Safety Review and Confirmatory Analysis

Entergy's 10 CFR 50.59 Safety Evaluation

Algonquin Incremental Market (AIM)

Project Indian Point Energy Center (IPEC)

EXPLOSION

The ALOHA model was used for explosion scenario 1 of the original blast analysis report (ADAMS accession number ML14330A276) and used as a feeder to the Region I Inspecting Report (ADAMS accession number ML14314A052). The analysis conservatively assumed a pipe rupture equivalent to the diameter of the pipe at a maximum operating pressure of 850 psig. The pipe rupture was assumed to occur at the far end of the pipeline where the pipe rises above ground level and includes the volume of gas within the 3 mile length of pipeline between the nearest isolation valves. The ALOHA calculation for this scenario resulted in a maximum sustained methane release rate of 256,000 pounds/min and estimated the total release amount of 354,651 pounds averaged over 9 minutes. The calculation assumed that the entire pipeline gas volume between the isolation valves is released. The calculation conservatively assumed the maximum release over one minute (256,000 pounds of methane) and determined the TNT equivalent amount with a yield factor of 0.05 (WTNT). In the equation below, the minimum safe distance (d) to 1 psi overpressure is calculated to be 2351 ft by using Regulatory Guide 1.91 methodology as follows:

WTNT= (Mf * DHC * Y)/4500
Where
WTNT= TNT equivalent Mass, kg
Mf = Mass of vapor, kg
DHC = Heat of combustion, kj/kg (50030)
Y = Yield Factor (0.05)
$d= 45 * (w)^{1/3}$ where
d= minimum safe distance (ft) to 1 psi overpressure
w= TNT equivalent mass in pounds

The calculated minimum safe distance of 2351 ft is smaller than the actual distance of 2363 ft between the Security Owner Control Area (SOCA) barrier and the pipeline at the far end above ground. Furthermore, the pipeline at the far end above ground is located 2988 ft from the nearest safety-related structure, system, or component (SSC) within the SOCA. This is because the nearest safety-related SSC inside the SOCA is about (b)(7)(F) from the edge of the SOCA barrier. Therefore, a 1 psi overpressure is not expected to occur at any safety-related SSC inside the SOCA from a potential rupture and explosion at the far end of the pipeline located above ground. However, since the calculated minimum safe distance of 2351 ft is larger than the distance to SSC important to safety (ITS) outside the SOCA barrier, they may experience greater than 1 psi overpressure. Therefore, SSC ITS would be impacted. Nevertheless, their impacts are bounded by the severe/beyond design basis accidents considered as part of low

probability events such as natural phenomena that include seismic, hurricane and tornado events including Loss of Offsite Power and Station Black Out (SBO) considerations with design of redundant systems, engineering safeguards and mitigation measures in the plant UFSARs. A detailed discussion of the impact of SSC ITS, which was reviewed by NRC inspectors as part of their inspection report, is included in the licensee's submittal of their site hazards analysis submitted pursuant to 10 CFR 50.59 on August 21, 2014 (ADAMS accession number ML14253A339).

Due to concerns whether remote pipeline operators would be able to recognize that a pipeline ruptured occurred and then take timely actions to close the nearest pipeline isolation valves within 3 minutes, additional ALOHA modeling was performed to determine the sensitivity of valve closure times. The original scenario 1 modeling assumed (b)(7)(F) (b)(7)(F) as a conservative/bounding condition in determining the minimum safe distance to 1 psi overpressure and the potential heat flux due to a jet fire at the SSC/SOCA. In the bounding infinite source scenario, the analysis assumes that the pipeline isolation valves do not close and gas continues to flow, as if there was an infinite source, for one hour. Since the maximum calculated release of natural gas determined by the ALOHA model for the infinite source scenario is only slightly varied, the calculated results are marginally changed. The distance to 1 psi overpressure changed from 2351 ft to 2509 ft, which remains lower than the distance to the most limiting SSC inside the SOCA barrier of 2988 ft.

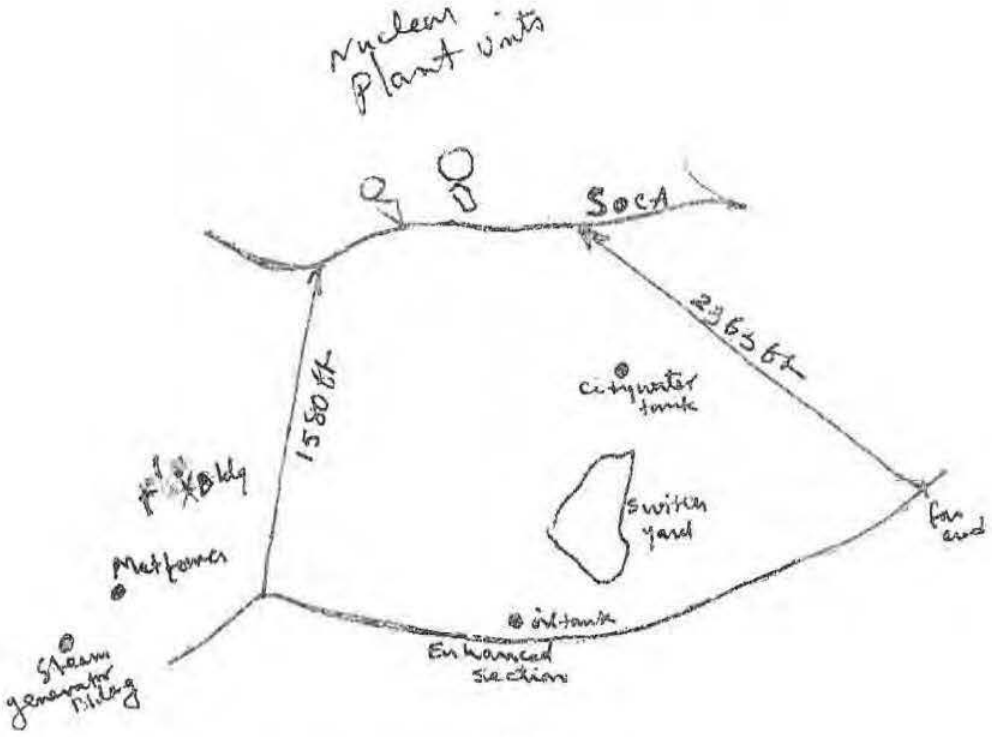
JET FIRE

Similar to the assumptions used for the ALOHA pipe explosion modeling, the ALOHA model for Jet Fire original Scenario 1 conservatively assumed a pipe (b)(7)(F) (b)(7)(F) at a maximum operating pressure of 850 psig, the pipe rupture was assumed to occur at the far end of the pipeline where the pipe rises above ground level, and the modeling includes the volume of gas within the 3 mile length of pipeline between the nearest isolation valves. Methane is assumed to be released from the ruptured pipe as a flammable gas. The ALOHA model resulted in a maximum burn rate of (b)(7)(F), and an estimated total amount burned of 354,651 pounds averaged over 9 minutes. The calculation assumed that the entire pipeline gas volume between the isolation valves is released. The distances to thermal radiation levels of (b)(7)(F), 5.0 kW/m^2, and 2.0 kW/m^2 calculated by ALOHA are (b)(7)(F) (b)(7)(F), respectively. In the infinite source scenario, this analysis is remodeled with the same conditions by imposing that the unbroken end of pipe (i.e.,upstream) is assumed to be connected to an infinite source (with no valves closed) for an hour. The maximum calculated burn rate of natural gas determined by the ALOHA model is not changed. The calculated heat fluxes, which are marginally changed at the SOCA distance of 1580 ft from the enhanced pipeline from 4.05 kw/sq.m to 4.63 kw/sq.m due to the sustained burning for an extended period of time, remain much lower than the potential threshold heat flux rate of (b)(7)(F) that would potentially damage any digital equipment.

CONCLUSION

Due to concerns that Entergy's assumption that remote control room operators would be able to recognize a pipeline rupture and take actions to close the nearest pipeline isolation valves within 3 minutes may not be realistic, the NRC staff performed a bounding sensitivity analysis. 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.

It should be noted that if the valves are not closed for an extended period time, potential adverse impacts consisting of direct property damage, some injuries and possible fatalities may result due to the fire in the close proximity of the pipeline, which is outside the preview of the NRC's regulatory frame work, consideration and jurisdiction from safe operation/shutdown of the nearby IPEC nuclear plant's perspective.



SOCA: Security owner controlled Area

distance to SOCA from enhanced section of pipeline = 1580 ft

distance to SSC from enhanced section of pipeline = 1830 ft

distance to SOCA from far end (surface) section of pipeline = 2365 ft

distance to SSC from far end (surface) section of pipeline = 2488 ft

SUMMARY OF RESULTS

SOCA = Security owner control Ar
SSC = Structure, systems and compo

Scenario	Minimum safe Distance to 1 PSI (Distance to SOCA) ((Distance to SSC))	Heat flux kw/m² at SOCA Distance of 1580 ft
pipe burst with unbroken end closed (valve closed) RG 1.91 (Direct explosion)	2351 ft (2363 ft) ((2988 ft))	—
pipe burst with unbroken end connected to infinite source (valve open)	2509 ft (2363 ft) ((2988 ft))	—
vapor plume explosion with no congestion	No explosion	— —
pipe burst with unbroken end closed	—	4.85
pipe burst with unbroken end of pipe connected to infinite source	—	4.87

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

February 26, 2015

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

IN RESPONSE REFER TO
FOIA Appeal 2015-0012A
(FOIA Request 2015-0062)

Dear Mr. Blanch,

On behalf of the U.S. Nuclear Regulatory Commission (NRC), I am responding to your January 21, 2015, letter. In that letter, you appealed the NRC's use of Freedom of Information Act (FOIA) Exemption 7(F) to withhold portions of the document that you requested in your November 19, 2014, FOIA request (FOIA/PA-2015-0062).

Upon further review, the NRC has reevaluated the document and has decided to release some of the information that was previously redacted in response to your FOIA request. The revised record is enclosed. The NRC has granted your appeal to the extent that it has elected to release some of the previously-redacted information challenged in your appeal. The NRC has denied your appeal with regard to some of the previously-redacted information, as it is continuing to withhold that information from public disclosure under Exemption 7(F).

Exemption 7(F) permits the withholding of information compiled for law enforcement purposes that, if disclosed, could reasonably be expected to endanger the life or physical safety of an individual. The information withheld in the enclosed record was compiled for law enforcement purposes because the information was created, gathered, and/or used as part of the NRC staff's efforts to analyze an issue related to an NRC licensee's compliance with the regulations that the agency has established to implement the Atomic Energy Act. The withheld information continues to be properly subject to Exemption 7(F) because it is expected to be useful to potential adversaries interested in executing an attack or other malevolent act. Thus, release of this information could reasonably be expected to endanger the life or physical safety of individuals living near the Indian Point Energy Center.

This is the NRC's final decision. As set forth in the FOIA (5 U.S.C. § 552(a)(4)(B)), you may obtain judicial review of this decision in a district court of the United States in the district in which you reside or have your principal place of business. You may also obtain judicial review in the district in which the NRC's records are located or in the District of Columbia.

The 2007 FOIA amendments created the Office of Government Information Services (OGIS) to offer mediation services to resolve disputes between FOIA requesters and Federal agencies. These mediation services are a nonexclusive alternative to litigation. In other words, using OGIS mediation services does not affect your right to pursue litigation. You may contact OGIS in any of the following ways:

Office of Government Information Services
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College Park, MD 20740
E-mail: ogis@nara.gov
Telephone: 202-741-5770
Fax: 202-741-5769
Toll-free: 1-877-684-6448

Sincerely,

Darren B. Ash
Deputy Executive Director
for Corporate Management
Office of the Executive Director for Operations

Enclosure: As stated

Safety Review and Confirmatory Analysis

Entergy's 10 CFR 50.59 Safety Evaluation

Algonquin Incremental Market (AIM) Project

Indian Point Energy Center (IPEC)

Introduction

Algonquin Gas Transmission, LLC (Algonquin) proposes an installation of new 42-inch diameter pipeline near the southern boundary of IPEC for the transport of natural gas as part of the AIM Project, to replace the existing 26-inch pipeline in vicinity of IPEC, which will remain in place but idled. Entergy prepared a 10 CFR 50.59 Safety Evaluation (Reference 1) related to the proposed AIM Project with an enclosure "Hazards Analysis" (Reference 2). The 10 CFR 50.59 safety evaluation and enclosure covered the consequences of a postulated fire and explosion following release of natural gas from the proposed new (southern route) AIM Project 42-inch pipeline south of IPEC and determined exposure rates associated with failure of that proposed 42-inch natural gas pipeline. Based on the hazards analysis and also accounting for the pipeline design and installation enhancements, Entergy has concluded that the proposed AIM Project poses no increased risks to IPEC and there is no significant reduction in the margin of safety. Therefore, Entergy further concluded that the change in the design basis external hazards analysis associated with the proposed AIM Project does not require prior NRC approval.

The NRO/DSEA/RPAC Staff at NRC Headquarters has reviewed Entergy's hazards analysis that supports the 10 CFR 50.59 Safety Evaluation related to the AIM Project, by performing independent confirmatory calculations to determine whether or not the licensee's conclusion is reasonable and acceptable, and also to ascertain that there is adequate reasonable assurance of safe operation of the plant or safe shutdown of the plant.

Summary of Evaluation

The staff has reviewed Entergy's "Hazard Analysis" supporting the 10 CFR 50.59 Safety Evaluation related to the AIM Project. Entergy evaluated potential hazards to safety-related structures, systems and components (SSCs) and also SSCs important to safety (SSC ITS) using reasonable assumptions and rationale. Entergy's methodology is appropriate and acceptable. The staff has performed independent confirmatory calculations with conservative assumptions and rationale using RG 1.91 methodology and also using the ALOHA model for vapor plume explosion. The staff also calculated the frequency of potential pipe line failure and determined that there is no additional potential risk to the safe operation of the IPEC units.

Based on the review of the hazards analysis provided as part of Entergy's 10 CFR 50.59 Safety Evaluation, and the staff's independent confirmatory calculation results using conservative

assumptions and rationale, the staff concludes that (1) no 1 psi overpressure is extended to any safety-related SSC inside the Security Owner Control Area (SOCA), (b)(7)(F) (b)(7)(F) However, nearby SSC ITS would be affected, because the calculated minimum safe distances to the impacts are exceeded. The staff finds that the impacts to the SSC 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 UFSARs. The cloud flash fire may occur aloft and burn very rapidly in a few seconds, without affecting any safety-related SSCs or equipment; and the existing margin of safety is not expected to be reduced due to a potential rupture of the proposed AIM Project pipeline near IPEC. The staff also finds that the applicant's conclusions, that the potential rupture of the proposed AIM Project pipeline near IPEC poses no threat to safe operation of the plant or safe shutdown of the plant, are reasonable and acceptable, and also comparable to the staff's conclusions.

Technical Evaluation

The staff's independent confirmatory analysis was performed based on the rupture of the proposed new
42-inch natural gas pipeline consisting of about 3 miles between isolation valves, of which the enhanced section of pipeline length is identified to be 3935 ft., located along the southern route near IPEC. 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. For the assessment of an unconfined explosion, RG 1.91 (Reference 3) methodology was used to calculate the minimum safe distance. For the jet flame, cloud fire, and vapor cloud explosion, the ALOHA chemical release modeling computer code (Reference 4) is used to determine the hazard impact distances which are compared with the actual distances at IPEC to structures, systems and components (SSCs) related to safety or SSCs important to safety (SSC ITS), as listed in Reference 2, Table 1, in order to assess the impact potential. ALOHA is run using the appropriate source term (amount of methane released) for the scenario considered, using conservative meteorological conditions (b)(7)(F) (b)(7)(F) Open country ground roughness conditions modeling assumptions were chosen.

