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

OFFICE OF THE
INSPECTOR GENERAL

February 13, 2020

MEMORANDUM TO: Chairman Svinicki

FROM: David C. Lee
Deputy Inspector General

SUBJECT: CONCERNS PERTAINING TO GAS TRANSMISSION LINES AT THE INDIAN POINT NUCLEAR POWER PLANT (OIG CASE NO. 16-024)

This accompanies the results of an Office of the Inspector General (OIG), U.S. Nuclear Regulatory Commission (NRC), event inquiry into concerns pertaining to NRC's oversight of a 42-inch natural gas pipeline that was, at the time, proposed to traverse Indian Point Energy Center (IPEC) property. A citizen stakeholder questioned the adequacy and completeness of the licensee's (Entergy) site hazards analysis and NRC's independent and followup analyses prepared to determine the safety impact on IPEC plant components due to the potential rupture of the proposed high pressure 42-inch gas pipeline. OIG examined an NRC inspection report and underlying analysis used to determine that Entergy appropriately concluded the 42-inch gas pipeline would not introduce significant additional risk at IPEC. OIG also examined NRC's response to the stakeholder's concerns over the 42-inch gas pipeline.

We have also provided this event inquiry report to the appropriate Majority and Ranking Members of Congress with oversight responsibilities for the NRC.

If you have any questions, please contact me, at 301-415-5930, or Rocco J. Pierri, Assistant Inspector General for Investigations, at 301-415-5925.

Attachment: As stated

cc: Commissioner Baran
Commissioner Caputo
Commissioner Wright

Office of the Inspector General

EVENT INQUIRY

Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant

Case No. 16-024

TABLE OF CONTENTS

Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant (Case No. 16-024)

Basis and Scope

The Office of the Inspector General (OIG), U.S. Nuclear Regulatory Commission (NRC), initiated this event inquiry in response to concerns, communicated to OIG, from a citizen stakeholder pertaining to NRC's oversight of a 42-inch natural gas pipeline that was, at the time, proposed to traverse Indian Point Energy Center (IPEC) property. This pipeline, now in operation, was part of the Algonquin Incremental Market (AIM) Project, which proposed to replace certain portions of the existing pipeline and install new pipeline in the northeast United States. NRC's role was to support the Federal Energy Regulatory Commission's (FERC) decision to approve or disapprove the project by providing information to the FERC on the impacts of the AIM Project on IPEC. NRC's findings were documented in its Third-Quarter Integrated Inspection Report issued to Entergy, IPEC's license holder, on November 7, 2014.

In a publicly available Title 10 of the *Code of Federal Regulations* Section 2.206 (10 CFR) petition, dated October 15, 2014, and a letter to NRC dated July 27, 2015, the stakeholder questioned the adequacy and completeness of the licensee's (Entergy) site hazards analysis and NRC's independent and followup analyses prepared to determine the safety impact on IPEC plant components due to the potential rupture of the proposed high pressure 42-inch gas pipeline. The stakeholder also questioned whether (1) NRC misled FERC and the public by claiming to FERC that there was no additional risk associated with the proposed 42-inch gas pipeline, thereby putting at risk 20 million people near IPEC; (2) NRC was aware of material false statements made by Entergy to NRC with respect to the 42-inch gas pipeline; (3) NRC violated its procedures and regulations when analyzing the potential safety impacts from the 42-inch gas pipeline; and (4) NRC is allowing IPEC to operate in an unanalyzed condition.

OIG's event inquiry examined NRC's inspection report and underlying analysis used to determine that Entergy appropriately concluded the 42-inch gas pipeline would not introduce significant risk to safety-related systems, structures, and components; and systems, structures, and components important-to-safety at IPEC. On March 3, 2015, FERC issued an order formally approving the AIM Project. On January 7, 2017, the pipeline went into use.

As part of this event inquiry, OIG also examined NRC's response to the stakeholder's concerns over the 42-inch gas pipeline.

Findings

Finding 1

While FERC's approval of the AIM Project pipeline relied in part on NRC's assessment of Entergy's site hazards analysis and NRC's independent analysis of the impact of a potential rupture of the portion of the pipeline that traversed IPEC property, OIG found (1) NRC's independent analysis was incorrectly portrayed in FERC's approval document as significantly more conservative than it actually was; (2) NRC's inspection report contained inaccuracies suggesting additional analysis had been conducted, when this was not the case; and (3) 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. Moreover, the majority of NRC's independent analysis described the impact of a potential rupture on an above ground point on IPEC 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 IPEC property but does traverse the IPEC property.

OIG also found that NRC decisionmakers had differing understandings of the assumptions and factors driving the analysis conducted by an NRC Physical Scientist, who NRC considered a subject matter expert and who was responsible for conducting, documenting, and communicating his results. While the Physical Scientist attributed his analysis assumptions to OIG as engineering judgment, he did not have a basis for it and did not document a basis or a methodology in his report. When OIG briefed NRC managers on the issues OIG identified in the Physical Scientist's analysis, one noted that because the Physical Scientist conducted multiple calculations with increasing credit for pipeline enhancements, it appeared to be backwards engineering to get a desired result. An NRC senior manager said the Physical Scientist's use of credit for enhanced piping was inappropriate in part because the pipeline enhancements were not intended to mitigate the impact of a blast, but rather to reduce the chances of a rupture in the first place.

Several NRC senior managers said that based on issues identified in this event inquiry pertaining to the Physical Scientist's analysis, it may be prudent to redo the analysis.

Finding 2

OIG found that through the stakeholder's 2.206 petition and associated concerns – which were relevant and on point – NRC was presented an opportunity to reevaluate and confirm work previously conducted that supported the agency's conclusion that Entergy's hazards analysis was reliable. However, NRC failed to thoroughly reexamine the underlying premises of its analyses and did not accurately communicate its analytical work performed.

First, in response to the stakeholder's assertion that it would take longer than 3 minutes for the pipeline operators in Houston, Texas, to close the valves, thereby stopping the flow of gas, NRC misrepresented the assumptions used in the followup bounding analysis that was conducted to assess the impact of 60 minutes of gas released. While NRC's response to the stakeholder described having conducted an assessment that assumed an infinite source of natural gas with the pipeline valves open for an hour, OIG's investigation found that NRC assessed only 1 minute of gas released. Moreover, NRC never confirmed the validity of the licensee's assumption that the valves could be closed in 3 minutes. OIG contacted the pipeline operator who estimated it would take at least 6 minutes after detection of a leak to close the valves. While the Physical Scientist told OIG he used 1 minute of gas released in his calculations, NRC managers had inconsistent understandings of the amount of mass the Physical Scientist used.

Second, in response to the stakeholder's question of whether NRC performed a validation and verification of NOAA's computer program to ascertain its adequacy for this purpose, NRC stated there was no need for NRC to perform a validation and verification of the computer program. However, OIG contacted NOAA, which confirmed the program is not designed for this purpose.

Third, NRC's response to the stakeholder stated that NRC used the methodology and equations of Regulatory Guide 1.91, NRC's guidance for evaluating postulated explosions near nuclear power plants, "without deviation"; however, OIG found 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.

Fourth, the stakeholder asked whether NRC had any quality assurance requirements/procedures for conducting safety related calculations. NRC responded that they do not perform safety related calculations and do not have a quality assurance program for these calculations, but they said a peer review by a qualified NRC engineer was performed on NRC's independent analysis and followup analysis. OIG's investigation revealed that the assigned engineer, who felt there were more qualified people in NRC to do this, performed a limited review that focused mainly on the licensee's hazards analysis and not NRC's analyses.

An NRC senior manager conveyed to OIG that NRC decisionmakers rely on accurate information from the staff to support decisions and communicate accurately to stakeholders and, in this case, another Federal agency. However, NRC managers confirmed they do not have a quality assurance process or a formal peer review process to review this type of assessment.

Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant (Case No. 16-024)

Background and Chronology

IPEC is a nuclear power station located on the east bank of the Hudson River in Buchanan, NY, about 24 miles north of New York City, New York. According to IPEC's website, the station's two operating reactors, Unit 2 and Unit 3, supply electricity for about 3 million customers. Unit 1 was shut down in 1974 and is undergoing decommissioning. Units 2 and 3 are scheduled for decommissioning beginning in 2020 and 2021, respectively. Initially licensed to Consolidated Edison Company of New York, Inc., IPEC's current license holder is Entergy Nuclear Operations, Inc. (Entergy), and regulatory oversight for IPEC is provided by the NRC Region I office located in King of Prussia, PA.

Natural gas pipelines have existed on the IPEC owner-controlled property since before plant construction. Algonquin Gas Transmission Company[1] (Algonquin) built a 26-inch diameter natural gas pipeline in 1952 and an adjacent 30-inch natural gas pipeline in 1965, and both traverse IPEC property. As part of the initial licensing basis, the licensee assessed each operating unit for postulated pipeline explosions of both pipelines. The assessment used the measured "shortest distance" from the pipeline to safety-related system, structures, and components (SSCs[2]) as the safe distance to meet NRC regulations. In response to later NRC requests focused on physical security, Entergy expanded the licensing basis to also include above ground sections of the pipelines. The assessments concluded no hazard to safe plant operation if a rupture of the gas pipelines occurred. Licensees are required to adhere to their current licensing basis or request an amendment depending on changes affecting the licensed operation of the plant.

