Group C

FOIA/PA NO: 2015-0076

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The following types of information are being withheld:

Ex. 1: ☐ Records properly classified pursuant to Executive Order 13526
Ex. 2: ☐ Records regarding personnel rules and/or human capital administration
Ex. 3: ☐ Information about the design, manufacture, or utilization of nuclear weapons
☐ Information about the protection or security of reactors and nuclear materials
☐ Contractor proposals not incorporated into a final contract with the NRC
☐ Other ____________
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ENCLOSURE 2 TO NL-14-106

HAZARDS ANALYSIS

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NOs. 2 and 3
DOCKET NOs. 50-247 50-286

Entergy

ENTERGY NUCLEAR MANAGEMENT MANUAL
EN-DC-149

VENDOR DOCUMENT REVIEW STATUS

☒ FOR ACCEPTANCE ☐ FOR INFORMATION

☒ IPEC ☐ JAF ☐ PLP ☐ PNPS ☐ VY ☐ ANO ☐ GGNS ☐ RBS ☐ W3 ☐ NP

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Document Title: CONSEQUENCES OF A POSTULATED FIRE AND EXPLOSION FOLLOWING THE RELEASE OF NATURAL GAS FROM THE NEW 42" PIPELINE ROUTED ALONG SOUTHERN ROUTE NEAR IPEC

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Acceptance does not constitute approval of design details, calculations, analyses, test methods, or materials developed or selected by the supplier and does not relieve the supplier from full compliance with contractual negotiations.

Responsible Engineer John Skonieczny / [signature] 8-19-14
Print Name Signature Date

Engineering Supervisor Rich Drake / [signature] 8-20-14
Print Name Signature Date

~~SECURITY-RELATED INFORMATION – WITHHOLD UNDER 10 CFR 2.390~~

Consequences of a Postulated Fire and Explosion Following the Release of Natural Gas from the Proposed New AIM 42" Pipeline Taking a Southern Route Near IPEC

Prepared for Entergy Nuclear Operations, Inc.

by

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~~SECURITY-RELATED INFORMATION – WITHHOLD UNDER 10 CFR 2.390~~

Consequences of a Postulated Fire and Explosion Following the Release of Natural Gas from the Proposed New AIM 42" Pipeline Taking a Southern Route Near IPEC

1. Overview

As part of the Algonquin Incremental Market Project (AIM Project), Spectra Energy (Spectra) has proposed to install approximately 37.6 miles of new 42" natural gas pipeline. Part of the proposed new 42" natural gas pipeline will be routed just south of the Indian Point Energy Center (IPEC).[1] Spectra's existing pipeline system includes 26" and 30" pipelines which cross the IPEC property through a 65' right-of-way on the east side of the Hudson River. Near IPEC, two routes were considered by Spectra for the new 42" pipeline; a "northern route" in which the pipeline would be routed along the current AGT pipeline right-of-way and a "southern route" in which the new pipeline is routed further away from IPEC, south of the IPEC security barrier.[2] As a result, the southern route is significantly more distant from IPEC's main plant systems, structures and components (SSC) within the Security Owner Controlled Area (SOCA) that are safety related or important to safety than is the existing gas pipeline right-of-way; at its closest, the southern route will be approximately 1580 feet from the SOCA.[3] Spectra has stated that the southern route is the preferred (and final selected) route.[4] Accordingly, this analysis considers the risks and potential consequences of a postulated failure of the proposed southern route pipeline, including a resulting fire and/or explosion, on safety-related and important-to-safety SSCs at IPEC.

2. Summary

A hypothetical rupture of the proposed new 42" natural gas pipeline located along the southern route can be postulated to result in a jet flame or cloud fire or, hypothetically and most unlikely, in detonation of a vapor cloud. Missile generation might also accompany rupture. Nuclear Regulatory Commission Guidance for explosions presented in Regulatory Guide 1.91, deems the risk posed by such events to be acceptable if they do not result in safety-related or important to safety SSCs being exposed to overpressures that exceed a 1 psi threshold or if the predicted frequency of events is less than 10^{-6}/year if conservative assumptions are made or 10^{-7}/year if realistic assumptions are made. Similar criteria can be applied for exposure to thermal radiation (a heat flux exceeding 12.6 kW/m^2, the heat flux at which plastic melts) and missiles (to be

[1] Spectra Energy Abbreviated Certificate Application for Public Convenience and Necessity, Docket CP14-96-000, dated February 28, 2014 (Certificate Application).
[2] Spectra Energy, Algonquin Incremental Market Project, Resource Report 10, November 5, 2013.
[3] Table 1.
[4] Figure 1.

outside a reasonable strike zone). The analysis of potentially hazardous events precipitated by pipeline rupture shows the threshold for damage to safety-related or important to safety SSCs within the SOCA will not be exceeded because of the distance between the SOCA and the new pipeline.

However, damage to certain SSCs important to safety located outside the SOCA and closer to or near the proposed southern route has also been considered to determine whether the damage thresholds might be exceeded should the pipeline rupture. These SSCs include the electrical switchyard with transmission lines, GT2/3 diesel fuel storage tank, the city water tank, the FLEX building, the Emergency Operations Facility (EOF), the meteorological tower and two steam generator mausoleums.[5] It is concluded, however, that such damage poses minimal or no increased risk to safe plant operation as, with two exceptions, conservative estimates of the frequency for hypothetical damage lie below the 10^{-6}/year threshold of concern or the SSCs in question can withstand the postulated damage. The exceptions pertain to damage to the meteorological tower and the Unit 3 steam generator mausoleum. This risk is further evaluated as required by 10 CFR 50.59 process. It is also concluded that the new pipeline will not introduce additional risk as a result of terrorism or damage caused by seismic events.

As discussed further below, this analysis takes credit for certain additional pipeline design and installation enhancements agreed to by Spectra for a substantial portion of the pipeline near IPEC, including thicker piping, enhanced corrosion resistance, deeper burial depth, and protective reinforced concrete mats to be located above the buried piping. Such measures substantially reduce the already-low probability of pipeline failures that could impact SSCs near the pipeline. For purposes of this analysis, the section of the pipeline with additional design and installation measures is labeled as "enhanced" and traditional piping is labeled as "unenhanced." The enhanced portion of the pipeline is depicted in green on Figure 1. The term "unenhanced," however, does not imply the piping is vulnerable to failure or damage, as such piping is also of superior quality and installed in accordance with all applicable regulatory requirements.[6]

3. Background

Two natural gas transmission pipelines, a 26" and 30" pipeline, owned and operated by Spectra Energy, currently cross the IPEC site along an existing pipeline right-of-way (corridor). The potential threats posed by the postulated rupture of these pipelines and the release of natural gas (essentially methane) from them were originally addressed in the IP3 Licensing process as discussed in the NRC Safety Evaluation Report of September, 9, 1973 "Two natural gas lines cross the Hudson River and pass about 640 feet from the Indian Point 3 Containment Structure. Based on previous NRC staff review, failures of these gas lines will not impair the safe operation

[5] The tanker trailer now stored outside the SOCA will be moved to a location that would not be impacted by the potential failure of the new pipeline and therefore is not evaluated further in this report.
[6] See Appendix B, Exhibits A and B.

of Indian Point 3." Failure was subsequently addressed in the Individual Plant Evaluation for External Events (IPEEE) issued in 1997 [1]. Hypothetical consequences that might ensue following a major release of natural gas were described in the IPEEE, but it was concluded that no major risk was posed because the predicted frequency of major release events was below a 10^{-6}/year threshold of concern.

Subsequently, a question[7] was raised regarding the potential impacts from a pipeline rupture near IPEC as a result of intentional and malicious activity and, therefore, it was decided to re-evaluate the consequences of natural gas releases from the existing 26" and 30" pipelines related to exposed portions of the pipeline.[8] A study performed for Entergy in 2008 [2], which included jet fire, vapor cloud fire, and vapor cloud explosion scenarios from assumed failures of one or both of the existing pipelines, concluded that "the rupture of the natural gas pipelines that cross the IPEC (site) and subsequent ignition of the methane released will result in a jet fire and injury or death to any people exposed to flames or intense thermal radiation. It will not, however, damage any safety related structure. Even in the unlikely event of a hypothetical vapor cloud explosion, structural damage to buildings other than the waterfront warehouse adjacent to the pipelines will not occur. A flammable vapor cloud fire that engulfs the plant is improbable because the turbulent momentum with which the methane exits the pipeline will only confine flammable methane concentrations close to the point of release." The NRC reviewed and dispositioned the request for information with that analysis.

In response to the proposed construction of a new 42" pipeline along the southern route, this evaluation of the potential impacts on safety related and important-to-safety SSCs that might be posed by this new gas pipeline has been prepared. It reflects advances in the understanding of the consequences of the release and ignition of flammable gases and current regulatory guidance regarding such events provided by the US Nuclear Regulatory Commission [3]. The potential impacts of natural gas releases and their subsequent ignition on SSCs important to safety but located away from the SOCA—the switchyard, the meteorological tower, the city water tank, the GT2/3 diesel fuel storage tank, the FLEX building, the Emergency Operations Facility (EOF) and the IP2 and IP3 steam generator mausoleums are also examined. The closest distances of these SSCs from the proposed southern route pipeline are presented in Table 1 below.[9] These SSCs perform the following functions:

- **Electrical Switchyard**: Power to the site is provided from the Buchanan switchyard by 138--kV feeders and two underground 13.8-kV feeders. Electrical power generated by

[7] NRC Request for Information RI-2008-A-021 letter dated March 12, 2008. Entergy's response was provided in a letter dated September 30, 2008, ENOC-080-00046.
[8] NRC RG 1.91, Evaluations of Explosions Postulated to Occur at Nearby Facilities and On Transportation Routes Near Nuclear Power Plants, does not mention or require consideration of terrorist action as initiating events. Nevertheless, in response to NRC's questions, Entergy conservatively assumed such actions could result in pipe failures but only where the pipeline comes above ground.
[9] Distances obtained using Google Earth.

the site is raised to 345 kV and delivered to the Buchanan switchyard for distribution. While no safety classification has been assigned to the switchyard, it is credited as a preferred source of power and so it is considered important to safety and is included in the technical specifications (TS).

- **Meteorological Tower:** The meteorological tower provides weather information such as wind speed and direction to the EOF and the control room. This structure is considered important to safety. There is a backup meteorological tower and weather forecasting services are also provided by the NOAA in case of tower unavailability.
- **City Water Tank:** The city water tank provides the backup water supply for the IP2 and IP3 auxiliary feedwater systems. It also serves as a backup for other SSCs including the IP2 Appendix R/station blackout A/C source. The tank was designed and evaluated as non-safety but is identified as important to safety for its functions and is included in the TS.
- **GT 2/3 Diesel Fuel Storage Tank:** The diesel fuel oil tank provides a backup fuel oil supply for the IP2 and IP3 diesel generators and its fuel oil can also be used by the IP2 and IP3 Appendix R / station blackout (SBO) diesels. The plant requires a sufficient supply of fuel oil to run the diesels for 7 days. This tank is required by the Technical Specifications. It is designed to industry standards but is considered important to safety because of its function.
- **The FLEX Storage Building:** This building will store the FLEXible strategy equipment for a Beyond Design Basis Accident, as required by NRC's post-Fukushima action items. The building is not safety related.
- **The Emergency Operations Facility (EOF):** This facility provides a response center for part of the Emergency Response Team. There are several other facilities used simultaneously by the Emergency Response Organization. A backup for this facility is located off-site.
- **Steam Generator Mausoleums:** The unit 2 and 3 steam generator mausoleums are robust concrete structures used to house the original steam generators.

Table 1

Closest Distances of SSC's from Proposed Pipeline Relative to the Southern Route

Item	Closest distance from proposed southern route where underground (Figure 1)	Closest distance from proposed southern route where above ground (Figure 2)	Closest distance from transitions between the enhanced and un-enhanced pipeline of the proposed southern route (Figure 3)
SOCA	1580 ft (482 m)	(b)(7)(F)	1580 ft (482 m)
Switchyard	115 ft (35 m)		1266 ft (386 m)
GT2/3 diesel fuel storage tank	105 ft (32 m)		1266 ft (386 m)
City water tank	1336 ft (407 m)		(b)(7)(F)
Meteorological tower	551 ft (168 m)		
The FLEX Building	1033 ft (315 m)		1162 ft (354 m)
The Emergency Operations Facility (EOF)	1002 ft (305 m)		(b)(7)(F)
Unit 2 steam generator mausoleum	1440 ft (439 m)		
Unit 3 steam generator mausoleum	477 ft (145 m)		

4. The Proposed Pipeline

The proposed new pipeline will be 42" in diameter with a normal operating pressure of 750 psig and a maximum operating pressure of 850 psig. The southern route has been selected by Spectra as the preferred route for this pipeline, and therefore this is the route that this analysis is based on. The route is shown in Figures 1, 2 and 3 together with the distances presented in Table 1.

Figure 1

(b)(7)(F)

Figure 2

(b)(7)(F)

Figure 3

(b)(7)(F)

The proposed 42" pipeline will be of state of the art construction, with a ~ 3935 ft (1199 m) segment near IPEC enhanced with additional design and installation features. This segment is shown in Figures 1 to 3; the additional design and installation features are detailed in Appendix B—Analysis of the Causes of and Determination of Exposure Rates for a Failure of the Proposed 42" AIM Natural Gas Pipeline near IPEC—and Exhibits A, B and C to that appendix.