EXPLOSION

The ALOHA model for explosion scenario 1 conservatively assumed that the pipe rupture occurred at the far end of the pipe line above the surface, considering the length of pipeline to be 3 miles, (b)(7)(F) at a maximum operating pressure of 850 psig. The ALOHA calculation for this scenario resulted in a maximum sustained methane release rate of (b)(7)(F) and estimated total release amount of (b)(7)(F) considering manual closure of the isolation valves within 3 minutes. Conservatively assuming the maximum release (b)(7)(F)

(b)(7)(F) and determining the TNT equivalent amount with a (b)(7)(F) (b)(7)(F) with equation given below, the minimum safe distance (d) to 1 psi overpressure is calculated to be (b)(7)(F) by using RG 1.91 methodology as follows:

WTNT= (Mf * DHC * Y)/4500 where
WTNT= TNT equivalent Mass, kg
Mf = Mass of vapor, kg
DHC = Heat of combustion, kj/kg (50030)
Y = (b)(7)(F)

$d = 45 * (w)^{1/3}$ where
d= minimum safe distance (ft) to 1 psi overpressure
w= TNT equivalent mass in pounds

This calculated minimum safe distance of (b)(7)(F) is smaller than the actual distance of (b)(7)(F) to the SOCA (Security Owner Control Area) from the pipeline at the far end above surface or (b)(7)(F) (b)(7)(F) to the nearest safety-related SSC (nearest safety-related SSC inside SOCA from is about (b)(7)(F) in from the edge of the SOCA) and therefore 1 psi overpressure is not expected at any safety-related SSC inside the SOCA from a potential rupture and explosion at the far end of the pipeline located above the surface. However, as the calculated minimum safe distance of (b)(7)(F) (b)(7)(F) is larger than the actual distances to all SSC ITS, they may experience greater than 1 psi overpressure. Therefore, the SSC ITS would be impacted. Nevertheless, their impacts are bounded by the severe/beyond design basis accidents considered as part of low probability events such as natural phenomena that include seismic, hurricane and tornado events including Loss of Offsite Power and Station Black Out (SBO) considerations with design of redundant systems, engineering safeguards and mitigation measures in the plant UFSARs. The frequency of exposure due to failure of these SSC ITS from potential rupture of AIM Project is also briefly presented later in this report to address whether the margin of safety is reduced or compromised due to rupture of AIM Project.

Assuming a (b)(7)(F) for an unconfined methane explosion (as given in RG 1.91), the methane amount determined from the maximum (b)(7)(F) of methane released (b)(7)(F) (b)(7)(F) determined from the ALOHA run) is used as an instantaneous methane release to simulate the vapor cloud dispersion, transport, and delayed explosion (b)(7)(F)

(b)(7)(F)

Moreover, the SSCs are generally designed to withstand an overpressure of 3 psi. (b)(7)(F) (b)(7)(F) as methane is buoyant and quickly rises aloft, disperses rather rapidly, (b)(7)(F) (b)(7)(F) Therefore, the ALOHA model was rerun with the same input except with an assumption of no congestion in the area. The ALOHA model resulted in no vapor cloud explosion of 1 psi

overpressure at any distance due to potential ignition. The potential pipe rupture underground at the enhanced section of the pipeline would be expected to result in a slower methane release rate, and thereby have potentially much lower impacts than those determined as above.

JET FIRE

The ALOHA model was run conservatively assuming that the pipe rupture occurred at the far end of the pipe line above the surface, considering the length of pipeline to be 3 miles, (b)(7)(F) (b)(7)(F) at a maximum operating pressure of 850 psig. Methane is assumed to be released from the ruptured pipe as a flammable gas and burning. The ALOHA model run resulted in a maximum burn rate of (b)(7)(F) and an estimated total amount burned of (b)(7)(F) and considering manual closure of the isolation valves within 3 minutes. The distances (Table 2) to thermal radiation levels of (b)(7)(F) 5.0 kW/m^2, and 2.0 kW/m^2 calculated by ALOHA are (b)(7)(F) (b)(7)(F) respectively.

The ALOHA model was also run conservatively assuming that the rupture of pipe occurred in the middle of the pipe located underground at the enhanced section identified close to the SOCA, considering half the length of the pipeline between isolation valves (1.5 miles) on each side of the rupture location, (b)(7)(F) (b)(7)(F) at a maximum operating pressure of 850 psig. Methane is assumed to be released from the ruptured pipe segment as a burning flammable gas. The ALOHA model run resulted in a maximum burn rate of (b)(7)(F) and considering closure of the isolation valves within 3 minutes. The calculated distances(Table 2) to the thermal radiation levels of (b)(7)(F) 5.0 kW/m^2, 2.0 kW/m^2 are (b)(7)(F) respectively.

The distances determined to the thermal radiation level of (b)(7)(F) (which has a potential to damage structures and equipment) due to potential pipe rupture at far end of the pipeline or in middle of the pipeline are (b)(7)(F) respectively. Both of these determined distances are smaller than the actual distances of (b)(7)(F) and 1580 ft, respectively, to the SOCA, and therefore, jet fire would not pose any adverse effect on SSCs related to safety. However, it may impact some of the SSC ITS as the radiation level of (b)(7)(F) may be exceeded for some SSC ITS outside of the SOCA. Nevertheless, the impacts to SSC ITS are bounded by the severe/beyond design basis accidents considered as part of seismic and tornado events covering Station Black Out (SBO) and Loss of Offsite Power considerations with design of redundant systems, engineering safeguards and mitigation measures already addressed in the plant UFSARs.

CLOUD FIRE

The ALOHA model was run conservatively assuming that the rupture of pipe occurred at the far end of the pipe line above the surface, considering the length of pipeline to be 3 miles, (b)(7)(F) (b)(7)(F) at a maximum operating pressure

of 850 psig. The ALOHA model run resulted in a maximum sustained release rate of (b)(7)(F) (b)(7)(F) and an estimated total release amount of (b)(7)(F) (b)(7)(F) considering manual closure of the isolation valves within 3 minutes. Conservatively assuming the maximum release rate (b)(7)(F) of methane (determined from the ALOHA run) is used as an instantaneous release (b)(7)(F) to simulate the vapor cloud dispersion, transport to determine the distance to reach the methane lower explosive limit (LEL) of 44,000 ppm. The ALOHA model determined a distance of (b)(7)(F) to reach the LEL. This estimated distance would bound the potential distance to the LEL from the rupture in the middle of pipe in the enhanced area buried underground. Even though the methane plume travels for a long distance, it is buoyant and rises aloft quickly and, therefore, also burns rather rapidly in seconds far above the ground without sustaining and without challenging the structures and components, if enough oxygen is available. Therefore, the impact from cloud fire on SSCs and equipment is not considered challenged.

DETERMINATION OF EXPOSURE RATE FOR FAILURE OF THE AIM PROJECT PIPELINE NEAR IPEC

Based on Pipeline Hazardous Materials Safety Administration (PHMSA) data (www.phmsa.dot.gov), and also published information from "Handbook of Chemical Hazards Analysis Procedures" (Reference 5), the accident rate of pipes greater than 20 inches diameter is about 5×10^{-4}/mile-yr. Assuming 3 miles of AIM Project pipeline near IPEC, the accident rate is determined to be 1.5×10^{-3}/yr. Based on the information in these references, estimating 1 percent of accidents result in a complete pipe break or 100 percent instantaneous release, and assuming also only 5 percent of the time that the released gas becomes ignited leading to potential explosion, the explosion frequency for the AIM project pipeline near IPEC is calculated to be about
7.5×10^{-7}/yr. If this release is due to the underground pipe, the frequency of explosion will be further reduced by at least an order of magnitude. In addition, the frequency of a large radioactivity release from the reactor due to the frequency of the above pipe rupture event, considering operating reactor conditional core damage frequency (CCDF), would be at least a few orders of magnitude lower, and therefore would not be identified as a design basis event. Therefore, it is concluded that the pipe failure resulting in a methane release from the proposed AIM Project near IPEC, 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.

CONCLUSION

Based on the review of the hazards analysis provided as part of Entergy's 10 CFR 50.59 Safety Evaluation related to the AIM Project near IPEC, and staff's independent confirmatory calculation results using conservative assumptions and rationale, the staff concludes that no 1 psi overpressure is extended to any safety-related SSC inside the SOCA (b)(7)(F) (b)(7)(F) However, nearby SSC ITS would be affected, as the calculated minimum safe distances to the

impacts are exceeded, but these impacts are bounded by the impacts from low probability events of extreme natural phenomena that include seismic, tornado winds, hurricanes which have been assessed and already addressed in UFSAR. Cloud flash fire may occur aloft and burn very rapidly in few seconds, without affecting any safety related SSCs or equipment, and the existing margin of safety is not expected to be reduced due to potential rupture of the proposed AIM Project pipeline near IPEC. The staff also finds that the applicant's conclusions that the potential rupture of the proposed AIM Project pipeline near IPEC poses no threat to safe operation of the plant or safe shutdown of the plant are reasonable and acceptable. The staff's review finds that the hazards analysis supporting the licensee's 10 CFR 50.59 safety evaluation is appropriate and shows that there is not more than a minimal increase to the likelihood of occurrence or consequences of damage to a safety-related SSC or SSC ITS, when compared to the current hazards analysis in the plant UFSARs.

REFERENCES

1. Entergy, "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. ML14245A110.

2. Entergy, "Hazards Analysis," Enclosure to NL-14-106, August 21, 2014. ML14245A111 (Non-public).

3. US Nuclear Regulatory Commission, Regulatory Guide 1.91, "Evaluations of Explosions Postulated to Occur at nearby Facilities and on Transportation Routes Near Nuclear Power Plants," Revision 2, April 2013.

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

5. FEMA, US DOT, US EPA, "Handbook of Chemical Hazard Analysis Procedures."

Principal Contributor: Rao Tammara

Date: October 16, 2014

Personal Notes
Z Hollcraft review of IP 2/3 proposed LNG pipeline 50.59 evaluation and accompanying hazards analysis

Entergy 50.59 Evaluation Observations:

1. Specific Hazards evaluated:
    a. Jet Fire: Methodology and assumptions seem appropriate, no threat to Safety related SSCs.
    b. Cloud Fire: The Gaussian plume models utilized don't account for the buoyancy of methane compared to normal air. As a result they over-conservatively show the plume exhibiting a flammable concentration that could threaten safety related SSCs within the SOCA. The licensee assumes that "the buoyant nature of methane generally precludes the formation of a persistent flammable vapor cloud at ground level let alone one that would travel downhill to the SOCA." However they provide no deterministic means of proving this. A more conservative approach would be to use either a model that does account for buoyancy of methane (e.g. FLACS or other computational fluid dynamics model), or evaluate by some other means the rate of ascent of methane in air (difficult to model in an unconfined state).
    c. Vapor Cloud Explosion: Methodology and assumptions seem appropriate, no threat to Safety related SSCs.
    d. Missile Generation: Methodology and assumptions seem appropriate, no threat to Safety related SSCs.
    e. PRA Analysis (Appendix B): The "enhanced" pipeline section does not have definitive statistical data on failure rates specifically accepted by the NRC (via RG 1.91) so the licensee calculated their own. Their assumptions appear conservative given the extra steps they are taking to harden the pipeline, but I'm not a risk engineer, so I cannot definitely say whether their PRA methodology is in keeping with regulatory guidance and is acceptable for this 50.59 evaluation.

2. Generic Comments:
    a. The GT2/3 tank doesn't seem to fit the normal model for SSCs within TSs and subject to GDCs. Without further study, I can't determine its licensing basis, but the licensee refers to it as an SSC "important to safety," which implies that it is not an Appendix B safety related SSC. It seems to be covered by TS 3.8.3.C which only states that >29,000 gallons of diesel fuel be on site. But the analysis does not state whether the tank is required to be hardened against external hazards or events.
    b. Question eight of the 50.59 evaluation (sheet 21 of 21) incorrectly concludes that "there is no departure from past methodologies used for the plant and does not depart from a method of analysis contained in the UFSAR." Seeing as how the PRA utilized in Appendix B of the Hazard Evaluation utilizes a technique endorsed by the NRC in a Regulatory Guide not implemented until 2011, it could not have been utilized during the initial license application. However, NEI 96-07 (endorsed by the NRC) allows for "different methods without first obtaining a license amendment if those methods have been approved by the NRC for the

Personal Notes

intended application." So the methodology is acceptable, but for a different reason.

NRC independent Hazard Analysis. The independent analysis performed by Rao Tammara is also completed using accepted methodologies and realistic, conservative assumptions. The conclusions match the licensee's.

Conclusion. From the documents provided to me, the 3rd quarter Indian Point Integrated Inspection Report (05000247/2014004 and 05000286/2014004) conclusion that the licensee appears to provide adequate evidence that the hazards analysis associated with the proposed pipeline does not require prior NRC review and approval is supported.

ALTERNATIVE CASE 1
Where pipe is broken in Middle

(5)

Alternatively if case 1 is run with the assumption that the pipe broke off in middle (not the end) and released from both ends having length 1.5 miles each (Total 3 miles). The release would be different

ALOHA is run with assumption so that the hazard impacts (1 Psi over pressure) could be evaluated in mid section of pipeline (around enhanced area)

ALOHA model resulted in max release of [(b)(7)(F)]

Using same assumptions as before. (on Page 2) with 1 min Release

$$WTNT = \frac{[(b)(7)(F)] * 50030 * 0.05}{2.2 * 4500} = [(b)(7)(F)]$$

$$\approx [(b)(7)(F)]$$

0.3334

$$d = 45 \left[[(b)(7)(F)] \right] = 2051 \text{ ft}$$

distance to SSC inside SOCA is about [(b)(7)(F)]

distance to SOCA is 1580 ft

distance to SSC inside SOCA is about 1580 + 250

≈ 1830 ft

If both sides release same amount

[(b)(7)(F)]

Assuming the enhanced pipeline, and applying about (b)(7)(F) for the release rate

Credit due to pipeline enhanced underground, and concrete bricks on the top of pipe, only (b)(7)(F)

the calculation is revised as follows based on 1min release and 5% yield

(b)(7)(F) *0.05 = (b)(7)(F)

(b)(7)(F)

$$WTNT = \frac{(b)(7)(F) * 50030 * 0.05}{2.2 * 4500} = (b)(7)(F) \approx (b)(7)(F)$$

$$d = 45 \left[(b)(7)(F) \right]^{0.3334} = (b)(7)(F)$$

(b)(7)(F) = (b)(7)(F)

which is less than 1580 ft

Alternative vapor plume explosion with ALOHA RUN with (b)(7)(F)

(b)(7)(F) *0.05 (b)(7)(F)

(b)(7)(F)

the ALOHA determined distance to 1Psi is (b)(7)(F) ≈ (b)(7)(F)

(b)(7)(F)

to LEL = (b)(7)(F) ≈ (b)(7)(F)

ALTERNATIVE CASE 1 (Average release rate)

7

Total release determined by ALOHA

for pipe broken in middle (with 1.5 mile length each side)

is (b)(7)(F)

(b)(7)(F) = (b)(7)(F)

Assuming average 1 min release

$$WTNT = \frac{(b)(7)(F) * 50030 * 0.05}{2.2 * 4500} = (b)(7)(F) \approx (b)(7)(F)$$

$$d = 45 \left[(b)(7)(F) \right]^{0.3334} = (b)(7)(F)$$

(b)(7)(F)

which is less than 1580 ft to SoCA

ALOHA run for vapor plume explosion

(b)(7)(F) * 0.05 = (b)(7)(F)

(b)(7)(F)

ALOHA determined distance to 1 Psi = (b)(7)(F)

≈ (b)(7)(F)

Two sides with (b)(7)(F) credit.

