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Updated Safety Review and Assessment of Natural Gas Transmission Pipelines Adjacent to the Indian Point Site

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OAK RIDGE NATIONAL LABORATORY
MANAGED BY UT-BATTELLE FOR THE US DEPARTMENT OF ENERGY

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Energy Science and Technology Directorate
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UPDATED SAFETY REVIEW AND ASSESSMENT OF NATURAL GAS TRANSMISSION PIPELINES ADJACENT TO THE INDIAN POINT SITE

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CONTENTS

LIST OF FIGURES

LIST OF TABLES

ACRONYMS AND ABBREVIATIONS

ADAMS	Agencywide Documents Access and Management System
AIM	Algonquin Incremental Market
ASME	American Society for Mechanical Engineers
CFR	Code of Federal Regulations
EPA	US Environmental Protection Agency
ERW	Electric Resistance Welded
FOST	fuel oil storage tank
GTCC	Greater Than Class C
ILI	in-line inspection
ISFSI	independent spent fuel storage installation
MAOP	maximum allowable operating pressure
M&R	metering and regulating
NRC	US Nuclear Regulatory Commission
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIR	potential impact radius
PSDAR	post-shutdown decommissioning activities report
PRCI	Pipeline Research Council International
psi	pounds per square inch
psig	pounds per square inch gauge
RG	Regulatory Guide
SCC	stress corrosion cracking
SFP	spent fuel pool
SOCA	security owner-controlled area
TEEL	Temporary Emergency Exposure Limits

EXECUTIVE SUMMARY

At the request of the Pipeline and Hazardous Materials Safety Administration, Oak Ridge National Laboratory conducted a review of the natural gas pipelines near the site of Indian Point Units 1-3 that are currently undergoing decommissioning. Review of inspection records for the pipelines shows them to be in compliance with regulations. In the event of a postulated rupture of one of the pipelines the greatest threat to the surrounding area is the radiant heat flux from a jet fire located at the point of the rupture. This heat flux is likely to cause brush fires and damage unprotected equipment, vehicles, and wood-frame buildings and cause injury to unprotected people. However, the heat flux is not likely to cause serious damage to the safety-related structures, systems, and components at the Indian Point site. Containers that store radioactive materials (class A, B, C, GTCC, and dry storage casks) are constructed of steel and concrete and are also unlikely to be damaged by the heat flux from a jet fire.

The 26 in. pipeline near the present-day site of Indian Point Units 1-3 was installed in 1951, followed by the 30 in. pipeline in 1963. More recently, the Algonquin Incremental Market (AIM) project installed a new, larger natural gas pipeline that has caused renewed concern about the safety of the natural gas pipelines in the area adjacent to Indian Point Units 1-3. The three Indian Point Units have reached the end of their operational lifetime and are currently undergoing decommissioning and decontamination. Spent fuel from Unit 1 has already been removed from the spent fuel pool and is in dry storage casks located in the Independent Spent Fuel Storage Installation (ISFSI). Spent fuel from units 2 and 3 is presently being removed from the spent fuel pools and moved to dry storage casks in the ISFSI. The ISFSI is located at the north end of the facility and is well separated from the three natural gas pipelines that pass south of the facility. The right-of-way for the 26 in. and 30 in. pipelines is approximately 1460 ft. from the existing ISFSI pad at its point of closest approach. Holtec has constructed a second ISFSI pad adjacent to the pre-existing ISFSI pad. Construction of the second pad reduced the distance to the right-of-way, to approximately 1360 ft. The distance from the pre-existing pad to the point of closest approach for the 42 in. pipeline is approximately 3247 ft., and the distance from the second pad to the 42 in. pipeline is approximately 3130 ft.

The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) requested that the Oak Ridge National Laboratory (ORNL) perform an independent review of a report issued by the U.S. Nuclear Regulatory Commission (NRC) Expert Evaluation Team and other relevant documents to identify potential hazards to the ongoing decommissioning activities at the Indian Point Site. PHMSA also requested that ORNL review a list of documents provided to Ms. Linda Daugherty, PHMSA Deputy Associate Administrator for Field Operations on October 6, 2021. The ORNL team reviewed the Expert Evaluation Team's Report, the Holtec Post-shutdown Decommissioning Activities Report, the AIM Final Environmental Impact Statement, the documents provided to Ms. Daugherty, and other relevant regulatory documents to assess the risks and consequences associated with a hypothetical break of any of the three pipelines near the Indian Point Site.

Assessments of worst-case consequences to the public, employees, property, and the environment resulting from a propagating crack that completely penetrates the line pipe wall or a full-bore guillotine rupture in a natural gas pipeline subdivide into:

- missile generation
- flash fires or fireballs
- jet fires that cause thermal radiation

- over-pressurization events caused by an explosion

The greatest hazard associated with a postulated worst case guillotine break of any of the pipelines is the radiative heat flux posed by an ensuing jet fire. A jet fire is a type of fire that results from the discharge of liquid, vapor, or gas into free space from an orifice. The momentum of the escaping material causes it to mix with the surrounding atmosphere. The radiative heat loads from a jet fire can be high enough to cause damage to some structures, equipment, and facilities as well as injury to unprotected personnel over a distance greater than the potential impact radius (PIR) for any of the pipelines. The PIR is the radius of a circle within which the potential failure of a natural gas pipeline could have significant impact on people or property. Projections of radiative heat loads that extend beyond the PIR distance for any of the three pipelines are not expected to cause significant damage to the containment buildings, spent fuel pool buildings, spent fuel storage casks, or class A, B, C, or GTCC waste containers. Analysis of the projected duration of the heat fluxes presumed that the isolation valves for the affected pipeline were closed eight minutes after the break. Reinforced concrete structures, such as the Units 1-3 containment buildings, and steel structures such as the fuel storage pool buildings are not expected to sustain serious damage because of their robust construction, distance from the pipelines being greater than the distance at which potentially damaging heat flux densities are expected, and the short-duration nature of the heat flux. Analysis of the impact of delaying valve closure to 16 minutes does not change this conclusion, since the heat flux values of greatest concern occur at the onset of the jet fire and immediately thereafter begin to decrease.

The Defueled Safety Analysis Reports for IPEC Units 2 and 3 indicate that the spent fuel pools can remain safe for at least 1.8 hours and 8.5 hours, respectively, without external cooling systems operating. These times have increased significantly (to currently more than 89 hours) as spent fuel has now cooled for more than a year and some fuel has been removed from the pools and placed in dry storage. This period of time provides ample opportunity for restoration of cooling function to the spent fuel pools, in the unlikely event that it is interrupted by a postulated pipeline rupture and jet fire. Waste packaging used for radioactive material is designed to withstand extreme conditions, including fire. As a result of the design, testing, and certification process that they undergo, class A, B, C, greater than class C (GTCC), and dry storage casks are not expected to be susceptible to damage from a short-duration gas release event.

Depending upon the time required for an ignition event to occur, a hypothetical jet fire may be preceded by a flash fire, also sometimes called a fireball. As with the jet fire, the greatest hazard posed if a flash fire occurs is the radiative heat flux. Flash fires generally have a duration of only a few seconds, and so the duration of the heat flux is short. As a result, this high radiative heat flux does not pose a hazard to the safety-related structures, systems, or components, or waste containers at the Indian Point Site. However, it may result in brush fires and damage to equipment or less robust facilities. It can also cause serious injury to unprotected personnel over an extended distance. Flash fires are not explosions and do not produce an overpressure condition. The timing of isolation valve closure does not impact the occurrence or severity of a flash fire. Flash fires are likely to occur within seconds after a pipeline break.

In the rare event of a pipeline rupture, objects near the rupture may become airborne missiles that can also result in damage. In this context, the word missile refers to a ballistic object moved by the force of the gas release, not a weapon of war. Fractured lengths of the line pipe itself are apt to cause damage because they can weigh several thousand pounds. Equipment, structures, and personnel within the PIR may be impacted by fractured line pipe or other missiles, such as loose fill material or other underground pipes. These objects are not expected to cause serious damage to safety-related structures, systems, or components at the Indian Point Site because these facilities are designed to be resistant to missiles such as might be generated during tornadoes. The distances from the pipelines to the safety-related structures, systems, and components are also greater than the broken segments of line pipe have been observed to travel. Radioactive waste containers (class A, B, C, GTCC, and dry storage casks) are subjected to drop tests designed to test for penetration as a part of their certification. Thus, these containers are not expected to sustain serious damage from missiles during a postulated pipeline rupture event.

Explosions involving methane plumes that result from pipeline breaks are unlikely because of the buoyant nature of the gas plume and the relatively low flame speeds of methane. A postulated release was examined using the Hazard Prediction and Assessment Capability (HPAC) model. The model predicts a buoyant plume with concentrations that decrease rapidly as the plume spreads beyond the immediate vicinity of the pipeline rupture. As the plume spreads the methane concentrations decrease to non-flammable levels.

Minimum safe distances from an explosion were calculated since the risk of an explosion, though very low, is not zero. NRC regulatory guidance specifies the use of a trinitrotoluene (TNT) equivalent model to evaluate the minimum safe distance to avoid structural damage in the unlikely event of an explosion. The mass of gas that could be released from any of the three pipelines can result in minimum safe distances that are greater than the distance from the pipelines to the safety-critical facilities at the Indian Point Site. Under this condition, the regulatory guidance specifies that assessment of the likelihood of an explosion is less than 1×10^{-7} per year or structural evaluations may be used to assure continued safe operation in the event of an explosion. This hazard has been reported to NRC and evaluated on previous occasions, as documented in the Expert Team Report. The Expert Team Report indicates that NRC structural experts have concluded that it is a good assumption that the safety-related structures, systems, and components at the Indian Point Site would be able to sustain the pressure resulting from an explosion. Radioactive waste containers (class A, B, C, GTCC, and dry storage casks) are designed to assure safety in extreme conditions, including tests for survivability in fire, impacts by penetrating objects, impact on flat surfaces, and when submerged in water. It is unlikely that even in the event of an explosion that these containers would sustain serious damage.

In summary, an unintentional natural gas release and subsequent ignition resulting in a flash fire followed by a jet fire that occurs anywhere along a pipeline can be a very serious and hazardous event. Consequences of an unintentional release from any of the three pipelines near the Indian Point Site are likely to include damage to buildings, equipment, and property near the right-of-way and injuries to people who cannot quickly reach shelter. However, it is improbable that an unintentional natural gas release from any of these three pipelines will cause physical damage that adversely affects the structural integrity of safety-related structures, systems, or components or the leak tightness of spent fuel casks and class A, B, C, and GTCC waste containers at the Indian Point Site, including spent fuel in dry storage at the ISFSI.

1. INTRODUCTION

In 2014, the Algonquin Gas Transmission, LLC initiated the Algonquin Incremental Market (AIM) Project to upgrade approximately 37.4 miles of natural gas pipeline within the existing Algonquin pipeline system. This pipeline system supplies natural gas to customers in the Northeastern states of Rhode Island, Connecticut, Massachusetts, New York, and New Jersey. A segment of the AIM Project pipeline is located adjacent to the site of Indian Point Units 1-3 in the village of Buchanan, NY (Westchester County). These three nuclear reactors, Units 1, 2 and 3, no longer produce electrical power and are being decommissioned.

- Unit 1 operated from August 1962 to October 1974. Its spent fuel was moved to dry storage in an independent spent fuel storage installation (ISFSI) on the Indian Point site. The spent fuel pool for Unit 1 has been drained and cleaned.
- Unit 2 began commercial operation in 1974 and was shut down in 2021. Spent fuel from unit 2 is presently stored in its spent fuel pool.
- Unit 3 began commercial operation in 1976 and was shut down in 2021. Spent fuel from Unit 3 is presently stored in its spent fuel pool.
- Portions of the spent fuel from Units 2 and 3 has been moved from the spent fuel pools to dry storage in the ISFSI; removal of spent fuel from both spent fuel pools is currently ongoing as decommissioning proceeds.

Addition descriptions of the three nuclear reactors at the IPEC are presented in the NRC Expert Evaluation Team Report. (U.S. Nuclear Regulatory Commission Expert Evaluation Team 2020)

1.1 SCOPE OF THE SAFETY REVIEW AND ASSESSMENT

This report reviews the safety of the Algonquin Gas Transmission pipeline system in general with emphasis on pipeline segments adjacent to the Indian Point Site. The safety review focuses on past assessments performed by the Pipeline and Hazardous Material Safety Administration (PHMSA), Federal Energy Regulatory Commission (FERC), and U.S. Nuclear Regulatory Commission (NRC) and includes safety assessments of potential impacts of an unintentional natural gas release from the pipelines adjacent to the Indian Point Site. These impacts could affect the public and environment along the pipeline rights-of-way and operations at the Indian Point site within the security owner-controlled area (SOCA). The scope of this report includes:

- identification of applicable minimum Federal safety standards specified in 49 CFR 192 and an assessment of pipeline compliance with these standards.
- identification of threats that could potentially affect the structural integrity of the pipelines and assessments of these degradation mechanisms on pipeline safety.
- methods used by the pipelines located adjacent to the IPEC for preventing or mitigation potential consequences of an unintentional natural gas release.
- assessments of potential impacts caused by an unintentional natural gas release from 26 in., 30 in., or 42 in. pipeline on:
  (a) operations within the SOCA.
  (b) Indian point safety-related structures, systems, and components (SSCs) including the spent fuel pools and the independent spent fuel storage installations.

(c) the public and environment outside the SOCA.

This report also summarizes the threats to the integrity of the pipeline segments located adjacent to the Indian Point Site and the potential impacts on the site, the public and the environment caused by an unintentional natural gas release from one of the pipelines.

1.2 ALGONQUIN GAS TRANSMISSION PIPELINE RIGHTS-OF-WAY

The Algonquin Gas Transmission pipeline rights-of-way adjacent to the Indian Point Site are shown in Fig. 2.1. The white line shows the location of the SOCA. The blue line shows the approximate center of the path of the right-of-way containing the 26- and 30-in. pipelines. The red line shows the approximate center of the path of the right-of-way containing the new 42-in. pipeline. The letters show the locations of some key facilities. Letters A, B, and C show reactor units 3, 1, and 2, respectively. Letter D indicates the location of the ISFSI. Letter E denotes the fuel oil storage tanks (FOST) that provide expanded onsite fuel storage for the backup generators associated with reactor units 2 and 3. As of the time of this report, the contents of both of these tanks have been removed. One tank has been demolished, with demolition of the second tank imminent. Letter F shows the location of the main entrance to IPEC, and letter G shows the location of a major electrical substation. The right-of-way for the two older pipelines is traversed by underground, surface, and overhead infrastructure associated with the Indian Point Site as described in Table 2.1. The electrical transmission lines passing overhead have now been de-energized. Additional aboveground infrastructure that is located outside the Algonquin Gas Transmission pipeline right-of-way for the 26- and 30-in. pipelines is described in Table 2.2. As decommissioning has proceeded, a number of these structures have already been demolished. The right-of-way for the new 42-in. pipeline passes the site further away; because of this routing there is less plant-related infrastructure near the new pipeline.

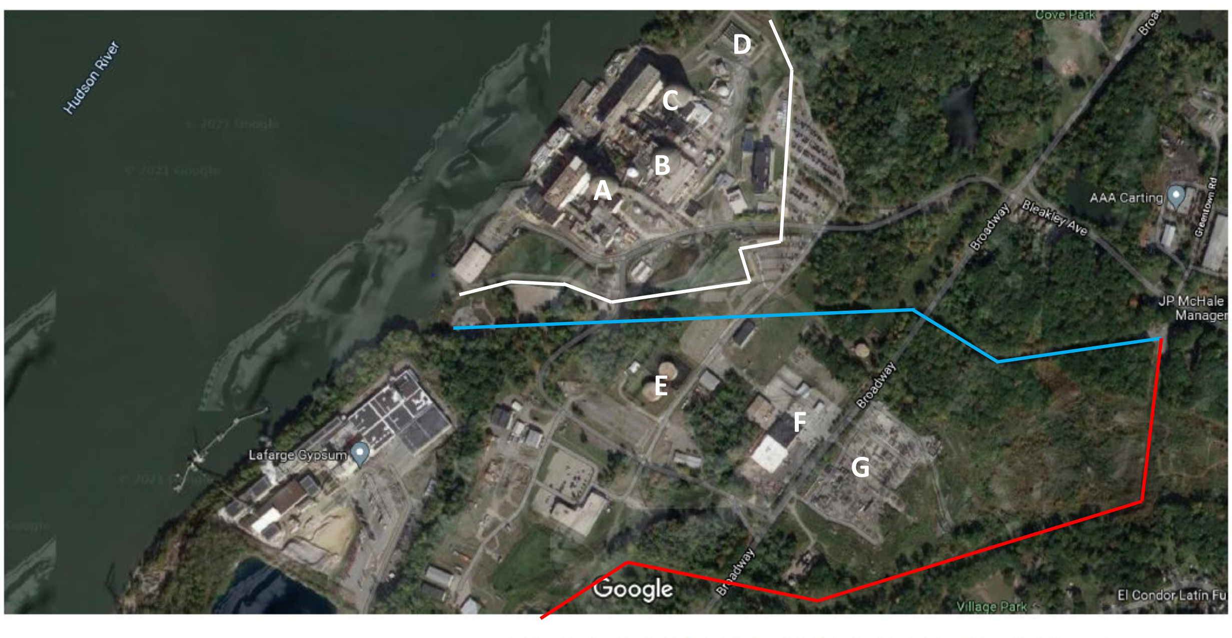

Figure 1.1 Gas transmission pipeline rights-of-way adjacent to the Indian Point Site. The white line indicates the SOCA boundary; the blue line is the approximate location of the right-of-way for the 26- and 30-inch pipelines. The red line is the approximate location of the right-of-way for the 42-inch pipeline.

Table 1.1 Infrastructure that traverses the pipeline rights-of-way adjacent to the Indian Point site.

Infrastructure Location	Infrastructure Description
Underground	Steam supply (8 in.) and condensate (4 in.) lines
	Fuel oil supply line (12 in.)
	Control, power, and telephone ducts
	Water lines
	Electrical feeds for plant equipment at Units 1-3
Surface	Access road to the IPEC
	Broadway Road
Overhead	Transmission line (de-energized)

Table 1.2 Aboveground infrastructure located outside the pipeline rights-of-way adjacent to the Indian Point site.

Infrastructure Location	Infrastructure Description
North of right-of-way	IPEC structures and equipment located inside the SOCA
	Parking lots
	Electrical Switchyard
	Emergency Operation Facility
	FLEX Storage Building
	Monitoring Station
	Meteorology Tower
	Observation Building
	Sewage Disposal Plant
	Steam Generator Mausoleums
	Storage Buildings
	Transmission Towers
South of right-of-way	Diesel Fuel Storage Tank Facility
	Access Road to the IPEC
	Broadway Road
	Water Tower
	Transmission Towers

The Algonquin Gas Transmission pipeline right-of-way located adjacent to the site is at least 40 ft higher in elevation than the high-water line of the Hudson River. In addition, no creeks or streams traverse the Algonquin Gas Transmission pipeline rights-of-way in the vicinity of the site.

