Gas Pipeline Q&A

The following provides responses to common questions raised related to the Algonquin Incremental Market (AIM) pipeline and legacy pipelines near the Indian Point facility (IP). The Algonquin pipeline system, including the AIM pipeline and the 26" and 30" pipelines located near IP, is a federally-regulated interstate pipeline.

On August 20, 2021, the federal agency known as the Pipeline and Hazardous Materials Safety Administration (or PHMSA) announced they will conduct a new analysis of the AIM pipeline. On September 30, 2021, PHMSA further confirmed that Oak Ridge National Labs will be conducting the independent analysis. DPS welcomes the independent review.

Oversight over the Algonquin Gas Transmission (AGT) Pipelines

What oversight is there? What accountability?

The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) has primary oversight jurisdiction over interstate transmission pipelines. In accordance with DPS' interstate agent agreement with PHMSA, the New York State Department of Public Service (DPS) performs and documents inspections of the operations and activities of the pipeline when scheduled by PHMSA. Currently, DPS Staff witnesses annual inspections of those remote-operated valves needed for emergency shutdown in the vicinity of Indian Point site. During the Indian Point decommissioning process, excavation in close proximity of the gas pipelines or heavy load crossings over the pipeline requires advance notification to DPS Staff in accordance with the Joint Proposal in Case 19-E-0730. Additionally, all excavation in NYS is subject to the One Call damage prevention regulations found in 16 NYCRR Part 753.

The federal Nuclear Regulatory Commission (NRC) has primary oversight jurisdiction over nuclear energy facilities. NRC performs and documents inspections of the operations and activities of the nuclear facility. NRC further requires licensees to perform a safety analysis when modifications are made to a facility that affect design function, method of performing or controlling a function, or an evaluation that demonstrates intended functions will be accomplished.

How does PHMSA ensure integrity?

PHMSA has included Transmission Integrity Management regulations in 49 CFR Part 192 and New York State has adopted them into 16 NYCRR Part 255. These regulations prescribe minimum requirements for an integrity management program on any gas transmission pipeline. An operator's integrity management program (IMP) requires the operator to identify all High Consequence Areas (HCAs), identify threats to each covered pipeline segment (which must include data integration and a risk assessment to perform a risk analysis), evaluate and assess these pipelines on a regular schedule, remediate conditions found during any integrity assessment, and implement preventive and mitigative measures for each covered segment.

PHSMA and DPS as the interstate agent for New York, perform regular audits of all Integrity Management Plans and the implementation of these plans. For interstate pipelines, enforcement actions are initiated by PHMSA when/if probable violations are identified during these audits.

NOTE: The “risk analysis” required by pipeline safety regulations deals with risks to the pipeline and helps prioritize the schedule of the assessment of pipeline and focuses efforts on measures that pipeline operators can (and must) take to prevent and mitigate the risks identified.

Who can make a decision to shut off the gas, such as by denying permits or issuing a corrective action order?

Authorization for construction and operation of the Algonquin Incremental Management (AIM) pipeline is granted by the Federal Energy Regulatory Commission (FERC).

The Algonquin Gas Transmission (AGT) pipelines, with regard to compliance with federal pipeline safety regulations (49 CFR Part 192), are under the primary oversight of PHMSA.

At a recent meeting, you noted that DPS and PHMSA staff are making sure Holtec and Enbridge talk to one another. Why are you putting our safety in the hands of Holtec and Enbridge to decide what to do about stopping the gas?

While Holtec and Enbridge are required to work within the scope of Indian Point’s decommissioning agreement in place (per the Joint Proposal in Case 19-E-0730), NYS DPS has representation and input in regular meetings during the shutdown period to ensure procedures are followed. Enbridge, as the operator of the pipelines, and Holtec, as the owner of the site, are responsible for safety. PHMSA and NRC regulations require operators meet or exceed safety requirements. PHMSA and DPS, under an interstate agent agreement perform audits and inspections of Enbridge to ensure that these regulations are met. All enforcement is handled by PHMSA.