(b)(7)(F) release

to LEL ≈ (b)(7)(F)

≈ (b)(7)(F)

(b)(7)(F)

(b)(7)(F)

1 kcal = 4186.8 J ≃ 4.2 kJ

1 cal = 4.2 joules 1000cal =

1000 cal = 3.9683 Btu

1 kcal = 3.9683 Btu

$$50030 \frac{\cancel{kJ}}{\cancel{kg}} * \frac{\cancel{kg}}{2.2 lbs} * \frac{1 \cancel{kcal}}{4.2 \cancel{kJ}} * \frac{3.9683 \text{ Btu}}{1 \cancel{kcal}}$$

$$= \frac{50030}{2.2 * 4.2} * 3.9683 \approx 21486 \frac{\text{Btu}}{\text{lb}}$$

$$\approx 22000 \frac{\text{Btu}}{\text{lb}}$$

Using DoT PIR equation the Potential Impact Radius is calculated as follows: for High consequence Area

PIR

$$R = 0.69 * \sqrt{P * d^2}$$

P = Pressure, psi
d = diameter, inches

$$= 0.69 * \sqrt{850 * 42 \times 42} \approx 8.45 \text{ ft}$$

$$Q = CA\sqrt{\frac{\cancel{lbf}}{ft^2}\left[P_0\right]\frac{lbm}{ft^3}(\rho_0)\; g_c\; \frac{\cancel{ft}\; lbm}{\cancel{lbf}\; s^2}}$$

$$= CA\sqrt{P_0\,\rho_0\,\frac{g}{c}\,C\,r\;\; lbm^2/ft^4\,s^2} = \frac{lbm}{s}$$

Safaricator 06%:

$$Q = C\,(9.6215)\,ft^2\sqrt{850\times144 * 0.041\,\frac{lbm}{ft^3}\;32.17\;0.34\;(1.306)}$$

$$Q = C\,(9.6215)\,ft^2\,(267.7) = 1597.2\;lbm/s$$

$$\rho_0 = 0.56\,\frac{\cancel{kg}}{m^3} * 2.2\,\frac{lbm}{\cancel{kg}} * \left(\frac{0.3048\,m}{ft}\right)^3 \Big/ sec^2$$

$$= 0.041\,\frac{lbm}{ft^3}$$ gasdensity

$$g_c\;\frac{lbm\;sec^2}{lbf\;ft}$$

$$\frac{g}{g_c} = \frac{ft/sec^2}{\frac{lbm}{lbf}\cdot ft/sec^2}$$

$$\boxed{\frac{lbf}{lbm}}$$

density
@
70°F
850 PSI
$\approx 2.84\,\frac{lbm}{ft^3}$

$$Q = c(9.625)\sqrt{850\times144 * 2.84 * 32.17 * 0.34 * 1.306}$$

$$\approx c(9.625) * 2228.4 = \frac{lb}{sec}$$

13293 ✓

use this instead of 0.041

$$850\,PSI * 6.89\,\frac{kP}{PSI} \approx 5856.5\,kPa$$

$$45.513\,kg/m^3 * 2.2\,\frac{lb}{kg}\,\frac{(0.3048\,m)^3}{ft^3} \approx 2.84\,\frac{lb}{ft^3}$$

mass den $= 45.513$

$$Mass = n * MW$$

$$n = \frac{mass}{MW}$$

$$PV = nRT$$

$$P = \frac{n}{V}RT =$$

$$P_0 = \left(\frac{Mass}{MW}\right)\frac{RT}{V} = \rho_0\,\frac{RT}{MW}$$

$$\rho_0 = \frac{P_0\,MW}{RT}$$

$$= \frac{\frac{lbf}{ft^2}\cdot MW}{ft\,\frac{lbf}{lbm\,°R}\,°R}$$

$$Q = CA\sqrt{P_0^2\,r\,\frac{g_c\,MW}{RT}\cdot\left(\frac{2}{r+1}\right)^{\frac{r+1}{r-1}}}$$

$$= CA\sqrt{P_0\cdot r\cdot g_c\cdot\rho_0\left(\frac{2}{r+1}\right)^{\frac{r+1}{r-1}}}$$

$$= CA\sqrt{P_0\,r\,g_c\,\rho_0\left(2/r+1\right)^{\frac{r+1}{r-1}}} = CA\sqrt{r P_0\,\rho_0\,g_c\left(\frac{2}{r+1}\right)^{\frac{r+1}{r-1}}}$$

from page 7-42
FM Global

$$wg = K\, cd\, A_r\, t \sqrt{2 \rho_t P_d}$$

$wg = kg$

$K = 0.68$

$cd = 1.0$

$A = 9.6215 ft^2 * \left(\frac{0.3048\, m}{ft}\right)^2 = 0.894\ m^2$

$\rho_t = 0.67\ kg/m^3$

$P_d = 850\ psi * \frac{1\, atm}{14.7\, psi} * \frac{1013\, mb}{atm} * \frac{100\, Pa}{1\, mb} = 58.632 \times 10^5\, Pa$

$t = 1\ sec$

$\therefore$

$$wg = 0.68 * 1.0 * 0.894 \times 1 \sqrt{2 \times 0.67 * 5863200}$$

$$0.68 * 1 * 0.89 \times 1 * 2803$$

$$= 1696\ kg/sec \approx 3739\ lbs/s$$

$\approx$ 18700 lbs for 5 sec

For Indian Point

$$Q_{max} = C A P_0 \sqrt{\frac{\gamma g_c MW}{RT}\left(\frac{2}{\gamma+1}\right)^{\frac{\gamma+1}{\gamma-1}}}$$

$C = 0.62$ to $1.$

A = area of whole $42''D \approx 3.5$ ft Dia.

≈ 1.75 ft radius

$A = \pi(1.75)^2 = 9.6215\,ft^2$

$g_c = 32.174$

$MW = 16$

$R = 1545.3$ $\frac{ft\ lbf}{lbmol\ ^oR}$

$P_0 = 850$ psig

$T = 25^oC \approx 77^oF \approx 537^oR$

γ: sp. heat of methane $= 1.306$

$$Q_{max} = 0.62 * 9.6215 * 850 \times 144 \sqrt{\frac{1.306 * 32.174 * 16}{1545.3 * 537}\left(\frac{2}{2.306}\right)^{\frac{2.306}{0.306}}}$$

$$= 0.62 * 9.6215 * 850 * 144 \sqrt{\frac{1.306 * 32.17 * 16}{1545.3 * 537} * 0.34}$$

$\left(\frac{2}{2.306}\right)^{\frac{2.306}{0.306}} = (0.867)^{7.536}$

$= 0.34$

$$= 0.62 * 9.6215 * 850 * 144 \sqrt{0.0002754}$$

$$= 0.62 * 9.6215 * 850 \times 144 * 0.0166$$

$= \cancel{12283.2}$ lbs/sec $\approx \cancel{735,741}$ lbs/hr

Turkey Point

24" dia 722 Psig

$r = \frac{24''}{12} = \frac{\cancel{12}\ ft}{2} = 1\ ft$

$A = 3.1416\ ft^2$

$Q = 0.62 * 3.1416 * 722 * 144 * \cancel{0.0166}\ 0.002$

$= \cancel{3362}\ lbs/sec$

1.405

$\cancel{201,698}\ lbs/min$

24308

∴ if $c = 1$

and $P_0 = 722 + 14.7$ psia $= 736.7$

then $Q = 3.1416 * 736.7 * 144 * \cancel{0.0166}\ 0.002$

$= \cancel{5532}\ 667\ lbs/sec$

3332.8 $\cancel{27669}\ lbs/$ for 5 sec

applicant 30,302 lbs/5sec

the pipe completely exposed to the air. It was also assumed that the ignition source existed at the break point. The safe distance to 1 psi overpressure is calculated by determining the mass of natural gas released, whereby the TNT mass equivalency methodology can then be employed as described in Subsection 2.2.3.1.1.1.

In order to determine the mass of natural gas release, the maximum release rate was determined. The release rate from a hole in a pipeline will vary over time; however for safety assessments, it is useful to calculate the maximum release rate of gas from the pipeline. A standard procedure for representing the maximum discharge is to represent the discharge through the pipe as an orifice. The orifice method always produces a larger value than the adiabatic or isothermal pipe methods, ensuring a conservative safety design.

Once it was verified that choke flow conditions would occur for a postulated break in the Florida Gas Transmission pipeline modeled, the maximum gas discharge rate from the break in the pipeline was calculated using the following equation which represents the release from the pipeline as an orifice.

$$Q_{max} = CAP_0\sqrt{\frac{\gamma g_c MW}{RT}\left(\frac{2}{\gamma+1}\right)^{\left(\frac{\gamma+1}{\gamma-1}\right)}} \qquad \text{(Equation 4)}$$

where

C = discharge coefficient (equals 1 for maximum case) = 0.62
A = area of the hole, ft^2
g_c = gravitational constant, $ft \cdot lb_m/lb_f \cdot s^2$
MW = molecular weight, lb/lb_{mol}
R = ideal gas constant, $ft \cdot lb_f/lb_{mol} \cdot °R$
T = initial pipeline temperature, °R
γ = Specific heat ratio of gas = 1.306 for methane

1 Mole = $\frac{lbm}{MW}$
MW = $\frac{lbm}{lbmol}$

Upon a complete pipeline rupture, the release rate of the gas (lb/s) will initially be very large, but within seconds the release rate will drop to a fraction of the initial release rate. Therefore, to estimate the amount of gas discharged for an instantaneous release, the maximum discharge rate was conservatively assumed to occur for a period of 5 seconds. This duration maintains the intent of the instantaneous detonation as applied in the TNT analysis—any longer and atmospheric dispersion effects will predominate resulting in a traveling vapor cloud—while maximizing the amount of gas released for the TNT analysis. This is also a conservative assumption given that the discharge rate will begin to

$$Q_{max} = C A \cancel{ft^2} * P_0 \frac{lbsf}{\cancel{ft^2}} \sqrt{\frac{\gamma \frac{\cancel{ft}\, lbm}{lbf\, s^2} g_c * \frac{lbm}{lbmol} MW}{\cancel{ft}\, lbf/lbmol\, \cancel{°R} * \frac{°\cancel{R}}{T}} \left(\frac{2}{\gamma+1}\right)^{\frac{\gamma+1}{\gamma-1}}}$$

$$= \frac{lbM}{lbf\, s} C A P_0 \sqrt{\frac{\gamma \frac{\cancel{ft}\, lbm}{lbf\, s^2} \cdot \frac{lbm}{\cancel{lbmole}} \cdot \frac{\cancel{lbmole}}{\cancel{ft}\, lbf}}{} \cdot \left(\frac{2}{\gamma+1}\right)^{\frac{\gamma+1}{\gamma-1}}} = CA_0 P_0 \sqrt{\frac{\gamma g_c MW}{RT}\left(\frac{2}{\gamma+1}\right)^{\frac{\gamma+1}{\gamma-1}}}$$

$$\frac{g_c\, MW}{RT} = \overset{g_c}{(32.17)}\ \frac{lbm \cdot ft}{lbf \cdot s^2} * \underset{(16)}{MW}\left[\frac{lbmas}{lbmol}\right] \cdot \frac{1}{\underset{(1545.4)}{R}\ \frac{ft \cdot lbf}{°R\,mol}\ T}$$

$$\frac{g}{g_c} = \frac{ft/sec^2}{lbm\ ft} \cdot lbf\ s^2$$

1 ton tnt = 4.2×10^9 Joules

1 gm TNT = 4184 joules or = Kcal

1 TON o TNT = 10^3 Kcal

9/15/2014

IPEC

PROPOSED 42" pipeline Analysis (Blast & Fire)

Applicant calculated

(b)(7)(F) kg 1st min

kg 2 min

kg after 3 min for 3 min

total release

kg in 6 min

(b)(7)(F) kg/sec $\approx$ (b)(7)(F) kg/sec

ALOHA RUN

made with pipedia, unbroken end of pipe with 850 psig

[(b)(7)(F) min] : gave release of 256,000 lbs/min

$$256{,}000 \text{ lbs/min} * \frac{\text{kg}}{2.2 \text{ lbs}} * \frac{1 \text{ min}}{60 \text{ sec}} \approx 1939.4 \text{ kg/sec}$$

it seems comparable.

Assuming 1 min Release and having 5% yield.

$$W_{TNT} = \frac{M_F \Delta H_c \alpha}{4500} = \frac{(b)(7)(F) * 50\,030 * 0.05}{4500} = (b)(7)(F) \text{ kg} \approx (b)(7)(F) \text{ lbs}$$

$$d = 45 \left[(b)(7)(F)\right]^{0.3334} = 2351.2 \text{ ft}$$

Assuming this will happen at surface the maximum safe dist

Methane $50,030 \frac{kj}{kg} * \frac{kcal}{4.2\,kj}$

$\approx \underline{\underline{11911.9}}$ kcal/kg

From
F-M global

$$W_e = W \frac{\Delta H_c f}{1.11 \times 10^6}$$

W_e = Mass of vapor TNT (Tonnes)
W = mass of vapor in cloud (kg)
f = yield
ΔH_c = heat of combustion kcal/kg

=

Gas discharge rate from pipe

$$m = A_h \sqrt{2 P_0 \rho_0 \left(\frac{\gamma}{\gamma-1}\right)\left[\left[\frac{P_1}{P_0}\right]^{2/\gamma} - \left(\frac{P_1}{P_0}\right)^{\frac{\gamma+1}{\gamma}}\right]}$$

where m = discharge rate, kg/s
A_h = opening area, m^2
γ = ratio of specificheats c_p/c_v
P_0 = Tank/pipe Pressure, Pascals
P_1 = Ambient Pressure, Pascals
ρ_0 = Density kg/m^3

$$A_h = \pi \left[\frac{42''}{12''} * 1ft * 0.3048\,\frac{m}{ft}\right]^2 / 4 = \overset{\pi D^2/4}{3.1416 \left[\frac{1.07^2}{4}\right]} = \underline{\underline{0.894}}\ m^2$$

$\gamma = 1.32$

850 PSIG $P_0 = 5860543.7$ Pascals

1Psi = 6894.76 Pascals $P_1 = 101325$ Pascals

1atm = 101325 Pascals $\rho_0 = 0.66$ kg/m³

ρ_0 = density = 0.66 kg/m³

$$m = 0.894 \sqrt{2 * 5860543.7 * 0.66 \left(\frac{1.32}{0.32}\right)\left[\left(\frac{101325}{5860543.7}\right)^{2/1.32} - \left(\frac{101325}{5860543.7}\right)^{\frac{2.32}{1.32}}\right]}$$

$$= 0.894 \sqrt{2 * 5860543.7 * 0.66 * 4.125 * \left[(0.01729)^{1.52} - (0.01729)^{1.76}\right]}$$

$$= 0.894 \sqrt{2 * 5860543.7 * 0.66 * 4.125 * \left[0.0021 - 0.00079\right]}$$

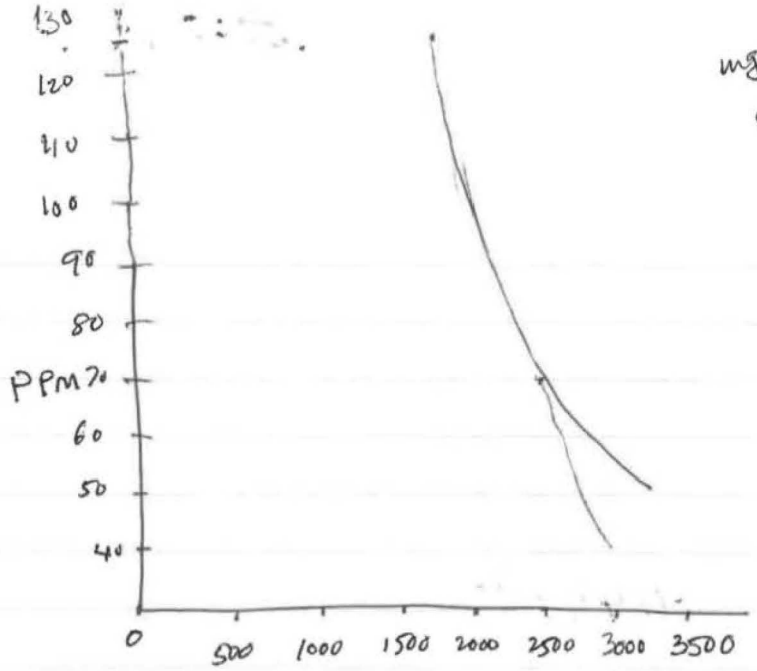
(3) For the closest distance from enhanced pipeline, ~~it is assumed that~~ due to higher depth of pipeline, additional concrete blocks on top of the buried pipeline and other engineering features, it is assumed that the 1min release is further held up and only (b)(7)(F) is released to atmosphere. Based on this assumption ALOHA run is made to calculate the minimum safe distance.

1min Release with 5% yield (b)(7)(F)

(b)(7)(F)

The minimum safe distance determined is about (b)(7)(F). Since the closest distance from enhanced pipeline to SOCA (b)(7)(F) 1580ft, and if SSC about 100ft further from SOCA it can be concluded that the minimum safe distance not exceeding 1PSI overpressure determined will be met and there would be no adverse impact on the safe operation of the plant.

(3) if the surrounding area is open flat and no congestion, then there would be no potential explosion due to release of the gas from proposed pipeline.



$$mg/m^3 = \frac{MW * ppm}{24.45}$$

$$mg/m^3 = \frac{16 * 42900}{24.45} = 28074 \ \frac{mg}{m3}$$

$$3000ft * 0.3048 \frac{m}{ft} = 914.4 \ m$$

$$\frac{\pi D^2}{4} * 10m \ (height) = \frac{3.1416 \times (914.4)^2}{4} \times 10$$

$$28074 \ \frac{g}{m3} * 6.57 \times 10^6 \ m^3 = 6.57 \times 10^6 \ m^3$$

42inch 1mi Release 5%

distance	PPM
~~500 ft~~	
1000 ft	900,000
1500 ft	300,000
2000 ft	125,000
2500 ft	70,000
2600 ft	60,000
2700 ft	55,000
2800 ft	51,500
2900 ft	47,000
3000 ft	42,900
3060 ft	40,900

$$2.8074 \times 10^4 \times 10^{-3} \ \frac{g}{m3} * 6.57 \times 10^6 \ m^3$$

$$2.8074 \times 10^7 \times 6.57 \ g$$

$$18.44 * 10^7 \ g$$

$$18.44 \times 10^4 \ kg$$

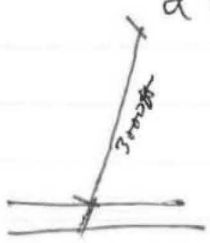
$$18.44 \times 10^4 \ (0.125)$$

$$23050 \ kg$$

$$\frac{23050 * 50030 * 0.05}{4500} = 12813.2 \ kg$$

$$1370 \ ft$$

$$d = 45 (12813.2 * 2.2)^{0.3334} = 1370 ft$$



Area should be

$914.4\ m * 10\ m = 9144\ m^2$

Exposure Determination

Handbook of Chemical hazard analysis Procedures

FEMA, DOT, USEPA Page 11-27

Accident rate
pipes $\geq 20''$ 5×10^{-4} / mile - yr.