2. BACKGROUND ON CONSEQUENCES OF AN UNINTENTIONAL PIPELINE RELEASE

Risk is the mathematical product of the likelihood (probability) and the consequences of events that result from a failure. (ASME International 2004) Risk reduction can be achieved by either decreasing the likelihood or the consequences of a failure, or both. Consequences of an unintentional release of natural gas from a pipeline system can include a combination of impacts on the public, employees, property, and the environment. Such consequences result from either a failure or rupture incident where:

- failure is a general term used to imply that a natural gas pipeline part in service:
  - (a) has become completely inoperable;
  - (b) is still operable but is incapable of satisfactorily performing its intended function; or
  - (c) has deteriorated seriously, to the point that is has become unreliable or unsafe for continued use.
- rupture is defined as complete failure of any portion of the natural gas pipeline.
- incident is an unintentional release of natural gas due to the failure of a pipeline.

The design, performance, and safety objective of a natural gas pipeline is to transport natural gas without an incident.

2.1 DESCRIPTION OF AN UNINTENTIONAL NATURAL GAS PIPELINE RELEASE

In a worst-case unintentional natural gas transmission pipeline release incident, a propagating crack or a full-bore guillotine rupture of the line pipe allows natural gas to begin flowing immediately through the break and into the surrounding atmosphere. The escaping natural gas creates a highly turbulent plume that increases in height above the release point due to the source momentum and buoyancy. Initially, the natural gas flow from each broken pipeline section is balanced, and the natural gas escapes to the atmosphere in the form of jets that depend on the alignment of the line pipe ends. Noise produced by the escaping natural gas is typically audible for a long distance. However, natural gas will not burn unless the gas concentration is within the flammable range. For methane, this range is between 5% and 15%.

As the release continues, the natural gas jet feeds the plume and entrains air that may contain ejected soil particles. Without an ignition source, the plume disperses into the atmosphere. If ignition of the released natural gas occurs immediately or shortly after the pipeline rupture, a flash fire or transient fireball will occur. The flash fire or fireball, which is the result of combustion of the vapor cloud, typically only lasts for a few seconds. After the flash fire, a quasi-steady-state jet fire will continue to burn until the escaping natural gas is consumed. (Acton, Acton and Robinson 2016) (Acton and Baldwin 2008) A natural gas pipeline fire should not be extinguished until the flow of natural gas stops.

2.2 AREA OF POTENTIAL IMPACT FOR AN UNINTENTIONAL NATURAL GAS PIPELINE RELEASE

According to definitions provided in 49 CFR 192, Subpart O, §192.903, the potential impact radius (PIR) means the radius of a circle within which the potential failure of a natural gas pipeline could have significant impact on people or property. The PIR is determined by the formula $r = 0.69 \times$ (square root of $(p \times d^2)$), 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. The constant 0.69 is the factor for natural gas. A potential impact circle is a circle with a radius equal to PIR. A heat flux of 15.8 kW/m^2 was selected as the threshold heat intensity for the purpose of sizing a high consequence area. This threshold corresponds to a 1% chance of mortality (i.e., 1 in 100 people directly exposed to this thermal load would not be expected to survive). It also represents a reasonable estimate of the heat flux below which wooden structures would not be destroyed, and below which wooden structures should afford indefinite protection to occupants. (Stephens 2000) Although exposure to a heat flux of less than 15.8 kW/m^2 could occur beyond the PIR, the amount of radiant heat received from a quasi-steady-state natural gas jet fire reduces with the square of the distance from the fire (e.g., a heat flux of 100 kW/m^2 at 100 ft from the flame decreases to a heat flux of 25 kW/m^2 at 200 ft from the flame and further decreases to 6 kW/m^2 at 400 ft from the flame.) Potential impacts of heat fluxes less than 15.8 kW/m^2 are discussed in Table 2.1 and Sect. 2.3.4. Even though the likelihood of a release at any given point is very low, an unintentional release can occur at any point along the pipeline segment. Additional mathematical models for quantifying the time-dependent variations in separation distances (distance from the radiant heat source) for specific heat flux densities were published in 2012. (Oland, et al. 2012) As discussed in Sect. 2.3.4, these models were used to study for the requirements of automatic and remotely controlled shutoff valves on hazardous liquids and natural gas pipelines with respect to public and environmental safety.

The area of impact for an unintentional release from a 30 in. natural gas transmission pipeline with a MAOP equal to 837 psig is described in an accident report pertaining to a rupture in New Mexico. (National Transportation Safety Board 2000) The force of the rupture and the ignition of the escaping gas created a 51-ft wide crater that extended about 113 ft along the pipeline. Figures 2.1 and 2.2 show the fire and the crater caused by the releases. A 49-ft section of line pipe was ejected from the crater in three pieces measuring approximately 3 ft, 20 ft, and 26 ft in length. The largest piece was found about 287 ft from the crater and another piece was found 234 ft from the crater. Investigators visually examined the pipeline that remained in the crater as well as the three ejected pieces. All three ejected pieces showed evidence of internal corrosion damage (i.e., metal loss), but one of the pieces showed significantly more corrosion damage than the other two. Pits were visible on the inside surface of this piece, and at various locations, the line pipe wall exhibited significant thinning. At one location, a through-wall perforation caused by corrosion was visible. No significant corrosion damage was visible on the outside surfaces of the three pieces or on the two ends of the pipeline remaining in the crater. Although the PIR for this pipeline was 599 ft, victims of the accident were found about 675 ft from the crater.

Figure 2.1 Fire with a flame height of approximately 496 ft resulting from an unintentional natural gas pipeline release. (National Transportation Safety Board 2000)

Figure 2.2 Crater resulting from an unintentional natural gas pipeline release. (National Transportation Safety Board 2000)

2.3 POTENTIAL CONSEQUENCES OF AN UNINTENTIONAL PIPELINE RELEASE

Assessments of potential consequences to the public, employees, property, and the environment resulting from an unintentional natural gas release within an impact area require consideration of at least the following factors. (ASME International 2004)

- population density
- proximity of the population to the pipeline (including consideration of manmade or natural barriers that may provide some level of protection)
- proximity of populations with limited or impaired mobility (e.g., hospitals, schools, child-care centers, retirement communities, prisons, recreation areas), particularly in unprotected outside areas
- possible property or environmental damage
- effects of an unignited gas release
- security of gas supply (i.e., impacts resulting from interruption of service)
- inconvenience to public, police, emergency personnel, and first responders
- potential for secondary failures

Sources of unintentional releases from a natural gas pipeline include:

- a hole in the line pipe wall due to metal loss caused by a corrosion pit.
- a propagating or non-propagating crack, longitudinal crack, or circumferential crack that completely penetrates the line pipe wall.
- a complete separation of the line pipe such as a full-bore guillotine rupture.

Pipeline ruptures have more potential for damage than pipeline leaks. Consequently, when a risk assessment approach does not consider whether a failure may occur as a leak or rupture, a worst-case assumption of rupture should be made.

The public, employees, property, and the environment can be adversely affected by an unintentional release of natural gas from a pipeline resulting from:

- missiles generation
- flash fire or fireball should ignition be delayed
- jet fires that cause thermal radiation
- over-pressurization events caused by an explosion

2.3.1 Potential Consequences of Missiles

An unintentional release of high-pressure natural gas from a transmission pipeline caused by a propagating crack or full-bore guillotine rupture can cause a crater in the right-of-way. The crater, which forms whether the natural gas ignites immediately or is delayed, will track the pipeline route, and may extend as far as the crack propagates. A crater such as this is shown in Fig. 2.2. Pictures of other craters caused by unintentional release of high-pressure natural gas from a transmission pipeline are shown in the NRC Expert Evaluation Team Report. (U.S. Nuclear Regulatory Commission Expert Evaluation Team 2020)

The backfill soil which may also contain sand, gravel, and rocks can be ejected from the crater. In addition, pieces of fractured line pipe may also be ejected along with pavement fragments and other objects such as water lines and conduits that cross the right-of-way near the break. This debris may become missiles that are thrown from the crater. These missiles could potentially contact people or buildings and cause personal injury or property damage.

Although wind borne objects such as fine soil may travel further from the crater, a review of National Transportation Safety Board (NTSB) pipeline accident reports suggests that damage is confined to the area within the PIR. (Stephens 2000) However, roads and utility lines that cross the pipeline within the area of the crater could be disrupted or hinder rescue operations by police, emergency personnel, and first responders.

As discussed in Sect. 4.3, the fiber reinforced concrete slabs that were installed above the top of the 42-in. line pipe to act as a physical barrier to third party excavation activities and acts of vandalism also reduce the potential for line pipe fragments and other debris being ejected from the crater resulting from an unintentional release from pipeline.

2.3.2 Potential Consequences of a Flash Fire or Fireball

A flash fire is the non-explosive combustion of a plume resulting from a release of flammable material into the open air which, after mixing with air, ignites. A fireball is the atmospheric burning of a fuel-air cloud in which the energy is mostly emitted in the form of radiant heat. The inner core of the fuel release consists of almost pure fuel whereas the outer layer in which ignition first occurs is a flammable fuel-air mixture. As buoyancy forces of the hot gases begin to dominate, the burning cloud rises and becomes more spherical in shape. The source of flammable fuel consumed in a flash fire or fireball could be an unintentional release of high-pressure natural gas from a transmission pipeline.

For natural gas pipelines, the possibility of a significant flash fire resulting from delayed remote ignition is low due to the buoyant nature of the gas, which generally precludes the formation of a persistent flammable vapor cloud at ground level.

While a flash fire or fireball might lead to local fires and possible injury and death to exposed people within the PIR, no significant overpressure results from a flash fire. In addition, the escaping natural gas from a propagating crack or full-bore guillotine rupture of a high-pressure natural gas transmission pipeline will continue to burn as a jet fire until the natural gas is consumed.

2.3.3 Potential Consequences of Jet Fires that Cause Thermal Radiation Effects

A jet fire is a fire type resulting from the discharge of liquid, vapor, or gas into free space from an orifice, the momentum of which induces the surrounding atmosphere to mix with the discharged material. The resulting jet fire is a turbulent diffusion flame resulting from fuel combustion. Jet fires reach full intensity very soon after ignition and change as the fuel's flow rate declines.

Ignition of a natural gas release from a transmission pipeline possibly will result in a jet fire. The fire will continue until the natural gas in the pipeline is consumed. The dominant hazard from a natural gas pipeline release is thermal radiation from a sustained jet fire, which may be preceded by a short-lived fireball. (Stephens 2000) Radiant heat produced by a fireball and jet fire has the potential to injure humans, damage property, and impact the environment by damaging plants and animals in the vicinity of the release. Potential consequences of a jet fire arise because of the high heat flux densities incident on exposed personnel or buildings. Effects of thermal radiation intensity on buildings and humans are described in Table 2.1.

Table 2.1. Effects of thermal radiation intensity on buildings and humans.

Approximate Radiant Heat Flux		Effects and Consequences
kW/m²	**Btu/hr ft²**	
1.0	320	Nominal solar radiant heat flux on a clear summer day (National Fire Protection Association 2011)
1.4	450	Thermal radiation flux considered acceptable by HUD for outdoor, unprotected facilities or open spaces where people congregate. (U.S. Department of Housing and Urban Development 2011)
2.5	800	Common thermal radiation exposure while firefighting. This energy level may cause burn injuries with prolonged exposure. (National Fire Protection Association 2011)
4.0	1,270	Glass breakage after exposure for 30 minutes. (LaChance 2009)
12.5	4,000	Minimum energy to ignite wood with a flame, melts plastic tubing, first-degree burns in 10 seconds, 1% lethality in 1 minute. (National Fire Protection Association 1995)
15.8	5,000	Threshold radiant heat flux used as the basis for determining *Potential Impact Radius* (PIR) which is defined by PHMSA in 49 CFR 912.903 as the radius of a circle within which the potential failure of a natural gas pipeline could have significant impact on people or property. (Stephens 2000), (Code of Federal Regulations, Title 49, Part 192 - Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards 2021) Radiant heat flux at which human skin experiences pain within 3 seconds and blisters within 6 seconds of exposure with second-degree burn injury. (National Fire Protection Association 2011)
20	6,340	Radiant heat flux for average ignition time of dry wood (poplar) in 75 seconds. (McAllister 2010) Cable insulation degrades after exposure for 30 minutes. (LaChance 2009)
25	7,930	Minimum energy to ignite wood at indefinitely long exposure without a flame. (National Fire Protection Association 1995) Steel deformation after exposure for 30 minutes. (LaChance 2009)
31.5	10,000	Allowable thermal radiation flux for determining the acceptable separation distance of a proposed HUD-assisted project building from a hazardous facility. (U.S. Department of Housing and Urban Development 2011)
37.5	11,900	Damage to process equipment, 100% lethality in 1 minute, 1% lethality in 10 seconds. (National Fire Protection Association 1995) Process equipment and structural damage after exposure for 30 minutes. (LaChance 2009)
39.4	12,500	Maximum tolerable level of radiation at the facade of an exposed building. This value, originally derived from work of the Joint Fire Research organization in the United Kingdom, is now generally accepted as that below which the pilot ignition of most cellulosic materials (wood) is unlikely to occur. Substantially higher levels of radiation are necessary to cause spontaneous ignition. (National Fire Protection Association 2012)
40	12,700	Radiant heat flux for average ignition time of dry wood (poplar) in 17 seconds. (McAllister 2010)
50	15,900	Radiant heat flux for average ignition time of dry wood (poplar) in 10 seconds. (McAllister 2010)
52	16,500	Radiant heat flux at which fiberboard ignites spontaneously after 5 seconds. (National Fire Protection Association 2011)
100	31,700	Steel structures collapse after exposure for 30 minutes. (LaChance 2009)

2.3.4 Potential Consequences of Thermal Radiation Effects as a Function of Distance and Time

Under steady-state conditions, effects of thermal radiation increase with time of exposure and decrease with the square of the distance from the radiant heat source. Thermal radiation that is generated by a flash fire, fireball, or jet fire during an unintentional natural gas transmission pipeline release varies with time and the heat flux decreases by a factor of four when the distance from the radiant heat source doubles.

Heat flux changes occur as the mass flow rate of natural gas decreases and the blowdown continues. Factors that can affect the mass flow rate include the following:

- the lengths and diameters of upstream and downstream pipeline segments including branch, crossover, and bypass lines.
- the time the compressors continue to operate following the release.
- the time the block valves are open following the release.

Natural gas pipeline release events are subdivided into three sequential phases – (1) Detection Phase, (2) Compressor Shutdown and Block Valve Closure Phase, and (3) Blowdown Phase. The total mass of natural gas discharged equals the sum of the mass released during each phase.

Propagating crack or full-bore guillotine ruptures with immediate ignition of the escaping natural gas produce thermal radiant intensities that are considered worst case because these types of ruptures result in the greatest release of natural gas in the shortest amount of time. Compressor shutdown and block valve closure have no influence on the mass of natural gas released during Phase 1. However, rapid detection of the break followed by immediate implementation of corrective actions during Phase 2 to isolate the damaged pipeline segment reduces the total mass of natural gas released. The effectiveness of compressors shutdown and block valve closure swiftness in mitigating the consequences of a natural gas pipeline release decreases as the duration of Phase 2 increases. Although the pressure in the pipeline begins to decrease as soon as the rupture occurs, Phase 3 does not begin until the compressors that are feeding natural gas to the pipeline are shut down and the block valves are closed, isolating the damaged pipeline segment from the remainder of the pipeline system.

Thermal radiation is the primary mechanism for injury or damage from fire and is the significant mode of heat transfer for situations in which a target is located laterally to the exposure fire source. Mathematical models are available for quantifying the time-dependent variations in separation distances (distance from the radiant heat source) for specific heat flux densities. (Oland, et al. 2012) These models were developed to assess thermal radiation effects on buildings and humans as a function of heat flux density and exposure duration. The following criteria were used to quantify thermal radiation effects on buildings and humans based on heat flux densities and exposure duration.

- Exposure to a heat flux of 1.4 kW/m^2 is considered acceptable for outdoor, unprotected facilities or open spaces where people congregate.
- Exposure to a heat flux of 2.5 kW/m^2 is considered acceptable while conducting firefighting and emergency response activities.
- Exposure of a building to a heat flux of 15.8 kW/m^2 is considered acceptable for an extended period (30 minutes) without burning and the threshold for minor damage to buildings.
- Exposure of a building to a heat flux of 31.5 kW/m^2 is considered acceptable for an extended period (15 minutes) without burning and the threshold for moderate damage to buildings.

- Exposure to a heat flux of 40.0 kW/m^2 is considered the maximum tolerable level of radiation at the facade of an exposed building and the threshold for severe damage to buildings.

It is important to clarify that the above-mentioned tolerances apply to buildings with combustible facades. Steel structures such as the spent fuel pool buildings and reinforced concrete structures of nuclear facilities such as the reactor containment buildings can withstand greater heat fluxes before damage occurs. (Bennett 1983) Additional heat flux densities and exposure durations that can be used as criteria are provided in Table 2.1. Note that steel structures can withstand heat fluxes up to 100 kW/m^2 for 30 minutes before collapsing but heat fluxes greater than 15.8 kW/m^2 only occur within the PIR.

2.3.5 Potential Consequences of Thermal Radiation Effects as a Function of Block Valve Closure

Parametric studies performed using the heat flux and exposure duration criteria given Sect. 2.3.4 provide the basis for the following observations.

Heat flux densities beyond the PIR peak soon after the natural gas is ignited and decline quickly as the natural gas in the pipeline escapes. However, these heat flux densities are sufficient to produce serious personal injuries and damage to combustible facades of exposed buildings, but substantially higher levels of thermal radiation are necessary to cause spontaneous ignition of wood. The rate of heat flux density decline increases as soon as the block valves are closed.

Delays in detecting the release and use of manually operated block valves could increase the potential for personal injuries and fatalities, property damage, and environmental impacts by extending the separation distance accessible to fire fighters. The effectiveness of block valve closure swiftness in mitigating the consequences of a natural gas pipeline release decreases as the duration of the detection and block valve closure phases increases.

Installation of automatic shutoff valves (ASVs) as a substitute for manually operated block valves can be an effective strategy for mitigating potential fire consequences resulting from a natural gas pipeline release and subsequent ignition provided all the following conditions are satisfied.

- The break is detected and the appropriate ASVs or remotely controlled valve (RCVs) close completely so that the damaged pipeline segment is isolated within 10 minutes or less after the break allows firefighting activities to begin outside the PIR soon after the firefighters arrive on the scene.
- ASVs or RCVs close in time to reduce the heat flux outside the PIR to 2.5 kW/m^2 (800 Btu/hr-ft^2) within 20 minutes or less after the break.
- Firefighters arrive on the scene and are ready to begin firefighting activities within 10 minutes or less after the break.
- Fire hydrants are accessible in the area outside of the PIR.

2.3.6 Potential Consequences of an Over-Pressurization Event Caused by an Explosion

An explosion results from the ignition of a plume of flammable vapor, gas, or mist in which flame speeds are able to accelerate to the speed of sound. Explosions can produce significant overpressure. There are three pre-conditions for an explosion.

1. There must be a release of flammable material into a congested area or area of high turbulence.

2. Ignition must be delayed, allowing the formation of a mixture with the fuel-air concentration in the flammable range.
3. There must be an ignition source of sufficient energy to ignite the fuel-air mixture.