In addition, consistent with DOT guidelines and requirements, the pipelines will be periodically inspected internally for flaws and reduced wall thickness using smart pigs. Aerial, vehicular and walking surveys of the pipeline routes are also made to detect gas leaks (often revealed by dead vegetation) and possible threats to pipeline integrity. As the portions of the pipeline closest to IPEC will be buried in wide, clear and well-marked rights of way, these portions of the proposed pipeline are unlikely to be damaged by careless construction or excavation. Most leakage in gas pipelines results from small pinholes and significant losses of gas do not occur unless induced

stresses cause a larger hole or rupture of the pipeline before it is repaired [4]. But in the unlikely event of a pipeline failure, a large break in the line would result in a remote (Houston, Texas) low pressure alarm and subsequent pushbutton isolation of the section of broken pipe—the section of pipe between isolation valves near IPEC is about 3 miles long. Details of the maintenance and inspection program are also presented in Appendix B, Exhibit B.

5. Properties of Natural Gas

Methane, the primary component in natural gas, has the following hazard-related properties [5, 6, 7].

Table 2

Hazard-Related Properties of Methane

Property	Value
Boiling point	-161.5°C
Flash point	-222°C
Lower flammable limit[10]	5.3%
Upper flammable limit	15%
Auto-ignition temperature	650°C
Laminar burning velocity	0.448 m/s
Initiation energy for immediate detonation	9.9×10^{10} mJ[11]
Toxic properties	Simple asphyxiant
Heat of combustion	50,030 kJ/kg

These properties demonstrate that methane is a buoyant (lighter than air) gas of low fuel reactivity [8].

6. Risks Posed By Natural Gas Releases

The rupture of a natural gas pipeline will result in the release of methane gas at high pressure as a turbulent jet with choked flow. Should this jet or the flammable vapor cloud ignite at some point, a number of consequences might ensue:

- A jet fire
- A cloud (or flash) fire or a fireball should ignition be delayed.

[10] Detonation limits are narrower than flammable limits [6].
[11] The corresponding value for a propane-air mixture is 4.1×10^8 mJ

- Vapor cloud explosions resulting from the deflagration or detonation of the methane-air cloud
- Missile generation—in addition to fires and explosion, the rupture of a pipeline might be accompanied by missile generation with fragments of the pipeline being thrown considerable distances

Pipeline rupture might result from accidents or random or seismic-induced failure of the pipeline. All these types of causes are evaluated and discussed below. It should be noted that ignition does not require a pre-existing source but might result from sparks created as ejected metal pieces or rocks rub together.

Jet Fire [6, 9]

A jet fire is a turbulent diffusion flame resulting from the combustion of a fuel. Jet fires have no "inertia"—they reach full intensity immediately after ignition and will change with the fuel's release rate. The risk posed by jet fires arise because of the high heat fluxes incident on exposed personnel or equipment. Should the gas jet impinge upon the side of the crater formed in the ground, some of the momentum in the escaping gas will dissipate and the jet will be directed upward, thereby producing a fire with a horizontal profile that is generally wider and shorter than would be the case for an unobstructed vertical jet [10].

Cloud Fires and Fireballs [6, 9]

A cloud or flash fire is a transient fire resulting from the ignition of a cloud of flammable gas without significant flame acceleration as a result of turbulence. No significant overpressures result from a cloud fire and, because the fire generally lasts for less than a minute, the integrity of structures engulfed in or exposed to cloud fires will not be challenged. Personnel engulfed in such a fire may suffer severe burns, however. Within the gas cloud, large scale eddies might carry flammable gas away from the bulk of the cloud. Consequently, local pockets of fire are possible. Typically in a cloud fire, the flame will burn its way back to the source—should the source be a ruptured gas pipeline, a jet fire will ensue. It should also be noted that "for gas pipelines, the possibility of a significant flash fire resulting from delayed remote ignition is extremely low due to the buoyant nature of the vapor, which generally precludes the formation of a persistent flammable vapor cloud at ground level" [10]. Therefore, the depiction of the methane cloud traversing the IPEC site is therefore conservative and not a real possibility here.

A fireball results from the rapid turbulent combustion of fuel as an expanding, radiant ball of flame. Normally, however, it results from the release of a pressurized liquid rather than the release of compressed gas and so it will not be considered further here [11].

Vapor Cloud Explosion [6, 9]

There are three pre-conditions for a vapor cloud explosion [6]:

- There must be a release of flammable material into a congested area or area of high turbulence.
- Ignition must be delayed to allow the formation of an ignitable mixture with the fuel-air concentration in the flammable range
- There must be an ignition source of sufficient energy to ignite the fuel-air mixture.

Vapor cloud explosions can occur as a result of deflagrations or detonations. In a deflagration, the flame propagates through the unburned methane-air mixture at a burning velocity that is less than the speed of sound. Overpressures generated in such an explosion will vary with the combustion rate. Given the low flame speed of methane, minimal overpressures are expected with deflagrations of methane and air—it has been concluded that "a deflagration traveling through unenclosed gas cloud will result in negligible overpressures" [11]. A deflagration can be initiated by a weak energy source.

In a detonation, the methane-air reaction front propagates as a shockwave that compresses the unburned gas-air mixture so that temperatures in the cells of the mixture exceed the auto-ignition temperature. The shockwave is therefore maintained by the combustion reaction that follows it.

A detonation can be achieved with a high energy ignition source or by flame acceleration within a highly congested area or a high momentum (jet) release. However, because of methane's low reactivity, a detonation within a methane–air cloud will not persist outside the congested or turbulent area [12]. This would suggest that for a gas pipeline that traverses near IPEC, a detonation will not draw upon methane outside the jet or the areas of congestion provided by trees adjacent to the right of way. With respect to congestion, tests performed on natural gas have shown that a high degree of congestion is required to obtain high flame speeds and overpressures with natural gas [13]; other experiments failed to initiate an explosion of natural gas and methane mixtures with air in a semi-open space even when explosive was used as an ignition source [14]. Thus the consensus amongst experts is that methane gas will not give rise to vapor cloud explosions unless confined [8, 15, 16[12]]. That said, various reports and studies prepared following the 2005 Buncefield explosion suggest that belts of trees provide sufficient congestion to facilitate flame acceleration that might lead to detonation [17-19]. Flame acceleration is particularly likely where thick undergrowth and deciduous trees prevail.

[12] FM Global [16] states that "the following materials do not present a significant or credible outdoor (Vapor Cloud Explosion) exposure....methane...."

With respect to ignition in the jet, field evidence suggests that intense turbulent mixing and air entrainment would limit the area in which any gas cloud would be flammable within a horizontal distance of (b)(7)(F) [redacted] of the rupture [8].

Missiles

The rupture or bursting of a gas pipeline might also result in large fragments being thrown a considerable distance—Lees [8] describes a 1965 incident in Natchitoches, La, in which a high pressure gas pipeline ruptured, splitting the pipe along a 26-ft (8m) length. In the subsequent blowout, three pieces of metal weighing ½ ton in all were thrown 130-360 ft (40 – 110m) from the point of rupture. Similarly, a PHMSA order issued following a 2/2/2003 incident in Illinois (PHMSA 3-2003-1002-H) briefly notes that pipeline fragments had been thrown as far as 900 ft (274 m).[13] A lesser distance was recorded in an NTSB report (PAR-95-01) for a pipeline rupture in New Jersey in which fragments of the ruptured pipeline were thrown 244 m (800 ft) Given this experience—274 m (900 ft) is the greatest distance noted in the literature for fragments of the pipeline to be thrown after rupture--and the greater distance of the proposed southern route to main plant systems and structures in the SOCA (~ 1580 ft or 482 m from the SOCA), missiles from a rupture or burst of the southern route pipeline will not endanger SSCs inside the SOCA. In addition, with respect to these fragments, we would note that Section 16.2.1 of the IP3 FSAR [20] states that Class I buildings and structures at IP3 are designed for tornado loadings calculated assuming the simultaneous application of a tangential wind velocity of 300 mph, a translational velocity of 60 mph, a pressure change (drop or increase) of 3 psi in 3 sec., and postulated tornado missiles with potential missiles including a 4000-lb automobile. Accordingly, we would conclude that the impact of pipe fragments on safety related systems, structures and components at IP3, the unit closest to the pipeline, is bounded by the scenarios considered in the FSAR. Potential impacts of missiles on the SSCs important to safety outside the SOCA and closer to the southern route are discussed below.

The release of gas at high pressure will of course also blow off any soil or fill cover above the pipeline and scour away earth from around the pipeline creating a crater. But such action will not harm SSCs within the SOCA or near the southern route pipeline.

7. Regulatory Guidance

The US Nuclear Regulatory Commission has issued Regulatory Guide 1.91 [3] that provides guidance for the evaluation of potential explosions near nuclear power plants; other potential but lesser hazards such as jet fires were not addressed, however.

[13] It will be noted this distance is less than the separation between the proposed pipeline and systems, structures and components important to safety in the SOCA.

Regulatory Guide 1.91 concerns itself with blast damage to nuclear power plant structures occasioned by "incident or reflected pressure (overpressure), dynamic (drag) pressure, blast-induced ground motion and blast-generated missiles". Of these the primary concern is with overpressure. The guide states that General Design Criteria for nuclear power plants would be satisfied with respect to potential nearby hazards and explosions if:

- The distance between critical plant structures and source of the blast is sufficient to avoid any impact from an explosion—if the distances between the explosion and systems, structures and components important to safety are such that no system, structure or component important to safety would be exposed to a conservatively determined positive peak incident overpressure in excess of 1 psi.

The regulatory guide then goes on to state that if the explosion is closer to systems, structures and components important to safety than this minimum safe distance, then the risk of damage caused by an explosion is acceptably low if:

- The exposure rate for such incidents is less than 1×10^{-6}/year if conservative assumptions are used in the analysis or 1×10^{-7}/year if realistic assumptions are used.

  Or

- The systems, structures and components important to safety can be demonstrated by analysis to be capable of withstanding the blast and missile effects associated with the explosion.

Looking specifically at explosions that might occur following releases of natural gas from a pipeline, the Guide states that "plume modeling based on site topography and meteorological conditions should be evaluated". The reference for such modeling, NUREG CR/6410 [21], makes explicit mention of the TNT equivalence method for vapor cloud explosion blast modeling. In discussing the atmospheric dispersion models, NUREG CR/6410 characterizes ALOHA as being "most useful for estimating chemical plume extent and concentration for short-duration chemical accidents"[14].

8. Software and Models

[14] NUREG/CR-6410 [21—Section D.6.5.1] notes a number of limitations to the ALOHA model. Of these, the only limitation pertinent to modeling the release of methane is that ALOHA does not consider ground topography in the area affected by the plume. But the same limitation is present in AFTOX, the dispersion model used within BREEZE Incident Analyst. It should be noted that the terrain near the switchyard and GR2/3 diesel fuel oil tank is relatively flat.

The consequences of the release scenarios described previously are predicted using the models contained within **ALOHA 5.4.4** and **BREEZE Incident Analyst 1.2** software.

ALOHA is a program designed to model chemical releases. It determines chemical release rates and generates a variety of scenario-specific outputs including threat zones for jet fires, vapor cloud explosions and exposure to flammable gases. ALOHA was developed by the US Environmental Protection Agency (EPA) and the US Department of Commerce, National Oceanic and Atmospheric Administration (NOAA). It was used here to model jet flames and vapor cloud dispersion but not vapor cloud explosions. The model in ALOHA was not used for vapor cloud explosions because the Regulatory Guide [3] explicitly deems a TNT equivalency method to be an acceptable method for establishing the distances beyond which no adverse effect of an explosion would be seen and because of the excessive conservatism in the assumption made in ALOHA that the entire flammable contents of a buoyant plume of methane will be involved in an explosion. This contradicts the evidence that detonation will involve much smaller masses of methane—the mass in a turbulent jet or lying in the wooded areas to the north and south of the gas pipeline right of way. Furthermore the assumption by ALOHA of (b)(7)(F) (b)(7)(F) (b)(7)(F) [redacted]. The basis for the models used in ALOHA and quality assurance performed on this software are described in a report issued by the NOAA, EPA and DOT [23].

BREEZE Incident Analyst comprises a user-friendly implementation of other models widely used to characterize chemical release scenarios. The models of concern here are The Gas Research Institute for jet flames, AFTOX for vapor cloud dispersion and the US Army TNT Equivalence model for vapor cloud explosions.

The models within ALOHA 5.4.4 and BREEZE Incident Analyst 1.2 software used to characterize the anticipated and hypothetical consequences of the release of natural gas from the proposed pipeline crossing near the IPEC site are listed in Table 3. The basis for the selection of these models is also presented in Table 3. Where two models were used to characterize the same scenario, the results can be compared to provide a measure of reassurance as to their validity.