3 miles

$5 \times 10^{-4} \times 3$ miles $\approx 1.5 \times 10^{-3}$ / yr

1% of the time complete pipe breaks or 100% release

$0.01 * 1.5 \times 10^{-3} = 1.5 \times 10^{-5}$ release

assume only 0.05 yield for detonation

only 5% time it ignited/detonates $0.05 \times 1.5 \times 10^{-5} \approx 7.5 \times 10^{-7}$

or Produces jet fire

For enhanced Section only 39356 ft

$5 \times 10^{-4} * \frac{39356 \text{ ft}}{5280 \text{ ft/mile}} = 3.7 \times 10^{-4}$ / yr

1% $0.01 * 3.7 \times 10^{-4} = 3.7 \times 10^{-6}$

$0.05 * 3.7 \times 10^{-6} = 1.8 \times 10^{-7}$ for explosion.

PHMSA (Pipeline Hazardous Materials Safety Administration)

2004 - 2013 transmission

117 / yr 321,000 miles

$\therefore \frac{117}{321000} \approx 3.65 \times 10^{-4}$ / mile-yr

assumed Alternative calculation

Based on literature paper

13% catastrophic accident 100% release

$5 \times 10^{-4} * 3 = 1.5 \times 10^{-3} \frac{\text{total events}}{yr} * 0.13 \frac{\text{catastrophic event}}{\text{total event}}$

$= 1.95 \times 10^{-4} \frac{\text{catastrophic release event}}{yr}$

5% release (yield) to TNT equivalent for potential amount for explosion

$1.95 \times 10^{-4} * 0.05 = 9.75 \times 10^{-6}$ TNT equivalent release

$\simeq \underline{\underline{1 \times 10^{-5}}}$

assuming only (b)(7)(F) of time lead to explosion, release lead to most likely to fire or deflagration but not explosion

$\therefore \; 1 \times 10^{-5} * 0.01 \simeq \underline{\underline{1 \times 10^{-7}}} / yr$

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
2100 RENAISSANCE BLVD., SUITE 100
KING OF PRUSSIA, PA 19406-2713

October 1, 2015

Mr. Paul Blanch
135 Hyde Road
West Hartford, CT 06117

Dear Mr. Blanch:

I am writing in response to your June 13, 2015, telephone call to the U.S. Nuclear Regulatory Commission (NRC) Headquarters Operation Center, during which you stated you had a significant, immediate safety concern with the present operation of the Indian Point nuclear facility. You also emailed a document that stated 12 concerns. The enclosure to this letter provides the responses to your concerns. Additionally, we are aware that you raised similar questions in your letter dated July 27, 2015. Responses to those questions will be addressed through separate correspondence.

Throughout our response, you will find references to publically available documents identified by Accession Numbers in the web-based Agencywide Documents Access and Management System (ADAMS). To retrieve the document, enter the Accession Number in the document properties field under the advanced search tab at http://adams.nrc.gov/wba/. Webpage links are also provided throughout the document where applicable.

Thank you for your questions regarding Indian Point. I hope this response addresses your concerns.

Sincerely,

/RA/

Arthur L. Burritt, Chief
Reactor Projects Branch 2
Division of Reactor Projects

Enclosure:
Response to Paul Blanch Letter
dated June 13, 2015

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dated June 13, 2015

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ADAMS Accession No. ML15274A356

☑ SUNSI Review		☑ Non-Sensitive ☐ Sensitive		☐ Publicly Available ☑ **Non-Publicly Available**	
OFFICE	RI/ORA/AE	RI/DRP			
NAME	BBickett/ JRB for	ABurritt/ ALB			
DATE	9/23/15	10/01 /15			

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Response to Paul Blanch Letter dated June 13, 2015

1, 2, 7. Regarding your assertions that both plants [Indian Point Units 2 and 3] are presently operating in an unanalyzed condition because no analysis exists other than a statement in the Final Safety Analysis Report (FSAR) that this event is not "feasible," or that the rupture of the gas pipeline must be considered as a design basis event and no risk analysis has been conducted, we note that extensive analyses have been done which have provided reasonable assurance that the failure of the existing gas pipelines will not impair the safe operation of Indian Point. The failure of the gas pipelines would not result in any offsite dose to the public in excess of limits specified in Title 10 of the *Code of Federal Regulations* (10 CFR) Parts 50 or 100. Therefore, we do not believe that a failure of the gas pipelines would represent a design basis event.

Among the many analyses documented are the Atomic Energy Commission's safety evaluation report, issued on September 21, 1973 (ML072260465), which stated on p. 2–4 that: "Two natural gas lines cross the Hudson River and pass about 620 feet from the Indian Point 3 containment structure. Based on previous staff reviews, failures of these gas lines will not impair the safe operation of Indian Point 3." The previous staff reviews were the NRC's review of the Preliminary Safety Analysis Report, submitted by Consolidated Edison on August 30, 1968 (ML093480204).

On December 6, 1995, the licensee submitted the Individual Plant Examination of External Events (IPEEE) report for Indian Point. In this report the licensee first evaluated any susceptibility to damage from seismic events. Based on a hazard analysis, the licensee concluded that the probability of occurrence was low enough that the pipelines could be screened out as a seismic vulnerability. The IPEEE did identify one area of seismic concern approximately 1200 ft from the plant in which the pipelines drop 40 ft in elevation over a distance of 100 ft. The evaluation concluded that due to the distance from the site, the section could be screened out as a potential vulnerability. The licensee next considered pipeline failures from other causes, such as an inadvertent overpressure condition. Although the licensee concluded there is a small probability that conditions could exist that would cause damage to some Indian Point Unit 3 structures, it screened this scenario out from further consideration based on the very low probability of the scenario. The NRC's staff evaluation report of the Indian Point Unit 3 IPEEE did not identify any discrepancies with this approach.

In April 2003, in response to questions from the public, NRC staff undertook a review of the possible consequences of a rupture of a pipeline, independent of the probability of a pipeline failure. The staff concluded that for a large rupture and resulting fire, safety-related structures would not be significantly affected. With respect to potential fires, the staff concluded that the effects are limited to possible ignition of flammable materials such as wood, as well as injury of exposed on-site personnel (principally skin burns). For the one scenario that might damage safety-related structures (the explosion of a large unconfined vapor cloud), the staff concluded that the factors needed to achieve an explosion creating sizeable overpressures make the probability for occurrence very low.

In 2008, the licensee contracted another evaluation of the pipelines because of concerns raised related to the potential for deliberate and malicious attempts to breach and ignite the pipelines. In an evaluation dated August 14, 2008, the contractor evaluated three scenarios based on a simultaneous rupture of both pipelines at the above ground location; a jet fire, a vapor cloud flash fire, and a large vapor cloud explosion. The contractor concluded that a jet fire would not cause major damage to Unit 3 facilities, but could injure people who are outdoors. At that time, the NRC reviewed this analysis and concluded failures of these gas pipelines would not impair the safe operation of Indian Point. Additionally, the 2008 review provided the bases for and context of the FSAR statement referred to in your assertion "an attempt to uncover, breach and ignite a buried portion of the pipeline was not considered feasible." The failure of underground portions of the gas pipelines has been considered and, as previously discussed, the NRC staff concluded that safety-related structures would not be significantly affected.

3, 4, 5, 6, 9, 10. Regarding your assertions that operators have not been trained to deal with an explosion or fire of the gas pipelines; or that procedures, training, automatic isolation valves, or awareness of the pipelines does not exist on how to respond to such an event, we note that as a condition of their license, Indian Point is required to have a Fire Protection Program where plant operators are trained as a fire brigade to respond to and fight a comprehensive variety of plant fires. Plant procedures are in place which require the call for offsite fire department assistance for numerous situations, including the case if the onsite fire brigade is unable to effectively control or extinguish the fire. In the case of a natural gas pipeline failure near Indian Point, it is expected that plant operators or fire brigade members would remain onsite within the protected area and that a call for offsite support would be made. Plant operators or fire brigade members would not be responsible to isolate the source of the natural gas, or rely on automatic isolation valves. Rather, the gas pipeline transmission operator continuously monitors and would isolate the source from a remote control station in a short period of time if necessary. The NRC regularly inspects the ability of the fire brigade to respond to fires through its Reactor Oversight Process baseline inspection program. To date, we have not identified any significant concerns with the ability of the site fire brigade to properly respond to or extinguish plant fires. Additionally, the failure of the gas pipelines has been determined to be a very low probability event, so more specific procedures are not required.

8. Regarding your assertion that there is no documentation or requirements verifying the integrity of these gas transmission lines, the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (U.S. DOT PHMSA) enforces regulations for the nation's gas pipeline transportation system. Spectra Energy implements standard operating procedures requiring: (a) periodic inspection of its pipelines using in-line inspection tools able to identify potential corrosion and damage defects, (b) monitoring of corrosion protection systems, and (c) frequent aerial patrols to identify unauthorized activities on the right-of-way. Since the Algonquin Indian Point right-of-way containing the 26-inch and 30-inch natural gas pipelines is located in a defined high consequence area (HCA) as interpreted and classified by Spectra, the PHMSA regulations require inspections of pipelines located in HCAs on a more frequent basis, with a maximum interval of seven years for the internal inspections.

Algonquin has advised Entergy that, consistent with those regulations, Algonquin most recently conducted in-line tool inspections of the existing 26-inch and 30-inch lines in 2011 and 2014, respectively. Algonquin further advised Entergy that all inspections and follow-up actions were completed in accordance with applicable regulations and its own engineering standards. Pursuant to regulations in 49 CFR Part 192, Spectra Energy is required to maintain pipeline records for the useful life of the pipeline. If you wish to review these records, we suggest that you contact the U.S. DOT or Spectra Energy, as the NRC does not own these records.

11. Regarding your assertion that the gas pipeline valves and piping were not considered in the relicensing application for buried piping, the natural gas pipelines are not in the scope of license renewal because they are not part of any system, structure, or component that is part of the Indian Point power station, and are not owned, rented, or managed by Entergy for license renewal or any purpose related to the safe or continued operation of the plant. However, the licensee is required to ensure that the pipeline would not adversely impact equipment necessary for safe plant operation and shutdown.

12. Regarding your assertion that there are no NRC or licensee requirements for the gas pipelines within the Protected Area of Indian Point, the existing gas pipelines do not intersect the security-related Protected Area at either Unit 2 or Unit 3. Rather, the existing gas pipelines intersect the Owner Controlled Area property which is separate, and outside of the security-related Protected Area fence. While the NRC does not regulate the construction or maintenance of gas pipelines and does not perform inspections of these pipelines at the Indian Point facility, there are specific requirements for the owner of the pipelines, Spectra Energy and its subsidiary, Algonquin Transmission Company, to do so. Again, the Indian Point systems, structures, and components must be able to perform their safety-related functions regardless of gas pipeline events that might occur. The NRC has assurance based on numerous reviews that these components would function acceptably.

Paul M. Blanch
Energy Consultant

9 October 2015

Paul Blanc
Deleted: !

Arthur L. Burritt, Chief
Reactor Projects Branch 2
Division of Reactor Projects USNRC
King of Prussia, PA

Dear Art:

This letter is in response to your letter addressed to me dated October 1, 2015. My reading of your letter is that it is an attempt to respond to the 12 "allegations" I made to the NRC hotline on June 13, 2015 and to attempt to justify why the NRC refuses to address these vital issues in a forthright manner.

About three days subsequent to my allegations I received a phone call from Tom Setzer of your office informing me that these items would not be accepted as allegations. I am not aware that any Allegations Review Board (ARB) was convened as required by the NRC's Management Directive 8.8 or if this was just a "command decision" to avoid addressing a serious safety issue. I formally request the documentation supporting this decision not to accept my allegations.

My review of Management Directive 8.8 does not mention any option of rejecting what are serious valid allegations. My review of MD 8.8 defined an allegation and the Glossary to MD 8.8 discusses items that are clearly not allegations. Your arbitrary rejection of my allegations is a clear abuse of the NRC's very clear process for addressing safety concerns.

Your lack of response to my legitimate concerns about vital safety issues related to operation of the plant is explained below. I am listing each concern separately and why I believe the responses are inadequate and evasive.

1. Both plants are presently operating in an unanalyzed condition. You provided no evidence that a proper analysis was done other than a statement in the FSAR that this event is not "feasible."

In your response you cited numerous documents attempting to explain why this is not an unanalyzed condition. You state: "extensive analyses have been done which have provided reasonable assurance that the failure of the existing gas pipelines will not impair the safe operation of Indian Point."

Your first citation is the plant's PSAR (ML093480204). This document does not provide any analysis, let alone "extensive analysis" of the probabilities of a pipeline accident, nor is there a discussion of the potential consequences of a pipeline rupture. It fails to address any potential for vapor cloud explosions.

The summary within this document is based on the assumption of the existence of automatic gas isolation valves. These isolation valves have been removed without any apparent analysis by the NRC or the licensee.

It further assumes the lines would be isolated within 4 minutes. The documented history of gas line explosions, however, indicates that this is neither realistic nor feasible. The origin of this isolation time is not referenced.

During our conversation on July 17, 2015 you confirmed to me the fact that the buried portions of the gas lines adjacent to Indian Point 3 have never been analyzed therefore the rupture of the gas lines and impact has never been analyzed.

You cite ML 072260465 that simply states: "Two natural gas lines cross the Hudson River and pass about 620 feet from the Indian Point 3 containment structure. Based on previous staff reviews, failures of these gas lines will not impair the safe operation of Indian Point 3." This statement is misleading in that most vital structures are located between the containment and the gas lines. I will agree that damage to the containment structure is not a major concern, however vital structures within this range have never been analyzed.

The 1995 IPEEE does not provide any analysis or justification as to why the failure of the buried pipelines is eliminated from consideration other than an undocumented assertion that this event is a "very low probability of the scenario." Where can I locate the analysis that determines this probability and what margins are considered for lines that are 63 years old?

With respect to the evaluation dated August 14, 2008, it is my understanding that this study did not evaluate the buried portions of the gas transmission lines and that this is reflected in the present FSAR concluding this event is "not feasible" as stated in the current licensing basis.

My allegation should be accepted because the analysis you cited does not provide evidence that the gas pipelines are presently operating in an analyzed condition. The Safety Evaluation Report (SER) assumes automatic isolation valves and an undocumented closure time of 4 minutes. Moreover, these pipes have been present for 63 years and have suffered normal aging thus increasing the probability of failure with time.

2. Entergy's 50-59 analysis dated August 2015 states: ". . conclude that the rupture of the gas pipeline must be considered as a design basis event under NRC guidance."

Entergy's 10 CFR 50.59 summary concludes that the proposed new 42-inch gas line must be considered as a Design Basis Event (DBE). It seems illogical that a gas line rupture event of a line located 1500 feet from the plant is considered a DBE whereas a line located within 600 feet of the containment and close to vital structures and the control room is not considered a DBE. Please explain this apparent discrepancy.

3. Operations personnel have not been properly trained to deal with an event such as fire or explosion of these gas lines.

I failed to observe in your letter that plant and operations personnel are fully aware of the presence of these gas lines located in the close proximity of the Indian Point plants. You did mention the Fire Protection Program. The people affiliated with that program may be properly trained to handle most fires, but certainly are not capable of controlling a major gas line rupture. According to my sources, neither operations nor the plant's fire brigade have procedures to contact the pipeline operator should an explosion occur. The NTSB reported on the San Bruno pipe explosion that: "Over 900 emergency response personnel responded to the accident" and this line was a single 30" gas pipeline not at a nuclear power plant.

4. Some operations personnel are not even aware of the existence of these ancient active gas transmission lines.

Your letter totally "sidestepped" the issue regarding whether plant personnel are aware of the potential for a gas line explosion and potential damage to safety related components and structures. Please respond directly to the above and specify the plant operations personnel who are aware of the existence and location of these ancient active gas transmission lines and identify the procedures that are in place for them to respond to a potential gas line rupture and explosion.

5. The fire brigade, including offsite responders, has not been trained to respond to such an event.

Same comments as #4 above. Please describe in detail the training that has been provided to the fire brigade, gas line operator notification including offsite responders regarding how to deal with a gas line explosion as well as the resulting potential damage to safety related components and structures.

6. There are no procedures available to counter this high probability event.

I was unable to find any statements in your letter that confirms the existence of any Indian Point procedures for responding to a gas line rupture event. I believe this omission confirms the lack of any procedures to combat a major gas explosion.