When an unintentional release of natural gas from a transmission pipeline occurs, high-pressure natural gas begins to escape into the atmosphere where it mixes with air. The escaping natural gas, which is buoyant in air, rises into a space above the break that is typically free of confining structures and congested areas. If ignition occurs soon after the natural gas starts escaping, a flash fire, jet fire, or fireball could occur making an explosion implausible. The lack of structures or objects that can confine the natural gas plume, together with the relatively low flame speed of methane, make an explosion involving unconfined natural gas very unlikely, if not completely implausible.

Releases of natural gas from a transmission pipeline typically result in deflagrations (fires) rather than detonations (explosions). In a deflagration, the flame propagates through the unburned fuel-air mixture at a burning velocity that is less than the speed of sound. Overpressures generated by deflagrations vary with the combustion rate. Given the low flame speed of methane, minimal overpressures are expected with deflagrations of methane and air. In a detonation, the flame velocity reaches supersonic speeds. Under some circumstances, however, it is possible for deflagration-to-detonation transition to occur, and this can be followed by a propagating detonation that quickly consumes the remaining detonable mixture of air and natural gas.

2.3.6.1 Nuclear Regulatory Commission (NRC) Guidance for Explosions

NRC Regulatory Guide 1.91 considers the effects of air blasts from explosions on highways, railways, water routes, pipelines, and nearby fixed facilities and establishes an acceptable method for establishing the distances beyond which no adverse effect would occur is based on a level of peak positive incident overpressure below which no significant damage would be expected. The NRC staff determined that, for the safety-related structures, systems, and components of concern, this level is conservatively 1.0 psi or 144 pounds per square foot. (U.S. Nuclear Regulatory Commission 2013)

Safety-related structures, systems, and components at the Indian Point Site are also designed to meet or exceed requirements for tornado effects specified in the following NRC standard review plan and regulatory guide.

- *Standard Review Plan, 3.3.2 Tornado Loads* (U.S. Nuclear Regulatory Commission 2007)
- *Design-Basis Tornado and Tornado Missiles for Nuclear Power Plants*, Regulatory Guide 1.76 (U.S. Nuclear Regulatory Commission 2006)

According to Regulatory Guide (RG) 1.76, the maximum design-basis tornado is 200 mph for Region II where the IPEC is located. (U.S. Nuclear Regulatory Commission 2006) Using the equation provided in *Standard Review Plan, 3.3.2 Tornado Loads*, this tornado wind speed produces a pressure-induced force that is applied to safety-related structures, systems, and components equal to 0.71 psi or 102 pounds per square foot. (U.S. Nuclear Regulatory Commission 2006) Regulatory Guide 1.76 also states that the pressure drop for a design-basis tornado is 0.9 psi or 130 pounds per square foot for Region II.

2.3.6.2 Environmental Protection Agency (EPA) Guidance for Explosions

Guidance for offsite consequence analyses of explosions is published by the United States Environmental Protection Agency. (U.S. Environmental Protection Agency 2009) The guidance is applicable to flammable substances including methane and is based on the following worst-case assumptions.

- The release results in a cloud containing the total quantity of the flammable substance that could be released from a transmission pipeline.
- The cloud detonates.
- The endpoint for the consequence analysis of an explosion is an overpressure of 1.0 psi or 144 pound per square foot. This endpoint was chosen as the threshold for potentially serious injuries to people resulting from property damage caused by an explosion (i.e., injuries from flying glass from shattered windows or falling debris from damaged structures).

These worst-case assumptions for an unintentional release of natural gas from a transmission pipeline caused by a propagating crack or a full-bore guillotine rupture of the line pipe are conservative because the total quantity of natural gas in the pipeline does not escape immediately, but rather escapes over time as flow through an orifice. Therefore, the endpoint for the consequence analysis of an explosion using EPA guidance is considered a conservative upper bound.

3. THREAT ASSESSMENTS FOR THE ALGONQUIN GAS TRANSMISSION PIPELINES

Federal pipeline safety regulations in 49 CFR 192, Subpart O—Gas Transmission Pipeline Integrity Management require operators to identify threats to pipeline integrity as part of their integrity management program as discussed in Appendix C. Threats that could adversely affect the integrity of natural gas pipelines are categorized as time-dependent, time-independent, and stable threats and are described this section. Those potential threats that are applicable to the 26 in., 30 in. and 42 in. pipeline segment located adjacent to the Indian Point Site are identified and assessed below.

3.1 TIME-DEPENDENT THREATS APPLICABLE TO THE 42 in. PIPELINE SEGMENT LOCATED ADJACENT TO THE INDIAN POINT SITE

There are time-dependent threats that could adversely affect the integrity of the 26 in., 30 in., and 42 in. pipeline segments located adjacent to the Indian Point Site; these include metal loss caused by corrosion and stress corrosion cracking (SCC).

3.1.1 External and Internal Corrosion

The exterior surfaces of the 42 in. pipeline segment located adjacent to the IPEC are protected from corrosion by a fusion-bonded epoxy coating applied to the inside and outside of the line pipe and a cathodic protection system. (Entergy Nuclear 2020) The 26 in. and 30 in. pipeline segments located adjacent to the IPEC also have an effective external coating and a cathodic protection system which are further discussed in Appendix B.

Coatings applied to exterior surfaces of buried pipelines provide a barrier to groundwater and soil moisture. These coating inhibit corrosion damage (i.e., metal loss) to the line pipe steel by disrupting the electrochemical corrosion process. Cathodic protection is an electrochemical means of corrosion control in which the oxidation reaction in a galvanic cell is concentrated at the anode and suppresses corrosion of the cathode in the same cell. Regulations for coatings and cathodic protection are provided in §192.461 and §192.463.

The 26 in., 30 in. and 42 in. pipeline segments located adjacent to the Indian Point Site are monitored and periodically inspected to detect corrosion damage in accordance with the integrity management program for the Algonquin Gas Transmission pipeline which is discussed in (Entergy Nuclear 2020), Appendix B, Exhibit A. The interior surfaces of the 26 in., 30 in., and 42 in. pipeline segments are not subjected to corrosion provided the pipeline transports pipeline-quality dry natural gas which is usually not corrosive to steel line pipe. However, if corrosion is detected, the following rules in 49 CFR 192 Subpart M--Maintenance apply.

<u>Subpart M—Maintenance</u>

§192.712 Analysis of predicted failure pressure

(b) Corrosion metal loss: states that suitable remaining strength calculation methods for assessing metal loss caused by corrosion including:

- ASME/ANSI B31G; (ASME International 2004)
- R–STRENG; (Pipeline Research Council International 1989) or
- an alternative equivalent method of remaining strength calculation that will provide an equally conservative result can be used to analyze metal loss due to corrosion.

Part 4 in the *Manual for Determining the Remaining Strength of Corroded Pipelines*, ASME/ANSI B31G provides methods for determining the maximum allowable longitudinal extent of corrosion and for evaluating of MAOP in the corroded area. (ASME International 2004)

The manual specifies that a contiguous corroded area having a maximum depth, d, of more than 10% but less than 80% of the nominal wall thickness, t, of a pipe with a nominal diameter, D, is allowed to extend along the longitudinal axis of the pipe for a distance, L. (ASME International 2004) The allowable extent of corrosion, either inside or outside the pipeline, along the longitudinal axis of the pipe for the 42 in. pipeline segment located adjacent to the IPEC is shown in Table 3.1.

Table 3.1. Maximum allowable longitudinal extent of corrosion for the 42 in. pipeline segment located adjacent to the site.

d, in.	d/t, %	L, in.
0.00	0.0	24.6
0.07	10.0	24.6
0.13	17.5	24.6
0.14	20.0	16.5
0.22	30.0	8.2
0.29	40.0	5.9
0.36	50.0	4.6
0.43	60.0	3.8
0.50	70.0	3.2
0.58	80.0	2.8

According to criteria in Part 4, if the measured maximum depth of the corroded area is greater than 10% but less than 80% of the nominal wall thickness and the measured longitudinal extent of the corroded area is not greater than the value in Table 3.1, the safe maximum pressure for the corroded area is equal to the greater of the established MAOP (i.e., 850 psig) or the design pressure for the 42 in. pipeline segment (i.e., 960 psig). However, if the measured longitudinal extent of the corroded area is greater than the value in Table 3.1, the pipeline may need to be repaired or replaced or the allowable operating pressure may need to be reduced for the pipeline to continue operating safely.

The maximum allowable longitudinal extent of corrosion for the 26 in. and 30 in. pipeline segments located adjacent to the Indian Point Site are comparable in length to those for the 42 in. pipeline segment shown in Table 3.1.

Pipeline operating, inspection, and maintenance procedures and inspection, testing, and repair specifications and procedures for the Algonquin Gas Transmission pipeline are identified and described in (Entergy Nuclear 2020), Appendix B, Exhibit A. Periodic use of in-line inspection tools can be used to detect corrosion and SCC and monitor and trend flaw progression. Documents and procedures for addressing time-dependent threat to pipeline integrity are listed in Exhibit A. This exhibit includes integrity management program documents and procedures that comply with pipeline integrity management regulations in 49 CFR 192, Subpart O Integrity Management. Regulations in Subpart O, §192.939 that apply to the 26 in., 30 in., and 42 in. pipeline segments located adjacent to the Indian Point Site specify a maximum reassessment interval of seven calendar years. Further discussions about requirements in Subpart O, §192.939 for minimum reassessment intervals for pipelines that operated at specific hoop stress levels are provided in Appendix C.

3.1.2 Stress Corrosion Cracking

The 26 in., 30 in., and 42 in. pipeline segments located adjacent to the Indian Point Site are not susceptible to SCC because the groundwater and soil used to backfill the pipelines is not contaminated with chemicals that are necessary to promote environmentally induced cracking. (Federal Energy Regulatory Commission 2015) In addition, the coatings on the outside surfaces of the 26 in., 30 in., and 42 in. pipeline segments are an effective barrier to contact with these hostile environments. Damage caused by SCC to pipeline segments located adjacent to the Indian Point Site can be detected by periodic in-line inspections and evaluated as part of a comprehensive integrity management program based on regulations in 49 CFR 192, Subpart O as discussed in Appendix C. If SCC is detected, the following regulations in 49 CFR 192 Subpart M--Maintenance apply.

Regulation in Subpart M—Maintenance, §192.712 Analysis of predicted failure pressure state in §192.712(d) When analyzing cracks and crack-like defects under this section, an operator must determine predicted failure pressure, failure stress pressure, and crack growth using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both), material properties (pipe and weld properties), and boundary condition used (pressure test, in-line inspection or other). The Algonquin Gas Transmission pipeline integrity management program includes documents and procedures for complying with regulations in Subpart M—Maintenance, §192.712(d). These documents and procedures are identified and described in (Entergy Nuclear 2020) Appendix B, Exhibit A.

3.2 TIME-INDEPENDENT THREATS APPLICABLE TO THE PIPELINE SEGMENTS LOCATED ADJACENT TO THE Indian Point Site

The following time-independent threats can adversely affect the integrity of the 26 in., 30 in., and 42 in. pipeline segments located adjacent to the Indian Point Site.

- third party and mechanical damage
- incorrect operational procedure
- weather-related and outside force

3.2.1 Third party damage

The 26 in. and 30 in. pipeline segments located adjacent to the IPEC are covered by at least 36 in. of normal soil. This cover depth is consistent with requirement in §192.327.

In response to regulations in Subpart O Integrity Management, §192.935 regarding additional preventive and mitigative measures for operators, the 42 in. pipeline segment located adjacent to the site was constructed with a minimum depth of cover of 48 in. rather than the minimum depth of cover of 36 in. required in §192.327, and fiber reinforced concrete slabs were installed above the top of the line pipe to act as a physical barrier to third party excavation activities and acts of vandalism. In addition, warning tape was installed above the pipeline to reduce the possibility of an external force event. (U.S. Nuclear Regulatory Commission Expert Evaluation Team 2020)

Mechanical damage to a pipeline such as a dent or metal loss caused by a third party that does not result in an immediate natural gas release can be detected and, if necessary, repaired as part of a comprehensive integrity management program based on regulations in 49 CFR 192, Subpart O discussed in Appendix C.

3.2.2 Incorrect Operational Procedure

Threats to pipeline integrity can be caused by incorrect operating procedures or failure to follow a procedure. To minimize risk to pipeline integrity resulting from incorrect operation, the Algonquin pipeline system is monitored 24 hours a day from Houston, Texas.

Pipeline operating, inspection, and maintenance procedures and gas control and pipeline operation procedures for the Algonquin Gas Transmission pipeline are identified and described in (Entergy Nuclear 2020), Appendix B, Exhibit A.

3.2.3 Weather-Related and Outside Force Threats

Weather-related and outside force threats that could potentially affect the integrity of the 26 in., 30 in., and 42 in. pipeline segments located adjacent to the IPEC include:

- Brittle fracture of the steel line pipe
- Lightning
- Heavy rains or floods
- Earthquakes
- Landslides

Brittle fracture of the steel line pipe

Pipelines with cracks or crack-like defects can fail suddenly and without warning by brittle fracture resulting in a release of natural gas into the environment. Therefore, locating and removing defects before they grow to a critical length is necessary to maintain pipeline integrity.

Regulation in Subpart M—Maintenance, §192.712 Analysis of predicted failure pressure state in §192.712(d) When analyzing cracks and crack-like defects under this section, an operator must determine predicted failure pressure, failure stress pressure, and crack growth using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both), material properties (pipe and weld properties), and boundary condition used (pressure test, in-line inspection or other). The Algonquin Gas Transmission pipeline integrity management program includes documents and procedures for complying with regulations in Subpart M—Maintenance, §192.712(d). These documents and procedures are identified and described in (Entergy Nuclear 2020) Appendix B, Exhibit A.

Lightning

Lightning is not a threat to the integrity of the 26 in., 30 in., and 42 in. pipeline segments located adjacent to the IPEC because the pipeline is buried at least 36 in. beneath the soil surface.

Heavy rains or floods

Heavy rains or floods are not a threat to the integrity of the 26 in., 30 in., and 42 in. pipeline segments located adjacent to the IPEC because creeks or streams that are subject to washout or scour to the depth of the top of the pipeline do not cross the right-of-way and the pipeline right-of-way is at least 40 ft higher in elevation than the high-water line of the Hudson River.

Earthquakes

Welded steel natural gas pipelines are not vulnerable to earthquake-related peak ground acceleration but are vulnerable to earthquake-related peak ground velocity and peak ground deformation along the pipeline route. (Federal Emergency Management Agency, 2013) Potential damage to a natural gas pipeline caused by these two ground motion parameters are leaks and breaks that allow natural gas to escape into the surrounding environment, whereas earthquake damage to a pipeline that does not release natural gas is not a hazard to humans or the environment. A leak could originate at a crack in the line pipe caused by seismically induced buckling of the pipe wall and a break in the line pipe could be caused by seismic wave propagation. Although the risk of damage to the 26 in., 30 in., and 42 in. pipeline segments located adjacent to the IPEC by earthquakes is low, the consequences of a line pipe leak or break caused by an earthquake are no more severe than the potential consequences of a jet fire discussed in Sect. 2.3.3.

Landslides

Landslides are not a threat to the integrity of the 26 in., 30 in., and 42 in. pipeline segments located adjacent to the IPEC because based on the low landslide incidence potential in the AIM Project area the potential for landslides to affect the AIM Project is low. (Federal Energy Regulatory Commission, 2015) Although the risk of damage to the 26 in., 30 in., and 42 in. pipeline segments located adjacent to the IPEC by landslides is low, the consequences of a line pipe leak or break caused by a landslide are no more severe than the potential consequences of a jet fire discussed in Sect. 2.3.3.

3.3 STABLE THREAT ASSESSMENTS

Stable threats to pipeline integrity include manufacturing-related, welding and fabrication-related, and equipment-related defects. These threats do not have implied time dependence and may be events that occur randomly in time.

3.3.1 Manufacturing-Related Threat Assessments

Stable threats to pipeline integrity, such as a defective pipe seam or a defective section of pipe that occurred during manufacturing process, can typically be addressed by pressure testing. (ASME International 2004) Pressure testing has long been an industry-accepted method for validating the integrity of pipelines and is used as both a strength test and a leak test. The pressure test performed before the 42 in. pipeline segment located adjacent to the IPEC was placed in service eliminated this threat because any manufacturing defects that could affect pipeline integrity were repaired or replaced during the construction process. Compliance with regulations in 49 CFR 192, Subpart B—Materials can mitigate these threats.

Minimum leak-test and strength-test requirements for pipelines are specified in 49 CFR 192, Subpart J—Test Requirements. This subpart prescribes minimum leak-test and strength-test requirements for pipelines. Pressure test procedures for the 26 in., 30 in., and 42 in. pipeline segments located adjacent to the IPEC are described in (Entergy Nuclear 2020), Appendix B, Exhibit B.

3.3.2 Welding and Fabrication-Related Threat Assessments

Stable threats to pipeline integrity resulting from welding and fabrication defects that may include defective pipe girth welds, defective fabrication welds, wrinkle bends or buckles, stripped threads, broken pipes, and coupling failure. These construction and manufacturing-related defects are typically identified by quality assurance inspections and pressure testing. Defects that exceed acceptance criteria are usually repaired or replaced before the pipeline is placed in service. Compliance with regulations in 49 CFR 192, Subpart E—Welding of Steel in Pipelines and Subpart G—General Construction Requirements for Transmission Lines and Mains can mitigate these threats.

Inspection, testing, and repair specifications and procedures for pipeline projects including construction, procurement, and inspection for the Algonquin Gas Transmission pipeline are identified and described in (Entergy Nuclear 2020), Appendix B, Exhibit A.

3.3.3 Equipment-Related Threat Assessments

Random threats to pipeline equipment such as gasket or O-ring failures, control or relief equipment malfunctions, or seal and pump packing failures are typically addressed through maintenance programs that comply to regulations in 49 CFR 192, Subpart M—Maintenance. These maintenance programs use past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records, and all other conditions specific to each pipeline to repair or replace defective pipeline equipment that could adversely affect pipeline integrity.

Inspection, testing, and repair specifications and procedures for the Algonquin Gas Transmission pipeline are identified and described in (Entergy Nuclear 2020), Appendix B, Exhibit A.

4. ASSESSMENT OF CONSEQUENCES OF A BREACH NEAR THE INDIAN POINT SITE

Consequence assessments for an unintentional natural gas release from pipeline segments located adjacent to the Indian Point Site are based on a worst-case scenario in which high pressure natural gas is released from any point along any pipeline segment. The release may be caused by either a propagating crack that completely penetrates the line pipe wall or a full-bore guillotine rupture in a natural gas pipeline. This worst-case assumption is conservative because it has greater potential impacts than lesser ruptures and leaks.

4.1 PIR LOCATIONS RELATIVE TO THE INDIAN POINT SOCA

The PIRs for the 26 in. and 30 in. natural gas pipeline located adjacent to the site are 430 ft (0.08 mi) and 567 ft (0.11 mi), respectively. The approximate location of the 30 in. pipeline is shown in Figure 4.1 as a solid blue line, with the approximate location of the 42 in. pipeline shown as a solid red line. The SOCA fence is denoted by the solid white line. The dashed blue lines indicate an approximate distance of 567 ft. from the 30-in. pipeline. The PIR for the 42 in. pipeline segment located adjacent to the IPEC is 845 ft (0.16 mi). Figure 4.2 again shows the approximate locations of the 30 in. and 42 in. pipelines as solid blue and red lines. The dashed red line shows an approximate distance of 845 ft. from the 42 in. pipeline in the northerly direction. For reference, the SOCA fence is 1,581 ft (0.30 mi) from the 42 in. pipeline at its nearest point and is shown as the white line. (U.S. Nuclear Regulatory Commission Expert Evaluation Team 2020) The right-of-way for the 26 in. and 30 in. pipelines is approximately 1460 ft. from the pre-existing ISFSI pad at its point of closest approach. Holtec has constructed a second ISFSI pad adjacent to the pre-existing ISFSI pad. Construction of the second pad reduced the distance to the right-of-way, to approximately 1360 ft. The distance from the pre-existing pad to the point of closest approach for the 42 in. pipeline is approximately 3247 ft., and the distance from the second pad to the 42 in. pipeline is approximately 3130 ft. These distances were established using the measure distance tool within the PHMSA National Pipeline Mapping System.