Table 3

Models Used

Scenario	Model	Basis for Selection
Jet flame	BREEZE: Gas Research Institute (assuming a vertical jet)	This model addresses fires that may result from the leak or rupture of a pipeline containing a compressed gas.
	ALOHA	This feature of ALOHA was developed and tested by US regulatory agencies.
Cloud dispersion (extent of flammable cloud)	BREEZE: AFTOX—(US) Air Force Toxics Model for neutrally buoyant vapor cloud releases[15]	AFTOX was included in the comprehensive model evaluation exercise reported by Hanna et al. [24]. Since AFTOX does not treat the dispersion of denser-than-air gases, the model was mainly evaluated using field experiments where the releases were neutrally buoyant. In general, AFTOX over-predicted the observed concentrations by a small amount.
	ALOHA	Looking specifically at explosions that might occur following releases of natural gas from a pipeline, Regulatory Guide 1.91 states that "plume modeling based on site topography and meteorological conditions should be evaluated". The reference for such modeling, NUREG CR/6410 [21], characterizes ALOHA as being "most useful for estimating chemical plume extent and concentration for short-duration chemical accidents" in discussing the atmospheric dispersion models.
Vapor cloud explosion	BREEZE: US Army TNT Equivalence model	This model comprises the implementation of equations 1 to 4 presented in Regulatory Guide 1.91 [3]. The predictions closely match those calculated using the equations.

[15] Reference, but without comment, is made to AFTOX in NUREG/CR-6410 [21].

9. Possible Releases and Their Consequences

While we exclude no cause of release from this evaluation, and in particular we will allow for delayed ignition in the event of a large release, pipeline ruptures and the releases considered are presumed to occur at or from the natural gas pipeline at points nearest to the SOCA, the switchyard, the GT2/3 fuel storage tank, the city water tank, the FLEX building, the Emergency Operations Facility, meteorological tower and the steam generator mausoleums.

The following scenarios will be considered:

- A jet fire
- A vapor cloud (or flash) fire
- A hypothetical vapor cloud explosion involving detonation
- Missile generation.

Releases will be assumed to result from the guillotine rupture of a pipeline, the creation of a 6" diameter hole in a pipeline or the rupture of a 2" line that branches off the pipeline. It should be noted that the proposed 42" pipeline will have no outlets, taps, branches, fittings, drips or tees near IPEC and therefore the lesser releases are presented solely for comparison purposes. In modeling releases and their consequences, we assume that the contents of a 3 mile length of gas pipeline are released at a pressure of 850psig (the MAOP of the 42" pipeline), that valves isolating this length of pipeline will be closed within 3 minutes of a major release[16] and that the interior of this pipeline is smooth[17]. The guillotine rupture of the pipeline is assumed to result in a double-ended release of natural gas fed with full-bore flow from both sides of the rupture with the resulting releases merging. This assumption is conservative in that it ignores lesser ruptures and the impact that flows from either side of the rupture will have on each other. To model such a release, we assume the release is equivalent to that from a pipeline (b)(7)(F) [redacted] (b)(7)(F) [redacted] The wind speed and air stability assumed are the 1.5 m/s wind speed and F-class stability proposed for worst case

[16] After valve closure, full bore release from the pipeline will persist for another 2 to 3 minutes. The release following guillotine rupture will therefore be ~ 5 to 6 minutes duration.
[17] The release rate is higher if the interior of the pipeline is smooth (b)(7)(F) [redacted] of the 42" pipeline).

consequences in the EPA Risk Management Guidance [22]. Alternative results were obtained using the 3 m/s wind speed and D-class stability proposed by the EPA. These latter meteorological conditions are more common[18]. Missile generation will be assumed to accompany rupture some of the time.

Jet Fires

Immediate ignition of the release, possibly caused by sparks created as ejected metal pieces or rocks rubbing together, will result in a jet fire anchored on the pipeline with a flame that might rise (b)(7)(F) [redacted] delayed ignition will often result in a vapor cloud fire that burns back to the pipeline and ends up as a jet fire. The consequences of thermal radiation at various intensities are presented in Table 4; the thermal consequences of jet fires following specific releases are presented in Table 5. In general, the threshold for damage caused by jet flames and thermal radiation is 12.6 kW/m^2, the heat flux at which exposed plastic melts and damage to instrumentation and electrical equipment can be anticipated. For damage to concrete buildings, however, the threshold heat flux is much higher, (b)(7)(F) [redacted] The jet flame created by ignition of a double-sided full bore release of natural gas following the guillotine rupture of the 42" pipeline will result in a thermal flux of 12.6 kW/m2 at a distance of 386 m (1266 ft) from the point of rupture making use of the largest distance calculated for this flux—the distance calculated using ALOHA..

From these results we can conclude that in the event of a jet fire involving the guillotine rupture of the proposed natural gas pipeline in proximity to the SOCA, personnel across the plant site close to the point of rupture who are unable to quickly take shelter will be injured and might die. However, the levels of thermal radiation seen following the guillotine rupture of the 42" pipeline will neither cause plastics to melt nor cause the spontaneous ignition of wood within the SOCA[19]. Similarly, a lesser release through a 6" diameter hole in the pipeline or from the assumed guillotine rupture of a hypothetical 2" line that branches off a larger pipeline will only expose personnel outdoors and near the point of rupture to possible injury or death. There will be no damage to equipment within the SOCA.

Considering next possible damage to the meteorological tower, the GT2/3 diesel fuel storage tank, the city water tank, the FLEX building, the EOF, the steam generator mausoleums and switchyard, all located outside the SOCA, as a result of the rupture of a pipeline and jet fire at the closest points to these items, damage is assumed to occur as noted in Table 6. This damage might result from engulfment in flames (e.g., in the event of a jet fire initiated on a pipeline on

[18] For example, at night between the hours of 9 pm and 6 am at Westchester County Airport, atmospheric conditions with a wind speed of ~ 3 m/s and D air stability are twice as common as those with a wind speed of 1.5 m/s and F stability. Furthermore, F stability will not be encountered in the daytime while D will.
[19] Furthermore, we would note that no such exposed equipment exists in SOCA—most equipment lies indoors behind concrete walls and the transformers would be shaded from this thermal radiation.

the proposed southern route directly impinging on the GT2/3 fuel tank) and intense thermal radiation that might damage equipment and, for the fuel tank, cause a tank vent fire. Without accounting for the very low probability of such events, pipeline ruptures on the proposed southern route could introduce additional risk to equipment located away from the SOCA. This additional risk is, however, minimal as:

- No damage to the city water tank is anticipated should the pipeline rupture and a jet fire ensue due to the substantial distance between the tank and closest point of the proposed pipeline of 1,336 feet (407 m). Similarly, no damage to the FLEX building or the Unit 2 steam generator mausoleum is anticipated as a result of thermal radiation as the distance between the pipeline and these SSCs is too great.

- Damage to the switchyard may occur from a jet fire caused by a guillotine rupture of the 42" pipeline at the point closest to the switchyard and assuming the jet fire is directed toward the switchyard.[20] However, both IP2 and IP3 have three emergency diesel generators (with sufficient diesel fuel stored on-site for these generators to run at least 2 days) and an Appendix R/station blackout diesel generator with additional fuel to mitigate the loss of offsite power. Therefore there will be more than two days to obtain additional fuel should both the switchyard and GT2/3 fuel tank be unavailable. However, a jet fire close to the switchyard might cause simultaneous damage to both the switchyard and GT2/3 diesel fuel storage tank, but as discussed further below, the probability of such an event involving the enhanced pipeline is below NRC's threshold for further consideration..

- Damage to the meteorological tower may also occur from a jet fire caused by a guillotine rupture of the 42" pipeline at the point closest to the switchyard and assuming the jet fire is directed toward the tower.[21] The potential consequences of damage to the meteorological tower, however, can be mitigated as the data it provides can be obtained from other sources, including a backup meteorological tower and weather forecasting services such as those provided by the NOAA.

- As the SSC important to safety closest to the proposed southern route, damage to the GT 2/3 fuel tank may occur from either a guillotine rupture of the 42" pipeline or from a leak through a 6" hole. The consequences of damage to the GT2/3 fuel tank, however, can be mitigated by the availability of alternative sources of diesel fuel should the on-site reserve diesel fuel tanks be unavailable. [redacted] (b)(7)(F) Also, as discussed above, the likelihood of a failure of the enhanced pipeline that could cause such damage is below NRC's 10^{-6}/year threshold of concern.

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20 (b)(7)(F) [redacted]

21 [redacted]

Damage to external instrumentation (b)(7)(F) might occur as a result of exposure to a heat flux of 12.6 kW/m^2 or more subsequent to pipeline rupture and the creation of a jet flame. Building damage to the Unit 3 steam generator storage mausoleum might also occur as a result of heat fluxes in excess of 31.5 kW/m^2. Such damage, however is unlikely to be of consequence given the robust design of the structure.

Finally, we note that a jet fire originating from a ruptured above-ground portion of the pipeline east of the SOCA, where the new 42" pipeline will connect to the existing right of way, will not cause damage to SSCs within the SOCA, the meteorological tower, the GT2/3 fuel tank, the city water tank, the FLEX building, the EOF or switchyard because of the distance between this above-ground portion of the pipeline and the other objects (Figure 2, Table 7).

In summary, as SSCs important to safety might be exposed to thermal radiation in excess of a relevant threshold subsequent to pipeline rupture and ignition of the release, general potential exposure rates for damage need to be determined.

Table 4

Consequences of Exposure to Thermal Radiation [8]

Thermal Radiation (kW/m^2)	Consequence
2	Pain within 60 s
5	Tolerable to escaping personnel
8	Fatal after exposure for several minutes
10	Potentially fatal in 60 s
12.6	Plastic melts, piloted ignition of wood[22]
25	Non-piloted ignition of wood
31.5	Building damage [29]
35	Equipment damage

[22] Piloted ignition is defined as the appearance of a flame at the surface of a material which has been exposed to external heating with an ignition source present in the volatile stream created as the material is heated [25].

Table 5

Consequences of Jet Fire Scenarios

Scenario	Consequences—Distances at which Level of Radiation Seen
(b)(7)(F)	

Table 6

Potential Damage at Closest Distances from Proposed Pipeline in the Event of Pipeline Rupture and a Jet Fire

(b)(7)(F)

Table 7

A Comparison of Distances from Above-Ground Portions of the Proposed Pipeline and the Impact Distance to a heat flux of 12.6 kW/m^2

(b)(7)(F)

Cloud Fire

A cloud fire is anticipated should a methane release ignite after a delay. This may involve the contents of the turbulent jet, and, especially for jets that are not vertical or for ruptures of smaller diameters, the contents of a vapor cloud that is dispersed as a buoyant plume once momentum effects dissipate (typically after ~ 10 s), noting that the turbulent momentum with which the methane exits the pipe line will result in low methane concentrations close to the point of release.

The discharge rate in a release occasioned by a guillotine rupture of a pipeline will fall rapidly; lesser releases will persist for longer times. Regardless, given the appropriate wind direction and speed and air stability, a flammable gas cloud might traverse the IPEC site after the rupture of the pipeline. However, the buoyant nature of methane generally precludes the formation of a persistent flammable vapor cloud at ground level [10] and thus the likelihood of people or equipment being engulfed in a flammable cloud of methane at some distance from the release is remote.

With delayed ignition, a vapor cloud fire and the scorching and depletion of oxygen would ensue within those portions of the cloud where the methane concentration exceeds the lower flammable limit noting that because of the possibility that flammable pockets of methane might lie outside the main cloud, the vulnerable area is typically placed within a contour representing 60 % of the lower flammable limit for methane.. While such a fire might lead to injury and death to exposed personnel and local fires, it would not damage equipment or structures—a vapor cloud fire will be of short duration ("a few tens of seconds") and thus "the total radiation intercepted by an object near a flash fire is substantially lower than from ... a jet fire" (p 79, [6]). Again the conservatism of this characterization of the consequences of a cloud fire needs be stressed. Thus while this cloud could travel very considerable distances depending upon the wind speed and air stability at the time of release (Table 8), the buoyant nature of methane generally precludes the formation of a persistent flammable vapor cloud at ground level let alone one that would travel downhill to the SOCA.

Table 8 Consequences of Cloud Fires
[redacted]

Vapor Cloud Explosions

As noted above, it is not likely that any release of methane from a natural gas pipeline will result in a vapor cloud explosion and that, should this occur, it will entail a deflagration with low resulting overpressures rather than a detonation. A detonation is hypothetically possible, however, in the turbulent methane jet entrained with air and within the belts of trees adjacent to a right of way associated with the southern route for the proposed 42" pipeline. In both cases, a detonation might occur as a result of [redacted] A detonation is also possible if ignition is caused by a high energy source. In neither case though would the detonation persist beyond the congested or turbulent area. In calculating the consequences of a hypothetical detonation within the turbulent jet, [redacted] in calculating the consequences of a hypothetical detonation within wooded areas, we assume the detonation to be centered about the middle of that wooded area in which a flammable concentration of methane might be found.

[23] Based on an average release rate of [redacted] This rate comprises the release of [redacted] in the first minute (from ALOHA), a release [redacted] in the next two minutes (accounting for the pressure drop) and [redacted] after valve closure. This last will take an additional 3 minutes after the valves are closed (from ALOHA).

In evaluating vapor cloud explosions, the critical distances are:

- The shortest distance from the 42" pipeline (the assumed center of an explosion in the turbulent jet) to a system, structure or component important to safety in the SOCA (the Primary Water Storage Tank or PWST) is (b)(7)(F) The shortest distance to the SOCA is ~ 482 m (1580 ft).
- For the 42" pipeline on the southern route, the shortest distance from the mid-point of an explosion initiated in trees to the northeast of the right of way to a system, structure or component important to safety (the PWST) is (b)(7)(F) for large releases.
- The other distances from the 42" pipeline to the safety-related or important to safety SSCs of concern are presented in Table 1.