What proactive steps is DPS taking to manage pipeline safety when decommissioning work is being conducted near the pipeline?

DPS Staff has undertaken or will be undertaking the following proactive steps:

- DPS Staff is facilitating regular meetings with Holtec and AGT to ensure that both are aware of any construction on their facilities.
- Per the Joint Proposal in Case 19-E-0730, Holtec is required to notify DPS Staff and the pipeline operator at least five business days in advance of any excavation that could affect the pipelines.
- Federal pipeline safety regulations and Company procedures require the pipeline operator to monitor excavation activities within or near its pipeline right-of-way. DPS Staff will contact the pipeline operator to ensure that it is taking appropriate actions in response to excavation activities or heavy crossings on its pipeline.
- In coordination with PHMSA, DPS performs inspections of pipeline operations and maintenance activities, with particular attention to the pipeline and remote operated valves in the vicinity of Indian Point.

3-Minute Drill

Why can't the gas be shut off if Enbridge missed the 3-minute drill the approval was based on? If a pipeline company lies to get a permit, who has the power to rectify it?

Authorization for construction and operation of the AIM pipeline was granted by FERC in 2015.

While FERC had primary responsibility for approval of the AIM pipeline construction, NRC advised FERC regarding the impact of the pipeline on the Indian Point facility. Under 10 CFR 50.59, former Indian Point facility owner, Entergy, was required to evaluate if additional risk would be posed to the nuclear facility by the construction of the new pipeline. Entergy's August 24, 2014 10 CFR 50.59 analysis utilized a 3-minute valve closure time for isolation of the pipeline in the event of a rupture to calculate whether critical nuclear safety structures would be affected. The NRC accepted this analysis by Entergy. Since the filing of the analysis, petitioners to the NRC noted that the 3-minute valve closure time was unrealistic, but the NRC rejected this petition.

On October 5, 2018 – NYS DPS witnessed Enbridge operate each of the five remote-operated valves that would be needed to isolate each of the three AGT pipelines (26-inch, 30-inch, and 42-inch line) that run near the Indian Point Power plant in Westchester County, NY. NYS DPS observed that, from the time the controller in the control room in Houston initiated the valve closure, the valve took approximately 30 seconds to close. This included the two remote-operated valves (ROVs) to isolate the 42-inch AIM pipeline near the Indian Point Property.

On October 9th and October 10th, 2019, NYS DPS performed a similar inspection to the one performed in October 2018, in which NYS DPS observed Enbridge operate the five ROVs needed to isolate the three pipelines in the Indian Point area. NYS DPS observed that each valve was operable remotely and was able to close in approximately 30 seconds.

On September 30th, 2020, NYS DPS performed a similar inspection to the one performed in October 2019, in which NYS DPS observed Enbridge operate the five ROVs needed to isolate the three pipelines in the Indian Point area. NYS DPS observed that each valve was operable remotely and was able to close in approximately 30 seconds.

To verify the 3-minute closure time, NYS DPS called for a control room drill observed by DPS and federal regulators. During the week of April 29, 2019, DPS Staff performed focused control room inspection of pipelines within Indian Point area (26-inch, 30-inch, and 42-inch pipeline). Staff focused on the Supervisory Control and Data Acquisition (SCADA) sensors in the area and actions a controller would take to close a valve. As part of this control room inspection, NYS DPS Staff travelled to Houston and observed the controller initiate a valve closure of one of the valves needed to isolate the 30-inch pipeline in the Indian Point area. At the same time, local NYS DPS Staff observed the actual closure of the valve in the field. Staff did not observe any issues with operation of the ROV and confirmed that the ROV took approximately 30 seconds to close from initiation. However, DPS staff also observed that the valve closure times would likely exceed 3 minutes due to the time it would take for on-site verification of an incident.