On February 28, 2014, Algonquin applied to FERC to construct, install, operate, and maintain approximately 37 miles of pipeline and related facilities in New York, Connecticut, and Massachusetts. The project was referred to as the Algonquin Incremental Market (AIM) Project and proposed to replace certain portions of existing pipeline and to install new pipeline in other areas. The AIM Project included a stretch of new 42-inch pipeline across IPEC's southern side. This new pipeline would transmit gas at higher pressures than the existing 26- and 30-inch pipelines and would be located further away than the existing pipelines from the plant's safety-related SSCs and Security Owner Controlled Area (SOCA), but closer to eight important to safety (ITS[3]) SSCs. A portion of the 42-inch pipeline crossing IPEC property would be enhanced with more safety features than normal for new pipelines. The closest two

[1] Algonquin is an indirect wholly owned subsidiary of Enbridge Energy Corporation.
[2] Nuclear power plants are designed with SSCs that prevent or mitigate the consequences of postulated accidents which could cause undue risk to the health and safety of the public.
[3] Structures, systems, and components ITS shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed.

pipeline safety valves (which could be used to shut off gas to the portion of the pipe crossing IPEC property) encompassing the IPEC section of the pipe would be 3 miles apart. The next two closest safety valves, which encompass the 3-mile stretch of pipeline and its two safety valves, would be approximately 15 miles apart.

On April 2 and 23, 2014, NRC and FERC representatives met to discuss the AIM Project, the Federal review process, and regulatory responsibilities. FERC provided an overview of the role of a cooperating agency.[4] NRC declined to become a cooperating agency but agreed to provide appropriate information, as needed, on the impacts of the AIM Project.

On August 6, 2014, FERC issued a draft Environmental Impact Statement (EIS) concerning the impact of the pipeline.[5] FERC concluded that based on its consultation with NRC, Entergy was required to assess any new safety impacts on its IPEC facility and provide its analysis to NRC. NRC's role was to ensure that the IPEC licensee adequately assessed the safety implications of the proposed pipeline at the nuclear site, as well as to determine if the licensee's analysis met the NRC's requirements regarding plant changes.

On August 24, 2014, Entergy completed its 10 CFR 50.59[6] safety evaluation and an associated hazards analysis, which covered the consequences of a fire and explosion following release of natural gas from the proposed new AIM Project 42-inch-diameter pipeline. The 10 CFR 50.59 report noted,

> While the proposed 42-inch pipeline is further from IP2 and IP3 SSCs within the SOCA used to control access to the main plant area than the existing pipelines, the new pipeline has a larger diameter than the existing lines and operates at a higher pressure, and therefore is a change to the current licensing basis for external hazards located near IP2 and IP3.

Because the 10 CFR 50.59 safety evaluation concluded there is a change to the current licensing basis for design basis external hazards, Entergy was required to undertake the associated hazards analysis. Entergy hired a consulting firm to prepare two supporting evaluations referred to as the "hazards analysis." The first evaluation included calculations for the consequences of postulated explosions and fire with missile generation[7] following the release of natural gas from the proposed new 42-inch pipeline

[4] Under the National Environmental Policy Act (NEPA), upon request of a lead agency preparing an EIS, any other Federal agency which has jurisdiction by law shall be a cooperating agency. In addition, any other Federal agency which has special expertise with respect to any environmental issue that should be addressed in the EIS may be a cooperating agency upon request of the lead agency.

[5] NEPA requires Federal agencies prepare an Environmental Impact Statement (EIS) if a proposed major federal action is determined to significantly affect the quality of the human environment.

[6] A 10 CFR 50.59 review is a technical evaluation performed by a licensee to determine if a proposed change to the facility represents a significant modification to the plant design and licensing bases as described in the Final Safety Analysis Report and, therefore, requires NRC approval prior to implementation.

[7] Missile generation are projectiles associated with detonation of potentially explosive material.

at two locations. Location one was the area on the underground piping that measured the shortest distances to the SSCs ITS, as committed to in IPEC's licensing basis. Location two was based on measurements of an above ground pipeline rupture point on the 42-inch pipeline, referred to as the "tie-in[8]" location. Although the above ground location was further away from the plant than the underground location, it was assessed because of the potential impacts from intentional and malicious activity.

For both locations (above and below ground), Entergy measured the shortest distances from the new 42-inch pipeline to several SSCs ITS and developed a table that identified these distances per component.

For Entergy's first evaluation, they used several methodologies and included in their analysis factors for pipeline enhancements such as thicker piping, thicker corrosion protection, greater burial depth, and installation of protective reinforced concrete mats to impede access to the buried piping. Entergy assumed the isolation valves were 3-miles apart and would close within 3 minutes of a pipeline rupture. Entergy claimed to have done the explosion and fire assessments in accordance with NRC Regulatory Guide 1.91, "Evaluations of Explosions Postulated to Occur at Nearby Facilities and on Transportation Routes Near Nuclear Power Plants," Revision 2[9], (RG 1.91) as well as using Areal Locations of Hazardous Atmospheres (ALOHA) and BREEZE computer programs.

Entergy's second evaluation was a statistical analysis of fire and explosions using "best available" accident data for pipeline rupture frequency. This assessment determined Exposure Rates[10] for a failure of the proposed 42-inch pipeline.

As documented in its 10 CFR 50.59 Safety Evaluation and Hazards Analysis, Entergy concluded that the proposed pipeline did not pose a "significant reduction in the margin of safety" for the public and that the change did not require prior NRC approval (i.e., a license amendment). Entergy based this conclusion on pipeline design and installation enhancements, the results from the fire and explosion evaluation, and the exposure rate assessment. However, there were two exceptions that were below NRC's threshold criteria which required additional evaluation. The two exceptions were the meteorological tower and the steam generator storage facility which are SSCs ITS. For these two exceptions, Entergy provided safety justifications. Specifically, for the meteorological tower, Entergy stated it had an alternative means to perform the meteorological function. For the steam generator storage facility, the safety evaluation demonstrated that failure of this component would not exceed the radiation dose limits imposed by NRC guidelines.

In September 2014, NRC Region I performed a permanent plant modification inspection (PMMI) at IPEC. One of several PMMI objectives is to verify that modifications to the

[8] Pipeline "tie-in" locations are above ground and used for inspection and maintenance throughout the entire pipeline.
[9] Agencywide Documents Access and Management System (ADAMS) Accession Number ML12170A980
[10] Exposure rates are analyses that demonstrate risk.

plant have not affected the safety functions of important safety systems. As one of three samples chosen for this inspection, NRC reviewed the 10 CFR 50.59 safety evaluation and supporting hazards analysis, conducted a walk-down of the proposed pipeline routing, and performed an independent analysis of the potential hazards relative to the new 42-inch pipeline.

An NRC Region I Security Inspector conducted this inspection with support from a Physical Scientist from NRC headquarters Office of New Reactors[11] (NRO), Radiation Protection and Accident Consequences Branch (RPAC). The Physical Scientist was considered an NRC subject matter expert on external hazards. The Region I Security Inspector did the on-site inspection activities while the Physical Scientist was tasked to perform independent confirmatory calculations. The Physical Scientist documented the results of his review in a six-page technical report titled, "Safety Review and Confirmatory Analysis, Entergy's 10 CFR 50.59 Safety Evaluation, Algonquin Incremental Market (AIM) Project, Indian Point Energy Center (IPEC)" (NRC AIM Project Safety Review). This report stated that the Physical Scientist performed independent confirmatory calculations with conservative assumptions and rationale using NRC RG 1.91 methodology and/or the ALOHA computer program to assess an explosion, jet fire, and cloud fire at the above ground point on the pipeline and the closest point (underground). The Physical Scientist's analysis was based on a stretch of pipeline consisting of about 3 miles between isolation valves, of which the enhanced section of pipeline length is identified to be 3,935 feet, and closure of the isolation valves within 3 minutes.

The Physical Scientist concluded that safety-related SSCs inside the SOCA passed the safety criteria, but that nearby SSCs ITS would be affected because the calculated minimum safe distances from the above ground reference point exceeded the safety criteria. To address the exceedance, the report stated,

> The staff finds that the impacts to the SSCs ITS from the proposed new 42-inch pipeline are bounded by the impacts from low probability events of extreme natural phenomena (including seismic activity, tornado winds, and hurricanes) which have been assessed and already addressed in the Indian Point Units 2 and 3 Updated Final Safety Analysis Report.[12]

The Physical Scientist's NRC AIM Project Safety Review was reviewed by the Region I Physical Security Inspector who shortened it into a four-page summary, or "feeder." This "feeder" was approved by two Region I Branch Chiefs and was incorporated into the NRC's Third-Quarter Integrated Inspection Report, issued to Entergy's IPEC Site Vice President on November 7, 2014[13]. The inspection report concluded that the proposed pipeline does not introduce significant additional risk to safety-related SSCs and SSCs ITS at Indian Point Units 2 and 3; and, therefore, the change in the design

---

[11] On October 13, 2019, NRO was reunified with the Office of Nuclear Reactor Regulation (NRR) and the resulting organization retained the title NRR.
[12] The most recent final safety analysis report (FSAR) includes the plant-specific design-basis information.
[13] ADAMS Accession Number ML14314A052

bases external hazards analysis associated with the proposed pipeline does not require prior NRC review and approval.