Vapor cloud explosions were modeled using US Army TNT equivalent explosion model as implemented within BREEZE Incident Analyst. The minimum safe distances beyond which the overpressure will not exceed 1 psi were also calculated using equation (1) in the Regulatory Guide [3][24]. The mass of flammable material potentially involved in an explosion is estimated using an approach suggested by both the FM Data Sheets 7-42 [16] and Woodward [26] as directed by the Regulatory Guide. Essentially this leads to two types of explosion for each release—an explosion involving the mass of methane between the upper and lower flammable limits in the turbulent methane jet created by a rupture of the pipeline and explosions involving a "volume with sufficient confinement or congestion to create flame acceleration" [16] such as that created in the belts of trees adjacent to the proposed pipeline right-of-way. The calculation of the mass of methane that might contribute to an explosion is described in footnotes to Table 10 and Appendix A; the masses are also presented in Appendix A. In applying the TNT equivalency models, a yield (b)(7)(F) is assumed as suggested in Table 1 of the Regulatory Guide. A comparison of the minimum safe distances calculated using equation (1) in the Regulatory Guide and the implementation of the US Army TNT equivalency model in Breeze Incident Analyst shows small but consistent discrepancies. These are the result of a higher energy of explosion being assumed for TNT in the latter. It should be noted that while portions of the route proposed for the new 42" pipeline are now covered in trees, once built the pipeline will lie in a clear-cut 100-ft wide corridor. No trees or other congestion that might facilitate detonation of a natural gas release will therefore lie in immediate proximity to the proposed pipeline. Thus the assumption of explosions arising in belts of trees is conservative.

The consequences of these overpressures are described in Tables 9 and 10; plots of the overpressure that might be experienced following the guillotine rupture of the proposed 42" pipeline taking the southern route are presented in Figures 4 and 5.

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[24] The overpressures are calculated assuming a surface explosion rather than a free air explosion. This results in slightly higher overpressures being predicted.

- Figure 4 depicts the consequences of a hypothetical vapor cloud explosion initiated in the belt of trees to the northeast of the 42" gas pipeline taking the southern route. The epicenter of the explosion is placed in the middle of the belt of trees adjacent to the pipeline in which a flammable concentration of methane might persist should this be allowed by the wind and release directions and speeds.

- Figure 5 depicts the consequences of a hypothetical vapor cloud explosion initiated in the turbulent jet of methane following the guillotine rupture of the 42" gas pipeline taking the southern route. The epicenter of the explosion is placed on the pipeline at is closest point to a system, structure or component important to safety in the SOCA.

In all cases, the predictions were made using the US Army TNT equivalence model within Breeze Incident Analysis software. The sizes of the wooded areas and thus the volumes of natural gas that might be caught within them and the calculated masses of natural gas involved in a hypothetical detonation are presented in Appendix A.

The results presented in Table 10 show that no hypothetical detonation following the guillotine rupture of the pipeline will result in overpressures exceeding 1 psi at a system, structure or component important to safety within the SOCA. Similarly, no overpressures in excess of 1 psi are seen by systems, structures and components important to safety located away from the SOCA as a result of the rupture of (b)(7)(F) [redacted] of the pipeline. However, as overpressures in excess of 1 psi could be seen by certain systems, structures and components important to safety located away from the SOCA, as a result of (b)(7)(F) [redacted] (b)(7)(F) [redacted] and a subsequent detonation[25], exposure rates for such damage needs to be determined. This is documented in Appendix B.

Table 9

Consequences of Exposure to Overpressures [6, 8, 27]

Overpressure	Consequence
1 psi	Glass shatters
2 - 6 psi	Serious structural damage to houses
6 – 9 psi	Severe damage to reinforced concrete structures
10 psi	Destruction of buildings

[25] In evaluating releases from the pipeline at points close to important to safety SSCs outside the SOCA, it was concluded that as, following guillotine rupture of the pipeline, the flammable mass of methane in a turbulent jet arising from the rupture pipeline (b)(7)(F) [redacted] adjoining the pipeline right of way, (b)(7)(F) [redacted] (b)(7)(F) [redacted] Detonation within the turbulent jet is therefore the detonation normally considered.

Table 10

Consequences of Vapor Cloud Explosions

Scenario	Consequences—Distances at which a Given Overpressure Seen
(b)(7)(F)	

[26] Assuming (b)(7)(F) efficiency or yield factor.

Table 10 Consequences of Vapor Cloud Explosions	
Scenario	**Consequences—Distances at which a Given Overpressure Seen**
(b)(7)(F)	

[27] The volume of the momentum jet and mass of methane within it will vary as, following the guillotine rupture of the pipeline, the rate of release of natural gas will fall rapidly. Steady state calculations presented in Lees [8] (i.e., in equation 15.46.32 with an effective diameter ~ 1.6 times the actual diameter as calculated using equation (b)(7)(F) Lees [8]) suggest that the flammable momentum jet will contain (b)(7)(F) of methane following the guillotine rupture of the 42" line with a double-sided release, (b)(7)(F) of methane following release through a 6" diameter hole in the 42" line and (b)(7)(F) of methane following release through a 2" diameter hole in the 42" line (i.e., ~ 1 second of the natural gas jet release).

(b)(7)(F)

Figure 4

Consequences of a Vapor Cloud Explosion Following Escape of Methane after the Guillotine Rupture of a 42" Natural Gas Pipeline and Detonation of a Gas Cloud within the Trees to the Northwest of the Southern Route

(b)(7)(F)

(b)(7)(F)

Figure 5

Consequences of a Vapor Cloud Explosion after the Detonation of Methane in the Turbulent Jet Created after the Guillotine Rupture of a 42" Natural Gas Pipeline that Takes the Southern Route

(b)(7)(F)

(b)(7)(F)

Missile Generation

Given that missiles might be thrown as far as 274 m (900 ft) in the event of pipeline rupture, the switchyard, GT2/3 diesel fuel tank, the Unit 3 steam generator mausoleum and meteorological tower must all be considered as being vulnerable to missile damage should the pipeline rupture close to these objects. Therefore, we also examine the frequency of a gas pipeline rupture at points close to these SSCs and subsequent missile generation.

Summary of the Vulnerabilities to Risks

Potential hazards arising from the rupture of the new 42" gas pipelines that exceed the magnitude thresholds for exposure to thermal radiation, explosions and missiles are summarized in Table

11. This table also lists hazards that do not exceed this threshold and the basis for this conclusion. For those hazards that exceed the magnitude thresholds, exposure rates are developed in Appendix B and are presented in Table 13 below.

Table 11

Potential Hazards

SSC Important to Risk or Safety-Related	Event of Concern Following the Hypothetical Rupture of the 42" Pipeline	Disposition
SSCs inside SOCA	(b)(7)(F)	(b)(7)(F)
SSCs inside SOCA		
SSCs inside SOCA		
Switchyard		
Switchyard		
Switchyard		
GT2/3 diesel fuel storage tank		
GT2/3 diesel fuel storage tank and switchyard[28]		
GT2/3 diesel fuel storage tank and switchyard		
Emergency Operations Facility		
Emergency Operations Facility		

(b)(7)(F)

Table 11

Potential Hazards

Emergency Operations Facility	(b)(7)(F)	(b)(7)(F)
FLEX building		
FLEX building		
FLEX building		
Meteorological tower		
Meteorological tower		
Meteorological tower		
City water tank		
City water tank		
City Water tank		
Unit 2 steam generator mausoleum		
Unit 2 steam generator mausoleum		

Table 11

Potential Hazards

Unit 2 steam generator mausoleum	(b)(7)(F)	(b)(7)(F)
Unit 3 steam generator mausoleum		
Unit 3 steam generator mausoleum		
Unit 3 steam generator mausoleum		

10. Conservatisms in the Analysis

Conservative assumptions have been made in the modeling and analysis of potential hazards that might follow the hypothetical rupture of a natural gas pipeline. These are summarized in Table 12. In light of these conservatisms, we believe the appropriate and conservative threshold frequency of concern for pipeline rupture coupled with fire, explosion or missile generation is ~ 10^{-6}/year.

Table 12

Conservative Assumptions Made

Conservatism	Discussion
Detonation of natural gas is possible within the turbulent jet created by a release or in congested areas	While such a hypothetical event has been considered and an upper-bound probability as to its occurrence applied, in fact no such detonation has been recorded and experts question its possibility.
The largest possible magnitude of release rates is assumed—the guillotine rupture of the 42" pipeline [redacted] (b)(7)(F)	Pipeline rupture studies typically assume a single sided release. The assumption made is conservative in that: • Pressures on the downstream side and thus flow rates from the downstream side will be lower • [redacted] (b)(7)(F) As a result of the high discharge rates assumed, damage contours move further out and the predicted frequency of events that cause damage to a specific SSC [redacted] (b)(7)(F)
The release of natural gas is assumed to be vertical	Many releases from buried pipelines will impact the walls of the crater created, reducing momentum, turbulence and flame temperature in the gas jet and thus the magnitude of the effects of the jet flame or hypothetical detonation

Table 12

Conservative Assumptions Made

Conservatism	Discussion
The size of the jet flame and turbulent jet assumes the peak gas release rate	The gas release rate will fall rapidly resulting in lower heat fluxes from jet flames and a smaller mass of gas within the jet.
The gas pipeline pressure prior to release is assumed to be the 850 psig MAOP (Maximum Allowable Operating Pressure).	The normal operating pressure will be 750 psig, which is less than the MAOP. Higher gas pressures translate into higher release rates and damage potential.
Missiles are assumed to fly horizontally for a distance of 274 m (900 ft)	The distance is an upper bound; missiles might also fly over closer objects
Damage is deemed possible if the closest point of an SSC of concern is impacted by overpressures or heat fluxes in excess of a threshold.	The switchyard covers a large area and only specific equipment will be of concern.

11. Causes and Likelihood of Releases of Natural Gas and Subsequent Fire and Explosion or Missile Generation

Likelihood and Consequences Fire and Explosion

The causes and likelihood of the rupture of the proposed 42" natural gas pipeline and subsequent fires, detonations and missile generation are addressed in detail in Appendix B. The conclusions of this analysis, as predicted using conservative models, are presented in Table 13 which itself is drawn from Tables B-4 and B-5 in Appendix B.

Table 13

Vulnerability to Risk

SSC Important to Risk or Safety-Related	Event of Concern Following the Hypothetical Rupture of the 42" Pipeline	Is the Pipeline Involved Enhanced or Not?	Exposure Rate (/year)
Switchyard	Exposure to thermal radiation as a result of a jet fire	Enhanced	7.23×10^{-7}
Switchyard	Exposure to an overpressure exceeding 1 psi subsequent to a detonation	Enhanced	5.52×10^{-8}
Switchyard	Missile generation	Enhanced	1.32×10^{-7}
GT2/3 diesel fuel storage tank	Missile generation	Enhanced	1.51×10^{-8}
Switchyard and GT2/3 diesel fuel storage tank[29]	Exposure to thermal radiation as a result of a jet fire	Enhanced	5.20×10^{-7}
Switchyard and GT2/3 diesel fuel storage tank	Exposure to an overpressure exceeding 1 psi subsequent to a detonation	Enhanced	4.25×10^{-8}
Emergency Operations Facility	Exposure to thermal radiation as a result of a jet fire	Enhanced	4.02×10^{-7}
Emergency Operations Facility	Exposure to an overpressure exceeding 1 psi subsequent to a detonation	Enhanced	2.79×10^{-8}

[29] Because of their proximity, simultaneous damage to both the GT2/3 diesel fuel oil storage tank and the switchyard is possible in the event of a jet flame or detonation.

Table 13

Vulnerability to Risk

Meteorological tower	Exposure to thermal radiation as a result of a jet fire	Both enhanced and unenhanced	1.86×10^{-6}
Meteorological tower	Exposure to an overpressure exceeding 1 psi subsequent to a detonation	Both enhanced and unenhanced	1.50×10^{-7}
Meteorological tower	Missile generation	Both enhanced and unenhanced	2.06×10^{-9}
Unit 3 steam generator mausoleum	Exposure to thermal radiation as a result of a jet fire	Unenhanced	1.38×10^{-6} (for thermal radiation that would damage the building)
Unit 3 steam generator mausoleum	Exposure to an overpressure exceeding 1 psi subsequent to a detonation	Both enhanced and unenhanced	1.95×10^{-7}
Unit 3 steam generator mausoleum	Missile generation	Both enhanced and unenhanced	3.83×10^{-8}

The results show that, with two exceptions, the frequencies of all events that might damage important to safety or safety-related Systems, Structures and Components outside the SOCA lie below the 10^{-6}/year threshold for concern. The exceptions are possible damage to instrumentation on the meteorological tower as a result of pipeline rupture and creation of a jet flame and possible damage to the Unit 3 steam generator mausoleum. As noted earlier, however, these remain very low probability events. Furthermore, the potential consequences of damage to the meteorological tower can be mitigated as the data it provides can be obtained from other sources, including a backup meteorological tower and weather forecasting services such as those provided by the NOAA. Similarly, damage to the Unit 3 steam generator mausoleum is both unlikely (the structure is rugged) and will not have serious consequences (a Safety Evaluation concluded that even if the structure were to fail, dose limits imposed by NRC guidelines would not be exceeded).