The NRC Office of Inspector General, in its report issued on February 13, 2020, noted concerns regarding the usage of the 3-minute valve closure time in the NRC's analysis. The NRC issued its expert evaluation team report, in response to the OIG findings, on April 8th, 2020. In the response report, the NRC confirmed that 3-minutes would be a "best-case scenario" for identification and closure of remote-operated valves, and remote valve closure would likely take 3 to 8 minutes.

DPS Staff believes the NRC's expert evaluation team report resolves outstanding concerns regarding the 3-minute valve closure time. The revised Entergy 10 CFR 50.59 analysis, submitted on September 16, 2020, uses a valve closure time of 8 minutes. The revised analysis found that there would be no damage to site structures, systems, and components (SSCs) from a pipeline rupture; the NRC accepted Entergy's revised 10 CFR 50.59 with no findings.

Most damage after a rupture would be done within a few minutes.

DPS Staff does not disagree with this statement, but notes the number of aforementioned actions taken by DPS Staff to verify the steps taken by Enbridge during the construction and operations of these pipelines to mitigate risk of leaks or damage to prevent a rupture on the pipeline.

The time to shut the remote valves from Houston doesn't include the time to identify a pipeline rupture which can take at least 30 minutes and up to hours. None of the 900+ incidents reported to PHMSA were shut in less than 30 minutes.

Staff has reviewed the list of 920 incidents reported to PHMSA. The list primarily consists of events that did not lead to a pipeline rupture. Only 118 of the 920 listed incidents were on transmission piping, of which 23 were shutdown within 30 minutes and another 26 where the pipeline did not need to be shutdown at all. Ultimately, it is not possible to infer a shutdown time for the AIM pipeline based on the list of PHMSA reportable incidents.

In the unlikely event of an incident on the AGT pipelines within the Indian Point area, the pipelines have the following that leave them well-positioned to be shut within 30 minutes:

- Gas flow the pipelines can be isolated via remote-operated valves that can be initialized from Enbridge's control room, so time is needed for qualified personnel to travel to individual valves can be eliminated. DPS Staff has verified valves close within 30 seconds of initialization by the controller. Valves necessary for isolation have been pre-identified and are inspected at least once annually for operability.

- DPS Staff has verified that there are multiple SCADA sensors near the area that would alert Enbridge controllers to a pressure drop on the pipeline.
- All pipelines are downstream of the nearby the Stony Point Compressor Station; the high discharge alarms would provide an initial alert to controllers of a rupture condition on the pipeline.

At the NRC Petition Review Board hearing on July 15, 2015, Richard Kuprewicz raised concerns **about the potential impact radius of a pipeline rupture near Indian Point:**

PHMSA accident data suggests that the potential impact radius (PIR) near Indian Point is more than adequate, given critical systems at Indian Point are twice the PIR. As part of the investigation for its report, the NRC expert evaluation team interviewed Richard Kuprewicz on March 19, 2020.

From the "Indian Point Expert Team Final Report":

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

Entergy, Indian Point's previous owner, and the federal Nuclear Regulatory Commission also evaluated theoretical impacts that might be posed by an accident on a legacy line; they concluded that the IP3 reactor and spent fuel building would not be adversely impacted. See NRC Report, Enclosure 2 (dated May 27, 2020) at 6-10.

Risk Assessment

What is the purpose of a risk assessment?

As part of a gas pipeline operator's Integrity Management Program, an operator is required to undertake a process for the identification of threats to each "covered pipeline segment" (a segment of gas transmission pipeline located at a high consequence area – e.g., near Indian Point), which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment and to evaluate the merits of additional preventive and mitigative measures for each covered segment.

A gas pipeline operator must conduct a risk assessment per 49 CFR Part 192 and 16 NYCRR Part 255.901-951 that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments, and to determine what additional preventive and mitigative measures are needed for the covered segment.

The purpose of a risk assessment is not to have zero risk, but to determine threats to the system and prioritize the taking of preventive and mitigative actions to minimize risk from identified threats, particularly those in pipeline segments that are in (or could directly affect) high consequence areas, such as Indian Point.

