FOIA/PA NO: 2015-0246

GROUP: A

RECORDS BEING RELEASED IN THEIR ENTIRETY

Heater, Keith

From:	McCarver, Sammy
Sent:	Friday, December 12, 2014 8:09 AM
To:	Tifft, Doug; Lorson, Raymond; Burritt, Arthur; Krohn, Paul; McCoppin, Michael
Cc:	Dimitriadis, Anthony
Subject:	FW: Draft responses to NRC Questions re: AIM Project - ~~Privileged and Confidential~~

Below is the draft response I received from Entergy/IPEC regarding our questions on Spectra's monitoring of the gas line and the basis for the 3 min closure time Entergy/IPEC used in their 50.59 analysis

Sam McCarver

From: Prussman, Stephen G [SPrussm@entergy.com]
Sent: Friday, December 12, 2014 4:24 AM
To: McCarver, Sammy
Cc: Pickett, Douglas
Subject: FW: Draft responses to NRC Questions re: AIM Project - ~~Privileged and Confidential~~

Mr. Carver, you recently asked for certain additional information related to Entergy's 10.C.F.R. 50.59 Safety Evaluation and supporting evaluations prepared in response to the proposed Algonquin Incremental Market Natural Gas Project (AIM Project), including the basis for certain assumptions in those analyses. We provide our responses below.

As a preliminary matter and as NRC is aware, Entergy is not the sponsor or applicant for the AIM Project which is pending before the Federal Energy Regulatory Commission (FERC). Entergy's involvement is limited to evaluating any increased risks or consequences to Indian Point pursuant to its obligations as the licensed operator for Indian Point Units 2 and 3. As such, Entergy has worked closely with Algonquin to better understand the scope of the AIM project and confer regarding means to avoid any potential adverse impacts to IPEC. In doing so and as discussed further below, Entergy relied on certain information filed by Algonquin with FERC and on information provided by Algonquin to Entergy related to piping system operations.

Question 1: Can Entergy provide information regarding how Spectra maintains control (monitors) over the closure of the gas pipeline. How do they know that there is a rupture and how long will it take them to react and how long will it take the valves to close.

Resource Report 11, "Reliability and Safety," filed with FERC by Algonquin in February 2014 related to the AIM Project states as follows:

"A gas control center is maintained in Houston, Texas. The gas control center monitors system pressures, flows, and customer deliveries. Further, the gas control center is manned 24 hours a day, 365 days a year. Algonquin also operates area and sub-area offices along the pipeline route whose personnel can provide the appropriate response to emergency situations and direct safety operations as necessary. Algonquin's proposed AIM Project pipeline will be equipped with remote control shutoff valves as required by the USDOT regulations. This allows the shutoff valves to be operated remotely by the gas control center in the event of an emergency, usually evidenced by a sudden loss of pressure on the pipeline. Remotely closing the shutoff valve allows the section of pipeline to be isolated from the rest of the pipeline system. Data acquisition systems are present at all meter stations along the system. If system pressures fall outside a predetermined range, an alarm is activated and notice is transmitted to the Houston gas control center. The alarm provides notice that pressures at the station are not within an acceptable range."

In addition to the above information filed with FERC, Entergy conferred with Algonquin regarding remote monitoring of gas pipelines and responses to potential pipeline ruptures. Algonquin confirmed that the gas control center is manned 24 hours per day, 365 days per year. Algonquin also stated that electronic instruments at the valve site provide an alarm signal to gas control center if abnormal flow conditions occur, e.g., a pipeline pressure drop. The well-trained gas control personnel can then immediately diagnose the situation. Gas control personnel will acknowledge an alarm in seconds and will initiate a 'close' command following prompt evaluation of data generating the alarm condition, and

A1

sending a "close" signal to the valve takes only seconds, and the valve closing time is a little over one minute. An Entergy consultant also independently determined that natural gas isolation valves, similar to those proposed to be used on the AIM Project near Indian Point, generally close at approximately 1 inch per second. Therefore, a 42-inch valve is expected to close within the one minute timeframe provided by Algonquin.

Question 2: Entergy used a three minute valve closure time in its evaluation of the AIM Project. Does Entergy have any more information as to why this time is appropriate?