In Appendix B, terrorism or wanton damage to the pipeline and the possibility of seismic damage are also discussed. It is concluded that such damage is unlikely or not credible.

12. Summary Discussion

The rupture of the proposed 42" natural gas pipeline in or close to the IPEC site and subsequent ignition of the methane released might result in a jet or cloud fire and injury or death to any one exposed to flames or intense thermal radiation. Such a fire will not, however, damage a system, structure or component important to safety within the SOCA. Similarly, in the hypothetical event of a vapor cloud explosion initiated by or involving a detonation, no structural damage to buildings in the SOCA is anticipated as the southern route lies beyond the minimum safe distance established for such a pipeline. A similar conclusion can be drawn about missile generation.

Damage to systems, structures and components important to safety away from the SOCA—the switchyard, GT2/3 fuel tank, Emergency Operations Facility (EOF), FLEX building, Unit 3 steam generator mausoleum and meteorological tower—is hypothetically possible under very low probability scenarios. We therefore conclude that the southern route will not introduce material additional risk to the safe maintenance and operation of safety-related and important to safety SSCs at IPEC.

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APPENDIX A

Volumes of Flammable Clouds and Masses of Methane involved in Hypothetical Vapor Cloud Explosions (Detonations)

(b)(7)(F)

[30] The mass of methane present in the congested area—the belts of trees—is calculated from the volume of the flammable vapor cloud assuming an average 10 % volume of methane in air. The height of vapor clouds within the trees is assumed to be 10 m.
[31] Relative to the closest point on a pipeline to the IP3 control building.

APPENDIX B

Analysis of the Causes of and Determination of Exposure Rates for a Failure of the Proposed AIM 42" Natural Gas Pipeline near IPEC

B1. Introduction

Nuclear Regulatory Commission (NRC) regulations require that safety-related and important to safety nuclear power plant structures, systems, and components (SSCs) be appropriately protected against dynamic effects resulting from equipment failures and from events and conditions that may occur outside the nuclear power plant. These latter events include the effects of explosion of materials that may be at nearby facilities or carried on nearby transportation routes, including natural gas pipelines. NRC regulations also require that the nature and proximity of hazards related to human activity (e.g., natural gas pipelines) be evaluated to determine if a plant design can accommodate commonly occurring hazards, and if the risk of other hazards is very low.

Based on proximity to IPEC, the proposed Algonquin Incremental Market (AIM) Project 42" pipeline, currently planned to be installed along a southern route located approximately 1580 ft. south of the IPEC security owner controlled area (SOCA), poses a potential hazard that must be evaluated as to the consequences and likelihood of (or exposure rates for) postulated failures of the pipeline. As part of that evaluation, Entergy has conducted a hazard analysis contained in the main body of this report. The analysis contained in that report indicates that a postulated failure would not adversely impact any SSCs within the SOCA due to the distance from the southern route to the SOCA. Similarly, certain SSCs outside the SOCA—the city water tank, FLEX building and Unit 2 steam generator mausoleum—will not be adversely affected by hypothetical fire, explosion or missile damage because the distances between the SSCs and the proposed pipeline are such that the overpressure, heat flux and missile damage thresholds are not exceeded (i.e., the city water tank and Unit 2 steam generator mausoleum) or because the SSC in question is of rugged construction with no exposed instrumentation and thus able to withstand the overpressure and heat fluxes to which it might be exposed (i.e., the FLEX building). The diesel fuel oil tanker that is used to transport fuel oil from the GT2/3 diesel fuel oil storage tank to the plant will be relocated so as not to be adversely affected by hypothetical fire, explosion or missile damage from the proposed pipeline. However, certain SSCs important to safety located outside of the SOCA could be damaged should a failure occur on the 42" AIM pipeline closest to such equipment. The SSCs important to safety identified as being potentially vulnerable to damage are the switchyard, the GT2/3 diesel fuel storage tank, the Emergency Operations Facility (EOF) and the meteorological tower. The Unit 3 steam generator mausoleum was also identified as being of potential concern. Here we conservatively assume in general that damage to these SSCs might occur were they to be exposed to 1-psi overpressure following an explosion,

to a thermal radiation heat flux occasioned by pipeline rupture and the ignition of the natural gas released that exceeds 12.6-kW/m^2, or to the possibility they might be struck by missiles when the pipeline ruptures. The 1-psi overpressure is a threshold of concern established by the Nuclear Regulatory Commission in Regulatory Guide 1.91 [3]; the 12.6-kW/m^2 heat flux is that required to melt plastic.

In accordance with applicable NRC guidance (Regulatory Guide 1.91), if SSCs important to safety may be damaged due to a postulated failure due to proximity to the hazard, the licensee may show that the risk is acceptably low on the basis that thresholds for damage (e.g., the 1 psi overpressure) are not exceeded or that exposure rates are low; a demonstration that the exposure rate for damage is less than 1×10^{-6} per year when based on conservative assumptions, or 1×10^{-7} per year when based on realistic assumptions, is acceptable.

As demonstrated below, based on proposed design and installation enhancements to the 42" pipeline to be installed near IPEC, the potential for damage or exposure rates for pipeline failure and damage to SSCs near the pipeline are, with two exceptions, below NRC's threshold criteria and, therefore, are not considered credible events. (b)(7)(F) (b)(7)(F) (b)(7)(F) [redacted] However, that pipeline also has a very low probability of failure and, even if a failure and damage to the meteorological tower is assumed, there are established alternative means to provide meteorological data to the plant in the event of an emergency. Similarly, thermal damage to the exterior of the Unit 3 steam generator mausoleum will not have other consequences because this structure is of rugged concrete construction. Furthermore, a safety evaluation performed for the steam generator storage facility project shows that even if the structure were to fail, the dose limits imposed by NRC guidelines would not be exceeded [28].

B2. Purpose and Objective of This Report

The purpose of this report is to determine exposure rates for failure of the AIM project 42" pipeline, to be installed along the southern route outside of the main IPEC facility, and subsequent events accounting for the substantial pipeline and installation design enhancements discussed below.

B3. Statistical Analysis of the Exposure Rates for a Fire and Explosion

The average rupture frequency of all pipelines with a diameter of 36" or more[1] is ~ 2.75 x 10^{-5} /mile.yr. [2] This frequency is derived using US data for all natural gas transmission pipelines with a diameter of 36" or more regardless of the date of pipe manufacture and installation, wall thickness, coating thickness and cover depth. Improvements in the design and manufacture of pipe and corrosion protection and increased wall thickness and cover depth have all served to reduce the likelihood of pipeline ruptures [29, 31][3]. As discussed below, because segments of the proposed AIM pipeline near IPEC will be a design-enhanced, state-of-the-art installation, and reflect improvements in manufacture achieved in recent decades, a lower rupture frequency will apply to these segments of the proposed AIM pipeline.

When assessing the US Department of Transportation Pipeline and Hazardous Material Safety Administration (PHMSA) data, we note that in the period 1/1/2002 to 7/1/2014 only 2 of the 12 onshore transmission gas pipeline ruptures in pipelines with a diameter of 36" or more occurred in a pipeline installed after 1980. The PMHSA data then allow us to predict a rupture frequency for a new 42" pipeline equal to 1.32 x 10^{-5} /mile.yr.[4] The predicted frequency of pipeline rupture

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[1] As too few data are available for 42" pipeline alone, data for all pipelines of 36" or more in diameter were considered for this analysis. In selecting data to be used in this analysis, a balance must be achieved between the availability and applicability of data. Noting that rupture rates fall with increasing pipeline diameter, we seek to obtain a reasonable amount of incident (rupture) and exposure data for pipelines with a diameter as close to the 42" diameter of the proposed pipeline. Hence in general, data for pipelines of 36" or more in diameter are used rather than, for example, the larger sets of data with a diameter of 24" or more.

[2] This frequency is calculated from:

1. Rupture data for gas transmission pipelines of 36" or more in diameter. These data are for the period 1/1/2002 to 7/1/2014 and are provided by the US Department of Transportation Pipeline and Hazardous Material Safety Administration (PHMSA). 12 ruptures were recorded in the 12.5 year period.
2. The total length of the transmission system pipelines of 36" or more in diameter recorded in Part H of the PHMSA 2012 annual transmission system report (34,851 miles).

The average rupture frequency is calculated by dividing the number of ruptures (12) by the exposure—the product of the length of the transmission system pipelines of 36" or more in diameter (34,851 miles) and duration of the period for which rupture data were gathered (12.5 years). The result is a calculated frequency of 2.75 x 10^{-5} /mile.yr. This is a preliminary estimate and the actual number would be an underestimate as not all the 34,851 miles of pipeline of 36" or more in diameter was installed in 2002.

This frequency of incidents is in accord with European experience [29] and earlier estimates [30]. This 12.5 year period was again selected to achieve a satisfactory balance between the availability and applicability of data. While more ruptures would be included were a longer period of time to be selected, the improvements in pipeline reliability seen in recent decades would be masked were data from earlier decades to be used.

[3] The lower rupture frequency exhibited by newer pipelines would not appear to be driven by the effects of aging in older pipelines [32].

[4] The pipeline rupture frequency is calculated by dividing the number of ruptures that occur in a period of time with the exposure of pipelines to rupture in that period. The latter is expressed in cumulative pipeline mile.years. The calculation of pipeline exposure to rupture reflects the fact that in any period of time, lengths of pipeline are installed and thus the total length of pipeline in place at the beginning of the period will be less than that in place at the end. By averaging the lengths of piping over the time period, an equivalent mile-year exposure when compared

and a subsequent fire is therefore ~ 6. 61 x 10^{-6} /mile.yr[5]; the predicted frequency of a hypothetical vapor cloud explosion involving a detonation following a pipeline rupture is conservatively estimated as being less than ~ 5.95 x 10^{-7} /mile.yr[6]. Note that while descriptions of pipeline rupture and fire events often make mention of "explosions", these appear to refer to the bursting of the pipeline itself or to a subsequent deflagration of a vapor cloud rather than to a

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to a shorter length over a longer period can be calculated. The calculation of the 1.32 x 10-5/mile.yr rupture frequency makes use of the observation that US Energy Information Administration data for new completed natural gas pipeline projects in the period 6/26/2009 to 6/20/14 [32] show that, where pipeline length and diameter are given, 35 % of new pipeline involved pipelines of exclusively 36" or more in diameter. Now 36,763 miles of pipeline was installed in the period 2000-2012. Assuming 35 % of this is 36" or more in diameter, 12,867 miles of 36" or greater diameter pipeline were installed in the period 2000-2012. Now in 2013 a total of 34,851 miles of 36" or greater diameter is installed of which 12,867 miles were installed in 2000 or later and thus 21,984 miles installed before 2000. The question is how much of this 21,984 mile pipeline length was installed between 1980 and 1999, 1980 being the year in which marked improvements in pipeline reliability appear. Let us conservatively assume the percentage of pipeline 36" or more in diameter installed before 2000 that was installed in the period 1980-1999 is identical to the fraction for all pipeline installed before 2000 that was installed in the period 1980-1999. This percentage is 21.3 %. The total length of pipeline of 36" or more in diameter installed in the period 1980-1999 is therefore 21,984*0.213 or ~ 4682 miles. The total length of pipeline 36" or more in diameter installed in or after 1980 and present in 2013 is therefore (4682 + 12867) or 17,550 miles. The average length of such pipeline in place over the period 2002-2013 is obtained by interpolation as 12,106 miles noting that an estimated 17,550 miles of pipeline of 36" or more in diameter were present in 2013 and an estimated 6661 miles were present in 2002. The 6661 miles present in 2002 comprises the 4682 miles estimated to be present in 2000 and (2/13) of the 12,867 miles estimated as being added in the period 2000-2002.

The pipeline rupture frequency is then calculated by dividing the number of ruptures in pipeline of 36" or more in diameter and installed in 1980 or after that occurred in the time period 2002-2014 (2 events) by the exposure of such pipeline (12,106 miles x 12.5 years). The result (2/(12,106 * 12.5)) is 1.32 x 10^{-5} ruptures/mile.yr.

[5] This frequency is calculated by multiplying the rupture frequency (1.32 x 10^{-5} /mile.yr) by the ignition probability (b)(7)(F) The latter is calculated from PHMSA data for gas transmission pipelines of 36" or more in diameter for the period 1/1/2002 to 7/1/2014. Twelve ruptures were recorded in the 12.5 year period. Of these, ignition occurred 6 times (i.e., in 50 % of the incidents). This ignition probability is in accord with European experience [28].