Figure 4.1. Approximate PIR distances for the 30-in pipeline, shown as dashed lines. The solid white line is the SOCA; the solid blue line is the 30 in. pipeline and the solid red line is the 42 in. pipeline.

Figure 4.2. Approximate PIR distance in the northerly direction for the 42-in pipeline is shown as a dashed red line. The solid blue line is the 30 in. pipeline and the solid red line is the 42 in. pipeline.

4.2 SCOPE OF THE CONSEQUENCE ASSESSMENTS

Assessments of worst-case consequences to the public, employees, property, and the environment resulting from a propagating crack that completely penetrates the line pipe wall or a full-bore guillotine rupture in a natural gas pipeline are subdivided into:

- missile generation
- flash fires or fireballs
- jet fires that cause thermal radiation
- over-pressurization events caused by a vapor cloud explosion

Consequences of this worst-case incident can affect the infrastructure identified in Table 1.1 that traverses the Algonquin Gas Transmission pipeline right-of-way adjacent to the IPEC and the aboveground infrastructure that is located within and adjacent to the PIR boundary. These consequence assessments include effects on the public, employees, property, and the environment inside the PIR and effects on IPEC safety-related structures, systems, and components inside the SOCA.

4.3 CONSEQUENCE ASSESSMENTS OF MISSILE GENERATION

Potential missiles generated by rupture of the 26 in., 30 in., or 42 in. pipeline segment located adjacent to the IPEC and the subsequent crater that is formed by the escaping natural gas include:

- backfill soil that may also contain sand, gravel, and rocks ejected from the crater
- pieces of fractured line pipe

- pavement fragments
- fuel oil lines, water lines, and conduits that cross the right-of-way near the site of the release

As discussed in previously, this debris may become missiles that are ejected from the crater and could potentially contact people or buildings and cause personal injury or property damage. However, the 3 ft x 8 ft x 6 in fiber reinforced concrete slab that are centered above the 42 in. pipeline will likely interfere with the energy and trajectory of the missiles that are ejected from the crater.

Using a comparative analysis approach, the largest pipeline fragment for the unintentional release from the natural gas pipeline discussed in Sect. 2.1.3.1 was ejected about 287 ft from the crater which is about 48% of the PIR for this pipeline (i.e., 0.48 × 599 ft). This pipeline was backfilled with soil and did not have concrete slabs installed above the pipeline. Therefore, based the principle on conservation of momentum, it can be rationalized that:

- the energy and trajectory of a fractured 42 in. line pipe fragment which weighs as much as 4,000 lbs would be influenced by the fiber reinforced concrete slabs installed above the pipeline which weigh approximately 1,800 lbs each. In addition, the 42 in. pipeline segment was buried to a minimum depth of 48 in. compared to the requirements minimum depth of 36 in.
- the concrete slabs, while offering protection to the pipelines from damage may also become displaced in the event of a rupture of the 42 in. pipeline. It is not possible to predict whether these slabs could become airborne or simply be displaced to one side during the rupture event. The slabs, together with the line pipe would absorb the potential energy that results from the pressure release, likely decreasing the distance that the line pipe travels away from the breach as compared to pipelines that are not covered with concrete slabs.
- fractured 42 in. line pipe fragments would not be ejected more than about 400 ft from the crater which corresponds to 48% of the PIR for the 42 in. pipeline (i.e., 0.48 × 845 ft).
- fractured 30 in. line pipe fragments would not be ejected more than about 272 ft from the crater (0.48 X 567 ft).

4.3.1 Effects of Missile Generation within the PIR

According to Standard Review Plan SRP 3.3.2 requirements, tornado-generated missile characteristics and the design-basis tornado missile spectrum for safety-related structures, systems, and components are provided in Regulatory Guide (RG) 1.76. (U.S. Nuclear Regulatory Commission 2007) The following tornado missile spectrum apply to safety-related structures, systems, and components in nuclear power plants including IPEC which, according to RG 1.76, is located in Region II in the United States. (U.S. Nuclear Regulatory Commission 2006)

15-ft long 6.625-in. diameter schedule 40 steel pipe that weighs 287 lbs traveling at 112 ft/s (76 mph).

4,000-lbs automobile traveling at 112 ft/s (76 mph).

1-in. diameter solid steel sphere that weighs 0.147 lbs traveling at 23 ft/s (15 mph).

By comparison, a 12.5 ft long 42 in. line pipe section with a 0.72-in. wall thickness weighs about 4,000 lbs. However, it is very unlikely that a fractured section of 42 in. line pipe that weighs more than 4,000 lbs, which exceeds the design-basis missile spectrum used to design IPEC structures, systems, and components, is ejected beyond the PIR by an unintentional high-pressure natural gas release. In addition, measures taken by the AIM Project to protect the 42 in. pipeline from third-party damage would tend to absorb energy required to eject fractured sections of 42 in. line pipe from the crater.

A solid steel sphere with a diameter of 1 in. and a weight of 0.147 lbs is approximately four times denser than a limestone rock of the same size. The corresponding diameter a limestone rock with the same weight is about 1.5 to 1.6 in. depending on the density of the limestone. Thus, airborne rocks typical of the fill used in pipeline installations would not exceed the design basis outlined in RG 1.76.

In addition to pieces of fractured line pipe, a release from the 42 in. pipeline segment where it crosses the street at Broadway would likely cause damage to the roadway surface and create missiles that include pavement, water line, and conduit fragments that could cause personal injury or property damage. Similar missiles could be generated by a release from the 26 in. or 30 in. pipelines at several locations on the grounds of the Indian Point Site as well as where this pipeline crosses beneath Broadway. Missile generation from either pipeline within the PIR (but outside the SOCA) could cause localized damage to structures not designed per the design basis for nuclear facilities specified in Regulatory Guide (RG) 1.76. In particular, the fuel oil storage tanks (FOST) may be susceptible to missile damage from a breach of either the 30 in. or 42 in. pipelines. As these tanks have been emptied of their contents, damage to the tanks can no longer result in a hazardous material release or subsequent fire.

4.3.2 Effects of Missile Generation within the SOCA

Fractured line pipe fragments produced by an unintentional natural gas release from the 42 in. pipeline segment would not damage safety-related structures, systems, and components within the SOCA for the following reasons.

- The safety-related structures, systems, and components within the SOCA were designed to comply with requirements in Regulatory Guide (RG) 1.76. (U.S. Nuclear Regulatory Commission 2006)
- Fractured line pipe fragments that could be generated by an unintentional natural gas release from the 42 in. pipeline segment located nearest to the Indian Point Site will not be ejected beyond the PIR as discussed in Sect. 4.3, and the PIR for the 42 in. pipeline does not overlap the SOCA.
- There are no buried pipes or conduits that cross the right-of-way for the 42 in. pipeline segment located at a point nearest to the Indian Point Site. Therefore, there are no pipe-type missiles that could exceed the design basis for nuclear power plants provided in Regulatory Guide (RG) 1.76.

Missiles generated by a release from the 26 in. or 30 in. pipeline could enter the SOCA, however:

- the safety-related structures, systems, and components for the closest unit, Unit 3, are more than 350 feet from the pipeline; this distance is greater than the estimated maximum distance that pipe fragments or other missiles generated near the point of release could travel.
- the safety-related structures, systems, and components are designed to withstand wind loading and impacts as outlined in Regulatory Gide (RG) 1.76.

Therefore, the safety-related structures, systems, and components within the SOCA are not vulnerable to missile damage caused by an unintentional natural gas release from any of the three pipelines located near the Indian Point Site.

Radioactive waste packaging (class A, B, C, GTCC, and dry storage casks) is tested to assure that accidents that could be encountered during transport do not cause penetration of the containers. loaded and are being stored for transport inside a building (such as the reactor containment building) will be protected by the building structure in addition to the design criteria for the package itself. The spent fuel pool building and the containment building are outside the PIR, and so missiles are not expected in the area where radioactive waste packaging is being prepared for transport. Packages that have been

Missiles generated by an unintentional natural gas release from the pipeline segments located adjacent to the site that could affect the structural integrity of structures, systems, and components within the SOCA do not exceed the design basis for nuclear power plants provided in Regulatory Guide (RG) 1.76. Vehicles and equipment being used during decommissioning could certainly be damaged or destroyed if they were in the area where the PIR overlaps the SOCA.

4.4 CONSEQUENCE ASSESSMENTS OF FLASH FIRES OR FIREBALLS

The primary hazard resulting from flash fires and fireballs is thermal radiation as discussed previously. Effects of various thermal radiation intensity on buildings and humans are described in Table 2.1.

The amount of gas involved in a flash fire is dependent upon the time between the pipeline breach and ignition of the plume. Although the exact causes and timing of plume ignition are uncertain, there is a correlation between the pipeline size and pressure and the likelihood of ignition. (Acton and Baldwin, Ignition Probability for High Pressure Gas Transmission Pipelines 2008) (Acton, Acton and Robinson 2016) The ignition probability for a break of the 26- or 30 in. pipelines is 34%; the probability of ignition is 83% for the 42 in. pipeline. The mass of gas involved in a flash fire is dependent upon the delay time between the break and ignition of the gas cloud. 74% of ignition events occur within 2 minutes. (Acton, Acton and Robinson 2016) Considering an ignition event at 2 minutes after the break, the 26 in. pipeline could release over 400,000 kg of gas; deflagration of this gas could result in 2nd degree burns to unprotected personnel over a distance of 0.6 - 0.8 miles. (U.S. Environmental Protection Agency 2009) The two larger pipelines can vent this mass of gas in shorter times. Importantly, valve closure times to isolate the sections of pipeline near IPEC do not have any bearing on the severity of a flash fire, since the ignition event is likely to occur sooner than the best-case valve closure scenario.

The thermal radiant heat posed by a flash fire would be intense but short-lived, since flash fires generally have durations of a few seconds. The radiative heat flux is dependent upon how much gas burns in the fireball, which is in turn dependent on the time that lapses between the rupture and ignition. Variability in these factors makes a precise estimate of the radiative heat flux difficult, but at least one study has measured a heat flux of 70 kW/m^2 at a distance of 200m from a pipeline rupture. (Cowling, et al. 2019) This short-duration heat flux could result in localized brush fires and damage to unprotected people, equipment, and facilities. However, its short duration precludes serious damage to the safety-related structures, systems and components of any of the Indian Point units. Similarly, packaging containers (class A, B, C, GTCC, or dry storage casks) for radioactive wastes would be expected to resist this short duration heat load without serious damage.

Although flash fires and fireballs resulting an unintentional natural gas release from the pipeline segments located adjacent to the site can cause personal injury, no significant overpressure results from a flash fire or fireball.

4.5 CONSEQUENCE ASSESSMENTS OF JET FIRES THAT CAUSE THERMAL RADIATION EFFECTS

Figure 4.3 shows the projected radiative heat loads as a function of distance normalized by the PIR. This plot is based on calculation of the blow-down of a pipeline through a critical-flow orifice with a diameter equal to the pipeline diameter. This method calculates the mass of gas ejected through the pipeline rupture, which in this case is assumed to be the entire diameter of the respective pipeline. As the calculations step forward in time (at 30 second increments) the pipeline pressure and temperature are re-calculated based on the mass of gas remaining in the pipeline and an assumption that the gas remaining in the pipeline cools as a result of the reduction in pressure that it experiences. These new pressure and temperature values are then used to again calculate the mass of gas that is ejected. This process repeats for the next time step until at least 30 minutes have elapsed. Since each half of the rupture participates in ejecting gas, the mass of gas ejected from one side is doubled to represent the flow that occurs when both sides of the breach are considered. This aggregate mass of gas is then used to calculate the heat energy released by combustion of the ejected gas. The distances at which particular radiative heat flux values can be experienced are then calculated.

The three pipelines have different PIRs as previously discussed. The distances at which specific heat loads exist for each pipeline are proportional to its PIR. The plot shows the distance at which heat loads can exist for each pipeline, divided by the PIR for that pipeline. When displayed in this fashion, these projections collapse to a single family of curves that can be used for all three of the pipelines. The plot shows projections for a blow-down of a full-bore guillotine break at the center of a 100-mile length of pipeline. The projection includes valve closures to isolate a 10.9-mile section of pipeline at 8 minutes. The 100-mile initial length provides a large gas source on both sides of the break that initially feeds the plume resulting from the pipeline break. 8 minutes is the maximum time stated by Enbridge for closure of valves to isolate a breach near IPEC, and 10.9 miles is the length of the isolated breached pipeline segment using the 2nd valves both upstream and downstream of the IPEC.

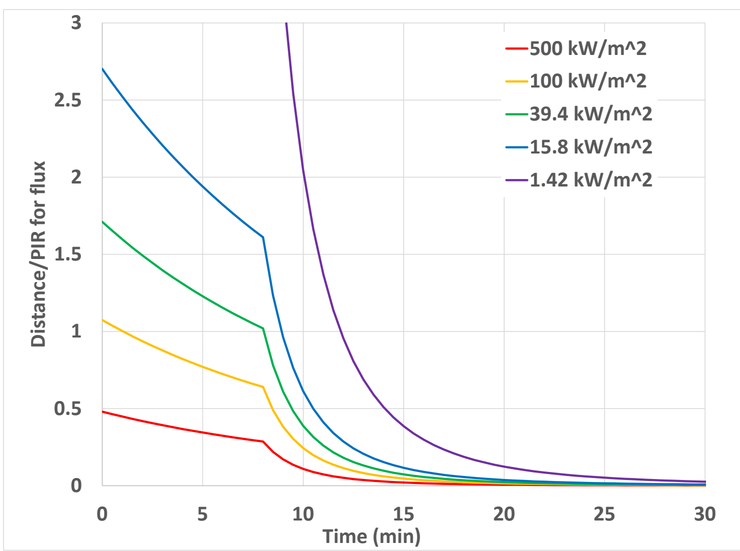

Figure 4.3. Projected radiative heat flux densities versus time as a function of distance normalized by the PIR.

The projections show that initially high radiative heat flux densities exist both within and outside the PIR for each pipeline but begin to decline immediately because the pressure in the affected pipeline begins to decline as gas is ejected from the breach. The initial heat flux is determined by the pipeline pressure and diameter and is not influenced by the timing of valve closure. Once the valves close to isolate the breached pipeline segment, the hazardous radiative heat loads decrease more rapidly and are contained to the PIR within two minutes. This trend occurs because when the isolation valves close, the volume of gas in the ruptured pipeline segment is much lower. As this gas is vented, the pressure in the breached pipeline segment decreases more rapidly. The red curve shows the locations that can experience a 500 kW/m^2 radiative heat flux density; this heat flux can thermally ablate concrete from structural walls. This extreme radiative heat load only extends to approximately half of the PIR distance initially and contracts to about one fourth of the PIR distance before valve closure occurs. A radiative heat flux density of 100 kW/m^2, shown by the yellow curve, can cause steel structures to collapse with 30 minutes of exposure. The green curve shows that a 39.5 kw/m^2 initially extends to a distance just greater than 1.5 times the PIR distance. This heat flux density is the maximum tolerable radiative load to avoid piloted ignition of cellulosic (wood) building facades. The blue curve shows the extent of the 15.8 kW/m^2 radiative heat flux density that is used in sizing the PIRs for pipeline ruptures. 1.42 kW/m^2 is the radiative heat flux density deemed safe for unprotected people conducting outdoor activities; it is denoted by the purple curve.

The red and yellow curves are important because these are the heat fluxes that could potentially cause damage to safety-related structures, systems, and components if they are exposed to these heat fluxes for extended periods of time. Steel structures (such as the steel construction of the spent fuel pool buildings) must not be exposed to 100 kW/m^2 radiative heat fluxes for 30 minutes, for example, to avoid risk of structural collapse. This level of radiative heat flux exists outside the PIR distance for each pipeline for approximately 1 minute after the release but is thereafter contained within the PIR distance for each pipeline.

A calculation was also carried out with both the initial pipeline length and the time needed for valve closure to occur doubled (200 miles of pipeline and 16 minutes required for valve closure). The results of this calculation are shown in Figure 4.4. These changes increase the length of time that potentially damaging heat fluxes persist, though their exposure distances continue to decrease with time and are quickly contained to the PIR distance. Importantly, these results highlight the fact that the initial length of pipeline and the time required for valve closure do not influence the distances at which damaging heat fluxes are expected to occur. Damaging heat fluxes are still essentially eliminated within 25 minutes.

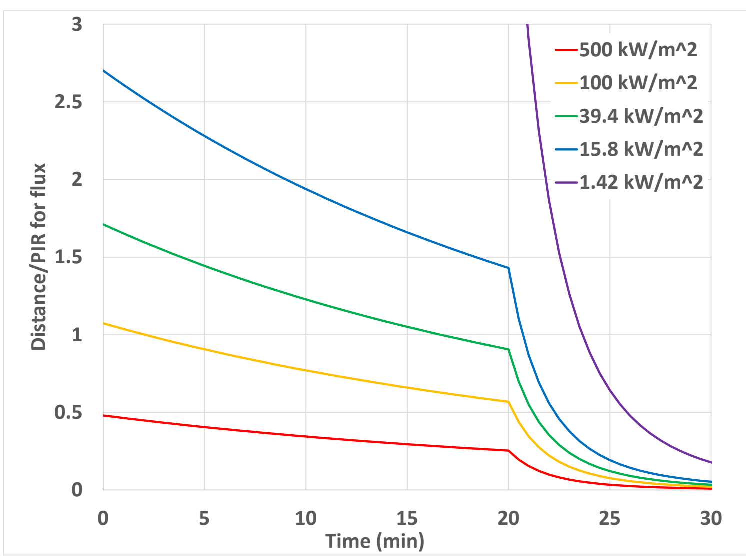

Figure 4.4. Projected radiative heat flux densities versus time as a function of distance normalized by the PIR using 200-mile pipeline length and 16 minute valve closure time.

4.5.1 Effects of a Jet Fire from the 42 in. Pipeline

While the PIR for the 42 in. pipeline lies entirely outside the SOCA, a hazard distance of 1.5 times the PIR would extend into the SOCA as well as to nearby facilities not associated with IPEC. Injuries to unsheltered people located within the PIR and to a distance greater than three times the PIR during a jet fire are probable because the thermal radiation far exceeds the heat flux threshold of 1.4 kW/m^2 (450 Btu/hr ft^2) which is considered the acceptable level of thermal radiation for people in open spaces. Firefighting activities are also limited within areas where the thermal radiation exceeds the heat flux threshold of 2.5 kW/m^2 (800 Btu/hr ft^2) which is considered the acceptable level for common firefighting activities. An unintentional natural gas release beneath Broadway could disrupt surface transportation, electrical power, communication, and water services that could be needed by the public, workers at the Indian Point Site, emergency personnel, and first responders. In addition, the jet fire could cause brush fires, property damage to cars and nearby structures, and injury or death to people that may be using the road or land areas affected by the fires.