As noted above, the estimated valve closing time for a 42-inch natural gas pipeline is approximately one minute. As documented on Sheets 7 and 8 of Entergy's 10 CFR 50.59 Safety Evaluation Form submitted to the NRC on August 21, 2014 (available on ADAMS as of September 12, 2014 at ML14253A339), Entergy also estimated the time for Gas Control Center personnel to respond to an abnormal flow condition alarm and initiate a valve close command at one minute. Entergy then conservatively estimated a total of three minutes in its evaluations of the AIM Project. Further, as documented on page 16 of the supporting AIM Project Hazards Analysis, Entergy did not assume an immediate cessation of gas release after valve closure. Instead, Entergy conservatively assumed a full bore release from the pipeline continues for another 2 to 3 minutes after valve closure. Entergy therefore assumed the natural gas release, following an assumed catastrophic failure of the 42-inch pipeline, would actually continue for 5 to 6 minutes.

Please let us know if you have any further questions.

Krohn, Paul

From:	Miller, Chris
Sent:	Friday, February 20, 2015 8:44 AM
To:	McCoppin, Michael; Pickett, Douglas; Tammara, Seshagiri; McCarver, Sammy; Setzer, Thomas; Burritt, Arthur; Krohn, Paul; Tifft, Doug; McNamara, Nancy; Stewart, Scott
Cc:	Banic, Merrilee; Beasley, Benjamin
Subject:	RE: Paul Blanch Comments on 3 Minute Valve Closure Time

Mike,
That would be very good information for the Board to understand and consider.

Thanks
chris

From: McCoppin, Michael
Sent: Friday, February 20, 2015 8:42 AM
To: Pickett, Douglas; Tammara, Seshagiri; McCarver, Sammy; Setzer, Thomas; Burritt, Arthur; Krohn, Paul; Tifft, Doug; McNamara, Nancy; Stewart, Scott
Cc: Miller, Chris; Banic, Merrilee; Beasley, Benjamin
Subject: RE: Paul Blanch Comments on 3 Minute Valve Closure Time

We will be glad to explain the results of the sensitivity study conducted by Rao that demonstrates that the 3 minute valve closure time is largely inconsequential. His follow up analysis demonstrates that if the valves fail to close no threshold is approached that would cause damage to an safety related SSC jeopardizing safe shutdown of the reactor.

mike

From: Pickett, Douglas
Sent: Friday, February 20, 2015 8:34 AM
To: McCoppin, Michael; Tammara, Seshagiri; McCarver, Sammy; Setzer, Thomas; Burritt, Arthur; Krohn, Paul; Tifft, Doug; McNamara, Nancy; Stewart, Scott
Cc: Miller, Chris; Banic, Merrilee; Beasley, Benjamin
Subject: Paul Blanch Comments on 3 Minute Valve Closure Time

Folks - As you know, the transcript of the PRB meeting of January 28, 2015 (ML15044A459), with Paul Blanch has been released. I immediately received an email from Mr. Blanch questioning the NRC's basis for accepting the 3 minute valve closure time. In the attached two emails, you will see my response to Mr. Blanch, which steals from a previous Region 1 response to Sandra Galef, and Mr. Blanch's response to that.

Please be prepared to discuss the thoughts expressed below by Chris Miller during next week's PRB meeting. I am also requesting that Mike McCoppin and Rao Tammara discuss their post-PRB sensitivity studies that demonstrated that the 3 minute valve closure time is largely inconsequential.

Doug

From: Miller, Chris
Sent: Thursday, February 19, 2015 4:43 PM
To: Pickett, Douglas
Subject: PRB Meeting

Hi Doug,
Can we get the tech folks to give us a bit more on the 3 minute estimate, how much difference that it makes in the blast/burn analyses and if there is any way to gauge the time from the open pipe to loss of pressure actuation, and the actual response time of the operators in the 24/7 center / (panel continuously monitored, or 1 person, who leaves panel to go on rounds, bathroom etc.)?This will be important in the upcoming review.
chris

Heater, Keith

From:	Beasley, Benjamin
Sent:	Tuesday, March 24, 2015 7:59 AM
To:	Setzer, Thomas; Burritt, Arthur; Tifft, Doug
Subject:	FW: Responses to Chairman's Questions on Indian Point Gas Pipeline
Attachments:	Questions for March 24 2015.docx

From: Pickett, Douglas
Sent: Monday, March 23, 2015 6:28 PM
To: Weil, Jenny; Rihm, Roger; Baggett, Steven
Cc: Beasley, Benjamin; McCoppin, Michael; Tammara, Seshagiri; Wilson, George; Miller, Chris
Subject: Responses to Chairman's Questions on Indian Point Gas Pipeline

The attached responses were prepared by NRR and NRO to support the Chairman.