As reflected in an Interagency Meeting Summary prepared by FERC, on October 17, 2014, FERC held a conference call with NRC to discuss NRC's review of Entergy's site hazards analysis for IPEC relative to Algonquin's proposed AIM Project. The summary reflects that one FERC staff, one individual from the Natural Resource Group, LLC, and six NRC staff members involved with IPEC attended the conference call. The meeting summary conveyed that NRC had conducted an independent analysis of Entergy's 10 CFR 50.59 submission and an independent confirmatory blast analysis. The summary stated that Algonquin had committed to take additional mitigation measures to enhance the pipeline design and construction, but that NRC's analysis did not allow any credit for these additional mitigation measures and assumed a catastrophic pipeline failure. The summary stated that the review covered everything within the SOCA, which includes everything inside the outer most fenced area of the facility (including the spent fuel rods) and that "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 10 CFR 50.59 submission acceptable and has determined that no prior approval from the NRC is needed."

On October 15, 2014[14], a citizen stakeholder submitted a 10 CFR 2.206[15] petition to the NRC requesting the NRC to take enforcement action against Entergy for violating the regulations of 10 CFR 50.9, "Completeness and Accuracy of Information," 10 CFR Part 50, Appendix B, "Quality Assurance Requirements," and 10 CFR 50.59, "Changes, Tests, and Experiments." The stakeholder provided numerous examples and direct quotes from IPEC's 10 CFR 50.59 Safety Evaluation and Hazard Analysis that he believed violated these regulations.

In January 2015, the stakeholder presented his 2.206 concerns before an NRC Petition Review Board (PRB). In the months that followed, the stakeholder continued to submit additional information to support his allegation, including documents from the stakeholder's Freedom of Information Act (FOIA) requests to the NRC.

Also in January 2015, FERC issued its final EIS for the entire pipeline, assessing the potential environmental effects of the construction and operation of the AIM Project in accordance with the requirements of the National Environmental Policy Act. The EIS conveyed the FERC staff's conclusion that "approval of the proposed project would result in some adverse environmental impacts; however, most of these impacts would

[14] ADAMS Accession Number ML14294A758

[15] 10 CFR 2.206 has been a part of the NRC's regulatory framework since the NRC was established in 1975. Section 2.206 permits any person to file a request to institute a proceeding pursuant to Section 2.202 of 10 CFR to modify, suspend, or revoke a license, or for other action as may be proper (hereinafter referred to in this directive as to take enforcement-related action). Such a request is referred to as a 2.206 petition.

be reduced to less than significant levels with the implementation of Algonquin's proposed mitigation and the additional measures[16] recommended in the final EIS."

The EIS quotes Entergy's Safety Evaluation conclusion that

> …based on the proposed routing of the 42-inch diameter pipeline further from safety related equipment at IPEC, and accounting for the substantial design and installation enhancements agreed to by [Algonquin], the proposed AIM project poses no increased risks to IPEC and there is no significant reduction in the margin of safety.

The EIS also describes NRC's assessment of Entergy's evaluation:

> The NRC has reviewed the site hazards analysis performed by Entergy and has performed an independent confirmatory analysis of the blast analysis as well. The NRC issued its findings in a report dated November 7, 2014. The NRC's analysis did not include factoring in the additional pipeline design measures identified by Entergy and committed to by Algonquin and assumed a pipeline catastrophic failure. The review covered everything within the Security Owner Controlled Area, which includes everything inside the outermost fenced area of the facility (including the area with the spent fuel rods). 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 facility.

On March 3, 2015, FERC's Chairman and Commissioners issued an order formally approving the AIM Project. Page 37 of the order states,

> The NRC reviewed the site hazards analysis performed by Entergy and performed an independent confirmatory analysis of the blast analysis as well. The NRC's analysis did not account for the additional pipeline design measures identified by Entergy and committed to by Algonquin and assumed a pipeline catastrophic failure. The review covered everything within the Security Owner Controlled Area, which encompasses everything inside the outermost fenced area of the facility including the area with the spent fuel rods. 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 Facility. Therefore,

---

[16] Where the pipeline crossed IPEC property, these measures included (1) using internally coated piping that "exceeds the most stringent Class 4 requirements set by the U.S. Department of Transportation (even though this area is predominantly Class 3), (2) installing two parallel sets of fiber-reinforced concrete mats over the pipeline that would act as a physical barrier over the buried pipe, (3) installing yellow warning tape above and below the concrete slabs, (4) burying the pipeline to a minimum depth of 4 feet from the top of the pipeline, and (5) providing thicker external corrosion protection and internal coating.

the final EIS concludes that the project will not result in increased safety impacts at the Indian Point facility.

On April 8, 2015, Entergy submitted a revised 10 CFR 50.59 assessment to the NRC, acknowledging that amended pipeline plans indicated the 42-inch pipe would not come above ground. The revised 10 CFR 50.59 assessment reevaluated the “tie-in” location with the installed piping configuration and concluded that there were no increased risks to IPEC from the proposed AIM Project and the original Safety Evaluation remained bounding.

In April 2015, the stakeholder received a second FOIA response that he believed supported his allegation that Entergy had provided a material false statement regarding Enbridge’s ability to close the isolation valves within 3 minutes. The stakeholder requested an opportunity for a second presentation to the PRB which was granted and held on July 15, 2015. During the presentation, it was agreed that the stakeholder would submit remaining questions in writing; subsequently, the stakeholder prepared a written list of 39 questions that he submitted to the NRC on July 27, 2015.

In September 2015[17], the NRC rejected the stakeholder’s petition and in November 2015, provided answers to the stakeholder’s 39 questions.

On January 7, 2017, the pipeline went into use.

<u>Part I. Problems Identified by OIG With NRC’s November 7, 2014, Inspection Report and Underlying Analysis</u>

OIG learned that while FERC relied heavily on NRC’s November 7, 2014, inspection report as its basis for determining that IPEC could be safely shut down if a pipeline accident occurred, the underlying analysis for the inspection report was based on

- **A series of NRC calculations – assessing the closest location of the pipeline to plant components at a below ground point – that gave increasing amounts of “credit” for pipeline enhancements until the level of “credit” given resulted in an answer that demonstrated no increased risk, if a rupture occurred, to any safety related SSCs and SSCs ITS inside the SOCA.** In contrast, both FERC’s EIS and its March 3, 2015, order approving the AIM Project, state that NRC’s analysis did not account for the pipeline enhancements. OIG notes that the approach used by NRC – of crediting enhancements – was less conservative than the approach as described in the FERC documents, which indicated that no credit was given for enhancements.

- **NRC’s analysis of the impact of a rupture in a non-existent, above-ground point on the 42-inch pipeline.** OIG learned that the 42-inch pipeline does not go above ground at the “tie-in” location.

[17] ADAMS Accession Number ML15251A023

- **An inaccurate statement in NRC's analysis that although there was increased risk to SSCs ITS outside the SOCA if a pipeline rupture occurred, this was acceptable because these impacts were "bounded" by the impacts of extreme natural phenomena (e.g., tornadoes, hurricanes), which have been assessed and already addressed in the Indian Point Units 2 and 3 Updated Final Safety Analysis Reports (UFSAR)**. OIG learned that these impacts are not addressed in the Indian Point UFSARs.

- **NRC's misguided use of the ALOHA program to assess an explosion, a jet fire, and a cloud fire for the above and below ground portions of the pipeline.** Officials at the National Oceanic and Atmospheric Administration, Office of Response and Restoration Emergency Response Division[18] (NOAA), which created ALOHA, told OIG that ALOHA is not intended to assess impacts of explosions involving the type of "supercritical[19]" gas that would flow through the 42- inch pipe at IPEC. NOAA also told OIG ALOHA cannot assess 3 minutes of gas release prior to valve closure even though NRC's analysis claimed to do so, and it cannot model a double ended pipe break, which NRC also claimed to have done.

  Finally, OIG learned from Enbridge that it would, in fact, take the pipeline operators a minimum of 6 minutes after a leak is detected to manually close the isolation valves and thereby stop the flow of gas into the ruptured portion, and not 3 minutes as NRC claimed to have calculated using ALOHA. Enbridge also told OIG that if there were an explosion near IPEC, operators would shut valves that were approximately 14 miles apart rather than 3 miles apart as NRC assumed in its analysis.

- **OIG also learned that NRC's November 7, 2014, inspection report included an inaccurate statement that as part of NRC's analysis, the agency assessed the impact of "missile generation" that would occur if safe distance was exceeded for SSCs ITS.** Although NRC determined that safe distance was exceeded for SSCs ITS outside the SOCA, OIG learned that the agency did not assess missile generation.