Damage to facilities that do not meet the requirements for seismic category 1 nuclear facilities and unprotected equipment is also likely within the PIR, as the heat flux densities inside the PIR can reach 500 kW/m^2 for a short period of time. The projections in Figure 4.3 show that the heat flux densities capable of causing damage to unprotected facilities and equipment extend to just over 1.5 times the size of the PIR. At the time of this writing, demolition of site-related facilities outside the SOCA is proceeding rapidly, making these facilities less of a concern. One of the tanks at the FOST has already been dismantled, with the second tank emptied of its contents and likely to be dismantled before this report is released. Thus, the potential for a pipeline rupture to cause a release of hazardous material and/or a fire at the FOST has been removed. The safety-related structures, systems, and components inside the SOCA are unlikely to be damaged by the radiative heat flux density that they may experience in the event of a breach of the 42 in. pipeline. In particular, the Unit 3 containment building and the Unit 3 spent fuel pool building are not projected to experience heat flux densities that could cause significant damage because these facilities have sufficient separation distance from the pipeline to prevent exposure. Spent fuel dry-storage casks and other radioactive material containers being removed from the spent fuel storage building and/or the containment building also have sufficient separation from the pipeline to prevent significant damage due to radiant heat flux from occurring. Unit 1 and Unit 2 facilities are further away from the pipeline than the Unit 3 facilities and are hence even less likely to be damaged in the unlikely event of pipeline rupture.

The Defueled Safety Analysis Reports for IPEC units 2 and 3 indicate that the spent fuel pools can remain safe for at least 1.8 hours and 8.5 hours, respectively, without external cooling systems operating. (Entergy Nuclear 2020) (Entergy Nuclear 2021) Spent fuel has been cooling in the pool for more than a year and some fuel has also been moved from the pools into dry storage in the ISFSI. As a result, the heat load has been reduced and the time that the pools can remain safe without external cooling systems operating has increased. The emergency plan for Units 2 and 3 in their permanently shut-down state indicates that at least 89 hours are available to mitigate a loss of spent fuel pool cooling before the water in the spent fuel pool were to boil down to 10 ft above the top of the fuel. (HOLTEC Decommissioning International 2022) The time available to mitigate a loss of spent fuel pool cooling will continue to increase as more fuel is removed from the pools and placed in the ISFSI. Backup generators continue to be available to support spent-fuel cooling electrical demands in the event that a pipeline rupture temporarily interrupts the underground electrical feeds for the site.

Postulated pipeline ruptures could result in fires and dangerous radiative heat flux densities; these are projected to abate in less than 1 hour. In the unlikely event that a rupture of a pipeline and subsequent jet fire interrupted the function of spent fuel pool cooling systems, there would be ample time after the jet fire is eliminated to restore cooling function before a boil down condition occurs.

4.5.2 Effects of a Jet Fire from the 26- or 30 in. Pipelines

The PIRs for the 26- and 30 in. pipelines are closer to the SOCA; in fact, they overlap some areas of the SOCA near Unit 3. Referring to Figure 4.3, the 500 kW/m^2 radiant heat flux initially extends to half of the PIR but recedes even before valve closures can occur. The 100 kW/m^2 radiant heat flux initially covers the entirety of the PIR but also recedes even before valve closures can occur. The spent fuel pool building for Unit 3 is the closest building of particular concern; the Unit 3 containment building is further away from the pipelines. The point of closest approach for the 26 in. pipeline to the spent fuel pool building is approximately 620 ft. The point of closest approach for the 30 in. pipeline to this building is approximately 650 ft. These distances were established using the measure distance tool within the PHMSA National Pipeline Mapping System. These distances exceed the PIR distances for these pipelines and also exceed the distance at which the 100 kw/m^2 radiative heat flux is expected to exist. The Unit 3 containment building is of reinforced concrete construction and is not expected to be significantly damaged by a 100 kW/m^2 radiative heat flux. Moreover, the primary auxiliary building for Unit 3 is located between the pipelines and both the Unit 3 spent fuel pool building and the Unit 3 containment building. The primary auxiliary building would therefore provide some shielding to the spent fuel pool building and the containment building in the event of a pipeline rupture. For these reasons, the Unit 3 safety-related structures, systems, and components are not expected to be significantly damaged by radiative heat flux from a jet fire originating with either the 26 in. or 30 in. pipeline.

A jet fire is likely to cause injury to unprotected personnel and damage to unprotected equipment over a large area of the site since damaging heat fluxes may exist to at least 1.5 times the PIR distance. Localized brush fires and vehicle fires are likely, especially if the break occurs at or near the large parking facilities for the site. As noted previously, buildings outside the SOCA (including the FOST) are being removed rapidly and represent a lesser risk as decommissioning proceeds.

Packaging designed to contain radioactive wastes from the decommissioning of the plant are designed to withstand thermal loads. For example, class B, C, GTCC, and dry storage casks are subjected to fires at 1475 °F for 30 minutes as a part of their certification process. Moreover, the separation distance between the Unit 3 Containment building equipment hatch and the 26 in. and 30 in. pipelines is greater than the distance at which heat fluxes that can damage concrete and steel structures are expected. While unprotected equipment used to transport these containers may be damaged in the event of a jet fire, the containers themselves are not likely to be severely damaged.

The ISFSI is located more than two times the PIR distance from the 26- and 30 in. pipelines. The projections in Figure 4.3 show that heat fluxes that could exist at that distance are less than 39.4 kw/m^2. This heat flux exposure scenario is not hazardous to the concrete and steel construction of the dry storage casks stored in the ISFSI.

The 26 in. and 30 in. pipelines are co-located within the same 65-ft. wide right-of-way. Should one of these pipelines rupture, it is likely that the other could be damaged or rupture as a result, assuming that both are in operation at the time of the rupture. If the rupture of one pipeline causes a rupture of the other nearly simultaneously, the release rate of gas would increase. In this event, the heat flux densities increase because of the larger combined gas flow rate of the two pipelines. Even in this case, the highest heat flux density of 100 kW/m^2 initially extends to approximately 1.5 times the PIR distance for the 30 in. pipeline. The highest heat flux density of 500 kW/m^2 initially extends to just less than 0.75 times the PIR distance for the 30 in. pipeline. Valve closure at eight minutes after the rupture results in a rapid decline of the hazardous heat fluxes over the following 10-15 minutes. This situation results in the same conclusions as for a single pipeline rupture. That is, the hazardous heat fluxes are of sufficiently short duration that the safety-related structures, systems, and components and radioactive material shipping containers are unlikely to experience serious damage.

4.6 CONSEQUENCE ASSESSMENTS OF OVER-PRESSURIZATION EVENTS CAUSED BY A POSTULATED EXPLOSION

Explosions involving unconfined natural plumes are highly unlikely. (Stephens 2000) Methane is the major component of natural gas. It has a relatively low flame speed and commonly forms a buoyant plume that rises into the air because the molecular weight of methane is lower than that of either molecular nitrogen or oxygen. As the plume rises, confinement by structures closer to the ground that could facilitate a deflagration to detonation transition becomes less likely and the methane dissipates into the surrounding atmosphere, rapidly reaching non-flammable concentrations. PHMSA staff consulted by the NRC expert team were not able to find any record of dense methane clouds igniting or exploding at a location away from the initial pipeline rupture. (U.S. Nuclear Regulatory Commission Expert Evaluation Team 2020) The expert team reviewed PHMSA's pipeline rupture data and concluded that the rupture risk for pipelines greater than 20 inches in diameter and operating at greater than 300 psi was 2.4×10^{-5} per mile per year. Considering the 30 in. pipeline segment passing near IPEC is approximately 0.4 miles long, the risk of a rupture is just less than 1×10^{-5} per year.

4.6.1 Hazard Prediction and Assessment Capability Modeling

The ORNL team performed an analysis of a release using the Hazard Prediction and Assessment Capability (HPAC) model. (Defense Threat Reduction Agency 2021) A horizontal jet release scenario was created using HPAC. Blowdown calculations for a 42 in. pipe initially at 864.7 psi and a temperature of 288 K result in the mass rates and velocities summarized in Table 4.1. A release scenario was created by averaging the mass of methane released over periods of two, five, and ten minutes as shown in Table 4.2. Mass rates are doubled to represent flow exiting from both ends of the severed pipe. This scenario assumes there is no gas flow cut-off for an hour, providing a worst-case analysis. This analysis presumes that no ignition occurs, so that the methane plume can spread as weather conditions dictate; no combustion event is present to consume the gas. The release scenario assumes that the 42 in. pipeline ruptures at the point of nearest approach to the IPEC SOCA.

The scenario was run with a typical weather day for the region (the 15th) of each month. Transport and dispersion of the methane results in surface concentrations depicted in the montage figures below for 5, 10, 15, 30, and 60 minutes after pipeline rupture. Results for each month are shown from top to bottom and left to right. The contours represent Temporary Emergency Exposure Limits (TEEL) for methane. (U.S. Department of Energy 2016)

Table 4.1. Mass flow rates calculated for a 42 in. pipeline blowdown.

Time (min)	Mass Rate (kg/s)	Exit Velocity (m/s)
0.0	5734.990	478.1055
1.0	4997.325	469.1116
2.0	4365.731	460.4498
3.0	3823.402	452.1021
4.0	3356.433	444.0516
5.0	2953.280	436.2829
6.0	2604.325	428.7813
7.0	2301.530	421.5333
8.0	2038.158	414.5263
9.0	1808.545	407.7484
10.0	1607.913	401.1886

Table 4.2. Mass releases used in the HPAC release scenario.

Time (min)	Duration (s)	Mass Rate (kg/s)	Exit Velocity (m/s)
:00	120	10376.7130	471.38082
:02	120	7927.3702	454.20757
:04	120	6114.8992	438.24176
:06	120	4759.3764	423.36035
:08	120	3735.5135	409.45649
:10	300	2522.2496	387.36645
:15	300	1463.8244	359.43687
:20	300	882.5640	335.26532
:25	300	451.4564	314.14092
:30	600	292.5868	287.35386
:40	600	131.9896	257.55653
:50	600	64.4581	233.42834

Table 4.3. Temporary emergency exposure limits for methane.

Level	Concentration (mg/m^3)	Description
TEEL-1	4.264×10^4	Threshold
TEEL-2	1.509×10^5	Injury Possible
TEEL-3	2.624×10^5	Death Possible

Results throughout the calendar year are very consistent with winds predominantly from the south. The horizontal range of methane at concentration levels sufficient to adversely affect humans is less than 100 m from the release point. Further, within an hour the methane has dissipated such that no serious threat remains, even in the immediate vicinity of the release. The TEEL-1 threshold concentration of 4.264×10^4 mg/m^3 is three orders of magnitude below the 4.4×10^7 mg/m^3 Lower Flammability Limit (LFL) for methane.

With March as the only exception, the farthest reach of TEEL-2 and TEEL-3 concentrations at ground level occurs at five minutes, as shown in Figure 4.5. The LFL is about 169 times higher than the TEEL-3 region methane concentration. This difference highlights the fact that the plume rapidly becomes non-flammable as it moves away from the pipeline break. Examination of the projected plume for a break occurring in February showed that as the plume departed from the area of the break, the concentration rapidly drops to less than 10% of the LFL, demonstrating that this plume is incapable of producing a large explosion. Figure 4.6 shows that in March concentration levels of concern reach farthest at 10 minutes, but the overall reach at ground level is shorter than in any other month. Figure 4.6 shows the projected ground level plumes at 15 minutes after the break. By 30 minutes (Figure 4.8) after the pipeline is severed the concentration is dissipated such that TEEL-2 and TEEL-3 levels reach only a few meters from the release point, and at the end of an hour (Figure 4.9) very little concentration remains. This is true consistently throughout the calendar year. February sees winds from the south-southeast, and TEEL-2 concentrations come close to reaching the nearby building. Thus, these weather conditions could necessitate a temporary evacuation.

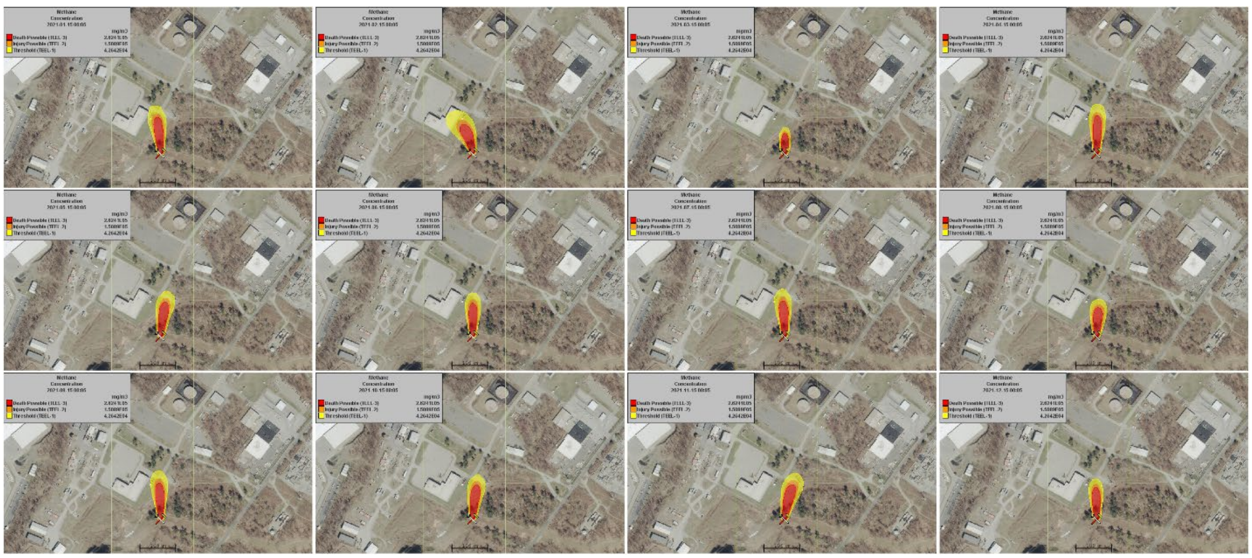

Figure 4.5. Projected plumes at five minutes after the break for each month.

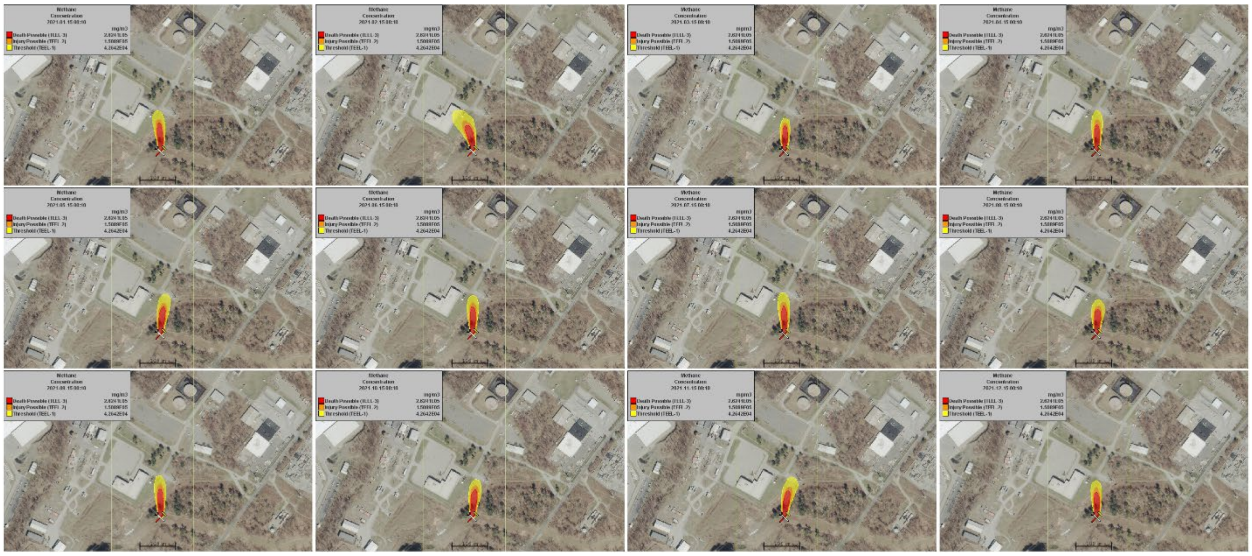

Figure 4.6. Projected plumes at 10 minutes after the break for each month.

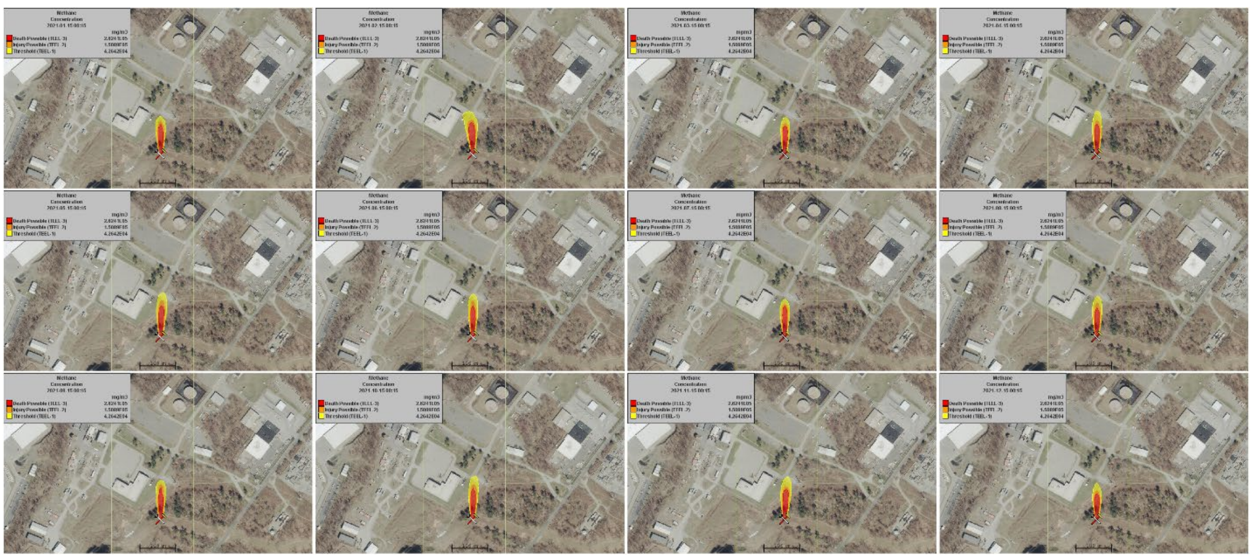

Figure 4.7. Projected plumes at 15 minutes after the break for each month.