7. No risk analysis has been conducted for this event.

I have reviewed all of the references cited in your letter and there is no risk analysis provided or referenced. The "risk analysis" conducted in 2008 did not evaluate the potential for a rupture of the buried gas pipe which is the most frequent cause of gas line disasters.

8. There is no documentation or requirements verifying the integrity of these gas transmission lines.

There are no statements within your response that either the NRC or Entergy has imposed or reviewed any testing of the integrity of these lines.

9. There are no automatic isolation valves or any isolation valves under the control of Indian Point to mitigate the consequences of this event.

Again, failing to address this issue is an admission by the NRC that there are no gas isolation valves within the control of Indian Point.

10. Operations personnel are not aware of the location of these isolation valves.

I assume this to be a valid statement as your response did not address this particular issue.

11. These valves and piping were not considered in the relicensing application for buried piping

Your response stated: "Regarding your assertion that the gas pipeline valves and piping were not considered in the relicensing application for buried piping, the natural gas pipelines are not in the scope of license renewal because they are not part of any system, structure, or component that is part of the Indian Point power station, and are not owned, rented or managed by Entergy for license renewal or any purpose related to the safe or continued operation of the plant."

10 CFR 54.4(a)(3) states: "(3) All systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63)." The words "owned, rented or managed" are not part of the regulations. The integrity of the gas lines is considered within the plant's safety analysis (ML072260465} PSAR (ML093480204), and the most recent FSAR.

.

12. Neither the licensee nor the NRC has imposed any requirements on the piping or the gas transmission line system within the protected area of Indian Point.

I apologize. I meant to state the "owner controlled area" vs. "protected area." Regardless, it appears the NRC is relinquishing it exclusive authority to oversee the safety of nuclear power plants and relying on Spectra, a non-NRC regulated entity and other government

agencies such as DOT and PHMSA to assure the safety of Indian Point and the millions of residents in the area. This is inconsistent and violates the intent of NRC regulations.

Requested information:

1. Please provide and cite the specific areas of Management Directive 8.8 that provided guidance of rejection an allegation without the convening of an Allegation Review Board.

2. If the NRC did convene an Allegations Review Board, please send me the supporting documentation.

3. Please provide the analysis that determines that the failure of the buried pipelines is a "very low probability of the scenario." What margins are considered for lines that are 63 years old?

4. Please explain the discrepancy regarding why the proposed new pipeline is a DBE and the existing, older one that is closer to SSCs is not considered a DBE.

5. Please provide copies of the actual "extensive analyses" (not a summary) discussed and cited in the references of your October 1, 2015 letter that clearly determines this postulated event not to be an unanalyzed condition.

6. Please discuss why vital SSCs located between the containment and the gas lines are not discussed. I believe this also includes the Unit #3 control room.

7. Subsequent to the SER, the automatic gas isolation valves were removed resulting in increased risk to the plant. Please provide a copy of the documentation approving this change.

8. You discussed an April 2003 review by the NRC Staff that has not been made available to me so I am not qualified to comment on the details or the results. I would appreciate a copy or reference to this document in order to file a FOIA request.

9. Please provide a definite statement that specific procedures are in place to notify Spectra in the event of a gas line rupture.

10. Please specify the plant operations personnel and the first responders who are aware of the existence and location of these ancient active gas transmission lines and identify the procedures that are in place for them to respond to a potential gas line rupture and explosion.

11. Please confirm that procedures are in place to deal with jet fires, vapor cloud fires, blast damage to vital structures within the blast radius.

12. Please provide calculations to demonstrate vital SSCs would not be impacted by a gas line rupture.

13. Does the NRC and/or the licensee review periodic pipe line inspections to assure compliance with today's applicable requirements, codes, and standards? If so, please provide them to me.

14. Should an un-ignited vapor cloud enter the control room or other vital areas, are there procedures or automatic isolation mechanisms to isolate and prevent ingress of flammable gas?

15. Please rewrite the NRC's letter to me dated August 14, 2015 properly characterizing my allegations and not distorted by the NRC's desires of what the allegation should be.

Your prompt response will be appreciated.

Paul M. Blanch

Paul M. Blanch
135 Hyde Rd.
West Hartford, CT 06117
860-236-0326

Tammara, Seshagiri

Paul M. Blanch Energy Consultant

From: Burkhart, Lawrence
Sent: Wednesday, November 30, 2016 [illegible]:13 PM
To: Flanders, Scott; Campbell, Andy; Helton, Shana
Cc: Tammara, Seshagiri
Subject: FW: QA Calculation for Indian Point blast radius
Attachments: Letter to Tammara on blast radius.pdf; ATT00001.htm

See email directly from Paul Blanch to Rao.

We should discuss how to respond. There is a request for Mr. Blanch to sit down with Rao to discuss the calculation.

Larry

From: McCoppin, Michael
Sent: Wednesday, November 30, 2016 4:05 PM
To: Burkhart, Lawrence <Lawrence.Burkhart@nrc.gov>
Subject: FW: QA Calculation for Indian Point blast radius

I believe this is for you…

From: Paul [mailto:pmblanch@comcast.net]
Sent: Wednesday, November 30, 2016 3:48 PM
To: Tammara, Seshagiri <Seshagiri.Tammara@nrc.gov>
Cc: Paul Blanch <pmblanch@comcast.net>; Burritt, Arthur <Arthur.Burritt@nrc.gov>; Miller, Chris <Chris.Miller@nrc.gov>; Beasley, Benjamin <Benjamin.Beasley@nrc.gov>; Pickett, Douglas <Douglas.Pickett@nrc.gov>; Dean, Bill <Bill.Dean@nrc.gov>; Beaulieu, David <David.Beaulieu@nrc.gov>; Haagensen, Brian <Brian.Haagensen@nrc.gov>; (b)(6); Setzer, Thomas <Thomas.Setzer@nrc.gov>; McCoppin, Michael <Michael.McCoppin@nrc.gov>; Dorman, Dan <Dan.Dorman@nrc.gov>; (b)(6); Amy Rosmarin <(b)(6)>; Ellen Weininger <(b)(6)>; Sandy Galef <(b)(6)>; David Buchwald <(b)(6)>; Dave Lochbaum <dlochbaum@ucsusa.org>; Jim Riccio <jim.riccio@greenpeace.org>; Lampert Mary <(b)(6)>; Karen Gentile <karen.gentile@dot.gov>; Joe Carson <(b)(6)>; William. R. Corcoran <William.R.Corcoran@1959.USNA.com>; Paul Gallay <pgallay@riverkeeper.org>; (b)(6); Richard Kuprewicz <kuprewicz@comcast.net>; CHAIRMAN Resource <CHAIRMAN.Resource@nrc.gov>; Dentel, Glenn <Glenn.Dentel@nrc.gov>
Subject: [External_Sender] QA Calculation for Indian Point blast radius

See enclosed pdf letter.

30 November 2016

Rao Tammara

USNRC

Washington DC

Dear Mr. Tammara:

Enclosed is a copy of a calculation conducted in accordance meeting the intent of the requirements of 10 CFR 50 Appendix B, Criterion III. We have additional calculations conducted by other professional engineers all using the equations of Regulatory Guide 1.91 with similar results. We have used the assumptions provided by the NRC for mass flow rate and total mass released.

I am fully aware the NRC has no Quality Assurances (QA) requirements for any of its calculations and is reflected in the numerous calculations provided me under FOIA. Because of this, there may be errors even in our calculations.

The following is one example of a calculation and methodology projecting a damaging blast radius of about 4200 feet within 3 minutes. Blast radius at 30 minutes is much greater. This blast radius would encompass the entire Indian Point site, including the unprotected control rooms, switchgear rooms and backup emergency power sources.

The likely outcome of this scenario may be core melting along with spent fuel damage with significant radioactive releases.

The assumed mass flow rates above were obtained from the NRC from numerous FOIA responses. All three independent calculations yielded about the same blast radius of about 4000 feet after a 3-6 minute release. We all used a yield factor of 5%, the least conservative value provided by Regulatory Guide 1.91.

We are aware of your statements January 12, 2015 (below) that you had not developed a "formal calculation package," yet your calculation formed the basis for the NRC's approval to FERC and the misleading statements made by the Chairman to members of Congress, thus placing 20 million persons at risk. According to FERC the NRC approval was provided in its Inspection Report of November 7, 2014. This was provided to me in response to a FERC FOIA request.

FERC's final approval for the safety of Indian Point and 20 million residents was predicated on "no formal calculation package," a statement made by you more than 2 months **after** FERC received approval from the NRC of "no significant risk." (See your email above). How could FERC approval be given without any formal calculation as you stated above?

Please review the enclosed calculation and identify our inconsistencies between our calculations. We would also like to discuss your meaning of and what does an "unbroken end" of a pipe burst mean. As an amateur plumber, I have not yet seen an "unbroken end" of a pipe burst. These types of errors had this calculation been conducted under some type of QA program.

As a cross check, I also ran the unapproved ALOHA program for a single ended pipe break and we can see below the high risk areas range from 4200 feet all the way to 5.8 miles, somewhat higher than the NRC's calculations of 1100 feet. The actual flow rate for a double ended break would be much greater and but not inconsistent with the NRC's calculated value of 376,000 kg/minute, a number also provided by FOIA. ALOHA may or may not be correct but it does project a blast radius similar to the engineering calculations.

The bottom line is that we have three professional engineers using a QA program and a physical scientist running calculations without any guidelines, procedures, reviews or approvals. The engineers project a blast radius in the range of 4200 feet and confirmed by ALOHA using a single ended break. You calculated a blast radius of about 1100 feet. Why the very significant difference? Claiming "Regulatory Infallibility" will not suffice.

FERC has based its approval of the AIM pipeline on the NRC's assessment of risk and this must be immediately corrected by informing FERC that the NRC's approval of the AIM pipeline must be rescinded until such time that our professional differences are determined.

Is it possible that we could sit down and have a professional dialog and determine why your informal calculation projected an 1100-foot blast radius whereas our formal calculations projected more than 4000 feet using the same approved NRC equations and input assumptions obtained under FOIA and your use of the prohibited EPA ALOHA program?

SITE DATA:

Location: Northeast US

Building Air Exchanges Per Hour: 0.45 (unsheltered single storied)

Time: November 30, 2016 & 1105 hours EST (using computer's clock)

CHEMICAL DATA:

Chemical Name: METHANE

CAS Number: 74-82-8 *Molecular Weight: 16.04 g/mol*

PAC-1: 65000 ppm PAC-2: 230000 ppm PAC-3: 400000 ppm

LEL: 50000 ppm UEL: 150000 ppm (Upper Explosive Limit and Lower Explosive Limit)

Ambient Boiling Point: -258.7° F

Vapor Pressure at Ambient Temperature: greater than 1 atmosphere

Ambient Saturation Concentration: 1,000,000 ppm or 100.0%

SOURCE STRENGTH:

Flammable gas escaping from pipe (not burning)

Pipe Diameter: 42 inches Pipe Length: 10000 feet

Unbroken end of the pipe is connected to an infinite source

Pipe Roughness: smooth *Hole Area: 1,385 sq in*

Pipe Press: 850 psia *Pipe Temperature: 70° F*

Release Duration: ALOHA limited the duration to 1 hour

Max Average Sustained Release Rate: 339,000 pounds/min

7

(Averaged over a minute or more)

Total Amount Released: 16,999,870 pounds

THREAT ZONE:

Threat Modeled: Flammable Area of Vapor Cloud

Model Run: Gaussian

Red : 1401 yards=4200 feet --- (30000 ppm = 60% LEL = Flame Pockets).

Yellow: 5.8 miles --- (5000 ppm = 10% LEL)

THREAT AT POINT:

Concentration Estimates at the point:

Downwind: 3400 feet *Off Centerline: 0 feet*

Max Concentration:

Outdoor: 42,300 ppm

Indoor: 13,500 ppm

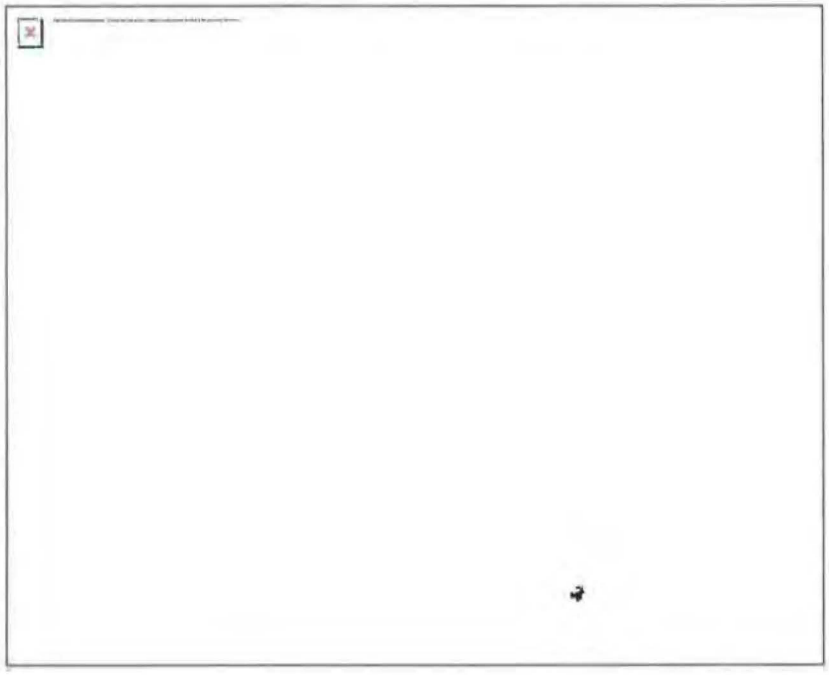
1 — Ex

1.8 psi

3 psi

8

Le



ALOHA calculated blast radius for 339,000 pounds/min release rate

Your prompt response to my request for a meeting will be appreciated as we can not await the normal response time of the NRC when faced with such differences of opinions and the fact that once the gas is flowing through the new 42-inch AIM line, the plants will be operating in an unanalyzed condition requiring an 8-hour report to the NRC.

Paul Blanch

135 Hyde Rd.

West Hartford, CT 06117

pmblanch@comcast.net

860-236-0326

Cell 860-922-3119

Double ended beaks in the middle of the pipeline can not be calculated by ALOHA

Both ends of pipe releasing methane would be close to the NRC number of 376,000 Kg/Min

Lower Explosion Limit

10 CFR 50.72 (B) The nuclear power plant being in an unanalyzed condition that significantly degrades plant safety.

Paul M. Blanch
Energy Consultant

30 November 2016

Rao Tammara
USNRC
Washington DC

Dear Mr. Tammara:

Enclosed is a copy of a calculation conducted in accordance meeting the intent of the requirements of 10 CFR 50 Appendix B, Criterion III. We have additional calculations conducted by other professional engineers all using the equations of Regulatory Guide 1.91 with similar results. We have used the assumptions provided by the NRC for mass flow rate and total mass released.

I am fully aware the NRC has no Quality Assurances (QA) requirements for any of its calculations and is reflected in the numerous calculations provided me under FOIA. Because of this, there may be errors even in our calculations.

The following is one example of a calculation and methodology projecting a damaging blast radius of about 4200 feet within 3 minutes. Blast radius at 30 minutes is much greater. This blast radius would encompass the entire Indian Point site, including the unprotected control rooms, switchgear rooms and backup emergency power sources.

The likely outcome of this scenario may be core melting along with spent fuel damage with significant radioactive releases.