In instances of colocation with a nuclear energy facility, NRC further requires the licensee of that nuclear facility to perform a separate safety analysis. The scope of this safety analysis, as outlined and required by 10 CFR 50.59, is to assess the integrity of the nuclear facility and safe operations thereof.

Agency studies are violating the basic laws of science concerning gas pipeline rupture and associated forces that result in massive cratering, pipe shrapnelling and violate science associated with such releases. It appears that agencies are attempting to dismiss risk as low when gas pipeline rupture may drive a new facility to non-safe shutdown in a highly sensitive area.

From the April 2020 NRC "Indian Point Expert Team Final Report":

> *If a rupture occurred on the stretch of 42-inch pipeline near Indian Point, the nuclear power plant would remain protected. The plant's safety systems are all far from the pipeline. They are two or more times the "potential impact radius" that the U.S. Department of Transportation designates for protecting people from pipeline ruptures and also far outside the distance where heat flux would be high enough to affect wooden structures, let alone the robust concrete structures that house the plant's safety equipment. The potential impact radius bounds most pipe rupture impacts observed in real-life accidents. In a more detailed transient*

> *analysis, the team found that the robust concrete structures housing the plant's safety-related equipment, spent fuel pool, and dry fuel storage containers would withstand the heat and pressure impacts of an explosion or fire that could follow a pipeline explosion. The safety related equipment would be able to safely shut down the reactors and maintain them in a safe shutdown condition. Equipment or structures outside these buildings could be affected, but these serve as backups or alternatives to the safety-related equipment. The team also conducted a risk assessment to consider the uncertainties of the events that could unfold at Indian Point and found that the risk of serious consequences from a postulated pipeline rupture was very small.*

You can't quantify risk: There is no precedent for a pipeline (let alone 3) on the site of a nuclear plant or during its decommissioning.

On March 9, 2020, NYS DPS sent a letter to FERC and NRC expressing a desire for a comprehensive and site-wide analysis of accident risks posed by all of the pipelines to the Indian Point facilities. In its May 27, 2020 response to DPS, NRC stated:

> *While the evaluation team primarily focused on the AIM pipeline efforts, there have been analyses of the two preexisting pipelines that cross the Indian Point site. These previous analyses concluded that the preexisting pipelines are unlikely to fail and that, if a rupture occurred, there are backup systems onsite at Indian Point that could safely shut down the reactors. In addition, the spent fuel would remain protected, whether it is in the plant's spent fuel pools (which were also analyzed for the heat load of the spent fuel), or out of the pools and in the dry spent fuel storage casks.*
>
> *While an additional site-specific analysis could address more factors such as site topography, weather, earthquake-initiated pipeline ruptures, and the capabilities of specific equipment and structures on site to withstand pipeline ruptures, the NRC staff has determined that it is unlikely that such an analysis would change the underlying findings of the prior reviews of the pipelines. Given that the risk posed by a potential pipeline rupture near Indian Point is low and is expected to decrease as the reactors transition to decommissioning within the next year, the NRC staff has concluded that conducting such an analysis is not warranted at this time.*

The pipeline failure rate in the US has been most prominent in newly-constructed pipelines since 1986.

DPS Staff is aware of an industry trend of an increased number of reportable incidents on recently constructed pipelines.

The 42-inch pipeline took extra steps during construction and pre-energizing testing to remediate risk associated with construction defects. The enhanced protections for the pipeline adjacent to Indian Point include:

- A more stringent design factor, higher-grade pipe, and deeper burial than required
- Fusion-bonded epoxy coatings for corrosion control outside the pipe, an abrasive resistant overlay outside the pipe, and no coating on field weld joints that could cause pipe metal cracking, such as shrink sleeves or tape coatings
- 100-percent non-destructive examination of all girth welds; 100-percent inspection of all welding, coating, and backfilling activities; and pigging after construction to identify and remediate any dents exceeding code limitations
- Hydrostatic testing before placing the pipeline segment into natural gas service, at over 1.5 times MAOP for 8 hours
- Enbridge also placed fiber-reinforced concrete slabs and warning tape above the pipeline near Indian Point to reduce the likelihood of construction digging or other activities inadvertently reaching and damaging the pipeline.