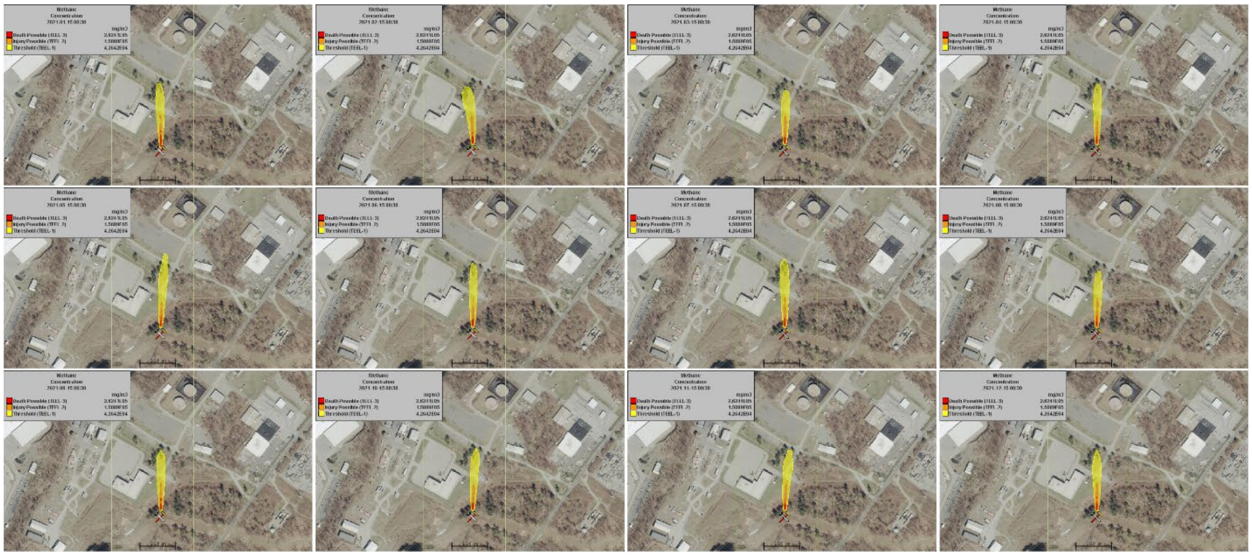

Figure 4.8. Projected plumes at 30 minutes after the break for each month.

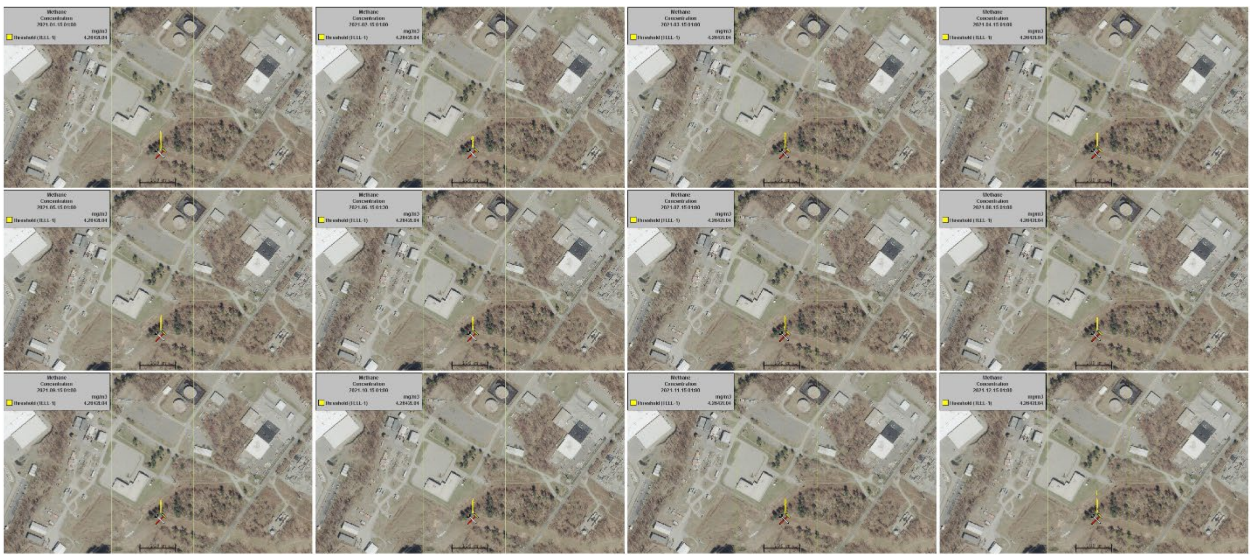

Figure 4.9. Projected plumes at 60 minutes after the break for each month.

The vertical extent of the modeled methane plume at 5, 10, and 30 minutes on 15 October is illustrated in Figures 4.10 and 4.11. In the plot panels the tan region represents terrain height above sea level.

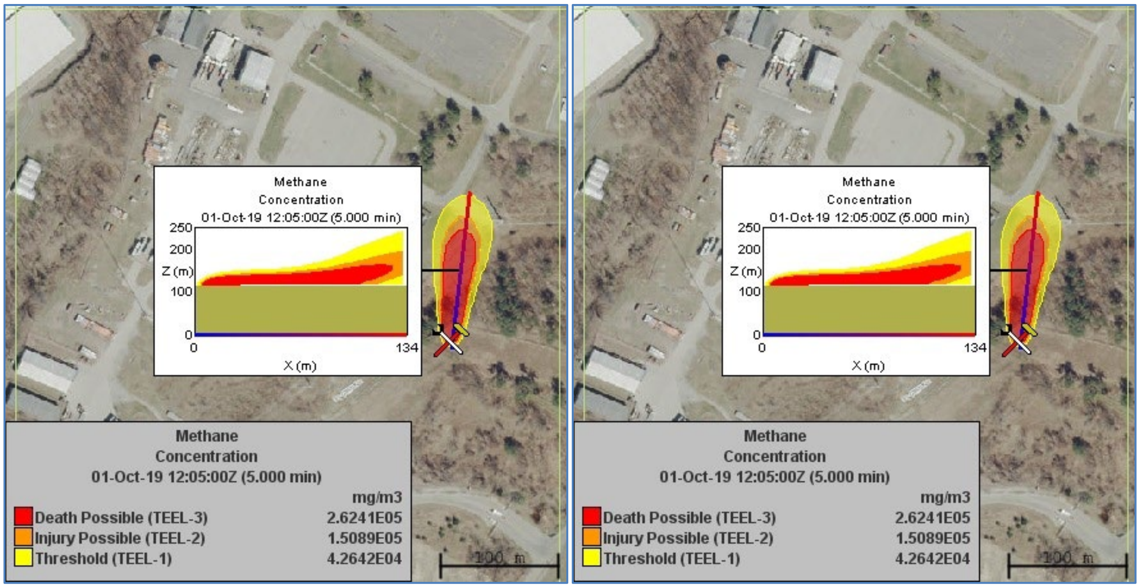

Figure 4.10. Projected plume vertical reach at 5 and 10 minutes on October 15.

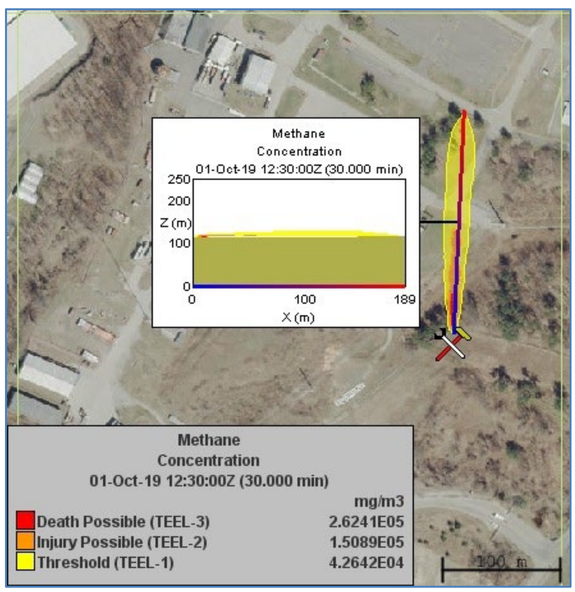

Figure 4.11. Projected plume vertical reach at 30 minutes on October 15.

Figure 4.12 shows the vertical slice at five minutes in more detail. TEEL-2 concentrations never reach 40 m vertically and range from 60 to 130 m horizontally along the slice axis. TEEL-3 concentrations never reach 20 m vertically and range from 80 to 125 m horizontally.

It is important to understand that the 12 results representing typical days might not cover outlier conditions involving storms and unusual weather events. However, the consistency in results across these days, which cover the seasons of the year, allow a confident assessment that the potential for adverse effects on personnel resulting from exposure to methane gas is very small.

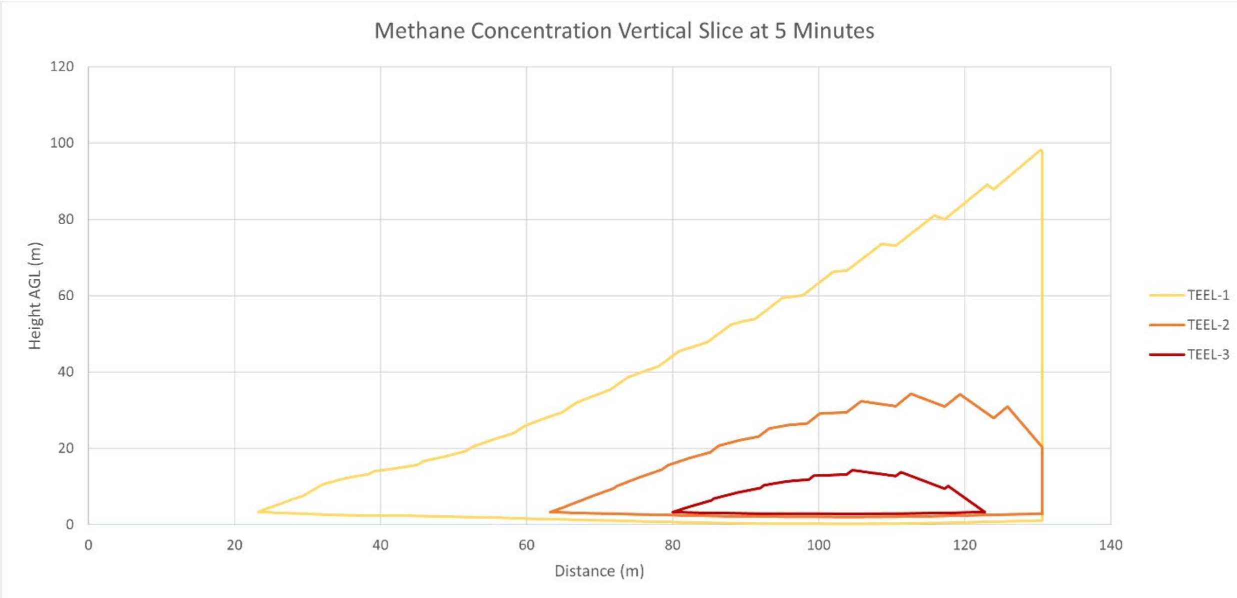

Figure 4.12. Methane plume projected concentrations on October 15, 5 minutes after the break as a function of horizontal and vertical distance from the break.

The HPAC projections for plume concentration and spread reinforce the fact that the risk of an explosion is very low. However, as an explosion cannot be completely eliminated as a possibility, minimum safe distances in the event of an explosion were calculated. These calculations used guidance provided by the NRC. (U.S. Nuclear Regulatory Commission 2013) Calculations included in the regulatory guidance are based on TNT-equivalent mass modeling of the effects of flammable substances (like natural gas) that are not intended for use as an explosive. Figure 4.13 shows the minimum safe distance from an explosion as a function of the mass of methane involved in the explosion. This analysis uses an alpha value of 5% of the methane mass participating in the explosion and a heat of combustion of methane of 50,000 kJ/kg.

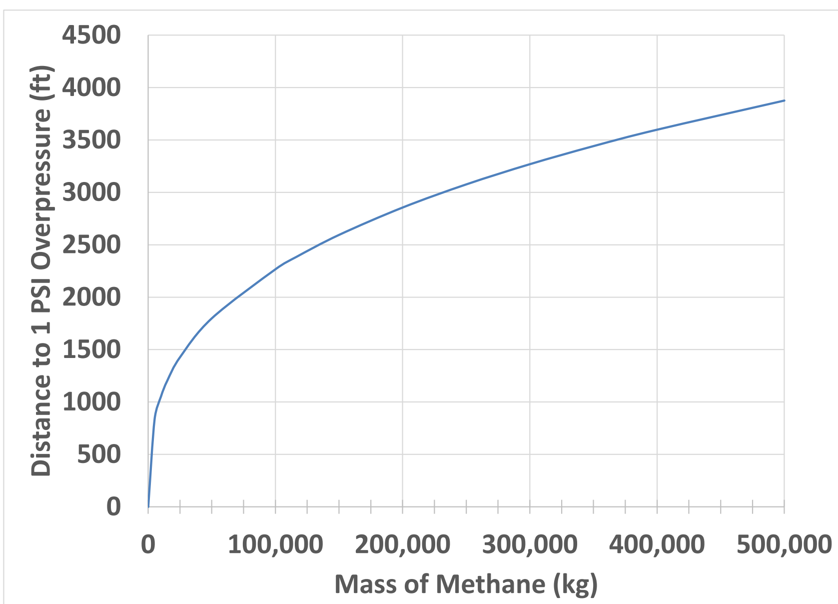

Figure 4.13. Minimum safe distance as a function of mass of methane released from a pipeline.

The point of closest approach for the 42 in. pipeline to the SOCA is 1,581 ft. The 26 in. and 30 in. pipelines are much closer, within approximately 150 feet at some points. The distances from the 26 in. and 30 in. pipelines to structures associated with IPEC Unit 3 are slightly more than 400 ft.

4.6.2 Effects of an Explosion

Buildings and structures that are further away than the minimum safe distance shown in Figure 4.4 should not experience damage from an overpressure event caused by a pipeline break. Structures that are closer than the minimum safe distance could be damaged by the overpressure from an explosion. NRC regulatory guidance indicates that buildings closer than the minimum safe distance should have a structural analysis conducted to determine their potential for damage in the event of a detonation. (U.S. Nuclear Regulatory Commission 2013) NRC also provides that if the likelihood of an explosion is less than $1x10^{-7}$ per year, the risk of damage from an explosion is acceptably low. This condition is satisfied for the pipelines passing near the Indian Point Site if less than 1% of ruptures result in an explosion. The NRC Expert Team report documents previous assessments by multiple organizations and experts concluding that the potential for an explosion are very low, with at least one expert describing this situation as “implausible.” (U.S. Nuclear Regulatory Commission Expert Evaluation Team 2020)

42 in. Pipeline
Figure 4.4 shows that the minimum safe distance for an explosion involving 34,500 kg of methane is 1590 ft. Blow-down of the 42 in. pipeline segment in the event of a full-bore guillotine break could release this amount of gas in less than five seconds. In the unlikely event of a methane explosion involving a breach of the 42 in. pipeline, safety-critical facilities and waste packages within the SOCA are likely to experience greater than one psi of overpressure.

26 in. Pipeline
The minimum safe distance for an explosion involving as little as 30 kg of methane is approximately 152 feet. This is the approximate distance from the 26 in. pipeline to the SOCA. This pipeline could release this amount of gas in less than one second. In the unlikely event of a methane explosion involving the 26 in. pipeline, safety-critical facilities and waste packages within the SOCA are likely to experience greater than one psi of overpressure.

30 in. Pipeline
The minimum safe distance for an explosion involving as little as 30 kg of methane is approximately 152 feet. This is the approximate distance from the 30 in. pipeline to the SOCA. This pipeline could release this amount of gas in less than one second. In the unlikely event of a methane explosion involving the 30 in. pipeline, safety-critical facilities and waste packages within the SOCA are likely to experience greater than one psi of overpressure.

Previous Overpressure Risk Evaluations
The risks posed by an explosion-generated overpressure to the safety-critical facilities at IPEC have been evaluated several times in the past, as documented in the NRC Expert Team Report. (U.S. Nuclear Regulatory Commission Expert Evaluation Team 2020) At least one expert described an explosion as “implausible” given the low flame speed of methane, relatively open conditions around the pipelines, and the buoyant nature of the gas plume that can be formed. These evaluations, including testimony by experts, have underscored the low risk for an explosion resulting from a break of one of the pipelines near the Indian Point Site. NRC structural engineering experts have reported that it is a good starting assumption that the seismic category 1 structures will be capable of withstanding the pressures from an explosion associated with a rupture of the 42 in. pipeline. The NRC report also observes that the HI-

STORM 100 dry cask storage system is designed for the same conditions as the category 1 buildings. (U.S. Nuclear Regulatory Commission Expert Evaluation Team 2020) Class B and C containers are also designed to resist conditions that could result from accidents in transit.

5. SAFETY ASSESSMENT SUMMARY

Safety assessment results for the pipeline segments adjacent to the Indian Point Site are documented in this report. These consequences could affect the public, environment, and safety-related structures, system, and components within the Security Owner-Controlled Area (SOCA).

The safety assessments are based on a worst-case unintentional natural gas transmission pipeline release that involves either a propagating crack or a full-bore guillotine rupture of the line pipe. The release allows natural gas to begin flowing immediately through the break and into the surrounding atmosphere.

5.1 SAFETY ASSESSMENTS OF THREATS TO PIPELINE INTEGRITY

Threats to pipeline integrity that are applicable to the 42 in. pipeline segment located adjacent to the site are categized as time-dependent, time-independent, and stable threats.

5.1.1 Time-Dependent Threats to Pipeline Integrity

Time-independent threats can adversely affect the integrity of the pipeline segments located adjacent to the site include internal and exterior corrosion and stress corrosion cracking (SCC).

Corrosion protection for the 42 in. pipeline segment is provided by fusion-bonded epoxy coatings applied to the inside and outside of the pipeline and a cathodic protection system. The 26 in. and 30 in. pipelines are also protected by an exterior coating and cathodic protection systems. Although these measures are intended to prevent corrosion, rules in 49 CFR 192, Subpart M—Maintenance identify suitable remaining strength calculation methods for assessing metal loss caused by corrosion. These calculation methods apply to corroded areas with metal loss that range from 10% to 80% of the wall thickness and are used to establish the maximum allowable operating pressure (MAOP) if corrosion thresholds are exceeded.

The pipeline segments located adjacent to the site are not susceptible to SCC because the groundwater and soil used to backfill the pipelines is not contaminated with chemicals that are necessary to promote environmentally induced cracking.

Threat identification is a key element of a comprehensive integrity management program which is required to comply with 49 CFR 192, Subpart O as discussed in Appendix C. The pipeline segments adjacent to the site are included in an integrity management program that includes documents and procedures for addressing time-dependent threats to pipeline integrity.

5.1.2 Time-Independent Threats to Pipeline Integrity

Time-independent threats to the pipeline segments located adjacent to the Indian Point Site, include:

- third party and mechanical damage
- incorrect operational procedure
- weather-related and outside force

The 42 in. pipeline segment located adjacent to the site was constructed with a minimum depth of cover of 48 in. rather than the minimum depth of cover of 36 in. required in §192.327 and fiber reinforced concrete slabs were installed above the line pipe to act as a physical barrier to excavation activities and acts of vandalism by third parties. In addition, warning tape was installed above the pipeline to reduce the possibility of an external force event. The 26 in. and 30 in. pipelines are installed with a depth of cover of at least 36 in. in compliance with regulations. Mechanical damage to the pipelines caused by a third party such as a dent or metal loss that does not result in an immediate natural gas release can be detected as part of a comprehensive integrity management program based on regulations in 49 CFR 192, Subpart O as discussed in Appendix C. The pipelines are part of an integrity management program that includes documents and procedures for addressing time-independent threats to pipeline integrity.