Witness interviews of 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 (EIS) and FERC's Commission relied heavily on NRC's expertise to determine if IPEC could be safely shut down in the event of a pipeline accident, for approval of the portion of the AIM Project that crossed IPEC property.

---

[18] Department of Commerce, National Oceanic and Atmospheric Administration, National Ocean Service Office of Response and Restoration Emergency Response Division, Seattle, Washington.
[19] Methane gas is in a "supercritical" state at 850 psi and 25° Celsius.

Review of NRC AIM Project Safety Review

The Physical Scientist's NRC AIM Project Safety Review examined the potential impact of a pipe rupture at two points on the pipeline. One point was underground; this was the shortest distance to the SOCA – which is a point addressed in the plant's current licensing basis. The other location, discussed in the next section of this report, also in the current licensing basis, was a site further from the plant where initial AIM Project plans indicated the pipe would come above ground. The Physical Scientist's review concluded that safe distance would not be exceeded for the safety-related SSCs inside the SOCA but would be exceeded for SSCs ITS outside the SOCA. According to his report, pipe failure would not reduce any further the existing safety margins, and would not pose a threat to the safe operation of the plant or safe shutdown because the potential impacts to SSCs ITS outside the SOCA were bounded by previous studies addressed in the licensee's UFSAR. OIG noted that about five pages of the NRC AIM Project Safety Review focused on the above ground point, and about one page focused on the below ground point.

NRC Conducted Multiple Calculations Giving Increasing Amounts of Credit for Pipeline Enhancements Until Answer Envisioned No Added Risk

In reviewing the Physical Scientist's documentary materials supporting his analysis of the nearest point, OIG noted the Physical Scientist conducted a series of calculations on a particular point where the pipeline was enhanced with thicker piping, greater corrosion resistance, deeper burial depth, and protective reinforced concrete mats located above the buried piping. OIG noted that for each calculation, the Physical Scientist made incremental adjustments by giving credit for pipe enhancement features and using the average release instead of maximum release rate for the mass input variable. OIG observed that once the calculation yielded results that met the safe distance requirement, no additional credits were given. The first calculation used maximum release rate and gave no credit for pipeline enhancement features and yielded results that exceeded safe distance for safety related SSCs and SSCs ITS within and outside the SOCA. The second calculation used maximum release rate and gave 65 percent credit for pipeline enhancement features and yielded results that exceeded safe distance for safety related SSCs and SSCs ITS within and outside the SOCA. The third calculation used average release rate and gave no credit for pipeline enhancements. The third calculation for safe distance met requirements for SSCs and SSCs ITS inside the SOCA; however, it exceeded safe distances for SSCs ITS outside the SOCA. The fourth calculation used average release rate and 65 percent credit for pipeline enhancements. Only the fourth calculation met the safe distance requirement for all reference points.

OIG noted that NRC's use of credit for pipe enhancement features as described above contradicts statements in FERC's EIS and March 3, 2015, order approving the AIM Project, which both state that NRC's analysis did not account for the pipeline enhancements.

The Physical Scientist told OIG he relied on his engineering judgment[20] in assigning 65 percent credit for the pipeline safety features and for factoring in average release rate. When asked to explain the basis for assigning 65 percent credit for pipeline enhancements and for using the average release rate, instead of providing any quantitative or empirical data to support his engineering judgment, the Physical Scientist stated, “That is my call. That is my assumption.” Regarding his assigning 65 percent credit for the pipeline safety features, the Physical Scientist told OIG, because the pipeline is underground and has a layer of concrete slaps above, the pipeline will leak at a slower rate than when above ground. “So that’s why one-third might be a reasonable number.” Regarding his substitution of average release for maximum release rate, the Physical Scientist told OIG, “an average value would be more [realistic] than a conservative maximum value” because the gas would release at a slower rate due to the pipe’s underground location. The Physical Scientist added, “At what rate I do not know. The only possible rate it can be is an average rate.” The Physical Scientist told OIG he did not describe the various underground scenarios in his NRC AIM Project Safety Review but included his conclusion that the underground scenario would not adversely impact the safe operation and shutdown of IPEC. He said it would have been “too confusing to address so many scenarios, so many things.”

The Physical Scientist’s Branch Chief at the time, who assigned the Physical Scientist to conduct the review, told OIG he was aware that the Physical Scientist ran many scenarios, but the Physical Scientist did not go over the results or details with him. The Branch Chief said that he knew the Physical Scientist took “65 percent credit” for the pipeline enhancements based on his engineering judgment. When OIG shared the four calculations and results with the fourth calculation not exceeding the minimum safe distance, the Branch Chief said that it appeared, from looking at the Physical Scientist’s scenarios, that the Physical Scientist was backward engineering for a desired result. When OIG shared the statement in FERC’s EIS that described that the NRC’s analysis did not include factoring in the additional pipeline design measures identified by Entergy and committed to by Algonquin, the Branch Chief said that description is contrary because the Physical Scientist did take credit for the pipeline enhancements.

NRC Analyzed a Non-Existent, Above-Ground Point

As noted above, the Physical Scientist also examined a second site further from the plant where initial AIM Project plans indicated the pipe would come above ground. However, OIG learned that while the initial 42-inch pipeline design proposed by Algonquin indicated the new pipeline would come above ground on IPEC property, the final pipeline design and pipeline as built never comes above ground on IPEC property.

OIG spoke with Enbridge regarding several matters under investigation. For the matter of the above ground scenario, Enbridge told OIG that the 42-inch gas pipeline on IPEC property never comes above ground. The only portion above ground is a “pig trap,” also

[20] NUREG 1913, “Design Control in Pursuit of Engineering Excellence, A Quick Reference Guide for NRC Inspectors,” defines engineering judgment as a determination based on prior examples, experience, or observation that has not been subjected to rigorous engineering validation.

known as a “pig station,” which is a configuration of pipes and “tie in” valves that are used for cleaning, maintenance, and inspection. For the pig station near IPEC, the largest diameter pipeline above ground is 26 inches.

OIG learned that while IPEC’s initial 10 CFR 50.59 analysis also assessed the proposed above ground point, on April 8, 2015, IPEC submitted to NRC a revised 10 CFR 50.59 that acknowledged the change-in-design and re-assessed the impact of an explosion on the pig station, using the specific dimensions associated with the as-built piping. Although the revised 10 CFR 50.59 was provided to NRC – approximately 1 month after FERC’s approval of pipeline construction and approximately 20 months before pipeline went into operation – the NRC never conducted further analysis on the actual as-built pipeline, and much of NRC’s analysis remains based on a non-existent, above ground location.

The Physical Scientist told OIG that although he conducted multiple scenarios at the underground closest location to the plant, the above ground location was the basis for his conclusion for the NRC AIM Project Safety Review and the NRC inspection report. The Physical Scientist viewed the above ground point as a more credible location for a potential pipeline rupture since it was exposed on the surface.

The Physical Scientist’s Branch Chief said he was aware that the Physical Scientist used the above ground point in his analysis. The Branch Chief said that Region I looked at the Physical Scientist’s calculations too and he recalled discussions that the calculations were based on the worst hazard to the closest SSCs. Furthermore, the Branch Chief believed some conservatisms were employed by the Physical Scientist in his calculations and modeling, such as catastrophic failure of the pipe closest above ground location to the plant, which should provide for the worst-case scenario.

The NRC IPEC Project Manager who was also assigned as the 2.206 petition manager for the stakeholder’s concerns was not aware that the reported result of the NRC’s independent analysis was primarily based on the above ground location rather than the closest point. The Project Manager, who was NRC’s primary communicator with FERC, told OIG he assumed the reported confirmatory analysis was done at the closest location to the plant for conservatism and to compare with Entergy’s analysis results. The Project Manager clearly recalled that the 42-inch pipeline did not come above ground while on IPEC’s property. The Project Manager said he would have expected the worst-case scenario (e.g., no credit taken for enhancements, maximum release rate, closest point to the plant) to have been assessed and was surprised that it was not.

NRC Incorrectly Stated Impacts Were Bounded by Previous Assessments

OIG also learned that both the NRC AIM Project Safety Review and NRC’s November 7, 2014, inspection report each included an inaccurate statement suggesting that prior analysis indicated that although the current analysis showed risk to the SSCs ITS, these risks were “bounded” by previous studies. Specifically, the two reports stated that impacts to the SSCs ITS outside the SOCA from both the above ground and below ground points analyzed

> …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 Points Units 2 and 3 UFSAR. Indian Point Units 2 and 3 would still be able to achieve safe shutdown conditions.

Through review of the Indian Point Units 2 and 3 UFSAR and verification with IPEC officials, OIG learned the UFSAR does not address the bounding effects of extreme natural phenomena on SSCs ITS outside the SOCA. RG 1.91 states that additional analyses are required if SSCs ITS safe distances are not met.

