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

June 29, 2015

Mr. Paul M. Blanch
135 Hyde Rd.
West Hartford, CT 06117

Dear Mr. Blanch:

I am responding to your letter dated March 17, 2015, to U.S. Nuclear Regulatory Commission (NRC or the Commission) Chairman Stephen G. Burns, Commissioner Kristine L. Svinicki, Commissioner William C. Ostendorff, and Commissioner Jeff Baran regarding the proposed 42-inch diameter natural gas pipeline that will traverse a portion of the Indian Point owner-controlled property. Your letter covered a number of related topics where you: (1) were critical of the NRC staff's handling of your petition of October 15, 2014, that you submitted under Title 10 of the *Code of Federal Regulations* (10 CFR) 2.206; (2) stated that Indian Point Unit Nos. 2 and 3 (Indian Point) are operating in an unanalyzed condition that significantly degrades plant safety; (3) requested that the Commission direct the staff to rescind its approval of the proposed pipeline to the Federal Energy Regulatory Commission (FERC); and (4) identified a number of deficiencies in the staff's independent confirmatory blast analysis of the proposed natural gas pipeline.

The following provides a brief summary of natural gas pipelines at the Indian Point site:

- Natural gas pipelines have existed on the Indian Point owner-controlled property since before plant construction. The Algonquin Gas Transmission Company built a 26-inch diameter natural gas pipeline in 1952 and an adjacent 30-inch natural gas pipeline in 1965. Operating licenses were granted to Indian Point Units 1, 2, and 3 in 1962, 1973, and 1975, respectively. The existing pipelines are located approximately 640 feet from the Unit 3 containment. The Atomic Energy Commission (AEC)/NRC performed confirmatory analysis to determine the impact of a rupture of the existing natural gas pipelines at the Indian Point facility in 1973, 2003, and 2008.

- In February 2014 Spectra Energy submitted an application to FERC to install 37.6 miles of a new 42-inch diameter natural gas pipeline that would cross over a portion of the owner-controlled property at Indian Point. Following issuance of an Environmental Impact Statement, FERC approved the proposal on March 3, 2015.

- NRC regulations require that the licensee perform a site hazards analysis to determine the impact of a rupture of the proposed natural gas pipeline on the safe operation and shutdown of the nuclear power plants. By letter dated August 21, 2014, Entergy submitted their analysis, pursuant to 10 CFR 50.59, and concluded that a rupture of the 42-inch natural gas pipeline would not represent an increased risk to the site, and that prior NRC review and approval was not required.

- While the new pipeline is larger than the existing pipelines, it will be routed significantly further away from safety-related structures, systems, and components (SSCs) than the existing gas pipelines at the Indian Point site. Therefore, the blast analysis performed by the licensee, as well as the confirmatory analysis performed by the NRC, concluded that resultant pressure waves and critical heat flux from a pipeline rupture would not adversely impact safety-related SSCs at the site.

- NRC staff from Region I, the Office of Nuclear Reactor Regulation (NRR), and the Office of New Reactors (NRO) reviewed the licensee's analysis and confirmed the licensee's findings in an inspection report dated November 7, 2014. NRO staff performed an independent confirmatory analysis of a postulated pipeline rupture and concluded that it would not adversely impact the safe operations at Indian Point.

Your petition of October 15, 2014, is currently being reviewed by a Petition Review Board (PRB) in accordance with the staff's guidance found in Management Directive 8.11. Your letter correctly pointed out that one of the timeliness goals of the Management Directive is to issue the proposed Director's Decision for comment within 120 days from the date of the acknowledgement letter. As of this date, the PRB has not issued an acknowledgement letter regarding your petition. Following your presentation before the PRB on January 28, 2015, the PRB performed a sensitivity study to determine the significance of the licensee's assumed 3 minute valve closure time and sought out an independent peer review of the staff's confirmatory analysis. This work, which has significantly extended the time needed for the staff's review, was considered necessary in order to make a determination whether to accept the petition. By email dated April 28, 2015, from Mr. Douglas Pickett of my staff, you were informed that the initial recommendation of the PRB was to reject your petition from review pursuant to 10 CFR 2.206 because the issues raised in your petition, along with its supplements, have already been the subject of NRC staff review and resolution has been achieved.

Additionally, you requested that the Commission rescind NRC's "approval" of the proposed pipeline to FERC. As you are aware, FERC, not the NRC, has statutory responsibility to approve the proposed pipeline. The NRC staff's role is limited to confirming that Entergy performed a site hazards analysis as required by NRC regulations in order to determine whether the pipeline would introduce unacceptable risks to the facility. While the NRC staff is not required to review and approve the licensee's 10 CFR 50.59 site hazards analysis, the staff performed an onsite inspection of the licensee's site hazards analysis and conducted an independent confirmatory analysis of the blast effects. In support of FERC's Environmental Impact Statement, the staff informed FERC of the licensee's analysis, the NRC staff's confirmatory analysis, and the NRC staff's inspection results. The NRC staff remains confident of these findings. As previously stated, FERC provided its approval of the proposed pipeline on March 3, 2015.