From NRC Regulatory Guide 1.91, Rev. 2, April 2013

Equation (1):

Rmax = Z * W^ 1/3

where

Rmax = distance from explosion to point where overpressure will drop to 1 lb psi

Z = scaled distance = 45 ft/lb^ 1/3 when R is in feet and W is in pounds

Z = scaled distance = 18 m/kg^ 1/3 when R is in meters and W is in kilograms

Check: NUREG-1805 (December 2004) Figure 15-1 suggests 45 ft/lb^ 1/3 for 1 psi overpressure

Equation (2):

Weff = (Hexp/Htnt) * Wexp

where

Weff = effective charge equivalent

Wexp = weight of the exposure charge

Hexp = heat of detonation of the explosive

Htnt = heat of detonation of TNT

Equation (3):

E = a * ΔHc * mf

where

E = blast wave energy, BTU or kilojoules

a = yield (fraction of available combustion energy participating in blast wave = 5% from Table 1

ΔHc = theoretical net heat of combustion (BTU/lb or kilojoules/kilogram)

mf = mass of flammable vapor released (pounds mass or kilograms)

Equation (4):

Wtnt = E / (1900 BTU/pound mass) or E / (4420 kilojoules/kilogram)

From FOIA 2015-0076:

ΔHc = 50,030 kilojoules/kilogram

Check: NUREG-1805 (December 2004) Table 3-2 gives 50,000 kJ/kg for LNG and 46,000 kJ/kg for LPG

Check: NUREG-1805 (December 2004) Table 15-2 gives 50,030 kJ/kg for Methane gas

Check: NUREG-1805 (December 2004) Table 15-2 gives 46,360 kJ/kg for Propane gas

Check: NUREG-1805 (December 2004) Table 15-2 gives 47,490 kJ/kg for Ethane gas

mf = 676,000 kilograms = 100,000 kilograms + 100,000 kilograms = 676,000 kilograms

Solving Equation (3):

E = a * ΔHc * mf

E = 0.05 * 50,030 kilojoules/kilogram * 676,000 kilograms

E = 1,691,014,000 kilojoules for 676,000 kilograms

E = 940,164,000 kilojoules for 376,000 kilograms

Solving Equation (4):

Wtnt = E / (1900 BTU/pound mass) or E / (4420 kilojoules/kilogram)

Wtnt = 382,382 kilograms for 676,000 kilograms

Wtnt = 212,797 kilograms for 376,000 kilograms

Solving Equation (1):

Rmax = Z * W^ 1/3

Rmax = 1,501 meters for 676,000 kilograms

Rmax = 4,269 feet for 676,000 kilograms

Rmax = 0.81 miles for 676,000 kilograms

Rmax = 1,070 meters for 376,000 kilograms

Rmax = 3,511 feet for 376,000 kilograms

Rmax = 0.67 miles for 376,000 kilograms

The assumed mass flow rates above were obtained from the NRC from numerous FOIA responses. All three independent calculations yielded about the same blast radius of about 4000 feet after a 3-6 minute release. We all used a yield factor of 5%, the least conservative value provided by Regulatory Guide 1.91.

We are aware of your statements January 12, 2015 (below) that you had not developed a "formal calculation package," yet your calculation formed the basis for the NRC's

approval to FERC and the misleading statements made by the Chairman to members of Congress, thus placing 20 million persons at risk. According to FERC the NRC approval was provided in its Inspection Report of November 7, 2014. This was provided to me in response to a FERC FOIA request.

> ---Original Message---
> From: Tammara Seshagiri
> Sent: Monday, January 12, 2015 11:02 AM
> To: McCoppin, Michael
> Subject: FW: IPEC Gasline Analysis
>
> Mike
>
> Please advise about this request. I have personal hand written calculations and ALOHA computer runs, but do not have a formal calculation package. Summarized methodology and results are included in the report transmitted to the Region for their use in the 50.59 Review and Evaluation/Inspection Report.
>
> Thanks

FERC's final approval for the safety of Indian Point and 20 million residents was predicated on "no formal calculation package," a statement made by you more than 2 months **after** FERC received approval from the NRC of "no significant risk." (See your email above). How could FERC approval be given without any formal calculation as you stated above?

Please review the enclosed calculation and identify our inconsistencies between our calculations. We would also like to discuss your meaning of and what does an "unbroken end" of a pipe burst mean. As an amateur plumber, I have not yet seen an "unbroken end" of a pipe burst. These types of errors had this calculation been conducted under some type of QA program.

pipe burst
with unbroken
end connected to
infinite source (valve open)

As a cross check, I also ran the unapproved ALOHA program for a single ended pipe break[1] and we can see below the high risk areas range from 4200 feet all the way to 5.8 miles, somewhat higher than the NRC's calculations of 1100 feet. The actual flow rate for a double ended break would be much greater and but not inconsistent with the NRC's calculated value of 376,000 kg/minute, a number also provided by FOIA. ALOHA may or may not be correct but it does project a blast radius similar to the engineering calculations.

The bottom line is that we have three professional engineers using a QA program and a physical scientist running calculations without any guidelines, procedures, reviews or approvals. The engineers project a blast radius in the range of 4200 feet and confirmed by ALOHA using a single ended break. You calculated a blast radius of about 1100 feet. Why the very significant difference? Claiming "Regulatory Infallibility" will not suffice.

[1] Double ended beaks in the middle of the pipeline can not be calculated by ALOHA

FERC has based its approval of the AIM pipeline on the NRC's assessment of risk and this must be immediately corrected by informing FERC that the NRC's approval of the AIM pipeline must be rescinded until such time that our professional differences are determined.

Is it possible that we could sit down and have a professional dialog and determine why your informal calculation projected an 1100-foot blast radius whereas our formal calculations projected more than 4000 feet using the same approved NRC equations and input assumptions obtained under FOIA and your use of the prohibited EPA ALOHA program?

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Time: November 30, 2016 & 1105 hours EST (using computer's clock)

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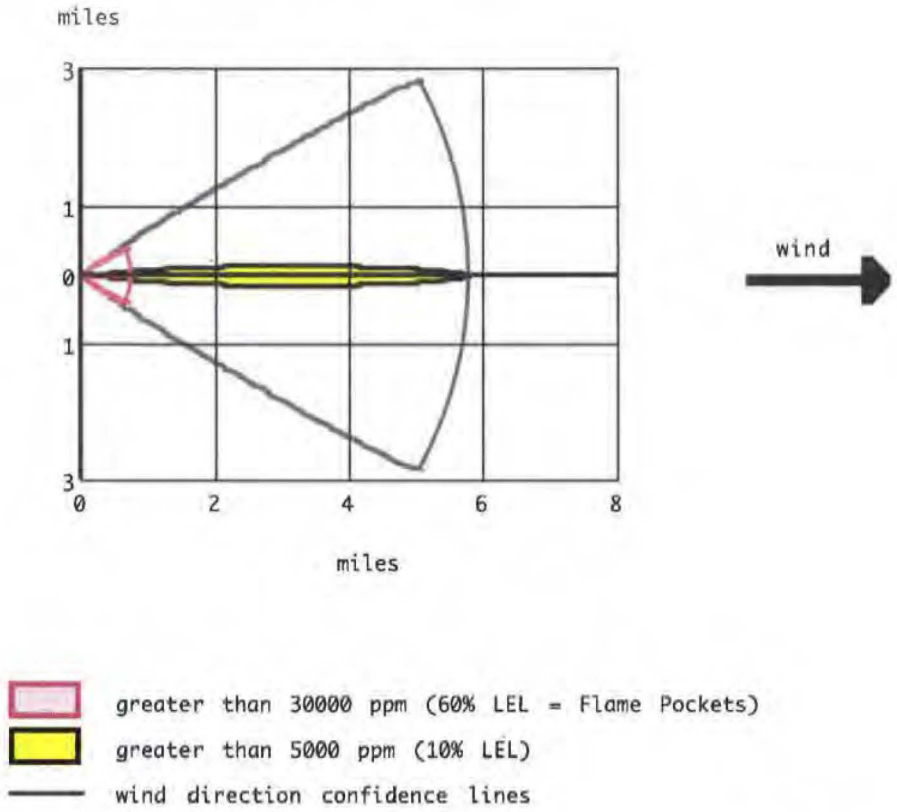
PAC-1: 65000 ppm PAC-2: 230000 ppm PAC-3: 400000 ppm
LEL: 50000 ppm UEL: 150000 ppm (Upper Explosive Limit and Lower Explosive Limit)
Ambient Boiling Point: -258.7° F
Vapor Pressure at Ambient Temperature: greater than 1 atmosphere
Ambient Saturation Concentration: 1,000,000 ppm or 100.0%

SOURCE STRENGTH:
Flammable gas escaping from pipe (not burning)
Pipe Diameter: 42 inches Pipe Length: 10000 feet
Unbroken end of the pipe is connected to an infinite source
Pipe Roughness: smooth Hole Area: 1,385 sq in
Pipe Press: 850 psia Pipe Temperature: 70° F
Release Duration: ALOHA limited the duration to 1 hour
Max Average Sustained Release Rate: 339,000 pounds/min[2]
(Averaged over a minute or more)
Total Amount Released: 16,999,870 pounds

THREAT ZONE:
Threat Modeled: Flammable Area of Vapor Cloud
Model Run: Gaussian
Red : 1401 yards=4200 feet --- (30000 ppm = 60% LEL*[3] *= Flame Pockets).
Yellow: 5.8 miles --- (5000 ppm = 10% LEL)

[2] Both ends of pipe releasing methane would be close to the NRC number of 376,000 Kg/Min
[3] Lower Explosion Limit

THREAT AT POINT:
Concentration Estimates at the point:
Downwind: 3400 feet *Off Centerline: 0 feet*
Max Concentration:
Outdoor: 42,300 ppm
Indoor: 13,500 ppm



ALOHA calculated blast radius for 339,000 pounds/min release rate

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Paul M. Blanch

Paul Blanch
135 Hyde Rd.
West Hartford, CT 06117

[4] 10 CFR 50.72 (B) The nuclear power plant being in an unanalyzed condition that significantly degrades plant safety.

pmblanch@comcast.net
860-236-0326
Cell 860-922-3119

November 30, 2016

Max 1 min flow

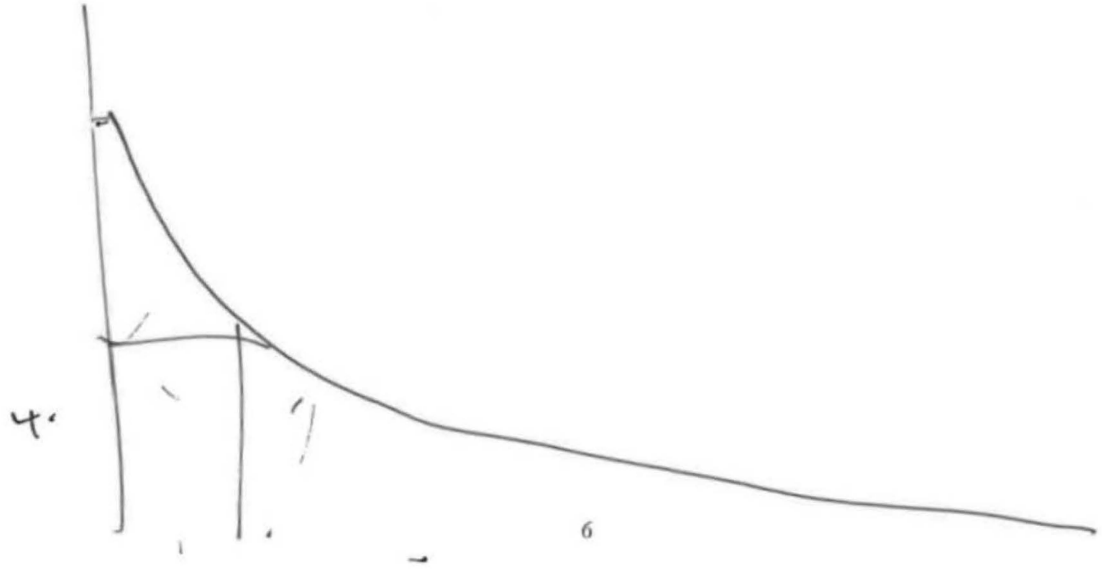
$$\frac{339{,}000 \text{ lbs} * 0.05 * 50030 \text{ kJ/kg}}{2.2 \text{ lbs/kg}} \quad \frac{4500 \text{ kJ/kg TNT}}{} * \frac{2.2 \text{ lbs TN}}{1 \text{ kg TNT}}$$

$$= \frac{339{,}000 * 0.05 * 50030 \text{ lbs TNT}}{4500}$$

$$= 188446.3 \text{ lbs TNT}$$

$$d = 45 \left[188446.3\right]^{0.3333} = \underline{2579} \text{ ft}$$

Which is less than <u>2988 ft</u>



Tammara, Seshagiri

From: Dipaolo, Eugene
Sent: Thursday, December 01, 2016 3:37 PM
To: Burkhart, Lawrence; Pickett, Douglas; Tammara, Seshagiri
Cc: Haagensen, Brian; Setzer, Thomas; Rich, Sarah; Bickett, Brice; Warnek, Nicole
Subject: RE: QA Calculation for Indian Point blast radius
Attachments: FW: COMMISSION E-READER - Thursday, December 1, 2016

Just for clarification, Region I was looking for help in determining whether the letter contained any new allegations. Our initial thought is that it does not.

Because the letter was not sent to Region I, we don't intend to take the lead in responding to Mr. Blanch. FYI, I did see today's Commission E-Reader. It contains an assignment for EDO response on 1/3/17 (see attached).

Gene DiPaolo
Chief (Acting)
Division of Reactor Projects, Branch II
U.S. Nuclear Regulatory Commission, Region I

W: 610-337-6959
C: (b)(6)

From: Burkhart, Lawrence
Sent: Thursday, December 01, 2016 3:22 PM
To: Pickett, Douglas <Douglas.Pickett@nrc.gov>; Tammara, Seshagiri <Seshagiri.Tammara@nrc.gov>
Cc: Dipaolo, Eugene <Eugene.DiPaolo@nrc.gov>; Haagensen, Brian <Brian.Haagensen@nrc.gov>; Setzer, Thomas <Thomas.Setzer@nrc.gov>; Rich, Sarah <Sarah.Rich@nrc.gov>
Subject: RE: QA Calculation for Indian Point blast radius

Doug,

I will talk to Rao and let you know what we come up with.

Larry

From: Pickett, Douglas
Sent: Thursday, December 01, 2016 11:27 AM
To: Burkhart, Lawrence <Lawrence.Burkhart@nrc.gov>; Tammara, Seshagiri <Seshagiri.Tammara@nrc.gov>
Cc: Dipaolo, Eugene <Eugene.DiPaolo@nrc.gov>; Haagensen, Brian <Brian.Haagensen@nrc.gov>; Setzer, Thomas <Thomas.Setzer@nrc.gov>; Rich, Sarah <Sarah.Rich@nrc.gov>
Subject: FW: QA Calculation for Indian Point blast radius

Larry/Rao –

Region I wants to respond back to Paul Blanch. Per our SRI's email below, could you confirm that 1) we assumed a detonation with a 1 minute release time, and 2) the probability of a detonation with a substantially delayed time (3-6 minutes) becomes increasingly small.

That type of understanding should provide a basis for our response to Blanch.

Let me know if you need to discuss.

Doug

Douglas V. Pickett, Senior Project Manager
Indian Point Nuclear Generating Unit Nos. 2 & 3
Douglas.Pickett@nrc.gov
301-415-1364

From: Haagensen, Brian
Sent: Thursday, December 01, 2016 7:19 AM
To: Dipaolo, Eugene <Eugene.DiPaolo@nrc.gov>; Setzer, Thomas <Thomas.Setzer@nrc.gov>
Cc: R1ALLEGATION RESOURCE <R1ALLEGATION.RESOURCE@nrc.gov>; Rich, Sarah <Sarah.Rich@nrc.gov>; Pickett, Douglas <Douglas.Pickett@nrc.gov>
Subject: FW: QA Calculation for Indian Point blast radius

FYI – any action required on our part at IPRO?

I am not completely familiar with the calculations that were done at NRC HQ but it seems to me that the key difference is that the NRC and Entergy assumed a 1 minute release time prior to the could explosion while Mr. Blanch (etal) is assuming a 3-6 minute release time. His vapor cloud will contain 3-6 times the amount of methane when it explodes – hence the damage radius is larger.

From what I have read (and I am not the expert), the probability of a delayed ignition event decreases as the time from pipe break to detonation/deflagration increases – i.e. a 1 minute delay for ignition is much more probable than a 3-6 minute delay. This maybe the fundamental underlying problem with a deterministic analysis. It appears the delay in ignition time may explain the difference between our respective damage radii in the analysis. We are looking at a more probable event than Mr. Blanch.

If the decreased probability of the substantially delayed (3-6 minute) ignition event is accounted for, it may be appropriate to specific screen that event out of consideration if the probability is < 1E-6 per Reg Guide 1.91.

Brian

From: Paul [mailto:pmblanch@comcast.net]
Sent: Wednesday, November 30, 2016 3:48 PM
To: Tammara, Seshagiri <Seshagiri.Tammara@nrc.gov>
Cc: Paul Blanch <pmblanch@comcast.net>; Burritt, Arthur <Arthur.Burritt@nrc.gov>; Miller, Chris <Chris.Miller@nrc.gov>; Beasley, Benjamin <Benjamin.Beasley@nrc.gov>; Pickett, Douglas <Douglas.Pickett@nrc.gov>; Dean, Bill <Bill.Dean@nrc.gov>; Beaulieu, David <David.Beaulieu@nrc.gov>; Haagensen, Brian <Brian.Haagensen@nrc.gov>; (b)(6) Setzer, Thomas <Thomas.Setzer@nrc.gov>; McCoppin, Michael <Michael.McCoppin@nrc.gov>; Dorman, Dan <Dan.Dorman@nrc.gov>; (b)(6) Amy Rosmarin <(b)(6)>; Ellen Weininger <(b)(6)>; Sandy Galef <(b)(6) David Buchwald <(b)(6)>; Dave Lochbaum <dlochbaum@ucsusa.org>; Jim Riccio <jim.riccio@greenpeace.org>; Lampert Mary <(b)(6)>; Karen Gentile <karen.gentile@dot.gov>; Joe Carson <(b)(6)>; William. R.