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

A5

Indian Point Proposed Natural Gas Pipeline

Question 1:

- Why did the NRC rely on Entergy's Hazards Analysis instead of performing an independent analysis of risk and consequences of construction and operation of the AIM project?

Response:

The NRC did not rely on Entergy's Hazards Analysis. The NRC performed an independent confirmatory analysis to evaluate the potential effects due to the proposed AIM 42-inch diameter natural gas pipeline near IPEC, and concluded that the pipeline would not have any adverse effects on the safe operation or safe shutdown of Indian Point Units 2 and 3.

The NRC staff reviewed Entergy's site hazards analysis and the result of this review is documented in an NRC inspection report dated November 7, 2014.

Question 2:

- Did the NRC evaluate the impact of "drilling fluids" used in the Horizontal Directional Drilling for AIM on the spent fuel rod pools located at Indian Point?

Response:

Horizontal directional drilling is being planned for that portion of the pipeline that will run beneath the Hudson River. The NRC staff does not review or inspect how the horizontal directional drilling will be performed. The pipeline that would run beneath the Hudson River and be constructed via horizontal directional drilling will be located over a half mile away from the Indian Point spent fuel pool buildings. The spent fuel pool buildings at Indian Point are seismically designed and the impact of drilling fluids would have no impact on these structures. Underground drilling with drilling fluids would have to be in extremely close proximity to the spent fuel pool buildings, such as within the protected area, to be of concern.

I am also concerned that NRC has been inconsistent in its reviews of the AIM project.

Question 3:

- For instance, compared to AIM, there is a smaller pipeline with lower gas pressure near the Turkey Point Nuclear Power Plant, in Homestead, Florida. However, the NRC predicted a greater damage radius in Florida than it did for AIM at Indian Point. Why?

Response:

The staff reviewed the Turkey Point Units 6 & 7 application, where the applicant evaluated the natural gas pipeline near the proposed units. The staff evaluated the potential effects of the Turkey Point pipeline in the same manner as that of the AIM project, and the resulting effects are lower for Turkey Point due to a smaller size pipeline and a lower operating pressure. However, the Turkey Point applicant performed their analysis based on an overly conservative assumption of a confined explosion which resulted in a larger calculated distance for a pressure

wave than the NRC analysis for Turkey Point. The applicant wanted to demonstrate that the 1 psi overpressure criterion is met by incorporating overly conservative assumptions. A reasonable assumption to consider would be an unconfined explosion which would give a lower yield factor for a potential explosion. The staff's independent confirmatory analysis ensured that the applicant met the required criteria. The NRC staff did not raise a concern because the applicant demonstrated a larger margin of safety.

Question 4:

- Why did the NRC use the ALOHA Manual instead of the NRC Regulatory Guide 1.91 when it performed a sensitivity study and determined that a delayed closure of the pipeline's isolation valves after a rupture would result in only a minimal increase in overpressure and heat flux at safety-related structures, systems, and components of the plant? The ALOHA model assumed an incident at the end of the pipeline. Why was a rupture in the middle of the pipeline not considered?

Response

The ALOHA model calculates the release rate of gas based on the pipeline and its operating characteristics and computes the resulting effects of a vapor cloud explosion, jet fire heat flux, and cloud fire based on flammable concentration limits. Since an instantaneous explosion at the pipe rupture is not realistic and thus not computed by the ALOHA model, the calculated release rate of gas from the ALOHA model was used to determine the amount of gas available for an instantaneous explosion. The evaluation of an instantaneous explosion used the methodology of RG 1.91 to compute the TNT equivalent for determining the minimum safe distance where a 1 psi overpressure would be predicted to occur.