Finally, you identified a number of aspects of the NRC staff's confirmatory analysis that you considered to be deficiencies. We have addressed these concerns in the enclosure to this letter. We are confident that the concerns you raised do not affect the staff's conclusions regarding the safety of the Indian Point nuclear plants in the event that the proposed pipeline is constructed as proposed.

We appreciate your questions and views. We trust that the information contained in this letter addresses the safety concerns that you included in your letter to the Commission dated March 17, 2015. If you have further concerns or new information regarding the gas pipelines at Indian Point, please contact Mr. Douglas Pickett at Douglas.Pickett@nrc.gov.

Sincerely,

Michael I. Dudek

Michael I. Dudek, Acting Chief
Plant Licensing Branch I-1
Division of Operating Reactors Licensing
Office of Nuclear Reactor Regulation

Enclosure:
NRC Staff Responses

U.S. Nuclear Regulatory Commission Staff Responses to Paul M. Blanch
Letter of March 17, 2015

Comment 1:

The analysis relies on the Environmental Protection Agency's (EPA) Areal Locations of Hazardous Atmospheres (ALOHA) code to predict the probability and consequences of fires, overpressure and radiant heat flux. The EPA document states the following:

> ***"ALOHA cannot model gas release from a pipe that has broken in the middle and is leaking from both broken ends." (Bold emphasis added by EPA)***

NRC Staff Response:

The ALOHA User's Manual includes conditions and limitations for its use. Specifically, when modeling a pipe rupture, ALOHA assumes unidirectional flow from only one end of the broken pipe. Thus, when modeling a guillotine pipe rupture, all flow is assumed to be released from one end of the broken pipe without any backflow from the opposite end of the pipe.

When evaluating a break in the middle of a pipeline, the U.S. Nuclear Regulatory Commission (NRC) staff modified the ALOHA input data to represent the scenario being considered by using half the length of pipeline and doubling the average release rate calculated by ALOHA. This provides a conservative, bounding gas release rate for the scenario. The staff also compared release rates calculated by ALOHA with average release rates calculated manually, based on equations available in reference literature and reports. The ALOHA model calculated maximum and average release rates that are higher than the release rates calculated by hand and, therefore, are considered conservative for this application. Accordingly, the staff is confident that its use of the ALOHA code is appropriate for this application and results in conservative gas release rates

Comment 2:

None of the cited references mention 3 minutes for a gas line rupture but do discuss a 1-hour time to be considered. History and expert opinions demonstrate gas blowdown times range from 30 minutes to many hours.

NRC Staff Response:

Entergy's site hazards analysis assumed that remote plant operators located in Houston, TX, would be able to recognize a pipe rupture from pressure sensors located in the pipeline and take appropriate actions to close the pipeline isolation valves within 3 minutes of a major pipe rupture. Due to concerns about remote operators being capable of performing these actions within 3 minutes, the NRC staff performed a sensitivity analysis. The staff's sensitivity analysis consisted of two cases. First, the staff considered the case with the valves closed. Second, the staff assumed the release of gas for a full hour with the

unbroken end of pipe connected to an infinite source. The resulting pressure pulse and heat flux values are only marginally different from one another and, in both cases, showed that equipment relied on to safely shut down the facility would remain available and operable. Therefore, the staff concluded that valve closure times do not have a significant impact on the site hazard analysis, and the licensee's assumption of a 3 minute valve closure time does not have a significant impact on that analysis.

Comments 3 and 4:

Using more realistic gas release of one to two orders of magnitude greater, the blast radius would encompass the city water tank and possibly tanks used for core cooling. The NRC/Entergy analysis stated the switchyard and the diesel oil storage tanks are within the blast radius. Loss of the switchyard and the oil tanks would result in a station blackout (SBO) and the loss of the city water tank would render the Unit 2 SBO diesel inoperable due to loss of SBO diesel generator cooling.

The city water tank serves to supply back-up water to the Auxiliary Feedwater System used to cool the core during loss of alternating current power/SBO event.

NRC Staff Response to Comments 3 and 4:

The licensee's site hazard analysis concluded that there will be no damage to safety related structures, systems, and components (SSCs). In its confirmatory analysis using conservative assumptions and rationale, the NRC staff also concluded that no overpressure event of ≥ 1.0 psi or potential damaging heat flux would be extended to any safety related SSCs inside the Security Owner Controlled Area (SOCA).