In addition, an inline inspection of the 42-inch pipeline was performed in 2020.

NYS risk assessment said that decommissioning increases the risk of a pipeline rupture. Is that still a concern?

The risk assessment commissioned by NYS did not specifically analyze decommissioning activities in relation to the pipelines within the Indian Point facility. However, the risk assessment did address certain threats associated with decommissioning activities, such as the outside force damage and excavation damage. The risk assessment did identify excavation damage as one of the higher risk threats posed to the pipeline. The risk assessment, however, assessed the risks in the context of general threats posed to a pipeline and also did not take into account actions to mitigate those threats. Mitigative measures include:

- The Indian Point facility is a highly controlled site where it would be highly improbable for third-party excavation to take place without prior knowledge and access of the facility owner.
- Excavation near pipelines must be conducted carefully following all protocols to prevent damage. The DPS is holding regular meetings with Holtec and AGT to ensure that both are aware of construction. All excavation activities must comply with 16 NYCRR Part 753 requirements such as – advance notification to Dig Safely New York, wait for mark outs, hand expose the pipe location, limitations on power equipment usage within tolerance zone and no usage of power equipment within 4 inches of the pipeline after identifying location, etc.

- Per the Joint Proposal in Case 19-E-0730, Holtec is required to notify DPS Staff and the pipeline operator at least five business days in advance of any excavation that could affect the pipelines.

Were the questions raised by DPS to FERC ever answered? Does NYS still care about the answers to those questions?

PHMSA announced that Oak Ridge will conduct an independent review by Oak Ridge National Labs. DPS, under its own separate authority (not in its role as a state agent of PHMSA), has shared and reiterated its perspective, and engaged with Senators Schumer, Gillibrand, and Representative Jones, who have raised the issue with Federal authorities. DPS will closely monitor the new analysis.

The pipeline poses a risk by being on two fault lines.

DPS Staff has confirmed that Enbridge has a seismic monitoring program in place in which it automatically receives earthquake notifications from the U.S. Geological Survey (USGS) GeoJSON and Natural Resources Canada (NRCan) RSS data feeds. These systems provide Enbridge with near real-time notifications of earthquakes in proximity to its pipelines. DPS Staff has confirmed that Enbridge has procedures in place to take appropriate actions in response to earthquakes near its pipelines.

In a letter sent to the NRC on March 26, 2020, NYS DPS, under its own separate authority (not in its role as a state agent of PHMSA) requested NRC conduct an overall site risk analysis including all three pipelines on the site and incorporating updated USGIS seismic information.

In Danville, KY there was a pipeline failure that resulted in a 30 ft. long pipeline section that landed 460 feet from failure site and left a 50 ft. long, 35 ft. wide and 13 ft. deep crater. How would that impact this site at Indian Point with the spent fuel and all the radioactive materials? Death of 1 person, hospitalization of 6 and destruction of homes. It was a 30" pipeline and AIM is a 42" diameter pipeline and there is also a 30" pipeline on this site.

The Danville, KY incident is under investigation by the federal National Transportation Safety Board; the NTSB is pending release of the final investigation report for this incident.

DPS Staff notes that the distances described by the commenter are within the calculated potential impact radius (PIR) of the 30-inch PIR of the Danville, KY. The April 8th, 2020 NRC Expert Evaluation Team report, which was informed utilizing a team of SMEs at NRC and PHMSA, states that double the calculated PIR of the 42-inch pipeline would not affect safety-related structures at the nuclear power plant.

On March 9, 2020, NYS DPS, under its own separate authority (not in its role as a state agent of PHMSA) sent a letter to FERC and NRC underscoring the value of a comprehensive and site-wide analysis of risks posed by pipelines at the Indian Point facilities.

Gas Shutdown During Decommissioning

Why don't you shut down the gas during decommissioning? Radioactive material is less protected during decommissioning, and thus more at risk of pipeline rupture.