[6] This frequency is calculated by multiplying the rupture frequency (1.32 x 10^{-5} /mile.yr) by a conservative estimate of the probability of a vapor cloud detonation following a major release from a pipeline. The latter value is calculated as 0.045. This value is presented based on the absence of detonation in the 65 ruptures of pipelines of 24" or more in diameter recorded by PHMSA between 1/1/2002 and 7/1/2014 (in no instance do the PHMSA or NTSB (National Transportation Safety Board) reports on these incidents refer to a detonation—"explosion" in PHMSA documents appears to refer to the explosive rupture of the pipeline or possibly to a vapor cloud explosion entailing deflagration)—assuming a binomial distribution, there is a 5 % probability of no detonations occurring in 65 ruptures if the detonation probability is 0.045. If the detonation probability were higher, the probability of no detonations occurring is approximately 5 % or less. The resulting detonation frequency is higher than the 1 x 10^{-7} $mile^{-1}.year^{-1}$ frequency cited as an upper bound probability of an explosion in the State of California guidance protocol for school site risk analysis [10]. Here the data used comprise ruptures in pipelines of 24" in diameter or more. As the rupture of a 24" pipeline might still result in a turbulent jet containing over 1000 kg of methane in the flammable range, the absence of detonation in such ruptures is judged applicable in determining the probability of detonation after the rupture of large pipelines.

detonation. For example, the pipeline incident described by PHMSA corrective action order 3-2011-1018-H is noted in the PHMSA incident database as having involved an explosion. The corrective action order itself, however, describes the event as involving rupture and a fireball.

Looking at the set of natural gas transmission pipeline rupture events that occurred in the period 1/1/2002 to 7/1/2014, the dominant causes of pipeline rupture in all pipelines are found to be external corrosion, construction/installation/fabrication problems and excavation damage (Table B-1). In pipelines installed in or after 1980, however, we see that corrosion disappears as a cause of pipeline rupture.

Table B-1

Causes of Rupture of Natural Gas Transmission Pipeline Rupture Events involving Pipeline of 36" or more in Diameter that Occurred in the Period 1/1/2002 to 7/1/2014 (PHMSA Data)

Cause of Pipeline Rupture	Number of Events: all Events	Number of Events: Events in Pipeline Installed In or After 1980
External corrosion	5	0
Fabrication construction/installation	2	1
Excavation (3rd party)	1	1
Earth movement (landslides, subsidence, heavy rains, etc).	1	0
Miscellaneous/unknown	3	0
Total events	12	2

Spectra and Entergy have agreed to a number of pipeline enhancements to a ~ 3935 ft (1199 m) segment of pipeline near IPEC in order to further reduce the already low predicted frequency of failure and address the above listed primary causes of pipeline rupture. The location of this "enhanced" pipeline is shown in Figure 1 of the main report. These additional safety features will be installed and implemented to mitigate internal and external corrosion, excavation threats, abnormal operations, damage from natural forces (i.e., seismic) and other potential threats. In summary, these enhancements include:

- The pipeline will have a greater wall thickness increasing it from 0.510" to 0.720" (a 41% increase)

- The pipeline will be X-70 steel (70,000 psi yield strength). The increased wall thickness and the higher yield steel material will together result in a 41% operating pressure margin above the planned 850 psig MAOP.
- The X-raying of 100 % of all welds and approval of the radiographs by trained X-ray technicians
- The pipeline will be buried to a greater depth from the normal 3 feet to a minimum of 4 feet from the top of the pipeline to natural grade (a 33% increase).
- The fusion bonded epoxy (FBE) pipeline corrosion coating will be increased.
- An Abrasive Resistant Overlay (ARO) will be added over the FBE coating.
- Fiber reinforced concrete mats with warning tape layers placed over the pipeline.

Details of Spectra's normal design, installation and operating practices and these additional design and installation features are presented in Exhibits A and B; a cross-sectional schematic of the enhanced pipeline with reinforced concrete mats and warning tape is shown in Exhibit C.

While US pipeline incident data do not allow the development of direct correlations to calculate the precise probability impact of these additional features on pipe rupture frequencies[7], there is strong evidence that the effect will be appreciable. European data [29] suggest that rupture and overall failure frequencies decline markedly when pipe wall thickness and cover depth increase (Figures B-1, B-2 and B-3). This conclusion is supported by US PMHSA data that show of the 12 rupture events involving natural gas transmission pipelines of 36" or more in diameter encountered in the period 1/1/2002 to 7/1/2014, only one involved pipelines with a wall thickness of 0.5" or more; this event was caused by a construction defect at a joint. Similarly, with respect to corrosion it has been concluded that for "pipelines with wall thicknesses greater than (0.59 in.) and with corrosion control procedures in place, the corrosion control frequency can be assumed to be negligible" [33]. UK studies have also demonstrated that by installing a concrete slab and visible warning tape, the frequency of pipeline ruptures occasioned by external interference will be reduced by 95 % [34]. Finally, X-raying of all welds and verification of the radiographs by trained technicians and the greater wall thickness in the enhanced pipeline will diminish the likelihood that defects in fabrication or construction might result in a subsequent pipeline rupture. A 75 % reduction in the predicted frequency of pipeline rupture as a result of defects in fabrication or construction in the enhanced segments of the pipeline is assumed here to reflect these improvements.

[7] As an example, there are no data available that relate the length and diameter of pipelines to specific diameters, wall thicknesses and cover depths.

Figure B-1

Frequency of Pipeline Rupture Occasioned by External Interference as a Function of Cover Depth [transcribed from 29]

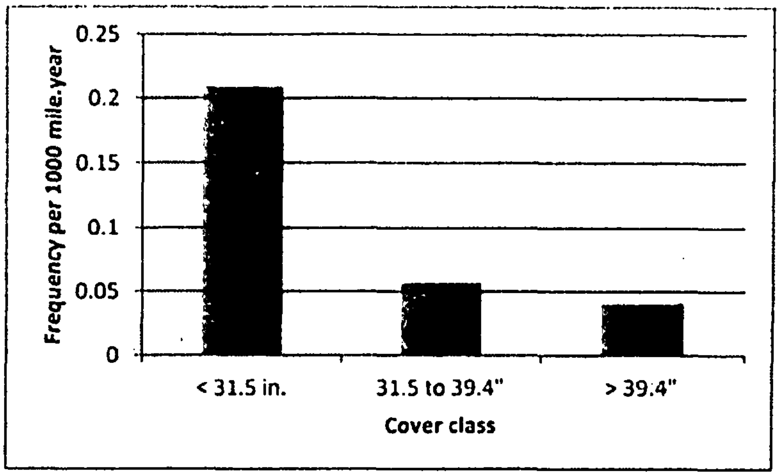


Figure B-2

Frequency of Pipeline Rupture Occasioned by External Interference as a Function of Wall Thickness [transcribed from 29]

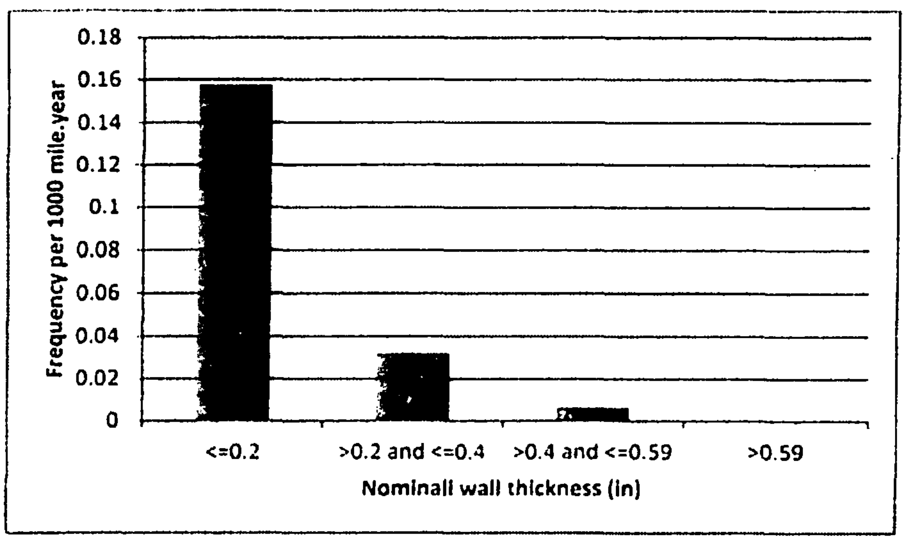
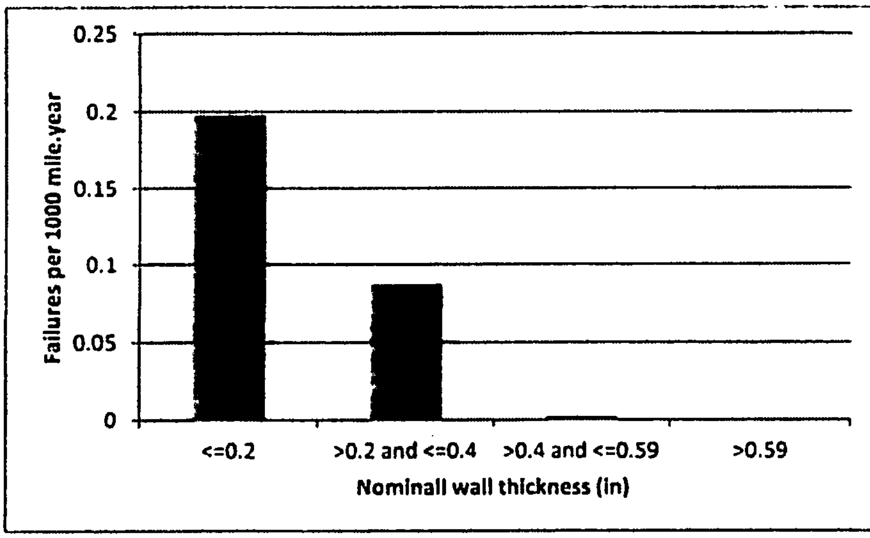


Figure B-3

Frequency of Corrosion-Induced Pipeline Failure as a Function of Wall Thickness [transcribed from 29]



If we assume that half the ruptures that might occur with new but not enhanced pipeline related to 3rd party excavation and half to fabrication and construction problems, and reduce rupture rates to account for the enhancements, we arrive at an overall rupture rate that is 15 % of that calculated for 42" pipeline that is not enhanced (Table B-2). A frequency of ~ 1.98 x 10^{-6} /mile.yr will therefore be assumed for pipeline that incorporates these additional safety features. This in turn translates into a frequency of pipeline rupture and ignition of [redacted] and a frequency of pipeline rupture followed hypothetically by [redacted]

[8] Multiplying the 1.98 x 10^{-6}/mile.yr rupture frequency with [redacted] probability of ignition
[9] Multiplying the 1.98 x 10^{-6}/mile.yr rupture frequency with a [redacted] probability of detonation

Table B-2

Relative Pipeline Rupture Frequency After Enhancements

Failure Cause	Fraction of Rupture Events Attributed to Cause	Multiplier to Apply Effect of Enhancement	Basis for Effect	Contribution After Enhancement
3rd party excavation	0.5	(b)(7)(F)	Reduction for concrete mats and warning tape	(b)(7)(F)
Fabrication/construction problems	0.5		Engineering judgment as to benefit of 100 % of all welds being X-rayed and thicker walls	
Total	1			

Let us now apply these frequencies to the pipeline rupture events of concern. In calculating exposure rates, the lengths of pipeline that lie within specific distances of the SSCs of concern are determined. It is assumed that if pipelines were to rupture along these lengths and fire, overpressure or missile damage were to ensue, damage to the SSC is possible. The lengths were determined using Google Earth. Details of the exposure rate calculations are presented in Table B-3.

Table B-3

Exposure Rate Calculation for Jet Fires and Explosions[10]

		Lengths of Pipeline where Rupture Might Lead to Damage		Pipeline Rupture Frequency (/mile.yr)			
SSC of Concern	**Damage Source**	**Enhanced Pipeline**	**Unenhanced Pipeline**	**Enhanced Pipeline**	**Unenhanced Pipeline**	**Probability of Ignition or Detonation**	**Exposure Rate (/year)**
Switchyard	Jet fire	(b)(7)(F)	0	1.98×10^{-6}	1.32×10^{-5}	(b)(7)(F)	7.23×10^{-7}
Switchyard	Vapor cloud explosion (detonation)		0	1.98×10^{-6}	1.32×10^{-5}		5.52×10^{-8}
Switchyard and GT2/3 storage tank[11]	Jet fire		0	1.98×10^{-6}	1.32×10^{-5}		5.20×10^{-7}

[10] Where damage ensues only after the rupture of enhanced pipeline or only after the rupture of unenhanced pipeline, the exposure rate for a given type of damage is calculated as the product of:

- The length of pipeline where rupture might cause that damage
- The rupture frequency for the pipeline
- The probability of the damage event given rupture (i.e., 0.5 for a jet flame and 0.045 for hypothetical detonation).

Where the rupture of both enhanced and unenhanced pipeline might cause damage, these calculations are performed separately for both enhanced and unenhanced pipeline and the resulting exposure rates summed.

[11] Because of the proximity of the switchyard and GT2/3 storage tank, the same pipeline rupture event might cause high heat fluxes or overpressures exceeding 1 psi in both the switchyard and GT2/3 storage tank.