Corcoran <William.R.Corcoran@1959.USNA.com>; Paul Gallay <pgallay@riverkeeper.org>; (b)(6) ; Richard

Paul M. Blanch

Energy Consultant

Kuprewicz <kuprewicz@comcast.net>; CHAIRMAN Resource <CHAIRMAN.Resource@nrc.gov>; Dentel, Glenn <Glenn.Dentel@nrc.gov>

Subject: [External_Sender] QA Calculation for Indian Point blast radius

See enclosed pdf letter.

1 December 2016

Rao Tammara

USNRC

Washington DC

Dear Mr. Tammara:

Enclosed is a copy of a calculation conducted in accordance meeting the intent of the requirements of 10 CFR 50 Appendix B, Criterion III. We have additional calculations conducted by other professional engineers all using the equations of Regulatory Guide 1.91 with similar results. We have used the assumptions provided by the NRC for mass flow rate and total mass released.

I am fully aware the NRC has no Quality Assurances (QA) requirements for any of its calculations and is reflected in the numerous calculations provided me under FOIA. Because of this, there may be errors even in our calculations.

The following is one example of a calculation and methodology projecting a damaging blast radius of about 4200 feet within 3 minutes. Blast radius at 30 minutes is much greater. This blast radius would encompass the entire Indian Point site, including the unprotected control rooms, switchgear rooms and backup emergency power sources.

The likely outcome of this scenario may be core melting along with spent fuel damage with significant radioactive releases.

The assumed mass flow rates above were obtained from the NRC from numerous FOIA responses. All three independent calculations yielded about the same blast radius of about 4000 feet after a 3-6 minute release. We all used a yield factor of 5%, the least conservative value provided by Regulatory Guide 1.91.

We are aware of your statements January 12, 2015 (below) that you had not developed a "formal calculation package," yet your calculation formed the basis for the NRC's approval to FERC and the misleading statements made by the Chairman to members of Congress, thus placing 20 million persons at risk. According to FERC the NRC approval was provided in its Inspection Report of November 7, 2014. This was provided to me in response to a FERC FOIA request.

FERC's final approval for the safety of Indian Point and 20 million residents was predicated on "no formal calculation package," a statement made by you more than 2 months **after** FERC received approval from the NRC of "no significant risk." (See your email above). How could FERC approval be given without any formal calculation as you stated above?

Please review the enclosed calculation and identify our inconsistencies between our calculations. We would also like to discuss your meaning of and what does an "unbroken end" of a pipe burst mean. As an amateur plumber, I have not yet seen an "unbroken end" of a pipe burst. These types of errors had this calculation been conducted under some type of QA program.

As a cross check, I also ran the unapproved ALOHA program for a single ended pipe break and we can see below the high risk areas range from 4200 feet all the way to 5.8 miles, somewhat higher than the NRC's calculations of 1100 feet. The actual flow rate for a double ended break would be much greater and but not inconsistent with the NRC's calculated value of 376,000 kg/minute, a number also provided by FOIA. ALOHA may or may not be correct but it does project a blast radius similar to the engineering calculations.

The bottom line is that we have three professional engineers using a QA program and a physical scientist running calculations without any guidelines, procedures, reviews or approvals. The engineers project a blast radius in the range of 4200 feet and confirmed by ALOHA using a single ended break. You calculated a blast radius of about 1100 feet. Why the very significant difference? Claiming "Regulatory Infallibility" will not suffice.

FERC has based its approval of the AIM pipeline on the NRC's assessment of risk and this must be immediately corrected by informing FERC that the NRC's approval of the AIM pipeline must be rescinded until such time that our professional differences are determined.

Is it possible that we could sit down and have a professional dialog and determine why your informal calculation projected an 1100-foot blast radius whereas our formal calculations projected more than 4000 feet using the same approved NRC equations and input assumptions obtained under FOIA and your use of the prohibited EPA ALOHA program?

SITE DATA:

Location: Northeast US

Building Air Exchanges Per Hour: 0.45 (unsheltered single storied)

Time: November 30, 2016 & 1105 hours EST (using computer's clock)

CHEMICAL DATA:

Chemical Name: METHANE

CAS Number: 74-82-8 *Molecular Weight: 16.04 g/mol*

PAC-1: 65000 ppm PAC-2: 230000 ppm PAC-3: 400000 ppm

LEL: 50000 ppm UEL: 150000 ppm (Upper Explosive Limit and Lower Explosive Limit)

Ambient Boiling Point: -258.7° F

Vapor Pressure at Ambient Temperature: greater than 1 atmosphere

Ambient Saturation Concentration: 1,000,000 ppm or 100.0%

SOURCE STRENGTH:

Flammable gas escaping from pipe (not burning)

Pipe Diameter: 42 inches Pipe Length: 10000 feet

Unbroken end of the pipe is connected to an infinite source

Pipe Roughness: smooth *Hole Area: 1,385 sq in*

Pipe Press: 850 psia *Pipe Temperature: 70° F*

Release Duration: ALOHA limited the duration to 1 hour

Max Average Sustained Release Rate: 339,000 pounds/min

(Averaged over a minute or more)

Total Amount Released: 16,999,870 pounds

THREAT ZONE:

Threat Modeled: Flammable Area of Vapor Cloud

Model Run: Gaussian

Red : 1401 yards=4200 feet — (30000 ppm = 60% LEL = Flame Pockets).

Yellow: 5.8 miles — (5000 ppm = 10% LEL)

THREAT AT POINT:

Concentration Estimates at the point:

Downwind: 3400 feet *Off Centerline: 0 feet*

Max Concentration:

Outdoor: 42,300 ppm

Indoor: 13,500 ppm

ALOHA calculated blast radius for 339,000 pounds/min release rate

Your prompt response to my request for a meeting will be appreciated as we can not await the normal response time of the NRC when faced with such differences of opinions and the fact that once the gas is flowing through the new 42-inch AIM line, the plants will be operating in an unanalyzed condition requiring an 8-hour report to the NRC.

Paul Blanch

135 Hyde Rd.

West Hartford, CT 06117

pmblanch@comcast.net

860-236-0326

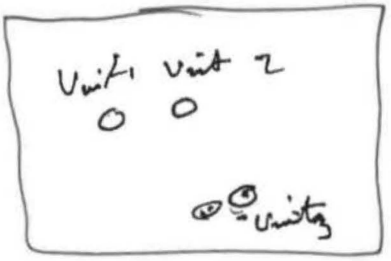
Cell 860-922-3119

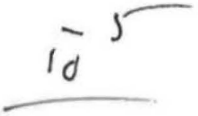
Double ended beaks in the middle of the pipeline can not be calculated by ALOHA

Both ends of pipe releasing methane would be close to the NRC number of 376,000 Kg/Min

Lower Explosion Limit

10 CFR 50.72 (B) The nuclear power plant being in an unanalyzed condition that significantly degrades plant safety.


Unit 1
Unit 2
Unit 3



Tammara, Seshagiri

From: Setzer, Thomas
Sent: Tuesday, January 03, 2017 12:49 PM
To: Burkhart, Lawrence; Tammara, Seshagiri
Cc: Dipaolo, Eugene; Haagensen, Brian
Subject: FW: This is what happens from 30" LINE RUPTURE 125 yards from the control room from a jet fire

Hi Larry and Rao-

Happy New Year! Our Senior Resident at IPEC (Brian) has gotten more correspondence from Mr Blanch. Brian has a couple questions here below...can you help in answering them for Brian's benefit?

If a call is better, I can arrange one. Also, by the way, beginning February 5, I will take over Gene's spot as Branch Chief. So I look forward to working with you guys.

Thanks
TOM

From: Haagensen, Brian
Sent: Tuesday, January 03, 2017 12:37 PM
To: Dipaolo, Eugene <Eugene.DiPaolo@nrc.gov>; Setzer, Thomas <Thomas.Setzer@nrc.gov>; R1ALLEGATION RESOURCE <R1ALLEGATION.RESOURCE@nrc.gov>
Cc: Pickett, Douglas <Douglas.Pickett@nrc.gov>; Rich, Sarah <Sarah.Rich@nrc.gov>; Safouri, Christopher <Christopher.Safouri@nrc.gov>
Subject: Re: This is what happens from 30" LINE RUPTURE 125 yards from the control room from a jet fire

The other difference (according to Mr. Blanch) is the release rate from the rupture. He is estimating 114,000 lbm/min. We estimated (b)(7)(F) which is equivalent to (b)(7)(F). I don't presuppose to know why his release rate is (b)(7)(F) our release rate.

Is this difference correct? Any possible reason? Could this be the issue that we added the upstream line release rate to the downstream line release rate but only provided one of the two release rates to him in our FOIA response?

Brian C. Haagensen
Senior Resident Inspector
Indian Point Energy Center
914-739-9630/1 (office)
(b)(6) (cell)
(home)

From: Haagensen, Brian
Sent: Tuesday, January 3, 2017 12:16 PM
To: Dipaolo, Eugene; Setzer, Thomas; R1ALLEGATION RESOURCE
Cc: Pickett, Douglas; Rich, Sarah; Safouri, Christopher
Subject: Fw: This is what happens from 30" LINE RUPTURE 125 yards from the control room from a jet fire

I am forwarding this email to R1Allegations for further review if desired. I did not find any allegations because the validity of his contentions are known and well-established.

Mr. Blanch continues to send emails that allege that our projections of blast overpressure and heat flux from a gas pipeline accident are non-conservative. He is now using the Aloha software to make projections that are significantly more impactful than what Entergy and our own experts have predicted. I expect the annual meeting will have many stakeholders alleging the kinds of impacts that he has been stating.

I think it would be important that we understand internally the bases for how we differ from his projections. From what I can tell, his projections are predicated on the delayed ignition scenario while our projections have ignition occurring within approximately one minute from the break. You can see by his estimates that he is delaying the ignition of the gas cloud by 60 minutes. This allows the gas cloud to build up into a large volume of explosive vapor around and above the plant. The impact of a substantially delayed ignition scenario may be much greater but I am pretty sure that the probability of this accident is very highly unlikely.

Now that he has provided his calculations, could we have someone (Rao?) at HQ who has expertise in the use of Aloha review what he has provided us and verify the bases for the differences between us? I would like to have this information available in my back pocket when I face the stakeholders at the AAM this year.

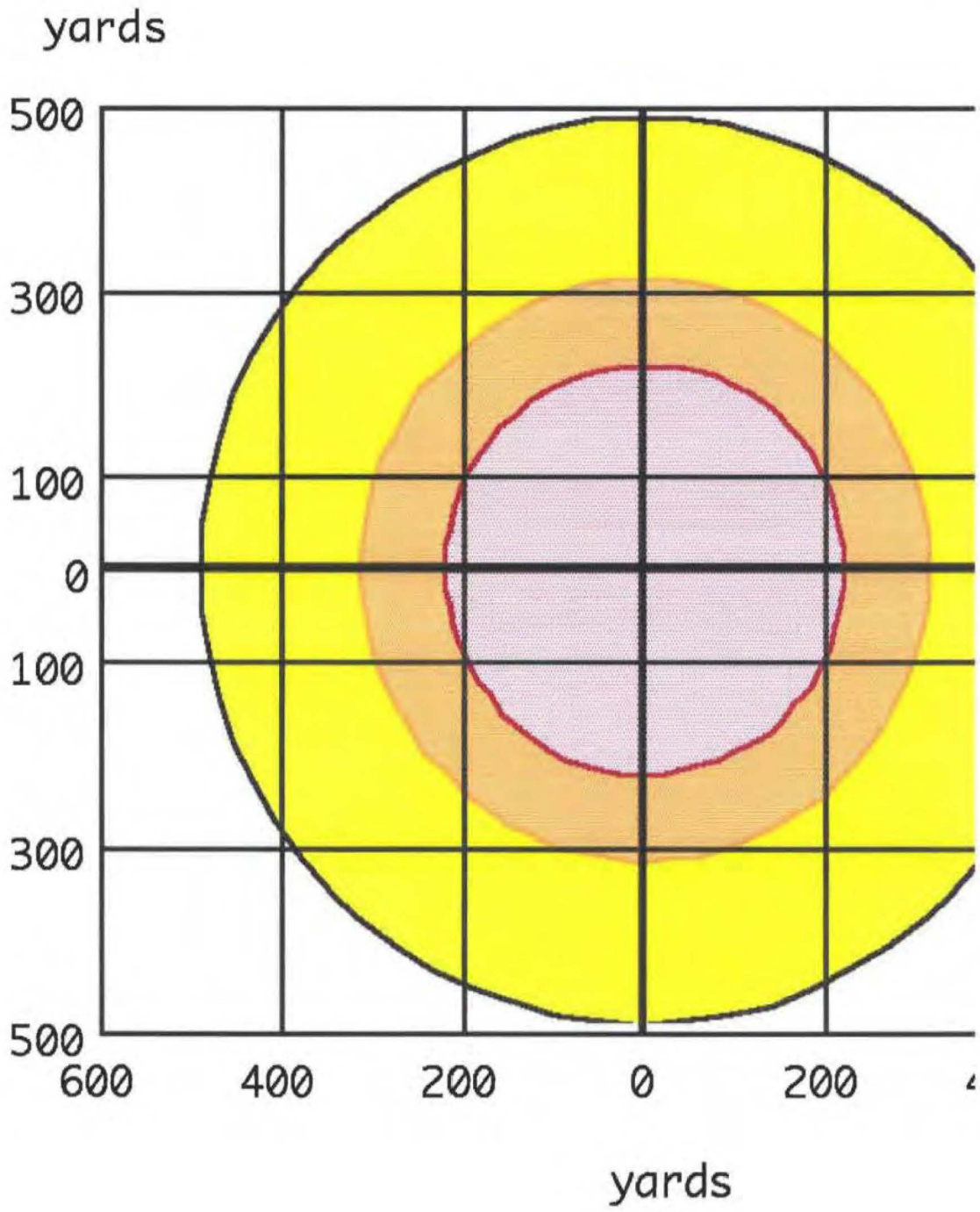
My understanding is that a 60-minute delayed ignition scenario is far less likely than a 1-minute delayed ignition scenario. I would hypothesize that the 60-minute scenario is at least 100x less likely than the 1-minute delayed ignition scenario and therefore, would screen out of consideration under the Reg Guide 1.94 methodology (as being <1E-6 or even 1E-7 using realistic assumptions). In addition, I note that his heat flux projections from the jet fire do not list the heat flux isopleth threshold and may be < 12.6 Kcal/cm2 (or whatever value we have been using).

Please let me know if my conjectures are reasonable and correct, or if there is more to this issue. I just want to be prepared for the inevitable questions to go beyond the statement 'Our experts have evaluated the issue and have concluded that our projections are accurate and bounding' if possible.

Brian

Brian C. Haagensen
Senior Resident Inspector
Indian Point Energy Center
914-739-9630/1 (office)
(b)(6) (cell)
(home)

From: Paul <pmblanch@comcast.net>
Sent: Tuesday, January 3, 2017 8:24 AM
To: Haagensen, Brian
Subject: [External_Sender] This is what happens from 30" LINE RUPTURE 125 yards from the control room from a jet fire



greater than 10.0 kW/(sq m) (pote

greater than 5.0 kW/(sq m) (2nd c

Paul Blanch PE
135 Hyde RD.
West Hartford CT 06117
pmblanch@comcast.net
Cell 860-922-3119
Home 860-236-0326

Tammara, Seshagiri

From: Pickett, Douglas
Sent: Monday, April 06, 2015 4:39 PM
To: McCoppin, Michael; Tammara, Seshagiri
Subject: LTR-15-0156-1 Response.docx
Attachments: LTR-15-0156-1 Response.docx

Mike/Rao –

Here is my proposed response to Paul Blanch. Could you please conduct a quick review of the attached and let me know that my changes are appropriate?

While I planned to provide a redline/strikeout version, there were too many changes to make that useful.

Thanks – Doug

Douglas V. Pickett, Senior Project Manager
Indian Point Nuclear Generating Unit Nos. 2 & 3
James A FitzPatrick Nuclear Power Plant
Douglas.Pickett@nrc.gov
301-415-1364

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 Nuclear Regulatory Commission (NRC) Chairman Steven 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 Units 2 and 3 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 a 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 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 and the confirmatory analysis performed by the NRC concluded that

resultant pressure waves and critical heat flux from a pipeline rupture would not adversely impact SSCs at the site.

- NRC staff from Region 1, the Office of Nuclear Reactor Regulation (NRR), and the Office of New Reactors (NRO) reviewed the licensee's analysis and concurred with the licensee's findings in an inspection report dated November 7, 2014. NRO staff performed an independent confirmatory analysis of a proposed gas pipeline rupture and concluded that it would not adversely impact safe operations at Indian Point.