In determining the release rates for the sensitivity analysis, the ALOHA model first assumed the case where the pipeline isolation valves were closed and a second case where the pipeline isolation valves remained open for an hour. The effects of a pipeline rupture were first evaluated for the case where the pipe breaks at a location where it is exposed above ground level and a second case where the pipe is located closest to the nuclear plant where the line is buried below ground. At the closest point to the plant, the pipeline is thicker, is buried deeper, and is physically protected by reinforced concrete mats. Because of these enhancements, the effects of a rupture closest to the plant are less than the rupture postulated at the above ground location.

Question 5:

- Doesn't Regulatory Guide 1.91 have provisions for jet flame, cloud fire, and vapor cloud?

Response:

No. RG 1.91 only calculates the minimum safe distance by evaluating the potential explosion at the source based on the amount of explosive in terms of TNT equivalent for a potential explosion. There is no provision in RG 1.91 for the evaluations of vapor cloud explosion, heat flux due to jet flame, or cloud fire.

Question 6:

Apparently there was a similar, but smaller-sized pipeline at Turkey Point that we required to be moved. Why not the AIM pipeline?

Response:

- The only pipeline within 5 miles of Turkey Point is the buried pipeline providing natural gas to Turkey Point Units 1 and 2.
- The NRC has not required that pipeline to be moved.
- The Turkey Point Units 6 & 7 new reactor COL application included the applicant's evaluation of a natural gas pipeline near the proposed units.
- The staff evaluated the potential effects of that pipeline in the same manner as that of AIM project, and the resulting effects were lower due to smaller size pipeline and lower operating pressure.
- The staff's independent confirmatory analysis concluding that the applicant's analysis was reasonable and acceptable ensures that the applicant meets the required regulations, criteria, and guidance provided.

Question 7:

Where are we on the 2.206 petition?

Response:

- In late February, the PRB met with the petitioners.
- NRR management has requested an outside peer review of a related calculation. The decision was made to seek technical assistance from staff at FERC. The PRB is continuing to try to obtain the independent peer review requested.
- The staff does not believe that Indian Point is operating in an "unanalyzed condition" (as suggested by Mr. Blanch).

Heater, Keith

From: Beaulieu, David
Sent: Monday, April 27, 2015 12:32 PM
To: Pickett, Douglas; Miller, Chris; McCoppin, Michael; Tammara, Seshagiri; Setzer, Thomas; Carpenter, Robert; Cylkowski, David; Banic, Merrilee; Beasley, Benjamin; Stuchell, Sheldon
Cc: Trapp, James; Dudek, Michael; Wilson, George; Gray, Mel; Krohn, Paul; Montgomery, Richard; Burritt, Arthur
Subject: Indian Point Gas Line Isolation Time

PRB,
Below are the excerpts that I discussed during today's PRB meeting:

1) Excerpts from the Indian Point 50.59 evaluation states, "The estimated time to respond to the alarm (less than one minute) and the closure time of the valves (about one minute) was used as the basis for an assumed closure time of three minutes for the analysis performed in the attached report."
2) National Transportation Safety Board 2011 report excerpt that states that "there is no DOT requirement for response time."
3) Oak Ridge report from 2012 includes two separate statements about closure time:
"The time between a pipeline break and RCV closure can vary from about 3 minutes for immediate leak or rupture detection to hours if field confirmation of a break is necessary to validate the closure decision."
"Consequently, delays of about 10 minutes will be required before RCV closure can be initiated for a typical line break scenario, if field verification of the break is not required."

<u>Excerpts from various sections of the Indian Point 50.59 evaluation involving the 3 minute isolation time.</u>

"This would result in all the gas between these valves at the time of closure being able to vent or burn. The estimated time to respond to the alarm (less than one minute) and the closure time of the valves (about one minute) was used as the basis for an assumed closure time of three minutes for the analysis performed in the attached report."

"The next closest isolation valve locations are at the Stony Point Compressor Station mile post 0.0 and at MLV 15 at mile post 10.52. Valve operation follows the requirements of the DOT Code and is tested on a periodic basis to ensure compliance with code requirements."