The Physical Scientist recalled reporting that a pipe rupture impacting the SSCs ITS was bounded by more severe accidents such as extreme natural phenomena already evaluated in IPEC's UFSAR. According to the Physical Scientist, he did not conduct additional analysis because he believed the UFSAR already established this analysis.

NRC Used ALOHA to Model Scenarios Outside of ALOHA's Parameters

Based on review of NRC's Project AIM Safety Review and the Physical Scientist's supporting documentation, OIG learned that the Physical Scientist used the ALOHA program to determine the impacts for the jet flame, cloud fire, vapor cloud explosion, and unconfined explosion on IPEC's SSCs related to safety and the SSCs ITS. NOAA officials told OIG that ALOHA is designed for use during accidental chemical spills to help emergency response professionals assess the risk associated with toxic air hazards, thermal radiation from fires, and blast effects. NOAA officials explained that although ALOHA includes an extensive library of chemical property data, and models to assess the rate at which a chemical is released from containment and vaporizes, it has technical limitations.

After reviewing the ALOHA assessments done by the NRC for IPEC, NOAA officials provided OIG several areas of concern because they are outside the technical limitations of ALOHA's capability. First, ALOHA is not intended to assess impacts of explosions involving the type of "supercritical" gas that would flow through the 42-inch pipe at IPEC. According to NOAA officials, the pressure and temperature of the methane gas that the NRC modeled is within the "supercritical" state. OIG provided NOAA officials with the Physical Scientist's ALOHA model assumptions and results. NOAA officials told OIG that a simplified sensitivity assessment they ran, based on the information provided by OIG, resulted in an approximate underestimation of mass of flammable vapor released by 9 percent. This underestimation of mass resulted in a less conservative value.

Second, NOAA officials told OIG that ALOHA lacks the capability to assess 3-minutes of gas release prior to valve closure – although NRC's analysis stated it used a 3-minute valve closure time in its NRC AIM Project Safety Review. According to NOAA, the ALOHA program can assess only two valve scenarios – these are (1) valves closed (i.e., 0 minutes of gas released) or (2) the valves are connected to an infinite source (i.e., 60 minutes of gas released). For the valves closed scenario, ALOHA calculates just the residual gas mass in the pipeline. ALOHA provides several results to include a 1-minute maximum release rate of mass and a total release of mass. Therefore, statements in the Physical Scientist's NRC AIM Project Safety Review describing the estimated impacts that would result from an explosion, jet fire, and cloud fire, "considering manual closure of the isolation valves within 3-minutes," are inaccurate because ALOHA does not have the capability to model this scenario.

Additionally, OIG learned that ALOHA is designed solely for vertical breaks into the atmosphere and surrounding area; it is not designed for horizontal pipe breaks, it is not designed to model buried pipe, and ALOHA cannot 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.

Finally, OIG learned from Enbridge that it would, in fact, take the company a minimum of 6 minutes after leak detection to seal off the pipe and thereby stop the flow of gas into the ruptured portion, and not 3 minutes as NRC tried to calculate using ALOHA. Enbridge officials also told OIG that in the event of a rupture, operators would seal off approximately 14 miles of the pipeline surrounding the rupture point, and not the 3 miles the Physical Scientist used in his calculations.

The Physical Scientist told OIG he used ALOHA to determine the impacts for the jet flame, cloud fire, vapor cloud explosion, and unconfined explosion on IPEC's SSCs related to safety and the SSCs ITS. The Physical Scientist told OIG he believed ALOHA had been validated by the industry and was an accepted Environmental Protection Agency (EPA) and NOAA model for the analysis conducted.

The Physical Scientist's Branch Chief was not aware of ALOHA's limitations as described by NOAA, and said they caused him concern. He did not recall any discussions with the Physical Scientist about the use of ALOHA.

NRC Inspection Report Incorrectly Stated Missile Generation Was Assessed

OIG compared the language in NRC's November 7, 2014, inspection report description of NRC's "independent calculation results using conservative assumptions and rationale" with the Physical Scientist's calculations and the description in the NRC AIM Project Safety Review. OIG noted that the inspection report states that NRC assessed "missile generation." Specifically, the November 7, 2014, inspection report stated,

> The NRC's Physical Scientist performed an independent analysis of the hazards associated with the proposed pipeline. The analysis was

> performed based on the following conditions and hypothetical scenarios: rupture of the proposed pipeline located near IPEC resulting in an unconfined explosion or jet flame at the source; delayed vapor cloud fire or vapor cloud explosion; and accompanying missile generation.

The NRC AIM Project Safety Review stated,

> The analysis assumed that rupture of the natural gas pipeline may result in an unconfined explosion or jet flame at the source, delayed vapor cloud fire, or vapor cloud explosion. Missile generation may also accompany the rupture/explosion.

However, OIG's review of the Physical Scientist's calculations did not support that missile generation was assessed.

The Physical Scientist told OIG that he did not calculate missile generation because the minimum safe distance did not exceed the SSCs. RG 1.91 suggests that additional analysis, such as missile generation, be done if the minimum safe distance is exceeded for SSCs ITS. However, the Physical Scientist argued that in light of his understanding of RG 1.91, only the SSCs required further analysis if the minimum safe distance was exceeded. The Physical Scientist acknowledged that he did not pay close attention to the wording in RG 1.91 for SSCs ITS.

Interviews of NRC Managers

The Region I Branch Chief, who signed the November 7, 2014, inspection report, confirmed that although Region I reviewed Entergy's initial 10 CFR 50.59 as part of the inspection, Region I relied heavily on the Physical Scientist's NRC AIM Project Safety Review to determine the inspection finding of "no finding" because Region I alone did not have the expertise to make that decision. The Region I Branch Chief believed FERC used NRC's inspection report as one of the bases for its EIS and approval and he believed the Physical Scientist used the most conservative location in his analysis, which he believed was above ground.

In contrast, the Region I Deputy Regional Administrator, who was then the Region I Director of Reactor Safety, said the staff's 10 CFR 50.59 inspection did not rely on the Physical Scientist's calculations for the inspection's outcome. However, the Physical Scientist's work gave the region added confidence that there was no technical issue that Entergy might have missed and therefore no reason to challenge Entergy's conclusion that the new pipeline did not pose an increased risk and warrant a license amendment. The Deputy Regional Administrator said prior to the OIG interview, he had not been aware of the specific assumptions and factors the Physical Scientist had used in his calculations pertaining to the above and below ground scenarios; however, he was comfortable with the Physical Scientist's approach. He said he was confident in the outcome because it was a "very, very conservative approach." Nevertheless, the Deputy Regional Administrator acknowledged that based on the discrepancies described by OIG, it would be prudent to conduct additional analysis to demonstrate there is no issue or problem.

In a series of meetings with NRC's then-Deputy Executive Director for Reactor Preparedness Programs (DEDR) (now retired), OIG described the discrepancies identified in NRC's AIM Project Safety Review. The DEDR was initially unfamiliar with the specifics of NRC's analysis, but said his understanding was the staff had done a thoughtful review and he was comfortable with the conclusions reached. However, based on the information OIG provided and his subsequent discussions with his technical staff, he told OIG he would be open to assess whether any additional work was needed after having an opportunity to review OIG's report. He said if the staff made any mistakes that raise questions, then "let's demonstrate to ourselves that this does not cast doubt on the overall conclusions that we drew. And, if it does, then we've got some more work to do…."

OIG briefed the current DEDR on the results of this event inquiry. The DEDR, who was familiar with Project AIM because he served as the Region I Regional Administrator in the 2014-2018 timeframe, expressed serious concerns about the issues identified by OIG. Specifically, the DEDR disagreed with the Physical Scientist's use of credits for enhanced piping in his underground calculations because the DEDR said the enhancements were not intended to mitigate the effects of a blast but were intended to reduce the chances of a pipe rupture in the first place (e.g., due to a backhoe or other digging equipment). In addition, the DEDR was concerned that the Physical Scientist did not provide a basis or explanation underlying his "engineering judgment." According to the DEDR, "engineering judgment does not mean winging it."

With regard to inaccuracies in NRC's November 7, 2014, inspection report (i.e., SSCs ITS bounded by UFSAR and that missile generation was examined), the DEDR said these factual errors were unacceptable and did not meet his expectations. The DEDR was concerned about information NRC had publicly communicated, especially in an agency decision document. The DEDR said if there were inaccuracies in an inspection report "that other agencies are relying on," there may be a need to clarify and amend the record.

With regard to NOAA's estimate that NRC's analysis underrepresented the mass of gas released in all scenarios by approximately 9 percent which resulted in a less conservative value, the DEDR remarked he would expect the users of a code to understand the code's parameters and he was concerned about the non-conservative results.

With regard to IPEC's revised 10 CFR 50.59 safety evaluation based on the 42-inch pipe not coming above ground in the final pipeline design, the DEDR assumed his inspectors were aware and had reviewed and assessed the impact of the design change. He was not concerned that the 42-inch pipe did not come above the ground because an above-ground explosion would have a more far reaching impact than a below ground explosion at the same location. Therefore, the DEDR said the Physical Scientist's initial assessment of the above ground point was bounding.