Threats to pipeline integrity can be caused by incorrect operating procedures or failure to follow a procedure. To minimize risk to pipeline integrity resulting from incorrect operation, the Algonquin pipeline system is monitored 24 hours a day from Houston, Texas. Pipeline operating, inspection, and maintenance procedures and gas control and pipeline operation procedures for the Algonquin Gas Transmission pipeline are identified and described in (Entergy Nuclear 2020), Appendix B, Exhibit A.

The minimum soil temperature at the top of the steel line pipe used to construct the 42 in. pipeline segment located adjacent to the site should not fall below 32°F because the pipeline is buried below the 48 in. frost line. At temperatures of 32°F and above, brittle fracture of the steel line pipe used to construct the 42 in. pipeline segment located adjacent to the site is not a safety concern.

Lightning is not a threat to the integrity of the pipeline segments located adjacent to the Indian Point Site because the pipelines are buried at least 36 in. in the soil.

Heavy rains or floods are not a threat to the integrity of the pipeline segments located adjacent to the site because creeks or streams that are subject to washout or scour to the depth of the top of the pipeline do not cross the right-of-way and the pipeline right-of-way is at least 40 ft higher in elevation than the high-water line of the Hudson River.

Welded steel natural gas pipelines are not vulnerable to earthquake-related peak ground acceleration but are vulnerable to earthquake-related peak ground velocity and peak ground deformation along the pipeline route. (Multi-hazard Loss Estimation Methodology – Earthquake Model, Federal Emergency Management Agency, 2013) Potential damage to a natural gas pipeline caused by these two ground motion parameters are leaks and breaks that allow natural gas to escape into the surrounding environment, whereas earthquake damage to a pipeline that does not release natural gas is not a hazard to humans or the environment. A leak could originate from a crack in the line pipe caused by seismically induced buckling of the pipe wall and a break in the line pipe could be caused by seismic wave propagation. Although the risk of damage to the 26 in., 30 in., and 42 in. pipeline segments located adjacent to the site by earthquakes is low, the consequences of a line pipe leak or break caused by an earthquake are no more severe than the potential consequences of a jet fire discussed in Sect. 2.3.3.

Landslides are not a threat to the integrity of the 42 in. pipeline segment located adjacent to the site because the landslide incidence potential in the area is low.

5.1.3 Stable Threats to AIM Project Pipeline Integrity

Stable threats to the integrity of the 42 in. pipeline segment located adjacent to the IPEC include manufacturing-related, welding and fabrication-related, and equipment-related defects. These threats do not have implied time dependence and may be events that occur randomly in time.

Defective pipe seams or a defective section of pipe that occur during line pipe manufacturing are typically addressed by pressure testing. The pressure test performed before the 42 in. pipeline segment located adjacent to the IPEC was placed in service eliminated this threat because any manufacturing defects that could affect pipeline integrity were repaired or replaced during the construction process.

Welding and fabrication defects may include defective pipe girth welds, defective fabrication welds, wrinkle bends or buckles, stripped threads, broken pipes, and coupling failure. These construction and manufacturing-related defects are typically identified by quality assurance inspections and pressure testing. Defects that exceed acceptance criteria are usually repaired or replaced before the pipeline is placed in service. Compliance with regulations in 49 CFR 192, Subpart E—Welding of Steel in Pipelines and Subpart G—General Construction Requirements for Transmission Lines and Mains can mitigate these threats.

Inspection, testing, and repair specifications and procedures for the Algonquin Gas Transmission pipeline are identified and described in documents and procedures developed for managing the Algonquin Gas Transmission pipeline system.

Random threats to pipeline equipment such as gasket or O-ring failures, control or relief equipment malfunctions, or seal and pump packing failures are typically addressed through maintenance programs that comply to regulations in 49 CFR 192, Subpart M—Maintenance. These maintenance programs use past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records, and all other conditions specific to each pipeline to repair or replace defective pipeline equipment that could adversely affect pipeline integrity.

5.2 CONSEQUENCE ASSESSMENTS FOR AN UNINTENTIONAL NATURAL GAS RELEASE

Assessments of worst-case consequences resulting from propagating crack that completely penetrates the line pipe wall or a full-bore guillotine rupture of one of the natural gas pipeline segments located adjacent to the Indian Point Site are subdivided into:

- missile generation
- flash fires or fireballs
- jet fires that cause thermal radiation
- over-pressurization events caused by an explosion

Consequences of a worst-case incident can potentially affect the public, employees, property, and the environment inside and outside the PIR including safety-related structures, systems, and components within the SOCA.

5.2.1 Consequences of Missiles Generated by an Unintentional Natural Gas Pipeline Release

Depending on where the release occurs, missiles such as backfill soil; pavement; fuel oil line, water line, and conduit fragments; and fractured pieces of line pipe could be ejected from the crater. These missiles could cause personal injury or property damage within the PIR of the relevant pipeline.

Missiles generated by an unintentional natural gas release could include fractured line pipe fragments. These larger fragments, which could weigh more than 4,000 lbs, are not expected to be ejected far enough to impact safety-critical facilities for the reasons discussed in Sect. 4.3. Therefore, the missile design basis for nuclear power plants provided in Regulatory Guide (RG) 1.76 is not exceeded, and the safety-related structures, systems, and components within the SOCA are not vulnerable to missile damage caused by an unintentional natural gas release from the pipeline segments located adjacent to the site.

5.2.2 Consequences of Flash Fire and Fireballs Resulting from an Unintentional Natural Gas Pipeline Release

Following a flash fire or fireball resulting from an unintentional natural gas release, injuries to unsheltered people at some distance from the rupture are probable because the thermal radiation far exceeds the heat flux threshold of 1.4 kW/m^2 (450 Btu/hr ft^2) which is considered the acceptable level of thermal radiation for people in open spaces. Firefighting activities are also limited within areas where the thermal radiation exceeds the heat flux threshold of 2.5 kW/m^2 (800 Btu/hr ft^2) which is considered the acceptable level for common firefighting activities.

The structural integrity of safety-related reinforced concrete elements within the SOCA would not be affected by a short duration (i.e., 30 seconds or less) flash fires and fireballs resulting from an unintentional natural gas release from the pipeline segments located adjacent to the site because the heat flux density experienced in such an event, while intense, is too short in duration to result in serious damage to these facilities. Spent fuel dry storage casks and shipping containers (class A, B, C, and GTCC) for radioactive waste are similarly robust and are also unlikely to be damaged by a short duration flash fire.

5.2.3 Consequences of a Jet Fire Resulting from an Unintentional Natural Gas Pipeline Release

Thermal radiation produced by a sustained jet fire is a serious hazard resulting from an unintentional natural gas release. Potential consequences caused by a jet fire include damage to buildings, vehicles, and property and injuries to people unable to find adequate shelter resulting from thermal radiation. Thermal radiation intensities from a jet fire vary with the distance from the radiant heat source and vary with time as the natural gas in the pipeline is consumed.

An unintentional natural gas release from one of the pipeline segments beneath Broadway that causes a jet fire could disrupt surface transportation, electrical power, communication, and water services that could be needed by the public, workers at the Indian Point Site, emergency personnel, and first responders. In addition, the jet fire could cause brush fires, property damage to car and nearby structures, and injury or death to people that may be using roads or land areas affected by the jet fires.

Calculations used to quantify the time-dependent variations in separation distances for specific heat flux densities show that exposure to a heat flux of 100 kW/m^2 initially occurs up to and beyond the PIR but is contained within the PIR within two minutes. A heat flux of 39.4 kW/m^2 exists at just over 1.5 times the PIR distance and retreats to the PIR distance within eight minutes. Once the isolation valves for the impacted pipeline segment close, damaging heat fluxes decay quickly and are essentially eliminated within 25 minutes. The relatively short duration of the damaging heat flux levels means that the safety-critical structures would not be likely to sustain serious damage in the event of a pipeline break. Similarly, the concrete and steel construction of radioactive material containers (class A, B, C, GTCC, and dry storage casks) would be resistant to this sort of short-duration heat load.

5.2.4 Consequences of Explosions Resulting from an Unintentional Natural Gas Pipeline Release

Explosions caused by unconfined methane gas plumes are highly unlikely, even in the event of a pipeline break. This fact is a result of the buoyant nature of the gas cloud and the relatively low flame speed for methane. In the unlikely event of an explosion, however, buildings and structures that are not designed to resist tornado wind effects may experience damage caused by an explosion resulting from an unintentional release of natural gas from a transmission pipeline caused by a propagating crack or a full-bore guillotine rupture of the line pipe. In addition, automobiles, vegetation, and other loose objects could become airborne and damage property or injure people within the area where the endpoint overpressure caused by a vapor cloud explosion equals or exceeds one psi.

The minimum safe distance at which an overpressure wave from an explosion diminishes to one psi or less is dependent on the mass of natural gas involved in the explosion, which is in turn dependent upon the time before ignition. The 42 in. pipeline is further away from the SOCA but has a greater initial gas flow rate than the 26- and 30 in. pipelines in the event of a break. However, a break of any of the three pipelines has the potential to vent enough natural gas within just a few seconds to cause the minimum safe distance to expand over portions of the SOCA.

Safety-related structures, systems, and components within the SOCA are designed to resist tornado wind speeds that produce pressure-induced forces equal to 0.71 psi or 102 pounds per square foot and a tornado-induced pressure drop equal to 0.9 psi or 130 pounds per square foot. Moreover, the risk of a methane explosion has been reported and evaluated several times for the Indian Point site. NRC structural engineers have assessed that it is a good assumption that the safety-related structures at the site would withstand the pressure resulting from a natural gas cloud explosion. Class A, B, C, GTCC, and dry storage casks used for radioactive waste packaging are also robust and tested to assure safety in the event of extreme conditions. The packages of waste are therefore also unlikely to sustain serious damage, including the spent fuel dry storage containers stored in the ISFSI.

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APPENDIX A – ALGONQUIN INCREMENTAL MARKET (AIM) PROJECT SCOPE AND DESCRIPTION

The Algonquin Gas Transmission pipeline currently connects the Texas Eastern Transmission and Maritimes & Northeast pipeline systems to natural gas customers in the Northeastern states of Rhode Island, Connecticut, Massachusetts, New York, and New Jersey. It was owned and operated by Spectra Energy until the company was bought out by Enbridge in 2016.

Underground natural gas pipelines have crossed the Indian Point site since a 26 in. pipeline was constructed in the 1950s and an additional 30 in. pipeline was constructed in the 1960s. The maximum allowable operating pressure (MAOP) for the 26 in. pipeline is 674 psig and the MAOP for the 30 in. pipeline is 750 psig. These two pipelines are located within the Algonquin Gas Transmission pipeline right-of-way and are closer to Unit 3 than to Unit 2, but in both cases are outside the SOCA for the site.

In 2014, the Algonquin Gas Transmission, LLC initiated the Algonquin Incremental Market (AIM) Project to upgrade approximately 37.4 miles of natural gas pipeline within the existing Algonquin pipeline system. The AIM Project involved:

- replacing 20.1 miles of 26 in. diameter pipeline with 42 in. diameter pipeline in Putnam, Rockland, and Westchester Counties in New York, and Fairfield County, Connecticut;
- installing approximately 2.0 miles of 36 in. diameter pipeline looping in Middlesex and Hartford Counties, Connecticut;
- replacing approximately 9.1 miles of 6 in. diameter pipeline with 16 in. diameter pipeline on the E-1 System Lateral in New London County, Connecticut;
- installing approximately 1.3 miles of 12 in. diameter pipeline looping in New London County, Connecticut; and
- installing approximately 4.1 miles of 16 in. diameter pipeline and approximately 0.8 miles of 24 in. diameter pipeline off its existing I-4 System Lateral in Norfolk and Suffolk Counties, Massachusetts.

In addition to these pipeline segments, Algonquin Gas Transmission, LLC modified six existing compressor stations and 24 existing metering and regulating (M&R) stations; constructed three new M&R stations; and removed an existing M&R station. Algonquin also modified three existing mainline valve (MLV) sites and five existing pig launcher/receiver sites, constructed five new launcher/receiver sites, constructed new MLV cross-over piping at two locations, and constructed a new MLV.

Pipeline replacement activities involved excavating a trench to remove the old pipe and re-excavating a wider and deeper trench to accommodate the new, larger diameter pipe. Replacement pipe was installed at approximately the same location as the old pipe in the existing Algonquin right-of-way. The horizontal directional drill (HDD) construction method was used to install the 42 in.-diameter pipe below the Hudson Riverbed. The right-of-way located downstream from the Hudson River crossing extends in an easterly direction and passes south of the IPEC.

The sections of the natural gas pipeline that are part of the AIM Project were placed into service in 2017.

APPENDIX B – DESIGN CRITERIA FOR PIPELINE SEGMENTS ADJACENT TO THE INDIAN POINT SITE

The 26 in. pipeline, which was installed in 1952, and the 30 in. pipeline, which was installed in 1965, were not required to comply with Federal pipeline safety regulations when they were designed, constructed, and placed into service because Congress did not pass the *Natural Gas Pipeline Safety Act of 1968* until Aug. 12, 1968. (Public Law 90-461) This law authorized the Secretary of Transportation to prescribe safety standards for the transportation of natural and other gas by pipeline, and for other purposes. As a result of this law, Federal pipeline safety regulations adopted by the U.S. Department of Transportation for gas pipeline are provided in 49 CFR 192.

The applicable design criteria for the 26 in., 30 in., and 42 in. pipeline segments located adjacent to the IPEC are discussed below. These design criteria are consistent with the following specific Federal safety standards provided in 49 CFR 192.

<u>Subpart A—General</u>

§192.5 Class locations

Algonquin Gas Transmission, LLC maintains and operates a natural gas transmission pipeline system within the state of New York. This pipeline system includes two loop lines totaling 86 miles of 26 in. and 30 in. lines and a newer 42 in. line segment. Only a portion of the 26 in. pipeline is above ground where it ends at a receiving in-line inspection tool trap, and no portions of the 30 in. or 42 in. pipelines are above ground.

The loop lines cross the Hudson River where the 26 in. line manifolds into two 24 in. north and south crossing lines. The 30 in. mainline remains 30 in. throughout the state including the Hudson River crossing. The 86 miles of 26 in. and 30 in. pipelines are located within various class locations as follows: Class 1 (32 miles), Class 2 (7 miles), and Class 3 (47 miles).

The alignment of the 42 in. pipeline, which has no outlets, taps, branches, fittings, drips, or tees, is shown in Fig. 4.1. (Entergy Nuclear 2020). This 42 in. pipeline segment meets or exceeds pipeline safety regulations in 49 CFR 192 for a Class 4 location.

Criteria for classifying the four pipeline class locations are provided in §192.5.

<u>Subpart B—Material</u>

§192.55 Steel pipe

New steel pipe is qualified for use under Part B if it meets the requirements of API Specification 5L, "Specification or Line Pipe," 45th edition, effective July 1, 2013; or if it was manufactured before November 12, 1970 and has substantially the same requirements with respect to mechanical and chemical properties as API Specification 5L, "Specification or Line Pipe," 45th edition.

Steel pipe used to construct the 26 in. pipeline segment has the following properties and characteristics.

Grade: X-52 (API Specification 5L)
Outside pipe diameter: 26 in.
Wall thickness: 0.281 in.
Specified Minimum Yield Strength (SMYS): 52,000 psi
Tensile strength: 66,000 psi

Steel pipe used to construct the 30 in. pipeline segment has the following properties and characteristics.

Grade: X-52 (API Specification 5L)
Outside pipe diameter: 30 in.
Wall thickness: 0.500 in.
Specified Minimum Yield Strength (SMYS): 52,000 psi
Tensile strength: 66,000 psi

Steel pipe used to construct the 42 in. pipeline segment has the following properties and characteristics.

Grade: X-70 PSL-2 (API Specification 5L)
Outside pipe diameter: 42 in.
Wall thickness: 0.72 in.
Specified Minimum Yield Strength (SMYS): 70,000 psi
Tensile strength: 82,000 psi

<u>Subpart C—Pipe Design</u>

§192.105 Design formula for steel pipe

Subpart C, §192.105 states that the design pressure for steel pipe is determined in accordance with the following formula:

$$P = (2\ St/D) \times F \times E \times T$$

where:

P = Design pressure in pounds per square inch gauge.
S = Yield strength in pounds per square inch determined in accordance with §192.107 Yield strength (S) for steel pipe.
D = Nominal outside diameter of the pipe in inches.
t = Nominal wall thickness of the pipe in inches §192.109 Nominal wall thickness (t) for steel pipe.
F = Design factor for the class locations determined in accordance with §192.111 Design factor (F) for steel pipe. (Class 1 = 0.72; Class 2 = 0.60; Class 3 = 0.50; Class 4 = 0.40)
E = 1.000 for longitudinal joint factor determined in accordance with §192.113 Longitudinal joint factor (E) for steel pipe.
T = 1.000 for 250°F (121°C) or less temperature derating factor determined in accordance with §192.115 Temperature derating factor (T) for steel pipe.

The design pressure for the 26 in. pipeline segment in a Class 2 location is 674 psig.
The design pressure for the 30 in. pipeline segment in a Class 3 location is 867 psig.
The design pressure for the 42 in. pipeline segment in a Class 4 location is 960 psig.

<u>Subpart D—Design of Pipeline Components</u>

§192.179 Transmission line valves

The minimum sectionalizing block valves spacing for natural gas pipelines varies by class location as follows:

10.0 miles for Class 1 locations

7.5 miles for Class 2 locations

4.0 miles for Class 3 locations

2.5 miles for Class 4 locations

Regulation in §192.935 further states that an operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. The additional preventive and mitigative measures include installation of automatic shut-off valves or remotely controlled valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs. Emergency response procedures for the Algonquin Gas Transmission pipeline are identified and described in (Entergy Nuclear 2020), Appendix B, Exhibit A.

The nearest remotely controlled valves to the Indian Point Site are about 2.8 miles apart. The next closest downstream valve—which is also remote controlled—is about 5.6 miles downstream. The next closest upstream valve is associated with the Stony Point compressor station which is located about 2.5 miles further upstream. In some cases, the pressure drop from a pipeline rupture may make it challenging to close the nearest valve to a rupture, and operators may need to close a valve further from the rupture.

Remotely controlled valves for isolating the 42 in. pipeline segment have operators that use gas pressure from either side of the valve to move a hydraulic actuator. These valves are remotely operated from the Houston control center. The control center can also monitor pressures on the upstream and downstream sides of the valves. After a rupture occurs, it would take several minutes to identify the rupture using the Supervisory Control and Data Acquisition (SCADA) system, confirm that the valves need to be closed, and close the valves. Inspections conducted in 2018 and 2019 verified that from the time the Houston control center-initiated closure, the valves took about 30 seconds to close.

If a pipeline were punctured, the nearest remotely controlled valve could be closed quickly. However, if a full guillotine rupture occurred, the pressure at the nearest remotely controlled valve would likely drop below the pressure required to activate the valve operator. In this case, the next downstream valve would be closed. For a full guillotine rupture, the pipeline length would more likely be 8.4 mi (assuming the operator closed the next closest downstream valve).

Gas control and pipeline operation procedures for the Algonquin Gas Transmission pipeline are identified and described in (Entergy Nuclear 2020), Appendix B, Exhibit A.