"This hazards analysis considers the effects of the gas pipeline rupture to involve the approximately 3 miles of pipeline between isolation valves and considers the event to be terminated by manual action within 3 minutes after any pipeline rupture event by closing the closest isolation valves and limiting the event to the gas between these valves."

"In modeling releases and their consequences, we assume that the contents of a 3 mile length of gas pipeline are released at a pressure of 850psig (the MAOP of the 42" pipeline), that valves isolating this length of pipeline will be closed within 3 minutes of a major release and that the interior of this pipeline is smooth."

"After valve closure, full bore release from the pipeline will persist for another 2 to 3 minutes. The release following guillotine rupture will therefore be ~ 5 to 6 minutes duration."

"Based on an average release rate of 1877 kg/s for a 360-second period. This rate comprises the release of 376,000 kg in the first minute (from ALOHA), a release of 200,000 kg in the next two minutes (accounting for the pressure drop) and 100,000 kg after valve closure. This last will take an additional 3 minutes after the valves are closed (from ALOHA)."

<u>National Transportation Safety Board. 2011. Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010. Pipeline Accident Report NTSB/PAR-11/01. Washington, DC. http://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1101.pdf</u>

A-4

Other than for pipelines with alternative maximum allowable operating pressures (MAOP), **the regulations do not require a response time to isolate a ruptured gas line, nor do they explicitly require the use of ASVs or RCVs**. The regulations give the pipeline operator discretion to decide whether ASVs or RCVs are needed in HCAs as long as they consider the factors listed under 49 CFR 192.935(c): Automatic shut-off valves (ASV) or Remote control valves (RCV). If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

Oak Ridge National Laboratory ORNL/TM-2012/411, "Studies for the Requirements of Automatic and Remotely Controlled Shutoff Valves on Hazardous Liquids and Natural Gas Pipelines with Respect to Public and Environmental Safety," December 2012,
http://www.phmsa.dot.gov/pv_obj_cache/pv_obj_id_2C1A725B08C5F72F305689E943053A96232AB200/filename/Final%20Valve_Study.pdf

Conclusions from the "Cost Benefit Study of Remote Controlled Main Line Valves" (Sparks, 1998) follow.

1. Virtually all injuries caused by pipeline breaks occur at, or very near, the time of the initial rupture. Of 81 injury incidents reviewed (1970 to 1997 NTSB Incident Reports), 75 reported injuries at the initial rupture. Of the other six incidents, four occurred within 3 minutes of the rupture. It seems clear, therefore, that early valve closure time will have little or no effect on injuries sustained, and no effect on rupture severity. Valve closure will be "after the fact" as far as most injuries and damage are concerned. There is no evidence that prolonged blowdown of a ruptured line causes injuries.
2. Further, a line break does not immediately evacuate the pipeline. Because of line pack (gas compressibility) some 5 to 10 minutes are normally required for low pressure alarms to be generated at Gas Control and/or nearby compressor stations. Delays depend upon break size and location, line size, operating pressure, and other operating and configurational variables. Additional time is then required (a) to determine the cause of low line pressure (e.g., loss of compression, load transients, faulty instrumentation, line break, or other causes) and (b) to determine break location. This will likely consume an additional 5 minutes. **Consequently, delays of about 10 minutes will be required before RCV closure can be initiated for a typical line break scenario, if field verification of the break is not required.** Early valve closure can, however, have a significant effect in reducing the volume of gas lost after a line break. Simulations show savings of about 50% for valve closure at 10 minutes versus closure at 40 minutes in a typical 30-inch/900-psi rupture scenario.

A different section of the Oak Ridge Report states:

The decision to close a RCV involves evaluating the sensor data received at the remote location and determining whether a problem does, or does not, exist. The evaluation process includes consideration of real-time pressure and flow data and communications with the public, emergency responders, or company field personnel. If the operator determines that block valve closure is necessary, the operator initiates the closure procedure by sending a signal to the valve site via the communications link. **The time between a pipeline break and RCV closure can vary from about 3 minutes for immediate leak or rupture detection to hours if field confirmation of a break is necessary to validate the closure decision.**

DAVID BEAULIEU *PROJECT MANAGER NRR/DPR/PGCB*
(bowl-yer) **301-415-3243 | O12D14** | David.Beaulieu@nrc.gov
U.S. Nuclear Regulatory Commission