In summary, the DEDR stated that NRC management has to rely on the information provided to them by the agency's technical experts. He said this information needs to be accurate and robust for sound decisionmaking. He commented that while communication can be challenging, in these matters, it needs to be sufficiently clear to allow for sound agency decisions.

Part II. NRC's Response to Stakeholder Concerns Over Project AIM Pipeline

NRC followed its 10 CFR 2.206 petition process in reviewing and responding to a citizen stakeholder's specific concerns about the impact of the new pipeline on IPEC property, which resulted in NRC's formal rejection of the stakeholder's concerns reflected in the original petition and in the stakeholder's associated correspondence to NRC. However, OIG learned that in communicating its decision to the stakeholder, NRC provided an inaccurate description of the work NRC conducted to assess the stakeholder's concerns. The investigation also revealed that NRC provided inaccurate information in response to the stakeholder's questions to NRC concerning the agency's NRC AIM Project Safety Review.

Specifically, the stakeholder challenged

- **Both Entergy's and the Physical Scientist's assumption, in their respective assessments, that the pipeline valves could be closed in 3 minutes.** The stakeholder asserted that it would not be possible for the valves to be closed within 3 minutes and questioned why NRC did not inform FERC that the fundamental assumptions and calculations were inaccurate. The stakeholder also asserted that Entergy violated 10 CFR 50.9 by providing a material false statement concerning the 3-minute valve closure times to the NRC in its 10 CFR 50.59 safety evaluation.

  OIG learned from Enbridge (the pipeline company) that it would take at least 6 minutes to close the valves after a leak is detected. The investigation also revealed that in response to the stakeholder's concern about a material false statement regarding the 3-minute closure time, NRC chose to conduct a 60-minute bounding analysis, and inaccurately described the results of its followup calculation. This analysis was used to refute the stakeholder's allegation of a material false statement.

- **NRC's use of ALOHA to assess the impact of pipe rupture on IPEC.** The stakeholder questioned why NRC would use ALOHA, which, according to the stakeholder, "is prohibited for use for a gas pipeline rupture [and] not referenced in RG 1.91, to calculate the blast radius of a rupture that could have a devastating impact to the more than 20 million persons residing in the vicinity of

Indian Point." The stakeholder also asked whether NRC performed a validation and verification of the ALOHA program to ascertain its accuracy.

OIG's investigation revealed that NRC informed the stakeholder that a validation and verification of ALOHA was not necessary. However, as noted previously in this report, NOAA, which created ALOHA, told OIG the program was not designed to assess the scenarios used by NRC to support the NRC AIM Project Safety Review.

- **NRC's deviation from RG 1.91 in calculating blast radius.** The stakeholder asserted that NRC modified the equation for calculating the blast radius in RG 1.91 and asked why NRC failed to provide a basis for deviation from the regulatory guide.

  Although NRC's response to the stakeholder claimed NRC used RG 1.91, Revision 2, without deviation, OIG's investigation identified that NRC deviated from RG 1.91 in a manner that was less conservative and had an impact on the outcome.

- **The quality assurance process used by NRC to verify the results of the NRC AIM Project Safety Review and followup assessment.** The stakeholder asked whether NRC has any quality assurance requirements/procedures for conducting safety related calculations.

  NRC responded to the stakeholder that NRC does not perform safety related calculations and does not have a quality assurance program for these calculations; however, they said a peer review by a qualified NRC engineer was performed on the NRC AIM Project Safety Review and followup assessment. OIG's investigation revealed the assigned engineer believed there were better qualified NRC staff to do the review and he performed only a limited review.

OIG Review of Correspondence

OIG reviewed correspondence between the citizen stakeholder and NRC dated October 15, 2014, through November 6, 2015, reflecting the stakeholder's concerns, and NRC's responses, about the safety impact on IPEC due to Enbridge's proposed 42-inch diameter natural gas pipeline that would traverse a portion of the owner-controlled property at IPEC. In at least four letters to NRC and two presentations to the NRC Petition Review Board (PRB), the stakeholder raised concerns and provided his technical analysis to support his questions. The NRC responded with correspondence that documented the agency's position.

On October 15, 2014, the stakeholder submitted a 10 CFR 2.206 petition requesting enforcement action against Entergy. This process is the primary mechanism by which the public can request NRC take enforcement-type action related to licensees or licensed activities. In the petition, the stakeholder stated that the hazards analysis, prepared by the licensee to determine the safety impact on IPEC due to the proposed pipeline, is inadequate and incomplete, which violates several regulations including 10 CFR 50.9, “Completeness and Accuracy of Information” and 10 CFR 50.59, “Changes, tests, and experiments.”

NRC responded to the stakeholder’s 2.206 petition by assigning a PRB to review the stakeholder’s concerns. Throughout the petition process, the stakeholder was informed of the staff’s progress primarily by the NRC IPEC Project Manager, who was assigned to be the Petition Manager. The stakeholder was also provided an opportunity to present to the PRB on two occasions. These actions align with guidance in Management Directive 8.11, “Review Process for 10 CFR 2.206 Petitions.”

On January 28, 2015, the stakeholder made his first presentation before the PRB and provided clarifying and supplemental information in support of his petition. During this presentation, the stakeholder was accompanied by an individual with expertise in gas pipeline operation and safety management.

Subsequent to that presentation, NRC informed the stakeholder that the PRB’s initial recommendation was to reject the petition because the staff had previously reviewed and resolved the items identified in his petition.

Prior to learning of the PRB’s initial recommendation, the stakeholder submitted a FOIA request for all documents related to the proposed 42-inch gas pipeline for IPEC. After receiving the FOIA responses, the stakeholder communicated additional concerns to the NRC PRB, as well as the Commission, that included potential flaws with the staff’s confirmatory analysis used to conclude there would be no hazard to safe plant operation if a rupture of the gas pipelines occurred at IPEC.

On July 15, 2015[21], the stakeholder made a second presentation before the PRB. The purpose of that meeting was to allow the stakeholder to comment on the initial recommendation of the PRB and to provide supplementary information to his petition. At this presentation, the stakeholder provided additional evidence to support his concerns with (1) NRC’s use of the computer program ALOHA, (2) deviations from RG 1.91 equations, and (3) valve closure time assumption – which the stakeholder declared as a material false statement.

Following the second presentation, the PRB met to determine whether the new information provided sufficient details to change or modify the initial recommendation.

In NRC correspondence dated September 9, 2015, the stakeholder was informed that the PRB recommended to reject the petition on the basis that all identified issues had been previously reviewed and resolved. NRC’s letter stated the PRB recommendation was reviewed and approved by senior management of the Office of Nuclear Reactor Regulation. As agreed during the second presentation before the PRB, the NRC

[21] ADAMS Accession Number ML15251A050

committed to providing responses to the 39 written questions from the stakeholder under separate correspondence.

On November 6[22], 2015, the NRC responded to each of the stakeholder's 39 questions. The staff concluded that based on the review of Entergy's 10 CFR 50.59 hazards analysis and the NRC's independent calculation results using conservative assumptions and rationale, Entergy had appropriately concluded that the proposed pipeline does not introduce more than minimal additional risk to IPEC, and therefore, the changes in the external hazards analysis associated with the proposed pipeline did not require prior NRC review and approval.

Additionally, the staff began its November 6, 2015, correspondence with a summary of several of the stakeholder's concerns. Of particular relevance to this case are

- For the assumption of a 3-minute isolation valve closure time that the stakeholder characterized as a material false statement (potential 10 CFR 50.9 violation) the NRC claimed it performed a bounding sensitivity analysis for two scenarios, one for 3 minutes of gas release and another for 60 minutes of gas release. NRC reported the result of the 60-minute bounding sensitivity analysis was only marginally different from the 3-minute valve closure assumption. According to the NRC, "the staff concluded that valve closure times do not have a significant impact on the site hazards analysis, and the licensee's assumption of a 3-minute valve closure time does not have a material impact on that analysis."

- Regarding the alleged inaccurate and incomplete 10 CFR 50.59 hazards analysis prepared by Entergy, NRC stated it disagreed with the stakeholder's assertions. The agency reported that the staff stood by the initial conclusion, as documented in the November 7, 2014, inspection report, that a potential rupture of the proposed pipeline posed no threat to the safe operation of the plant or safe shutdown of the plant.

- With respect to the NRC withdrawing its findings to FERC that the proposed pipeline would not present an unacceptable risk to IPEC, NRC stated that the staff performed a thorough review of Entergy's 10 CFR 50.59 site hazards analysis and performed its own independent confirmatory analysis that is in agreement with the licensee's results. "The NRC has no basis to withdraw its previous conclusions to FERC," the letter stated.

Assumption that Pipeline Valves Could Be Closed in 3 Minutes and NRC's Followup Analysis

In correspondence dated January 28, 2015, and July 27, 2015, the stakeholder alleged that Entergy's site hazards analysis has a material false statement because the analysis assumed that pipeline operators located in Houston, Texas, would be able to recognize

[22] ADAMS Accession Number ML15287A257

a pipe rupture from pressure sensors located in the pipeline and take appropriate actions to close the pipeline isolation valves within 3 minutes.