§192.201 Required capacity of pressure relieving and limiting stations

Overpressure protection for a natural gas pipeline segment is provided by pressure relief devices that prevent the pressure inside the pipeline from exceeding 1.1 x MAOP. Requirements specified in §192.201(2)(i) further states that the capacity of pressure relieving and limiting stations must be sufficient to prevent the hoop stress from exceeding 0.75 x the specified minimum yield strength (SMYS). The hoop stress ($PD/2t$) in the line pipe at a pressure equal to 1.1 x MAOP is as follows.

34,300 psi for the 26 in. pipeline which equals 66% SMYS

24,750 psi for the 30 in. pipeline which equals 48% SMYS

27,300 psi for the 42 in. pipeline which equals 39% SMYS

Subpart G—General Construction Requirements for Transmission Lines and Mains

§192.317 Protection from hazards.

Hazards including washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads were not design considerations for the 26 in., 30 in., and 42 in. pipeline segments that are adjacent to Indian Point Site because:

- terrain adjacent to the right-of-way is relatively level and not prone to landslides or slope instability.
- the minimum cover depth of soil above the top of the pipeline is 4 ft.
- creeks or streams that are subject to washout or scour to the depth of the top of the pipeline do not cross the right-of-way.

§192.327 Cover

The 26 in., 30 in., and 42 in. pipeline segments are buried with a minimum normal soil cover depth of 36 in. as required for pipelines in Class 2, 3, and 4 locations.

Specifications and procedures for pipeline projects including construction, procurement, and inspection for the Algonquin Gas Transmission pipeline are identified and described in (Entergy Nuclear 2020), Appendix B, Exhibit A.

Subpart I—Requirements for Corrosion Control

§192.457 External corrosion control: Buried or submerged pipelines installed before August 1, 1971.

This regulation states that except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with Subpart I.

§192.461 External corrosion control: Protective coating.

Exterior surfaces of the 26 in. and 30 in. pipelines, which were installed before August 1, 1971, have an effective external coating of coal tar enamel for corrosion control. The 42 in. pipeline segment has a fusion-bonded epoxy coatings applied to the inside and outside surface of the line pipe for corrosion control. (Entergy Nuclear 2020)

§192.463 External corrosion control: Cathodic protection

Cathodic protection systems are used on buried steel pipelines to protect the line pipe from corroding. The 26 in., 30 in., and 42 in. pipeline segments are protected from corroding by a cathodic protection system.

§192.465 External corrosion control: Monitoring.

The 26 in., 30 in., and 42 in. pipeline segments are included in the integrity management program discussed in Appendix C and the risk assessment process that manages, monitors, and addresses various types of corrosion, defects in the pipeline, third-party damage, operations issues, and weather.

Corrosion control, inspection, and remediation documentation for the Algonquin Gas Transmission pipeline are identified and described in (Entergy Nuclear 2020) Appendix B, Exhibit A.

Subpart J—Test Requirements

§192.505 Strength test requirements for steel pipeline to operate at a hoop stress of 30 percent or more of SMYS.

The 26 in. and 30 in. pipelines were successfully hydrostatically tested before they were placed into service at an internal pressure that produced a hoop stress in the line pipe wall that was at least 92% SMYS. A hydrostatic test was performed at 1.5 MAOP for 8 hours in 2016 before the 42 in. pipeline segment was placed into service. (U.S. Nuclear Regulatory Commission Expert Evaluation Team 2020)

Subpart L—Operation

§192.614 Damage prevention program.

The design of the 42 in. pipeline segment includes damage prevention measures intended to prevent excavation activities that could adversely affect the structural integrity of the pipeline. where the term "excavation activities" includes excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by either explosive or mechanical means, and other earthmoving operations. These measures included a minimum depth of cover of 48 in. rather than the minimum depth of cover of 36 in. required in §192.327 and fiber reinforced concrete slabs installed above the top of the line pipe to act as a physical barrier to excavation activities.

A cross section of the 42 in. line pipe buried in the ground is shown in (Entergy Nuclear 2020), Appendix B, Exhibit C. This cross section shows two parallel sets of fiber reinforced concrete slabs (dimensions 3 ft x 8 ft x 6 in.) centered above the pipeline with a 12 in. gap separating the two slabs and yellow warning tape placed in two layers – one layer at the top of concrete slabs and another layer 12 in. above the pipe. The bottoms of the two concrete slabs are 24 in. below grade and the yellow warning ribbons is a minimum of 18 in. wide.

§192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

The MAOP for the 26 in. pipeline is 674 psig. (U.S. Nuclear Regulatory Commission Expert Evaluation Team 2020)

The MAOP for the 30 in. pipeline is 750 psig. (U.S. Nuclear Regulatory Commission Expert Evaluation Team 2020)

The MAOP for the 42 in. pipeline is 850 psig. (Entergy Nuclear 2020)

Pipeline operating, inspection, and maintenance procedures and gas control and pipeline operation procedures for the Algonquin Gas Transmission pipeline are identified and described in (Entergy Nuclear 2020), Appendix B, Exhibit A.

APPENDIX C – INTEGRITY MANAGEMENT FOR THE 42 IN. PIPELINE SEGMENT ADJACENT TO IPEC

Regulations in Subpart O—Gas Transmission Pipeline Integrity Management prescribe minimum requirements for an integrity management program for gas transmission pipeline covered under 49 CFR 192. These regulations provide requirements for enhancing safety and protecting gas transmission pipeline segments located in high consequence areas. The definition of a high consequence area (HCA) is provided in §192.903.

The 26 in., 30 in., and 42 in. pipeline segments of the Algonquin Gas Transmission pipeline system that are located in Class 3 and Class 4 locations must comply with requirements in Subpart O because these locations are characterized as HCAs.

The terms pipeline integrity and pipeline integrity management are defined as follows.

- Pipeline integrity is the state of a pipeline that is without damage or defect.
- Pipeline integrity management is a system used by a pipeline owner and operator to ensure a pipeline's safety from its conception to its retirement.

<u>Subpart O—Gas Transmission Pipeline Integrity Management</u>

§192.911 What are the elements of an integrity management program?

A gas transmission pipeline operator's Integrity Management Program must include all of the following program elements:

- Identification of all high consequence areas
- Baseline Assessment Plan
- Identification of threats to each covered segment
- A direct assessment plan, if applicable
- Provisions for remediating conditions found during integrity assessments
- A process for continual evaluation and assessment
- A confirmatory direct assessment plan, if applicable
- A process to identify and implement additional preventive and mitigative measures
- A performance plan including the use of specific performance measures
- Recordkeeping provisions
- Management of Change process
- Quality Assurance process
- Communication Plan
- Procedures for providing to regulatory agencies copies of the risk analysis or integrity management program
- Procedures to ensure that integrity assessments are conducted to minimize environmental and safety risks
- A process to identify and assess newly identified high consequence areas

§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

An operator must identify and evaluate all potential threats to the covered segment. The operator must collect and integrate data from the entire pipeline that could be relevant to the covered segment and conduct a risk assessment in accordance with ASME/ANSI B31.8S. (ASME International 2004). If an operator identified any of the following threats, they must take specific actions to address the threats:

- Third Party Damage – Operators must use data integration from the assessment of other threats to identify potential third-party damage and take additional preventive and mitigative action. Time independent threats such as third-party damage, mechanical damage, incorrect operational procedure, weather-related and outside force damage would include consideration of seismicity, geology, and soil stability of the area. As discussed in Sect. 0, §192.614, the 42 in. pipeline segment located adjacent to the IPEC was constructed with a minimum depth of cover of 48 in. rather than the minimum depth of cover of 36 in. required in §192.327 and fiber reinforced concrete slabs installed above the top of the line pipe to act as a physical barrier to excavation activities.
- Cyclic Fatigue – Operators must use cyclic fatigue analysis to prioritize baseline assessments and reassessments
- Manufacturing and Construction Defects – Operators must prioritize a segment containing manufacturing or construction defects as high-risk segments unless it shows by analysis that the defect is stable and that the risk of failure is low
- ERW Pipe – Covered segments containing low frequency electric resistance welded pipe or lap welded pipe must be prioritized as a high-risk segment for the baseline assessment or reassessment and assessed using technologies proven to be capable of assessing seam integrity and of detecting seam corrosion anomalies.
- Corrosion – If corrosion is identified, all similar pipeline segments (both covered and non-covered) with similar coating and environmental characteristics must be evaluated and remediated, as necessary. As discussed in Sect. 3.1.1 and required in §192.461 and §192.463, the 26 in., 30 in., and 42 in. pipeline segment located adjacent to the IPEC have exterior coatings and cathodic protection systems to control corrosion.

§192.921 How is the baseline assessment to be conducted?
In accordance with regulations in §192.921, baseline assessments for the 26 in. and 30 in. pipelines were required to be completed by December 17, 2012 using the following assessment method or methods that is best suited to address the threats identified for the segment.

1. Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible.
2. Pressure test conducted in accordance with 49 CFR Subpart J.
3. Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking.
4. Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe.

Integrity management program documents and procedures for complying with requirements in Subpart O—Gas Transmission Pipeline Integrity Management for the Algonquin Gas Transmission pipeline are identified and described in (Entergy Nuclear 2020) Appendix B, Exhibit A.

In 2016, the completed 42 in. pipeline was subjected to a hydrostatic test continuously for eight hours in accordance with 49 CFR 192, and a multi-purpose in-line inspection was performed in 2020.

§192.935 What additional preventive and mitigative measures must an operator take?

Operators must conduct risk assessments to identify additional preventive and mitigative measures to protect high consequence areas and enhance public safety. Such additional measures include but are not limited to:

- Installing Automatic Shut-Off Valves or Remote-Control Valves
- Installing computerized monitoring and leak detection systems
- Replacing segments with heavier wall pipe
- Additional training
- Conducting drills with local emergency responders
- Implementing additional inspection and maintenance programs
- Enhancements to damage prevention programs.

§192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S, section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

ASME/ANSI B31.8S states: In-line inspection (ILI) is an integrity assessment method used to locate and preliminarily characterize metal loss indications in a pipeline (ASME International 2004). The effectiveness of the ILI tool used depends on the condition of the specific pipeline section to be inspected and how well the tool matches the requirements set by the inspection objectives. Commonly used in-line inspection tools include:

6.2.1 Metal Loss Tools for the Internal and External Corrosion Threat

6.2.2 Crack Detection Tools for the Stress Corrosion Cracking Threat

6.2.3 Metal Loss and Caliper Tools for Third-Party Damage and Mechanical Damage Threat

The integrity management program manual and the risk assessment process for the Algonquin Gas Transmission establishes the general approaches used to manage, monitor, and address various types of corrosion, defects in the pipeline, third-party damage, operations issues, and weather. (U.S. Nuclear Regulatory Commission Expert Evaluation Team 2020) Integrity management program documents and procedures and emergency response procedures for the Algonquin Gas Transmission pipeline are identified and described in (Entergy Nuclear 2020) Appendix B, Exhibit A.

Preventive maintenance activities for the Algonquin Gas Transmission pipeline involve a twice-weekly aerial survey, a twice-yearly foot patrol with leak survey equipment, a monthly vehicle patrol, and weekly inspection of cathodic protection. (U.S. Nuclear Reguatory Commission Expert Evaluation Team 2020) Additional preventive and mitigative measures for the Algonquin Gas Transmission pipeline are identified and described in (Entergy Nuclear 2020), Appendix B, Exhibit B.

§192.939 What are the required reassessment intervals?
Regulations for establishing the reassessment interval for pipeline segments operating at or above 30% SMYS are provided in §192.939(a). The maximum reassessment interval by an allowable reassessment method is seven (7) years. Allowable reassessment methods include:

- Pressure test or internal inspection or other equivalent technology.
- External Corrosion Direct Assessment.
- Internal Corrosion or SCC Direct Assessment

If an operator establishes a reassessment interval that is greater than seven years, the operator must, within the seven-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with § 192.931. The table that follows this section sets forth the maximum allowed reassessment intervals. This table shows the following.

- The maximum reassessment interval for pipelines operating at or above 50% SMYS, is 10 years provided that a confirmatory direct assessment as described in §192.931 is conducted by year seven in a 10-year interval.
- The maximum reassessment interval for pipelines operating at or above 30% SMYS, up to 50% SMYS, is 15 years provided that a confirmatory direct assessment as described in §192.931 is conducted by year seven and 14 of a 15-year interval.

The 26 in. pipeline was inspected in 1995 using an in-line inspection tool. The next inspection was conducted in 2006. (Form 1 Standard Inspection Report of a Gas Transportation Pipeline, January 25, 2005)

The 30 in. pipeline was inspected in 2004 and 2008 using different in-line inspection tools. (Form 1 Standard Inspection Report of a Gas Transportation Pipeline, January 25, 2005 and Form 5 Evaluation of Gas Pipeline & Compressor Station Construction, April 28, 2009)

The 42 in. pipeline was hydrostatically test in October and December 2016 before the pipeline segment was placed into service and a multi-purpose in-line inspection was performed in 2020. (U.S. Nuclear Regulatory Commission Expert Evaluation Team 2020)

Integrity management program documents and procedures for the Algonquin Gas Transmission pipeline are identified and described in (Entergy Nuclear 2020) Appendix B, Exhibit A.

APPENDIX D - HOLTEC DECOMMISSIONING PLANS

In accordance with the requirements of Title 10 of the Code of Federal Regulations (CFR)50.82, "Termination of license," paragraph (a)(4)(i), Holtec Decommissioning International, LLC (HDI) submitted a Post-Shutdown Decommissioning Activities Report (PSDAR) for Indian Point Energy Center (IPEC) Unit Nos. 1, 2, and 3 (IP1, 2 & 3) on December 19, 2019 to the NRC. The PSDAR established a timeline for decommissioning activities. (Holtec Decommissioning International, LLC 2019) Fuel removal from the Unit 2 spent fuel pool and into dry storage in the ISFSI is scheduled to begin in 2022 and be completed in 2023. Removal and storage of the Unit 3 fuel in the ISFSI is scheduled to begin in 2023 and be completed in 2024. Unit 3 is to be dismantled first, followed by Unit 2 and then Unit 1. Completion of Unit 3 demolition is scheduled to be completed in 2027, Unit 2 in 2029, and Unit 1 in 2031. Partial site release (except for the ISFSI) is anticipated to occur in 2033. The ISFSI is located at the north end of the plant, well-separated from the natural gas pipelines.

A major component of the decommissioning work scope for IP1, 2 & 3 is the packaging, transportation, and disposing of contaminated/activated equipment, piping, concrete, and soil. The transportation and disposal container requirements and transportation pathways are documented in the Waste Management Plan. Most waste will meet Class A, Low Specific Activity (LSA), or Surface Contaminated Object (SCO) definitions. Class A is considered low-level radioactive waste (LLW) and the waste with the lowest radiological hazard. The transportation approach for Class A, LSA, or SCO classes of waste is to use a combination of truck and rail to support bulk quantity removal of waste. Class A shipping containers are subject to tests to assure their safety under conditions normally encountered during transportation. These tests include water spray to simulate rainfall of two inches per hour, a free-fall drop test onto a hard, flat surface to ensure structural integrity, compression using a force at least five times the weight of the package, and a penetration test using a 13-pound, 1.25-in. bar dropped onto the container from a height of 3.3 feet.

For low level waste that meets Class B or C requirements, the guidance in NUREG-2155, "Implementation Guidance for Physical Protection of Category 1 and Category 2 Quantities of Radioactive Material" will be used for radioactive material that meet the form, concentration and quantity-of-concern criteria in 10 CFR 37, "Physical Protection of Category 1 and Category 2 Quantities of Radioactive Material." Shipping of these materials requires the use of approved Class B and C shipping containers. (Holtec Decommissioning International, LLC 2019) The IPEC PSDAR does not state the specific shipping container to be used. In the past, Holtec has used high-capacity HI-STAR 330 Class B/C waste containers. Class B/C shipping containers are designed to survive severe accidents. Tests for these containers include a 30-ft drop onto a flat, unyielding surface, a 40-in. free drop onto a 6-8-in. steel bar, exposure to fire exceeding 1475 °F for 30 minutes, and immersion under 50 ft of water. These tests are carried out sequentially on a test package.

Some waste will be classified as Greater Than Class C (GTCC) wastes. The majority of GTCC waste will be generated during dismantling of the Reactor Vessel Internals (RVI). Per the PSDAR, the GTCC waste that is generated will be placed in dry storage canisters, removed from the reactor buildings and stored at the ISFSI. (Holtec Decommissioning International, LLC 2019) During the decommissioning of Pilgrim Nuclear Power Plant, Holtec dismantled the Pilgrim RVI components entirely underwater in the reactor cavity and adjacent pools, all located within the containment structure. The parts were placed in containers, sealed, and then raised from the water. The IPEC PSDAR does not specifically state that the canisters will be loaded underwater; however, based on the Pilgrim decommissioning and the team's knowledge, the loading of GTCC waste generated by the IPEC RVI will also take place underwater in the reactor cavity and adjacent pools all located within the containment structure. Another source of GTCC waste is the Reactor Pressure Vessel (RPV). The PSDAR states that the RPV parts will be loaded into waste shipment casks using the reactor building crane and the loaded casks will be lowered through the access hatch and readied for transport to the disposal site. (Holtec Decommissioning International, LLC 2019) The loading of the cask will take place within the reactor containment structure. The reactor containment structure is a seismic Category 1 structure. (U.S. Nuclear Regulatory Commission Expert Evaluation Team 2020) The storage casks are subjected to the same series of tests as Class B/C containers to assure their safety in the event of extreme accident conditions.

All spent nuclear fuel will be moved out of the spent fuel pools and into dry cask storage. (Holtec Decommissioning International, LLC 2019) According to the PSDAR, handling of spent fuel assemblies will continue to be controlled under work procedures designed to minimize the likelihood and consequences of a fuel handling accident. (Holtec Decommissioning International, LLC 2019) Holtec states on its website that the process of moving and storing spent nuclear fuel is one that follows rigorous processes and procedures that Holtec has been implementing for more than 30 years. Fuel is safely transferred, underwater, into the casks. Once loading is completed, the cask is vacuum dried, welded, backfilled with an inert gas, and loaded into an overpack. It is then moved from the fuel storage building to the ISFSI pad. (Holtec Decommissioning International 2021) According to Entergy, the metal siding on the Unit 3 fuel storage building could be damaged by the heat flux from a pipeline fire, but the building has been evaluated for the effects of siding damage and fires, and the reinforced concrete spent fuel pool would not be affected. (U.S. Nuclear Regulatory Commission Expert Evaluation Team 2020)

In addition to the waste generated in the reactor building, some GTCC waste will be present in the Spent Fuel Pools (SFPs). This waste along with the GTCC waste generated during the dismantling of the SFPs will be placed in a dry storage cask, transported from the area, and stored on the ISFSI. All of these activities will take place within the fuel storage buildings. (Holtec Decommissioning International, LLC 2019)

The PSDAR notes that as part of the NRCs effort to develop generic, risk-informed requirements for decommissioning, the NRC staff performed analysis of the offsite radiological consequences of beyond-design-basis SFP accidents. The potential for decommissioning activities to result in radiological releases not involving spent fuel (i.e., releases related to decontamination, dismantlement, and waste handling activities) will be minimized by use of procedures and methods designed to minimize the likelihood and consequences of such releases. The results of the study also indicate that the risk at SFPs is low, and well within the NRC's Quantitative Health Objectives. (Holtec Decommissioning International, LLC 2019)