The licensee's site hazards analysis report did acknowledge that a rupture of the proposed gas pipeline could potentially impact SSCs important-to-safety (ITS), which include the switchyard, the diesel generator fuel oil storage tank, and the city water tank. Loss of SSCs ITS could cause a loss of offsite power. The licensee noted that loss of SSCs ITS could also occur from low probability events such as extreme natural phenomena (e.g., earthquake, tornado winds/missiles, hurricanes, etc.) because they are not designed against such events. However, loss of SSCs ITS have been analyzed and addressed in the Indian Point 2 and 3 Updated Final Safety Analysis Reports (UFSARs), and it is concluded that their loss would not lead to core damage.

An SBO event would not occur following loss of SSCs ITS such as the switchyard and the adjacent diesel generator fuel oil tank. An SBO event would require additional failures in addition to the loss of SSCs ITS, such as a common mode failure of the safety related diesel generators or failure to procure offsite diesel generator fuel oil supplies. Also, as discussed in NUMARC 87-00, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," an SBO event is assumed to be initiated by loss of offsite power resulting from a switchyard related event and not a low probability event such as fire, flood, or seismic activity. Therefore, when considering an SBO event, licensees do not postulate a concurrent low probability event.

Comments 5, 6 and 7:

The NRC stated in its analysis that the probability of an explosion after a pipe rupture is 5 percent yet this number is not contained in any of the cited references. Research shows almost 100 percent of pipe ruptures result in ignition.

The NRC analysis assumes that a total pipe rupture will occur in 1 percent of the pipeline accidents whereas the references clearly state this occurs in 20 percent of the accidents.

The NRC analysis states: "*If this release is due to the underground pipe, the frequency of explosion will be further reduced by at* ***least an order of magnitude.***" (Emphasis added) There is no documentation or reference supporting this non-conservative assumption.

NRC Staff Response to Comments 5, 6, and 7:

The NRC staff's acceptance criteria for evaluating potential hazards are found in NUREG-0800 (Reference 2). The acceptance criteria require that licensees determine the impacts by either: (i) using a deterministic approach, or (ii) estimating that the probability of the event having an expected rate of occurrence of potential exposures in excess of 10 CFR 50.34(a)(1), which is less than the NRC staff's objective of being within an order of magnitude of 10^{-7} per year.

The NRC staff performed an independent confirmatory analysis that calculated minimum safe distances using a conservative deterministic approach (Reference 2). The staff concluded that the distance between the pipeline and the nearest safety related SSCs exceeds the minimum safe distance that results in 1 psi overpressure or potentially damaging heat flux from the pipeline, and, therefore, there would be no adverse impacts to safety related SSCs within the SOCA. The staff verified that loss of SSCs ITS have been analyzed and addressed in the UFSARs. Since the NRC acceptance criteria were satisfied based on a deterministic analysis of the consequences impacting SSCs, probability estimates are neither required nor warranted. Therefore, the staff finds the licensee's conclusions acceptable.

Although the NRC staff concluded that a probabilistic analysis is not required, the staff nonetheless estimated the frequency of potential pipeline ruptures in evaluating the licensee's approach and assumptions. In estimating the pipeline rupture frequency, data from the "*Handbook of Chemical Hazards Analysis Procedures*" (Reference 3), along with project specific assumptions from the licensee's submittal of August 21, 2014 (Reference 4), were considered to allow credit for the enhanced design and installation features of the underground pipeline. It should be recognized that not all ignitions from a pipeline rupture generate explosions (i.e., producing pressure waves). Therefore, the fraction of pipe ruptures that result in explosions is assumed to be 5 percent based on the literature, *"Property Loss Prevention Data Sheets"* (Reference 5), and *"Risk Analysis of Natural Gas Pipeline Case Study of a Generic Pipeline"* (Reference 6). Also, gas releases due to pin-hole leaks or small breaks equivalent to 2- to 4-inch diameter are more frequent than a complete rupture that would result in a catastrophic burst and release. The catastrophic rupture release frequency of 13 percent is addressed in Reference 6. However, by applying reasonable credit for the enhanced design features of the buried pipeline (i.e., the enhanced pipeline is constructed of thicker diameter piping, is buried deeper, and has protective

concrete mats over the pipeline to provide additional physical protection), the staff considers a 1 percent catastrophic release frequency to be reasonable and more realistic. The staff's assumption that the frequency of explosion would be an order of magnitude lower for the enhanced portions of the underground pipeline was based upon engineering judgment and consideration that the underground pipeline would have a lower potential for ignition and explosion.

It should be noted that any technical argument regarding the probability of a pipeline rupture is moot because both the licensee and the staff performed a deterministic analysis that assumed the pipe would rupture and was not based on probability. As stated above, the NRC acceptance criteria were satisfied based upon a deterministic analysis and found acceptable.