Table B-3

Exposure Rate Calculation for Jet Fires and Explosions[10]

		Lengths of Pipeline where Rupture Might Lead to Damage		Pipeline Rupture Frequency (/mile.yr)			
SSC of Concern	**Damage Source**	**Enhanced Pipeline**	**Unenhanced Pipeline**	**Enhanced Pipeline**	**Unenhanced Pipeline**	**Probability of Ignition or Detonation**	**Exposure Rate (/year)**
Switchyard and GT2/3 storage tank	Vapor cloud explosion (detonation)	(b)(7)(F)	(b)(7)(F)	1.98×10^{-6}	1.32×10^{-5}	(b)(7)(F)	4.25×10^{-8}
EOF	Jet fire			1.98×10^{-6}	1.32×10^{-5}		4.02×10^{-7}
EOF	Vapor cloud explosion (detonation)			1.98×10^{-6}	1.32×10^{-5}		2.79×10^{-8}
Met tower	Jet fire			1.98×10^{-6}	1.32×10^{-5}		1.86×10^{-6}
Met tower	Vapor cloud explosion (detonation)			1.98×10^{-6}	1.32×10^{-5}		1.51×10^{-7}
U3 steam gen mausoleum	Jet fire (intense thermal radiation)	0		1.98×10^{-6}	1.32×10^{-5}		1.38×10^{-6}

Table B-3 Exposure Rate Calculation for Jet Fires and Explosions[10]							
		Lengths of Pipeline where Rupture Might Lead to Damage		Pipeline Rupture Frequency (/mile.yr)			
SSC of Concern	**Damage Source**	**Enhanced Pipeline**	**Unenhanced Pipeline**	**Enhanced Pipeline**	**Unenhanced Pipeline**	**Probability of Ignition or Detonation**	**Exposure Rate (/year)**
U3 steam gen mausoleum	Vapor cloud explosion (detonation)	(b)(7)(F) [redacted]	[redacted]	1.98×10^{-6}	1.32×10^{-5}	(b)(7)(F) [redacted]	1.95×10^{-7}

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Jet Fire – Electrical Switchyard and the GT-2/3 Diesel Fuel Oil Storage Tank

Looking first at a jet fire close to the switchyard and conservatively assuming damage will result with thermal radiation in excess of 12.6 kW/m^2 (see Table 4 in the main report), we are concerned with a guillotine rupture of the enhanced 42" pipeline within 386 m (1266 ft)[12] of the switchyard. This distance translates into a concern over guillotine rupture in a ~ 1175 m (3855 ft) length of enhanced 42" pipeline. An exposure rate for rupture followed by ignition of 7.23 x 10^{-7}/yr can be predicted for this length (Table B-3). Events that might result in simultaneous damage to both the switchyard and the GT2/3 diesel fuel oil storage tank have an exposure rate for rupture followed by ignition of 5.20 x 10^{-7}/yr. This last rate is calculated assuming guillotine rupture in (b)(7)(F) length of enhanced 42" pipeline within 386 m (1266 ft) of both the switchyard and the GT2/3 fuel oil storage tank.

Vapor Cloud Explosion involving Detonation – Electrical Switchyard and GT 2/3 Diesel Fuel Oil Storage Tank

If instead of a jet fire, assuming a hypothetical vapor cloud explosion involving detonation that follows the rupture of the proposed 42" gas pipeline close to the switchyard and GT2/3 fuel oil tank, our concern is with a guillotine rupture of the enhanced 42" pipeline in (b)(7)(F) length of enhanced 42" pipeline within (b)(7)(F)[13] of the switchyard and tank assuming it is only detonations that result in overpressures of 1 psi within the switchyard or at the fuel storage tank that are of concern. An exposure rate for rupture followed by detonation of 5.52 x 10^{-8} /yr. can be predicted for this length (Table B-3). Events that might result in simultaneous damage to both the switchyard and the GT2/3 diesel fuel oil storage tank have an exposure rate for rupture followed by ignition of 4.25 x 10^{-8}/yr. This last rate is calculated assuming guillotine rupture in a (b)(7)(F) length of enhanced 42" pipeline within (b)(7)(F) of both the switchyard and the GT2/3 fuel oil storage tank.

Jet Fire – Emergency Operations Facility (EOF)

Considering a jet fire close to Emergency Operations Facility (EOF) and conservatively assuming damage to wiring and instrumentation on the exterior of this facility will result with thermal radiation in excess of 12.6 kW/m^2 (see Table 4 in the main report), we are concerned with a guillotine rupture of the enhanced 42" pipeline within 386 m (1266 ft) of the EOF. This distance translates into a concern over guillotine rupture in a (b)(7)(F) length of 42" pipeline. An exposure rate for rupture followed by ignition of 4.02 x 10^{-7}/yr can be predicted for this length (Table B-3).

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[12] The (b)(7)(F) distance of concern is taken from the data for a 42" pipeline presented in Table 5 of the main report.

[13] The (b)(7)(F) distance of concern is taken from the data for a 42" pipeline presented in Table 10 of the main report.

Vapor Cloud Explosion involving Detonation – Emergency Operations Facility (EOF)

If instead of a jet fire, assuming a hypothetical vapor cloud explosion involving detonation that follows the rupture of the proposed 42" gas pipeline close to the Emergency Operations Facility (EOF), our concern is with a guillotine rupture of the 42" pipeline in (b)(7)(F) [redacted] length of enhanced 42" pipeline within (b)(7)(F) [redacted] of the EOF assuming it is only detonations that result in overpressures of 1 psi at the EOF that are of concern. A frequency of rupture followed by detonation of 2.79×10^{-8} /yr. can be predicted for this length (Table B-3).

Jet Fire – Meteorological Tower

Considering next the consequences of a jet fire close to the meteorological tower and conservatively assuming damage will result when thermal radiation exceeds 12.6 kW/m^2 (see Table 3 in the main report), we need be concerned with a guillotine rupture of the 42" pipeline within 386 m (1266 ft) of the tower. This distance translates into a concern over the guillotine rupture of a (b)(7)(F) [redacted] length of unenhanced 42" pipeline and (b)(7)(F) [redacted] length of enhanced 42" pipeline. An exposure rate for rupture followed by ignition of 1.86×10^{-6} /yr. can be predicted for these lengths (Table B-3).

Vapor Cloud Explosion involving Detonation – Meteorological Tower

Considering the rupture of the pipeline close to the meteorological tower and a subsequent vapor cloud explosion involving detonation, we need be concerned with a guillotine rupture in (b)(7)(F) [redacted] (b)(7)(F) [redacted] length of unenhanced 42" pipeline and a 203 m (666 ft) length of enhanced 42" pipeline within (b)(7)(F) [redacted] of the tower, assuming our concern is with detonations that result in a 1 psi overpressure. The exposure rate for this event is ~ 1.50×10^{-7} /yr (Table B-3).

Jet Fire – Unit 3 Steam Generator Mausoleum

A jet fire close to the Unit 3 steam generator mausoleum will result in thermal radiation in excess of 12.6 kW/m^2 (see Table 4 in the main report) being incident on the structure. However, given this is a robust concrete structure with no external instrumentation, our concern is with higher heat fluxes ~ 31.5 kW/m^2 or more that will cause building damage—we are concerned with a guillotine rupture of the 42" pipeline within 386 m (1266 ft)[14] of the mausoleum[15]. This distance translates into a concern over guillotine rupture in a (b)(7)(F) [redacted] length of unenhanced 42" pipeline. An exposure rate for rupture followed by ignition of 1.38×10^{-6}/yr can be predicted for this length (Table B-3).

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[14] The (b)(7)(F) [redacted] distance of concern is taken from the data for a 42" pipeline presented in Table 5 of the main report.

[15] Should the 42" pipeline rupture with a double sided full bore release of natural gas that ignites, the resulting jet flame will give a 31.5 kW/m2 thermal heat flux at (b)(7)(F) [redacted] from the point of rupture.

Vapor Cloud Explosion involving Detonation – Unit 3 Steam Generator Mausoleum

If instead of a jet fire, assuming a hypothetical vapor cloud explosion involving detonation that follows the rupture of the proposed 42" gas pipeline close to the Unit 3 steam generator mausoleum, our concern is with a guillotine rupture of the 42" pipeline in (b)(7)(F) [redacted] length of unenhanced 42" pipeline and (b)(7)(F) [redacted] length of enhanced 42" pipeline within 352 m (1155 ft)[16] of the mausoleum assuming it is only detonations that result in overpressures of 1 psi at the mausoleum that are of concern. An exposure rate for rupture followed by detonation of 1.95×10^{-7} /yr. can be predicted for this length (Table B-3).

These frequency calculations are summarized in Table B-4. These predictions pertaining to the exposure rates for fire and explosion following a pipeline rupture are highly conservative in that the assumptions made in calculating the distances at which overpressures and high heat fluxes can reach are conservative (see Table 12 in the main report). Consequently, the pipeline lengths used here to calculate exposure rates will also be conservative. Accordingly we can conclude that the proposed pipeline satisfies NRC criteria pertaining to explosion (detonation) risk as, with two exceptions, the predicted frequency of any postulated event is below the 10^{-6}/year criterion established in Regulatory Guide 1.91 for circumstances in which conservative assumptions are made. The exceptions are the met tower and Unit 3 steam generator mausoleum, which could suffer damage if a failure of the pipeline is postulated to occur in the piping closest to the tower that does not include enhanced design features. However, that piping still meets present design criteria (Exhibits A and B) and also has a very low probability of failure. Further, even if a pipeline failure and damage to the meteorological tower are postulated, that event poses no additional risk to IPEC as there are established alternative means to obtain meteorological data in the event of an emergency. Similarly, thermal damage to the exterior of the Unit 3 steam generator mausoleum will not have other consequences because this structure is of rugged concrete construction.

[16] The (b)(7)(F) [redacted] distance of concern is taken from the data for a 42" pipeline presented in Table 10 of the main report.

Table B-4

Exposure Rates for Potential Damaging Fire and Explosion Events

Event	Exposure Rate (/year)
Jet fire/switchyard	7.23×10^{-7}
Vapor cloud explosion involving detonation/switchyard	5.52×10^{-8}
Jet fire/switchyard and GT2/3 diesel fuel oil tank	5.20×10^{-7}
Vapor cloud explosion involving detonation/switchyard and GT2/3 diesel fuel oil tank	4.25×10^{-8}
Jet fire/EOF	4.02×10^{-7}
Vapor cloud explosion involving detonation/EOF	2.79×10^{-8}
Jet fire/meteorological tower	1.86×10^{-6}
Vapor cloud explosion involving detonation/ meteorological tower	1.50×10^{-7}
Jet fire/Unit 3 steam generator mausoleum	1.38×10^{-6}
Vapor cloud explosion involving detonation/ Unit 3 steam generator mausoleum	1.95×10^{-7}

B4. Likelihood and Consequences of Pipeline Rupture and Missile Generation

Given their proximity to the proposed southern route, the switchyard, GT2/3 diesel fuel storage tank, Unit 3 steam generator mausoleum and meteorological tower must all be considered as being potentially vulnerable to missile damage should the pipeline rupture close to these SSC's. All other targets of concern lie outside the 274 m (900 ft) distance that missiles can be thrown. The frequency of pipeline rupture and missile generation can be predicted as the product of the pipeline rupture frequency (1.98×10^{-6}/mile.yr assuming the additional safety features are in place) and the conditional probability of missile generation in a pipeline rupture (0.44[17]). The

[17] In 9 events involving the rupture of natural gas transmission pipeline reported upon in detail by the NTSB, mention is made of fragments of the pipeline being thrown off in 4 events (i.e., 44 % of the 9 events).. The 9 events in question are those involving the rupture of natural gas transmission pipelines for which detailed reports are available on the NTSB website (http://www.ntsb.gov/investigations/reports-pipeline.html). The events occurred between 1986 and 2010.

resulting frequency is thus 8.71×10^{-7}/mile.yr. In the absence of these enhancements, the frequency of pipeline rupture and missile generation is 5.81×10^{-6}/mile.yr (a rupture frequency of 1.32×10^{-5}/mile.yr multiplied by a 0.44 probability of missile generation). These frequencies cannot be applied, however, without assigning a probability that the missile would strike an object of concern. An upper bound estimate of this probability can be obtained by estimating the angle subtended by the object at its closest point to the pipeline—ignoring the possibility that missiles will fall short of or fly over the object and assuming that missiles are equally likely to be thrown in all directions. These frequencies, probabilities and the resulting exposure rates for missile damage for various SSCs are presented in Table B-5. From the exposure rates we can conclude that missile generation will contribute minimal additional risk.

Table B-5

Upper-Bound Missile Damage Frequencies

		Length of Pipeline within 274 m (900 ft) of the Object[18]		Pipeline Rupture Frequency (/mile.yr)			
SSC of Concern	**Conditional Probability of Missile Damage given Missile Generation[19]**	**Enhanced Pipeline**	**Unenhanced Pipeline**	**Enhanced Pipeline**	**Unenhanced Pipeline**	**Probability Missiles Generated**	**Exposure Rate (/year)**
Switchyard	(b)(7)(F)	(b)(7)(F)	(b)(7)(F)	1.98×10^{-6}	1.32×10^{-5}	(b)(7)(F)	1.32×10^{-7}
GT2/3 storage tank				1.98×10^{-6}	1.32×10^{-5}		1.51×10^{-8}
Met tower				1.98×10^{-6}	1.32×10^{-5}		2.06×10^{-9}

[18] The 274 m (900 ft) distance appears, from a literature survey, to be the greatest distance that missiles can be thrown after pipeline rupture.
[19] This conditional probability is calculated from the angle subtended by the SSC in question at the pipeline when the distance between the pipeline and SSC is least—it is the length of the arc that captures the SSC divided by the circumference of the circle in which the arc is to be found. The effective width of the meteorological tower is taken as 2 m assuming that pipe fragments are so large that a fragment passing the tower will strike it if it passes within 1 m.