There is no change in how radioactive material is handled/protected on an operating site versus a site undergoing decommissioning.

Heavy excavation work related to decommissioning will further jeopardize pipeline integrity.

Per the Joint Proposal in Case 19-E-0730, Holtec is required to notify DPS Staff and the pipeline operator five business days in advance of any excavation that could affect the pipelines. In addition, Holtec is required to notify DPS Staff and the pipeline operator 10 days in advance in the event of blasting or dredging at the site. Holtec states that it currently has no plans to perform blasting as part of decommissioning.

Federal pipeline safety regulations and Enbridge procedures require the pipeline operator to monitor excavation activities within or near its pipeline right-of-way. In addition, DPS Staff will contact the pipeline operator to ensure that it is taking appropriate actions in response to excavation activities or heavy crossings on its pipeline.

NYS confirmed that excavation near the pipeline heightens the risk of a pipeline rupture.

The Executive Summary of the risk assessment commissioned by New York State in 2018 identified excavation as one of the higher risks to the pipelines at the Indian Point site. The risk assessment commissioned by New York State characterized general risks to the pipeline, but did not take into account mitigative measures to reduce those risks and certain site-specific requirements/conditions that greatly reduce the threat of excavation damage at the site. Mitigative measures include:

- A more stringent design factor, higher-grade pipe, and deeper burial than required
- Fusion-bonded epoxy coatings for corrosion control outside the pipe, an abrasive resistant overlay outside the pipe, and no coating on field weld joints that could cause pipe metal cracking, such as shrink sleeves or tape coatings
- 100-percent non-destructive examination of all girth welds; 100-percent inspection of all welding, coating, and backfilling activities; and pigging after construction to identify and remediate any dents exceeding code limitations

- Hydrostatic testing before placing the pipeline segment into natural gas service, at over 1.5 times MAOP for 8 hours
- Enbridge also placed fiber-reinforced concrete slabs and warning tape above the pipeline near Indian Point to reduce the likelihood of construction digging or other activities inadvertently reaching and damaging the pipeline.
- The Indian Point facility is a highly controlled site where it would be highly improbable for third-party excavation to take place without prior knowledge and access of the facility owner.
- Excavation near pipelines must be conducted carefully following all protocols to prevent damage. DPS is holding regular meetings with Holtec and AGT to ensure that both are aware of any construction activities near the pipelines.
- Per the Joint Proposal in Case 19-E-0730, Holtec is required to notify DPS Staff and the pipeline operator five business days in advance of any excavation that could affect the pipelines.
- Federal pipeline safety regulations and Enbridge procedures require the pipeline operator to monitor excavation activities within or near its pipeline right-of-way.
- Increased DPS inspection activity in the area of Indian Point, including DPS Staff witnessing inspections of remotely operated valves that affect all three natural gas pipelines near Indian Point, control center audits verifying the ability to remotely operate valves in the vicinity of Indian Point, etc.
- Staff witnessed the IMP digs/inspection/repairs completed on Enbridge pipelines near Indian Point during the summer of 2021 and ensured excavation requirements were followed.
- Additionally, all excavation work is required to follow New York State's one call notification laws.

How has no decision been made on shutting down the pipeline during excavation? PSC must submit notification to PHMSA to issue a corrective action order to shut down the pipelines at Indian Point before demolition begins. Federal regulations outline the requirement pursuant to 49 U.S.C. 60112 to issue a Corrective Action Order "to protect the public, property, and the environment from potential hazards."

PHMSA has primary jurisdiction of interstate pipelines. PHMSA has delegated to the Department of Public Service certain regulatory oversight functions, but PHMSA retains full enforcement authority. DPS works in coordination with PHMSA to discuss audit and inspection scheduling, documentation, and findings.