- The proposed pipeline has gathered significant local stakeholder and political interest. Your petition and its supplements characterize Entergy's site hazards analysis as deficient and inadequate and requested an independent risk assessment of the proposed gas pipeline. Similar statements have been received from New York Assemblywoman Sandra Galef who represents the district that encompasses the site.

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, you made a presentation before the PRB on January 28, 2015, and the PRB subsequently met and provided its initial recommendation to senior NRR management for approval. When resolution is reached, you will be contacted and informed of the results.

You requested that the Commission rescind NRC's previous approval of the natural gas pipeline to FERC. The NRC approval was based upon a detailed review of the licensee's site hazards analysis that included a site inspection by NRC inspectors as well as an independent confirmatory analysis. As previously stated, FERC provided its approval of the proposed pipeline on March 3, 2015. The NRC staff remains confidant of these findings and sees no reason to rescind its findings to FERC.

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.

We appreciate your questions and your expression of your 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 Douglas Pickett at Douglas.Pickett@nrc.gov.

Sincerely,

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

- resultant pressure waves and critical heat flux from a pipeline rupture would not adversely impact SSCs at the site.

- NRC staff from Region 1, the Office of Nuclear Reactor Regulation (NRR), and the Office of New Reactors (NRO) reviewed the licensee's analysis and concurred with the licensee's findings in an inspection report dated November 7, 2014. NRO staff performed an independent confirmatory analysis of a proposed gas pipeline rupture and concluded that it would not adversely impact safe operations at Indian Point.

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We appreciate your questions and your expression of your 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 Douglas Pickett at Douglas.Pickett@nrc.gov.

Sincerely,

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

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ADAMS ACCESSION NO.: ML

OFFICE	LPL1-1/PM	LPL1-1/LA	LPL1-1/(A)BC	DORL/D	LPL1-1/(A)BC
NAME	DPickett	KGoldstein	MDudek	LLund	MDudek
DATE	04 / / 15	04 / / 15	04 / / 15	04 / / 15	04 / / 15

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Response to Paul M. Blanch
Letter of March 17, 2015

1. The analysis relies on the EPA 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)

Staff Response:

The ALOHA user's manual (Reference 1) addresses the ALOHA modeling capability of sources and scenarios and provides a sample input template on page 38 to be used for data input. The ALOHA model calculates the release rate of gas based on pipeline size, length, and its operating characteristics, and resulting potential impacts of vapor cloud transport and explosion, heat flux, and fire due to flammable concentration limits. For evaluating a pipe break in the middle, the NRC staff modified the ALOHA input data to capture conservative gas release rates to determine the amount of gas released. The release rates determined by ALOHA are compared 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 that calculated by hand and, therefore, are considered conservative for this application.

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.

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. The ALOHA model predicted that it would take 9 minutes to completely release the gas in the pipeline between closed isolation valves. 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. Therefore, it is concluded that the effect of valve closure times do not have a significant impact and the licensee's assumption of a 3 minute valve closure time does not have an adverse impact on the site hazards analysis.

3. Using more realistic gas release of one to two orders of magnitude greater, the blast radius would encompass the city water rank 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.

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

Staff Response to Items 3 and 4

The licensee's site hazard analysis concluded that there will be no damage to safety related structures, systems and components (SSCs). However, the report did acknowledge that a rupture of the proposed gas pipeline could potentially impact SSCs important to safety (SSCs ITS) that 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 or lead to station blackout. The licensee noted that a postulated gas pipeline rupture near SSCs ITS could occur from low probability events such as extreme natural phenomena (e.g., earthquake, tornado winds/missiles, hurricanes, etc.) which they are not designed against. 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.

In its confirmatory analysis using conservative assumptions and rationale, the NRC staff also concluded that no overpressure event of ≥ 1.0 psi is applied to any safety related SSCs inside the Security Owner Controlled Area (SOCA). Similar to the licensee, the staff also predicts that nearby SSCs ITS could be impacted because the calculated minimum safe distances exceed the distance from the pipeline to SSCs ITS. However, as discussed above, loss of SSCs ITS have been analyzed and addressed in the UFSARs and would not lead to core damage.

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

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

7. 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.

Staff Response to Items 5, 6, and 7

In evaluating potential hazards, the NRC's acceptance criteria are found in guidance documents (Reference 2). The acceptance criteria require that the licensee either determine the impacts using a deterministic approach or by 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) is less than the NRC staff's objective of being within an order of magnitude of 10^{-7} per year.

The licensee calculated the potential impacts to SSCs due to a potential rupture of the proposed 42-inch gas pipeline near Indian Point, and concluded that no safety related SSCs within the SOCA would be adversely impacted. The licensee acknowledged that some SSCs ITS could be impacted. However, as discussed above, these events have been analyzed and addressed in the UFSARs and the licensee concluded that the margin of safety is not significantly decreased.

Additionally, the licensee addressed the safety significance of loss of SSCs ITS from a postulated gas pipeline rupture. The licensee estimated the frequency of a postulated gas

pipeline rupture that could damage SSCs ITS giving credit to the enhanced design and installation features of the buried pipeline closest to the site and concluded it to be sufficiently low (on the order of 10^{-7} per year) and would not result in a significant reduction in the margin of safety.

The NRC staff's independent confirmatory analysis calculates minimum safe distances using a conservative deterministic approach (Reference 2). The staff's calculated minimum safe distances are less than the actual distance to the nearest safety related SSC and, therefore, it is concluded that there would be no adverse impacts to safety related SSCs within the SOCA. However, SSCs ITS could be affected but are not considered to be of concern because loss of SSCs ITS have been analyzed and addressed in the UFSARs. A postulated gas pipeline rupture at Indian Point does not create a new design basis event. Since the NRC acceptance criteria are satisfied based on the deterministic consequences impacting SSCs, probability estimates are neither required nor warranted. Therefore, the staff finds the licensee's approach reasonable and the 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 Reference 3, along with project specific assumptions from the licensee's submittal (Reference 4) are considered to provide 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% based on the literature (References 5 and 6). 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% is addressed in Reference 6. However, by taking credit for the enhanced design features of the buried pipeline, the staff considers that a 1% catastrophic release frequency to be reasonable and more realistic.

8. The analysis for the COLA permit for Turkey Point Units 6 and 7 predict a damage radius of more than 3000 feet from a smaller line operation 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.

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The NRC staff performed the review of the Turkey Point Units 6 & 7 Combined License (COL) application which addresses the hazards impact of a natural gas pipeline near the proposed units. The staff evaluated the potential impacts of that pipeline in the same manner as the AIM project and the staff's calculated impacts are lower for Turkey Point due to the smaller size pipeline and lower operating pressure. However, the Turkey Point licensee determined the minimum safe distance using RG 1.91 methodology as well as the ALOHA plume model based on an overly conservative assumption of a confined explosion which resulted in a larger minimum safe distance than the NRC analysis. The Turkey Point licensee demonstrated that the 1 psi overpressure criterion is met by assuming overly conservative assumptions. The NRC staff believes that a more realistic assumption would assume an unconfined explosion having a lower yield factor for a potential explosion. The staff's independent confirmatory analysis ensures that the Turkey Point COL application meets the required regulations and the staff's acceptance criteria.

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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.

Staff Response to Item 10:

The basis for the NRC staff's estimate of 7.5×10^{-7} per year probability of gas pipeline rupture was previously provided. The staff is not aware of letter writer's referenced calculations in order to review and respond.

REFERENCES

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.

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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. 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."

Tammara, Seshagiri

From: McCoppin, Michael
Sent: Friday, January 08, 2016 8:17 AM
To: Tammara, Seshagiri; (b)(6) ; (b)(6)
Subject: FW: DOT analyses

See below

From: Wilson, George
Sent: Friday, January 08, 2016 5:30 AM
To: Krohn, Paul <Paul.Krohn@nrc.gov>; Boland, Anne <Anne.Boland@nrc.gov>; Scott, Michael <Michael.Scott@nrc.gov>; Pelton, David <David.Pelton@nrc.gov>; Trapp, James <James.Trapp@nrc.gov>; Lorson, Raymond <Raymond.Lorson@nrc.gov>; McCoppin, Michael <Michael.McCoppin@nrc.gov>; Pickett, Douglas <Douglas.Pickett@nrc.gov>; Tate, Travis <Travis.Tate@nrc.gov>; Flanders, Scott <Scott.Flanders@nrc.gov>
Cc: Evans, Michele <Michele.Evans@nrc.gov>; Dean, Bill <Bill.Dean@nrc.gov>
Subject: DOT analyses

For your information, below is the gas line impact calculations performed by DOT for the AIM gas line by Indian Point. It also includes a link to their regulations.

The Potential Impact Radius or PIR is a calculation that is found in our regulations in 49CFR Part 192.903
The definition can be found on our website at this location:
http://www.ecfr.gov/cgi-bin/text-idx?SID=cd3084d70b2ae1bd480af98b15969ec3&mc=true&node=se49.3.192_1903&rgn=div8

Potential impact circle is a circle of radius equal to the potential impact radius (PIR).

Potential impact radius (PIR) means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula r = 0.69 (square root of ($p*d^2$)), where 'r' is the radius of a circular area in feet surrounding the point of failure, 'p' is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and 'd' is the nominal diameter of the pipeline in inches.*

NOTE: 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use section 3.2 of ASME/ANSI B31.8S (incorporated by reference, see §192.7) to calculate the impact radius formula.

Thus, the formula is: r = 0.69* (square root of ($p*d^2$)),

Using the Potential Impact Radius formula below for natural gas, where the diameter (d) of the pipe is 42",
For 800 psi MAOP, the PIR is 819.7'
For 900 psi MAOP, the PIR is 869.4'
For 850 (AIM Project Design MAOP by Indian Point), the PIR is 844.9'

I would like to add some additional information for your understanding of what the PIR represents. The PIR represents an area in which the heat from the ignition of an unintended release of natural gas would affect any person or any combustible material. The duration of these types of events are usually a brief period of time. The event may happen immediately after a pipeline failure and will last until the pipeline operators shut down the flow of gas. The shutdown is usually handled by turning valves on either side of the rupture area.

Note that there are additional issues to consider when analyzing the consequences of a failure. Some of these issues are:

1) not always does a release of natural gas ignite;
2) with the addition of remotely controlled valves that I believe is proposed for this area, the duration of a release would be reduced;
3) the greatest consequence taking place within the PIR is from the heat;
4) buildings made from material such as concrete would be much less affected by the heat.

DOT points of contact

Alex.Dankanich@dot.gov
karen.gentile@dot.gov

George Wilson
Deputy Director
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation
USNRC
301-415-1711
Office O8E4

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR data is current as of February 3, 2016

Title 49 → Subtitle B → Chapter I → Subchapter D → Part 192 → Subpart O → §192.903

Title 49: Transportation
PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS
Subpart O—Gas Transmission Pipeline Integrity Management

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§192.903 What definitions apply to this subpart?

The following definitions apply to this subpart:

Assessment is the use of testing techniques as allowed in this subpart to ascertain the condition of a covered pipeline segment.

Confirmatory direct assessment is an integrity assessment method using more focused application of the principles and techniques of direct assessment to identify internal and external corrosion in a covered transmission pipeline segment.

Covered segment or covered pipeline segment means a segment of gas transmission pipeline located in a high consequence area. The terms gas and transmission line are defined in §192.3.

Direct assessment is an integrity assessment method that utilizes a process to evaluate certain threats (*i.e.*, external corrosion, internal corrosion and stress corrosion cracking) to a covered pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.

High consequence area means an area established by one of the methods described in paragraphs (1) or (2) as follows:

(1) An area defined as—

(i) A Class 3 location under §192.5; or

(ii) A Class 4 location under §192.5; or

(iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or

(iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.

(2) The area within a potential impact circle containing—

(i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or

(ii) An identified site.

(3) Where a potential impact circle is calculated under either method (1) or (2) to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to

the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy. (See figure E.I.A. in appendix E.)

(4) If in identifying a high consequence area under paragraph (1)(iii) of this definition or paragraph (2)(i) of this definition, the radius of the potential impact circle is greater than 660 feet (200 meters), the operator may identify a high consequence area based on a prorated number of buildings intended for human occupancy with a distance of 660 feet (200 meters) from the centerline of the pipeline until December 17, 2006. If an operator chooses this approach, the operator must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 feet (200 meters) to the area of the potential impact circle (i.e., the prorated number of buildings intended for human occupancy is equal to 20 × (660 feet) [or 200 meters]/potential impact radius in feet [or meters]^2).

Identified site means each of the following areas:

(a) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or

(b) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or

(c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.

Potential impact circle is a circle of radius equal to the potential impact radius (PIR).

Potential impact radius (PIR) means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula $r = 0.69^*$ (square root of (p^*d^2)), where 'r' is the radius of a circular area in feet surrounding the point of failure, 'p' is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and 'd' is the nominal diameter of the pipeline in inches.

NOTE: 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use section 3.2 of ASME/ANSI B31.8S (incorporated by reference, *see* §192.7) to calculate the impact radius formula.

Remediation is a repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18231, Apr. 6, 2004; Amdt. 192-95, 69 FR 29904, May 26, 2004; Amdt. 192-103, 72 FR 4657, Feb. 1, 2007; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

Need assistance?

~~ATTORNEY-CLIENT COMMUNICATION – NOT FOR RELEASE OUTSIDE NRC~~

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

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~~ATTORNEY-CLIENT COMMUNICATION – NOT FOR RELEASE OUTSIDE NRC~~

NRC Staff Responses to Paul M. Blanch
Letter of March 17, 2015

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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 Nuclear Regulatory Commission (NRC) Chairman Steven 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 Units 2 and 3 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 a 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 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 and the confirmatory analysis performed by the NRC concluded that

resultant pressure waves and critical heat flux from a pipeline rupture would not adversely impact SSCs at the site.

- NRC staff from Region 1, the Office of Nuclear Reactor Regulation (NRR), and the Office of New Reactors (NRO) reviewed the licensee's analysis and concurred with the licensee's findings in an inspection report dated November 7, 2014. NRO staff performed an independent confirmatory analysis of a proposed gas pipeline rupture and concluded that it would not adversely impact safe operations at Indian Point.

- The proposed pipeline has gathered significant local stakeholder and political interest. Your petition and its supplements characterize Entergy's site hazards analysis as deficient and inadequate and requested an independent risk assessment of the proposed gas pipeline. Similar statements have been received from New York Assemblywoman Sandra Galef who represents the district that encompasses the site.

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, you made a presentation before the PRB on January 28, 2015, and the PRB subsequently met and provided its initial recommendation to senior NRR management for approval. When resolution is reached, you will be contacted and informed of the results.

You requested that the Commission rescind NRC's previous approval of the natural gas pipeline to FERC. The NRC approval was based upon a detailed review of the licensee's site hazards analysis that included a site inspection by NRC inspectors as well as an independent confirmatory analysis. As previously stated, FERC provided its approval of the proposed pipeline on March 3, 2015. The NRC staff remains confidant of these findings and sees no reason to rescind its findings to FERC.

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.

We appreciate your questions and your expression of your 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 Douglas Pickett at Douglas.Pickett@nrc.gov.

Sincerely,

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

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OFFICE	LPL1-1/PM	LPL1-1/LA	LPL1-1/(A)BC	DORL/D	LPL1-1/(A)BC
NAME	DPickett	KGoldstein	MDudek	LLund	MDudek
DATE	04 / / 15	04 / / 15	04 / / 15	04 / / 15	04 / / 15

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Response to Paul M. Blanch
Letter of March 17, 2015

1. The analysis relies on the EPA 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)

Staff Response:

The ALOHA user's manual (Reference 1) addresses the ALOHA modeling capability of sources and scenarios and provides a sample input template on page 38 to be used for data input. The ALOHA model calculates the release rate of gas based on pipeline size, length, and its operating characteristics, and resulting potential impacts of vapor cloud transport and explosion, heat flux, and fire due to flammable concentration limits. For evaluating a pipe break in the middle, the NRC staff modified the ALOHA input data to capture conservative gas release rates to determine the amount of gas released. The release rates determined by ALOHA are compared 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 that calculated by hand and, therefore, are considered conservative for this application.

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.

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. The ALOHA model predicted that it would take 9 minutes to completely release the gas in the pipeline between closed isolation valves. 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. Therefore, it is concluded that the effect of valve closure times do not have a significant impact and the licensee's assumption of a 3 minute valve closure time does not have an adverse impact on the site hazards analysis.

3. Using more realistic gas release of one to two orders of magnitude greater, the blast radius would encompass the city water rank 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.

pipeline rupture that could damage SSCs ITS giving credit to the enhanced design and installation features of the buried pipeline closest to the site and concluded it to be sufficiently low (on the order of 10^{-7} per year) and would not result in a significant reduction in the margin of safety.

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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. ML14245A110.

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

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