During the January 28, 2015, PRB meeting, an individual with expertise in pipeline safety presented to the PRB the technical rationale[23] as to why significantly more time would elapse before valve closure could be activated by the Houston-based pipeline operators. According to this expert, the main signal to close valves is a significant decrease in pipeline pressure. For example, this individual posed that if you have 15 miles of high-pressure gas pipeline, it would not go to zero pressure instantly – it might be 20 minutes before the operators can recognize the valves need to be closed.

In response to this concern, the PRB asked for a "bounding sensitivity analysis" to be conducted. The PRB sought to test what the impact would be with 60-minutes of gas being released, with the assumption that if safety margins were not exceeded for 60-minutes, then they would not be exceeded for 3 minutes. The Physical Scientist who prepared the NRC AIM Project Safety Review was assigned to conduct this task and docketed his report on March 19, 2015, in the Agencywide Documents Access and Management System (ADAMS). According to the report's conclusion,

> The analysis 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. Based on this analysis, the NRC staff has determined that there are only minimal changes to the peak overpressure calculation and the heat flux calculation. Therefore, the staff concludes that pipeline isolation valve closure times are inconsequential and the previous staff conclusions that the proposed 42-inch diameter natural gas 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 remain valid.

This conclusion was communicated to the stakeholder in NRC's correspondence dated November 6, 2015. This response conveyed that the staff considered one scenario where the isolation valves were assumed to close within 3-minutes, and a second scenario that "assumed the release of gas for a full hour with the unbroken end of pipe connected to an infinite source." The letter stated, "the staff concluded that valve closure times do not have a significant impact on the site hazards analysis, and the licensee's assumption of a 3-minute valve closure time does not have a material impact on that analysis."

OIG reviewed the Physical Scientist's calculations for both the initial Project AIM Safety Review and his work done in response to the PRB's followup request and determined that NRC's November 6, 2015, correspondence inaccurately described the work done by the Physical Scientist. Although ALOHA does have the capability to assess

[23] According to the expert, the laws of thermodynamics provide the basis for pipe line rupture systemic dynamics that sustain pressure in the system before the compressor station recognizes a rupture.

60 minutes of gas released with an infinite source as well as the gas released in the first minute, as noted earlier in this report, it does not have the capability to assess 3 minutes of gas release prior to valve closure. In fact, OIG determined that the Physical Scientist used the 1-minute maximum gas release rate from ALOHA for both the 3-minute scenario assessed in the NRC AIM Project Safety Review and the 60-minute scenario conducted in response to the PRB request.

The Physical Scientist acknowledged to OIG that he used the 1-minute maximum release rate for his 3-minute analysis in the NRC AIM Project Safety Review and in his followup analysis to the PRB request. He said he ran ALOHA for 60 minutes and got results for both the total amount of mass released for 60-minutes and the 1-minute maximum release. However, he added he used the 1-minute mass value in his calculations because he considered it more realistic. According to the Physical Scientist, he used engineering judgment based on his understanding that methane is lighter than air and rises and disperses quickly. Furthermore, the Physical Scientist said he reported out his results to the PRB as he described them in the NRC AIM Project Safety Review and Confirmatory Analysis. The Physical Scientist told OIG that he believed he accurately communicated to the PRB what he did and "how they interpreted it, I do not know."

While the Physical Scientist's Branch Chief told OIG he thought the Physical Scientist had used the 60-minutes total mass in the equation, the IPEC Project Manager who wrote the November 6, 2015, correspondence, told OIG he was aware that the Physical Scientist had used 1 minute. According to the Physical Scientist's Branch Chief, the mass value used by the Physical Scientist is not necessarily the issue; however, the value chosen needs to be communicated accurately and transparent to the public.

NRC's Use of ALOHA to Assess Impact of Pipe Rupture on IPEC

In communications with the NRC, the stakeholder questioned the use of ALOHA to assess the quantity of gas released in a pipeline rupture. His rationale for questioning this was his belief that ALOHA cannot be used since it cannot model gas release from a pipe that has broken in the middle and is leaking from both broken ends and is not referenced in RG 1.91. The stakeholder also asked whether NRC performed a validation and verification of the ALOHA program to ascertain its accuracy.

In a letter dated November 6, 2015, to the stakeholder, the NRC responded,

> There is no need for the NRC staff to perform a validation and verification of the ALOHA computer program. ALOHA has been measured against similar computer models and the results are considered comparable.

This letter conveyed NRC staff believed ALOHA was an adequate program to use for their assessments. Additionally, the letter conveyed that NRC was aware of the pipe break limitation. The letter explained how the staff modeled its independent analysis to address this limitation by doubling the predicted gas release from the upstream side of a pipe break to account for flow escaping from both sides of the break. The letter stated this was a conservative approach.

As described previously in this report, OIG learned from the developers of ALOHA (NOAA) that ALOHA does not model double-ended breaks plus several other limitations that the NRC failed to consider.

Further, OIG reviewed the Physical Scientist's calculations and observed that, contrary to the information conveyed in NRC's November 6, 2015, letter to the stakeholder, the Physical Scientist did not double the predicted gas release for the majority of calculations performed to support the November 7, 2014, NRC inspection report. He also did not double the predicted gas release when conducting the "60-minute bounding analysis" in response to the stakeholder's questions about the 3-minute valve closure time.

In contrast to NRC's assertion in its letter to the stakeholder that it doubled the mass in its independent and followup analyses, the Physical Scientist confirmed to OIG that he doubled the predicted gas release only for the underground scenario assessed during his NRC AIM Project Safety Review (where he also took 65 percent credit for the enhanced piping). The Physical Scientist acknowledged he did not double the mass when assessing the impact of a rupture above ground. The Physical Scientist said he accurately described to his management his assumptions and rationale (i.e., doubled the predicted gas release only for the underground scenario where he took 65 percent credit for enhanced piping and did not double the predicted gas release in other scenarios), and added, "but whether they absorb exactly that detail, everything, I'm not sure."

The IPEC Project Manager told OIG he knew ALOHA calculates flow only from one direction. Contrary to what the Physical Scientist told OIG, the IPEC Project Manager said it was his understanding that to compensate for this limitation, the Physical Scientist doubled the predicted gas release amounts for all results reflected in the November 7, 2014, inspection report to account for a double-ended break. The IPEC Project Manager told OIG that NRC did not provide calculations to FERC but talked them through the inspection report.

Also in contrast to the Physical Scientist's explanation to OIG, the Physical Scientist's Branch Chief told OIG it was his understanding the Physical Scientist doubled the mass value from ALOHA for both the above ground and below ground calculations. Also for the 60-minute bounding calculation, the Branch Chief said he thought the Physical Scientist assumed a double ended break. The Branch Chief recalled a meeting regarding IPEC with Federal and State Government officials where participants questioned this area and NRC discussed doubling the mass value to be conservative.

NRC's Deviation from RG 1.91 in Calculating the Blast Radius

In correspondence to NRC dated July 27, 2015, the stakeholder questioned NRC's adherence to RG 1.91 used to calculate the blast radius or safe distance. NRC Regulatory Guide (RG) 1.91, "Evaluations of Explosions Postulated to Occur at Nearby Facilities and on Transportation Routes Near Nuclear Power Plants," is the staff's guidance document for evaluating the impact of explosions from nearby transportation routes. This guidance defines an acceptable methodology for calculating safe distances beyond which no adverse effect would occur on nuclear plant safety components.

The stakeholder questioned why the NRC either modified and/or ignored its primary guidance, RG 1.91, and specifically questioned an undefined input parameter "Y" and the lack of a significant change in the results when the gas release continued for 60-minutes instead of 3 minutes. The stakeholder, using RG 1.91 equations, alleged the blast radius will increase by a factor of 2.71, or 3,000 feet, for the 60-minute assessment.

In correspondence dated November 6, 2015, the NRC reported,

> RG 1.91 is the staff's guidance document for evaluating the impact of explosions from nearby facilities and transportation routes. Entergy and the NRC used the methodology and equations of RG 1.91, without deviation, to determine the blast radius of 1.0 psi. No other methodology was used.

Additionally, the staff described that the "Y" represents the yield factor for methane as stated in Table 1 of RG 1.91. Regarding the stakeholder's concern with the lack of significant difference between the 3-minute and 60-minute valve closure assessments, the NRC reported,

> The NRC staff disagrees with the above extrapolation of the blast radius from 1,100 to 3,000 feet. As discussed in the response to question 4, it is a misapplication of Equation (1) of RG 1.91 to extrapolate a 3-minute gas pipeline release to a 1-hour gas pipeline release by multiplying the available mass by a factor of 20 and taking the cube root. Multiplying the calculated safe distances by a factor of 2.71 (i.e., the cube root of 20), ignores buoyancy of natural gas and artificially assumes that the entire amount of gas released over an hour will remain confined and available for an explosion. Thus, the above argument extending the calculated safe distance of 1,100 feet to 3,000 feet is flawed.