Based on inspections conducted of Enbridge in conjunction with PHMSA from 2015 to the present, DPS pipeline safety staff does not believe that a notification to PHMSA is warranted at this time. DPS Staff notes that representatives from PHMSA have been apprised and/or involved in the ongoing inspections and assessments of the pipelines, including the Indian Point Decommissioning Board Meeting on June 23rd, 2021 and as part of the NRC's expert evaluation team on concerns pertaining to the gas transmission lines near the Indian Point Nuclear Power Plant.

To prevent and mitigate any risk of damage to the gas pipelines during decommissioning activities, DPS Staff notes the following mitigative measures have been undertaken:

- DPS Staff is facilitating regular meetings with Holtec and Enbridge to ensure that both are aware of any construction on their facilities.
- Per the Joint Proposal in Case 19-E-0730, Holtec is required to notify DPS Staff and the pipeline operator five business days in advance of any excavation that could affect the pipelines.
- Federal pipeline safety regulations and Enbridge procedures require the pipeline operator to monitor excavation activities within or near its pipeline right-of-way.

DPS Staff will continue to contact the pipeline operator to ensure that it is taking appropriate actions in response to excavation activities or heavy crossings on its pipeline.

Holtec caused a power outage near Oyster Creek hitting a visible utility pole. What's going to happen with a buried gas pipeline?

The Oyster Creek event was not excavation damage, rather a Holtec construction vehicle that came into contact and knocked down a utility pole.

To prevent against excavation damage, if Holtec performs excavation near the pipelines, Holtec would be required to follow New York State's "Protection of Underground Facilities" regulation 16 NYCRR Part 753. This regulation requires safe excavation practices such as one-call notification to facility operators in the area and hand digging to verify underground facilities. In addition, per the Joint Proposal in Case 19-E-0730, Holtec is required to notify DPS Staff and the pipeline operator five business days in advance of any excavation that could affect the pipelines.

Federal pipeline safety regulations and AGT's procedures require the pipeline operator to monitor excavation activities within or near its pipeline right-of-way (ROW), participate in a one call system and mark out all facilities located within a proposed excavation area. Additionally, pipeline operators are required to install (and maintain) above ground pipeline markers along pipeline ROWs as required by 49 CFR Part 192.707. These markers alert the public, including excavators, that a buried pipeline is nearby.

On construction, demolition and/or excavation jobs, the first thing that's done is to SHUT OFF THE GAS. The PSC must submit Notification to PHMSA to issue a Corrective Action Order to shut the pipelines at Indian Point.

The requirements are to shut off gas connections directly to the building getting demolished. Buildings within the Indian Point facility do not have connections to natural gas pipelines, either from the AGT pipelines or from local gas distribution mains.

New England Gas Supply

Who needs the gas in New England? Why does it matter?

Several natural gas fueled electric generators have contracts for capacity on the AIM pipeline, as well as the local gas distribution companies such as National Grid.

The people on the other end of the pipeline do not need this particular gas…the Massachusetts Attorney General said they don't need this gas…Weymouth compressor station ships LNG to Canada and Weymouth opposes AIM too.

While there are liquefied natural gas facilities on the coast in New England, none have the capability to liquefy. They are receipt facilities for LNG that is received via tanker from other countries.

Gas shortages are designed to jack up prices.

Natural gas prices are established through trading at multiple trading points across the country. Natural gas markets are regional as pipelines generally travel across multiple states. Prices are set for day ahead trading and for longer term contracts. As there are multiple trading counter parties at each trading point, there is no opportunity for one individual purchaser, State or pipeline to cause price increases. Information on natural gas prices is publicly available through many sources.

Wouldn't New England gas customers want their energy sourced differently if they knew the risks posed by the pipeline?

We cannot speculate on what New England residents would want, only state what they currently use. According to the federal Energy Information Administration, 65% of New England's electricity is currently generated by burning natural gas. As of July 13, 2021, natural gas prices for delivery on the Algonquin Pipeline were 27 cents per dekatherm cheaper than the Henry Hub natural gas trading point in Louisiana, meaning natural gas is an economic alternative in New England. Please refer to https://www.eia.gov/dashboard/newengland/overview.