Comment 8:

The analysis for the Combined License Application (COLA) permit for Turkey Point Units 6 and 7 predict a damage radius of more than 3000 feet from a smaller line operating at a lower pressure. The NRC/Entergy analysis predicts a damage radius of 1155 feet for a line more than double in capacity operating at a higher pressure.

NRC Staff Response:

It is not appropriate to compare the Entergy analysis and the NRC staff confirmatory analysis for Indian Point to a separate analysis performed by the Turkey Point licensee, because these analyses were based upon vastly different assumptions. The site hazards analysis that was performed by the licensee for Turkey Point Units 6 and 7, calculated the minimum safe distance using the methodology of Regulatory Guide 1.91 (Reference 7) as well as the ALOHA plume model based on a very conservative assumption of a confined explosion. A confined explosion would assume that gas is trapped by local terrain and would accumulate near the vicinity of the plant prior to ignition. This assumption would maximize the calculated pressure and result in a larger safe distance.

The NRC staff believes that a more realistic model for Indian Point would assume an unconfined explosion. This determination is based upon observations and walkdowns of the proposed pipeline routing by NRC inspectors. Inspectors observed that the proposed pipeline will be buried in an open area where the local topography and plant life (i.e., trees) would not permit localized accumulations of natural gas. Modeling would allow for dispersion and mixing with air in an open terrain while minimizing the potential for congestion. The differences in assumptions used to model the two sites, including the differences between assuming a confined versus an unconfined explosion, would produce significantly different results.

Comment 9:

The cited reference "Handbook of Chemical Hazard Analysis Procedures" (Reference 3) is apparently dated circa 1987 and does not consider subsequent major gas-line explosions such as the San Bruno, CA, Sissonville WV, Cleburne TX, Carlsbad NM, and the Edison, NJ transmission and distribution explosions.

NRC Staff Response:

While the staff recognizes that more recent updated accident data may change previously determined unit accident rates (events/mile-year), any change would be expected to be minor, and would not be sufficient to alter the overall conclusion. This can be observed from the reported values from Reference 6 where the pipeline rupture frequency of 5.99×10^{-4} events/mile-year that covers the period from 1970-2007 is about the same magnitude as that of the value of 5×10^{-4} events/mile-year reported in Reference 3.

Comment 10:

The NRC calculates the probability of a gas line explosion at 7.5E-7 per year. My calculations and the invalid use of the EPA ALOHA code clearly show the probability of core damage to be orders of magnitude greater than predicted by the NRC/Entergy analysis.

NRC Staff Response:

The NRC staff reiterates that the NRC acceptance criteria were met based upon a deterministic analysis that assumes the pipeline will rupture and does not consider probability. Therefore, any argument regarding the probability of a pipeline rupture is moot.

Regardless, the basis for the NRC staff's estimate of the probability of a gas pipeline rupture of 7.5×10^{-7} per year is provided in Reference 8. As previously stated, the ALOHA code was not used inappropriately. The staff is confident that its confirmatory analysis provides reliable results; the staff has not seen the commenter's referenced calculations, and, therefore, cannot comment on them.

<u>REFERENCES</u>:

1. US EPA, NOAA, "ALOHA User's Manual," February 2007.

2. NUREG-0800," Standard Review Plan 2.2.3, Evaluation of Potential Hazards," Rev.3, March 2007.

3. FEMA, US DOT, US EPA, *"Handbook of Chemical Hazard Analysis Procedures," 1987.*

4. Energy, 10 CFR 50.59 Safety Evaluation and Supporting Analyses Prepared in Response to the Algonquin Incremental Market Natural Gas Project Indian Point Nuclear Generating Units nos. 2 & 3, NL-14-106, August 21, 2014. ADAMS Accession No. ML14245A110.

5. FM Global "Property Loss Prevention Data Sheets," 7-42, May 2005.

6. Chiara Vianello, Giuseppe Mascho,"Risk Analysis of Natural Gas Pipeline Case Study of a Generic Pipeline."

7. U.S. Nuclear Regulatory Commission (NRC), Regulatory Guide 1.91, *"Evaluations of Explosions Postulated To Occur on Transportation Routes Near Nuclear Power Plants,"* April 2013, ADAMS Accession No. ML12170A980.

8. FOIA/PA-2015-0012A Appeal Response, dated February 26, 2015, ADAMS Accession No. ML15061A219.

We appreciate your questions and views. We trust that the information contained in this letter addresses the safety concerns that you included in your letter to the Commission dated March 17, 2015. If you have further concerns or new information regarding the gas pipelines at Indian Point, please contact Mr. Douglas Pickett at Douglas.Pickett@nrc.gov.

Sincerely,

/RA/

Michael I. Dudek, Acting Chief
Plant Licensing Branch I-1
Division of Operating Reactors Licensing
Office of Nuclear Reactor Regulation

Enclosure:
NRC Staff Responses

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