OIG reviewed the Physical Scientist's calculations and determined the Physical Scientist did use RG 1.91 Table 1's Y value for methane. As noted previously in this report, the lack of significance for the 3-minute versus 60-minute valve closure assessments was due to 1-minute of mass that was used for both assessments.

However, OIG noted that although NRC said its assessment did not deviate from RG 1.91 methodology, in fact, the RG 1.91 calculations for the underground and above ground locations did deviate from RG 1.91 equations. Specifically, the Physical Scientist used a different denominator – resulting in less conservative results. The applicable RG 1.91 equation has the pre-set denominator of 4420 kJ/kg and the Physical Scientist used 4500 kJ/kg.

During the course of several interviews with OIG, the Physical Scientist provided varying explanations as to why he used 4500 kJ/kg for the denominator. None of his explanations were consistent with RG 1.91, Revision 2, which NRC claimed had been used without deviation. First, he said he rounded the denominator (4420 kJ/kg) to 4500 kJ/kg because he considered it a generally used "nominal value," whereas the 4420 kJ/kg was the "precise value" and his change of values was "not going to make that much difference." In a second attempt to explain to OIG his basis for using 4500 kJ/kg, the Physical Scientist provided a draft of RG 1.91 that preceded Revision 2, which contained the pre-set denominator of 4500 kJ/kg. (OIG notes that RG 1.91, Revision 2, had been approved in April 2013, more than 1 year prior to the Physical Scientist's independent analysis.) He also provided NRC fire protection references that use a denominator of 4500 kJ/kg. The Physical Scientist also admitted he typically uses the 4500 kJ/kg denominator in similar safety assessments related to other NRC licensed nuclear facilities.

The Physical Scientist did not consider his use of 4500 kJ/kg a deviation from RG 1.91 and as such did not inform NRC management of the change in the denominator. However, the Physical Scientist agreed that following an NRC regulatory guide without deviation meant following it as written to include applying "equations as they are."

The Physical Scientist's Branch Chief agreed that changing the denominator was a deviation from RG 1.91. He added that because the conversion factor was changed to a larger number, the results were less conservative, and this was an issue that should be addressed. He also said that if you deviate from RG 1.91, it should be in the more conservative direction and should be documented and communicated to all involved because if the deviations are not communicated, it would be assumed that the RG was used as written. According to the Physical Scientist's Branch Chief, the use of a larger denominator than prescribed in RG 1.91, in combination with 1-minute of mass (as discussed previously in this report), undermined the ability of the NRC to add conservatism for safety assurance.

The IPEC Project Manager was unaware that the denominator was changed and agreed that changing the pre-set denominator modified the equation. According to the IPEC Project Manager, the Physical Scientist reported that the equations in RG 1.91 were used as is and unchanged. The IPEC Project Manager explained to OIG that raising the pre-set denominator made the result less conservative. He was not aware of any flexibility that existed in RG 1.91 for using other values. He had no explanation as to why someone would use anything other than the values in RG 1.91 equations.

Quality Assurance Process Used by NRC To Verify the Results of the AIM Project Safety Review and Followup Assessment

In correspondence dated July 27, 2015, the stakeholder questioned NRC's quality assurance process for verifying safety related calculations. In correspondence dated November 6, 2015, the NRC responded to the stakeholder that the NRC staff does not perform "safety-related" calculations and does not have a quality assurance process for such calculations. The letter stated,

> The NRC does not perform "safety-related calculations." Therefore, the NRC staff does not have specific procedures for performing calculations used to support inspections or to perform confirmatory analysis. The term, "safety related calculations" implies formal calculations performed by licensees for the design of NRC regulated facilities. Safety-related calculations by licensees must be performed in accordance with approved plant procedures and associated quality control. Calculations performed by the staff do not require the same level of documentation and are performed as needed to support independent confirmatory analysis.

NRC's letter conveyed that in response to the stakeholder's concerns, the staff performed an independent analysis that received a peer review by a qualified NRC engineer.

OIG learned that a headquarters Reactor Oversight Process (ROP) Engineer was assigned to peer review the Physical Scientist's analysis. The ROP Engineer told OIG he was selected while attending an Executive Leadership Team meeting after he mentioned he previously worked for Bechtel Power performing hazards analysis calculations and had used ALOHA. He said he told the Executive Leadership Team there was a Region IV staff member with better qualifications to conduct the review; however, an NRC senior manager assigned the ROP Engineer to the task.

According to the ROP Engineer, he spent approximately 8 hours conducting this review, and about "99 percent" of his time was focused on reviewing the licensee's 10 CFR 50.59 safety evaluation. He said there is no formal process for conducting a peer review. He said his approach was to talk to the Physical Scientist who described his process to him; download ALOHA from the Internet; and apply the Physical Scientist's assumptions and numbers in ALOHA, which seemed reasonable to him; and he came up with similar results. Then he wrote his conclusion that the independent analysis performed by the Physical Scientist used acceptable methodologies and realistic conservative assumptions and the conclusions matched the licensee's. The ROP Engineer said that he wrote his review summary in such a way that it "sent signals" that his check was an unofficial peer review from one individual to another – similar to inspectors sharing notes. The ROP Engineer said he was uncomfortable performing this peer review since the NRC does not have a defendable, formal process in place to conduct quality assurance or peer reviews.

The IPEC Project Manager was aware that the NRC did a peer review to determine if the Physical Scientist's calculation looked reasonable. The IPEC Project Manager recalled that the peer reviewer was qualified to do the peer review since he had experience working with ALOHA in the past.

OIG learned from the Physical Scientist's Branch Chief that typically peer reviews are not done. However, due to the high visibility of this situation, to include the stakeholder, NRC management decided to task another knowledgeable NRC staff member with "taking a hard look" at the Physical Scientist's calculations. The Physical Scientist's Branch Chief remembered that the peer reviewer did not identify any problems.

Interviews of NRC Managers

The Region I Deputy Regional Administrator, who was then the Region I Director of Reactor Safety, was aware that 60 minutes of gas release was not used for the bounding analysis, but that the amount assessed was something between 0 and 60 minutes. While he initially stated he thought the Physical Scientist used a number of conservatisms in his assessment that made this situation "more safe," later in the interview he acknowledged there might be a need to reassess. The Region I Deputy Regional Administrator also told OIG that he was not aware the Physical Scientist made a change from the RG 1.91 equations. However, he could not speak to a potential change in the denominator since he did not know why the Physical Scientist would do that. However, if it was done, the NRC should have documented it and why the change was made.

NRC's then-Deputy Executive Director for Reactor Preparedness Programs (DEDR) (now retired), told OIG he would expect the information that NRC documented and provided to the stakeholder to align with the staff's actual work for the NRC AIM Project Safety Review. He also said he would be disappointed if the NRC used a draft regulatory guide. Regarding the peer review, he told OIG that without talking to the ROP Engineer who conducted the review, he did not have a sense of how thorough it was. However, based on the description provided by OIG, and given stakeholder attention to this issue and NRC's reliance on the Physical Scientist's assessment, NRC should have done a better job with the peer review.

The current DEDR said he thought the Physical Scientist had assessed 3 minutes of gas release and 60 minutes of gas release; however, based on the information provided by OIG (i.e., that only 1 minute of gas release was assessed under both scenarios), the DEDR said he was very concerned. He recalled the stakeholder's question about whether the pipe could actually be sealed off in 3 minutes, given the operators' location in Houston; he said this was why NRC chose to assess an hour because it would be a "very bounding analysis." However, he said, "what you are presenting to me here is not." He also recalled the stakeholder challenging the similarity of NRC's results for the 3-minute and 60-minute analyses, and based on discussion with OIG, he now recognized why the results were so similar (i.e., only 1 minute of mass was used for each scenario).

Regarding the Physical Scientist's use of a draft version of RG 1.91, the current DEDR said the Physical Scientist should not have used a draft, especially when there was an approved guide available. The DEDR also said he would not have expected the Physical Scientist to round the denominator unless it was a conscious decision to be more conservative. However, he noted, in this case the rounding was in the non-conservative direction and was not documented or explained.

Regarding the "peer review," the DEDR said it did not "sound like what was asserted as a peer review was really well thought out." OIG told the DEDR there were two NRC gas plume experts in Region IV and the DEDR said he was inclined to have them recalculate the blast radius and compare the outcome to the results that NRC has relied upon. According to the DEDR, "it goes to the materiality…this all raises a lot of questions."

In response to OIG's question about whether IPEC is operating in an unanalyzed condition due to risks posed by the new 42-inch pipeline, the DEDR said, "The only reason I would hesitate…to just jump in and say we are in an unanalyzed condition is Entergy did analyze it. I have questions about how well we validated their analysis, so I think we have more work to do, but I don't think I would say they are in an unanalyzed condition at this point."

HOTLINE NUMBER:
1-800-233-3497

THE OFFICE OF THE
INSPECTOR GENERAL

Attention: Hotline Program
Mail Stop O5E13
11555 Rockville Pike
Rockville, MD 20852-2738