Table B-5

Upper-Bound Missile Damage Frequencies

		Length of Pipeline within 274 m (900 ft) of the Object[18]		Pipeline Rupture Frequency (/mile.yr)			
SSC of Concern	**Conditional Probability of Missile Damage given Missile Generation[19]**	**Enhanced Pipeline**	**Unenhanced Pipeline**	**Enhanced Pipeline**	**Unenhanced Pipeline**	**Probability Missiles Generated**	**Exposure Rate (/year)**
U3 steam gen mausoleum	(b)(7)(F) [redacted]			1.98×10^{-6}	1.32×10^{-5}	(b)(7)(F) [redacted]	3.83×10^{-8}

B5. Potential Acts of Terrorism

NRC regulations governing evaluation of potential external hazards do not require consideration of terrorist-induced failures, but we would note that:

- No assumed rupture of the proposed pipeline will cause material damage to equipment within the SOCA (security owner controlled area) due to distance from the southern route to the SOCA. Furthermore, those portions of the pipeline closest to the SOCA lie underground on IPEC property. Therefore a terrorism threat to this section of pipe is not credible and not considered further.

- The segment of the enhanced pipeline near the switchyard, GT2/3 diesel fuel storage and Emergency Operations Facility would also be installed underground with at least 4' of cover and reinforced concrete mats. Therefore, consistent with the explanations provided above a terrorism threat for this section of pipe is not credible and not considered further.

- The above-ground portion of the pipeline located east of Broadway at the point at which the proposed 42" pipeline enters the existing right of way is hypothetically vulnerable to wanton damage. However, this point is so distant from the SOCA and systems, structures and components of concern outside the SOCA that a fire or explosion there will not cause material damage to them.

We conclude therefore that the proposed new pipeline will not introduce additional risk as a result of terrorism or other wanton damage.

B6. Seismic Events

PMHSA and European [29] data show ground movement has been responsible for a number of pipeline ruptures. While larger diameter pipelines are less susceptible to ground movement [35], they are still vulnerable—1 of 12 rupture events involving pipelines of 36" or more in diameter in the period 1/1/2002 to 7/1/2014 recorded by the PHMSA was attributed to this cause (but in this instance the ground movement was not attributed to a seismic event). That said, we can conclude that seismic events involving the proposed gas pipeline will not introduce additional risk as "The magnitude of earthquakes in the northeast is relatively low and would not pose a problem for a modern welded-steel pipeline" [36]. Furthermore, the potential for pipe ruptures as a result of earth movement in a seismic event is low as the liquefaction/cyclic failure potential of the soils above the bed rock (on site) appears to be low [35]. Finally, we note that in evaluating seismic events at IPEC, a loss-of-offsite power has already been assumed [1], thus any damage to the switchyard or the GT2/3 diesel fuel oil storage tank that might follow a hypothetical seismic-induced rupture of the pipeline would not introduce risks that have not been evaluated previously.

B7. References

(Note: the numbers assigned to references in this appendix are consistent with those used for references in the main body of the report)

[1] IP3 IPEEE, 1995.

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

[10] State of California, "2007 Guidance for Protocol for School Site Risk Analysis".

[28] Bechtel Associates Professional Corporation, "Replaced Steam Generator Storage Facility, Design Package 2, 5-22-87 NSE.

[29] EGIG, Gas Pipeline Incidents, 1970-2010, December 2011.

[30] Center for Chemical Process Safety, "Guidelines for Chemical Transportation Risk Analysis", American Institute of Chemical Engineers, New York, NY, 1995.

[31] US Department of Transportation, "The State of the National Pipeline Infrastructure", 2013.

[32] US Energy Information Administration, US Natural Gas Pipeline Projects, 7/1/2014 (http://www.eia.gov/naturalgas/data.cfm).

[33] Phil Hopkins, et al., "Pipeline Risk assessment: New Guidelines", WTIA/APIA Welded Pipeline Symposium, Sydney, Australia, April 3, 2009.

[34] Vania De Stefani, Zoe Wattis and Michael Acton, "A Model to Evaluate Pipeline Failure Frequencies based on Design and Operating Conditions", AIChE, 2009 Spring Annual Meeting.

[35] Enercon Services, Inc., "Report of Liquefaction Potential Assessment", Prepared for Entergy Nuclear, Report IP-RPT-14-00010, June 26, 2014.

[36] Spectra Energy Partners, Algonquin Incremental Market Project Resource Report 11, Reliability and Safety, FERC Docket No CP14-xxxx-000, February 2014.

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Exhibit A

In addition to the much thicker, stronger steel and protected pipe to be installed along a segment of the southern route described in the report (the enhanced pipe), it is important to note that Spectra Energy has proven Standard Operating Procedures (SOP's) that they will be implementing before, during and after the AIM pipeline is built. Many of these SOP's have been filed with FERC. These SOP's result in additional significant margins of safety to the pipeline further reducing the impacts from possible threats.

The Spectra SOP's include but are not limited to the following:

Document Title	Document Number	Description
SOP Administration		Overview of the Standard Operating Procedures, the organization, who is responsible, frequency of updates, etc.
Integrity Management Program Documents and Procedures		
Integrity Management Program	09-0000	Details the program used to comply with 49 CFR 192 subpart O and ASME B31.8S.
Action Item Summary Sheet	405	Gives frequency, form number, and responsibility of IMP tasks
External Corrosion	410	Part of the Threat Response Guidance Documents
Internal Corrosion	420	Part of the Threat Response Guidance Documents
Stress Corrosion Cracking	430	Part of the Threat Response Guidance Documents
Manufacturing	440	Part of the Threat Response Guidance Documents
Construction	450	Part of the Threat Response Guidance Documents
Equipment	460	Part of the Threat Response Guidance Documents
Third Party Damage	470	Part of the Threat Response Guidance Documents
Incorrect Operations	480	Part of the Threat Response Guidance Documents
Weather and Outside Forces	490	Part of the Threat Response Guidance Documents
Management of Pipeline Dents and Mechanical Damage	510	How to evaluate dents/mechanical damage and how to respond
Hardspots	511	Best practices for handling hardspots in piping
Selective Seam Corrosion	512	Best practices for handling SSC in piping
Effects of Pressure Cycles on DEGT System	513	Risk to system from fatigue crack growth is found to be negligible.

Document Title	Document Number	Description
Assessment Methodology for Site HCAs	514	How to implement the IMP on non-mainline portions of the system
Operating Pressure History	515	How to determine the operating pressure history for a line
Methodology for Selection of RCV Sites	516	The function of this technical document is to define the Company's methodology for determining the location of remote control valves (RCV) for the purpose of improving response time and minimizing consequences of pipeline emergencies. This methodology is applicable to both existing facilities and new construction.
Pipeline Operating, Inspection, and Maintenance Procedures		
CLASS DETERMINATION PROCESS	AP-CD1.3	Detailed listing of responsibility for work and deliverables and work flows to create and maintain Class Location Maps
MAXIMUM OPERATING PRESSURE CALCULATION	AP-CD3.0	Detailed listing of how to calculate and document a pipeline MAOP
Action Item Summary Sheet	1-1010	Frequency that various pipeline inspections and surveys should be conducted.
Gas Pipeline Shutdown	1-2010	This procedure describes the requirements and the sequence of events which must take place for a pipeline or compressor station to be removed from service.
Drying Gas Pipelines	1-2020	This procedure describes the process for removal of liquid from the pipeline.
Branch Connections - Hot Taps	1-3020	This procedure describes the necessary communications with Gas Control and the reporting requirements associated with cutting into an operating pipeline and connecting branch piping while the line is under pressure, also called "hot tapping."
Pipeline Road and Rail Crossings	1-3030	This procedure describes the requirements and procedures to install pipelines under existing roads and railroads, or making provisions to protect existing pipelines that are to be crossed by new roads or railroads.

Document Title	Document Number	Description
Changing Pipeline Service Status	1-3040	This procedure describes the activities associated with deactivating pipelines, abandoning pipelines in place or by removal and maintaining pipelines which are currently in inactive (idle), deactivated or decommissioned status.
Uprating Steel Pipelines	1-3060	This procedure describes the raising of the Maximum Allowable Operating Pressure (MAOP) or Maximum Operating Pressure (MOP) of an existing pipeline or a deactivated pipeline that is to be reactivated. In addition, it includes the studies, investigations, repairs, alterations, tests, and documentation necessary.
Excavation and Backfill	1-4010	This procedure describes the steps required to safely excavate and backfill around existing Company pipelines to prevent damage and provide adequate support and protection to minimize the stresses acting on the pipeline.
Locating Buried Pipelines Using Electronic Line Locators	1-4020	This procedure provides guidance for locating and temporary marking of buried Company pipelines. This applies to all locate requests from third parties and locates prior to excavation activities of Company pipelines. Locating Company pipelines with electronic line locators is intended to provide general location information.
Right-of-Way Maintenance	1-5010	This procedure describes right-of-way maintenance which protects the pipelines, permits access to the pipelines, and aids in avoiding interference with the land's intended use. During patrols, any evidence of erosion, scour, subsidence, or slides, or the potential for any of these conditions to occur will be noted.
Pipeline Facilities Identification	1-5020	This procedure describes the various methods used to identify Company pipelines and related facilities, as well as the activities involved with the placement and maintenance of the different methods of identification.
Pigging and Pig Trap Operation	1-5030	This procedure describes pigging and pig trap operation.
Handling of Pipeline Solids	1-5040	This procedure describes the handling and testing of pipeline solids which may be gathered from pigging operations or during the changing of filters.

Document Title	Document Number	Description
Clearing Freezes	1-5070	This procedure describes how to provide a safe, proven method for clearing pipeline freezes or blockages due to water or hydrates.
Pipeline Patrol and Leakage Survey Frequency Criteria	1-6010	This procedure describes the frequency of pipeline patrols and leakage surveys that will be conducted on the pipeline system for onshore and offshore pipelines that are in gas service, and for onshore pipelines that are in idle service to ensure the safety of the pipeline.
Leakage Surveys Utilizing Gas Detection Equipment	1-6020	This procedure describes the methods for conducting and documenting leakage surveys on above and below ground piping utilizing gas detection equipment.
Blasting Near Pipelines	1-6030	How to protect pipelines from blasting operations.
Aerial Pipeline Patrol	1-6040	This procedure describes the criteria for conducting and documenting aerial pipeline patrols.
Pipeline River and Waterway Crossing Surveys	1-6050	This procedure describes the criteria for conducting and documenting aerial pipeline patrols.
Mining Subsidence and Soil Slippage	1-6060	The investigation of proposed mining activities or unstable soils can reduce the possibility of pipeline damage due to earth movement and associated stresses, by identifying potential problem areas and allowing sufficient time to take preventive measures.
Right-of-Way Encroachments	1-6070	This procedure describes how to manage right-of-way encroachments which include foreign facility crossings. These outside forces could damage the pipelines or leave them vulnerable to future damage or an unsafe operating condition.
One-Call System Response	1-6090	This procedure describes the guidelines to be used by Area Management in preparing for and responding to one-call notifications and line locate requests.
Direct Non-LDC Customer Notification of Buried Pipelines	1-6100	This procedure describes how to provide notification of buried piping to customers who receive gas directly from the Company and whose buried Service, Farm or Industrial Lines are not owned by the Company.
Shutdown Worksheet Final.XLS		Form used when a pipeline section must be taken off line and blown down
Corrosion Control, Inspection, and Remediation		

Document Title	Document Number	Description
Action Item Summary Sheet	2-1010	Lists the frequency that pipeline corrosion inspection procedures should be used.
Glossary	2-1020	The definitions used in the Company Manuals are listed in the document.
Tables and Formulae	2-1030	For use on cathodic protection systems
Notes	2-1040	Notes on various Corrosion Control Standard Operating Procedures.
Structure-to-Electrolyte Potential Measurement	2-2010	It is used to evaluate the level of cathodic protection on a pipe or metallic structure.
Line Current Flow Measurement	2-2020	These line current flow measurements are useful in the overall evaluation of cathodic protection, interference currents, and corrosion activity.
Shunt or Resistor Current Flow Measurement	2-2030	Current flow determination is necessary to evaluate corrosion activity, effectiveness of cathodic protection, and the proper operation of rectifiers, galvanic anodes and effectiveness of critical bonds.
Soil Resistivity Measurement	2-2040	Soil resistivity measurements are used for anode bed design, location of corrosive areas on bare pipe, and evaluating the corrosivity of the soil.
pH Measurement	2-2050	This procedure describes the testing methods to determine the pH of a sample in the field.
Exothermic Weld	2-2060	This procedure describes the requirements to perform an exothermic weld.
Rectifier Inspection and Maintenance	2-2070	The purpose of a rectifier is to provide impressed current cathodic protection to underground metallic structures. The procedure for inspection and maintenance of these units is included in this procedure.
Groundbed Specifications and Inspection	2-2080	This procedure describes the installation and inspection of impressed current cathodic protection groundbeds.
Galvanic Anode Inspection	2-2090	This procedure describes inspection of galvanic anodes where anode leads and pipe contact leads are terminated in an accessible terminal box which allows current output measurements and where anode leads and pipe contact leads are buried, thus preventing current output measurements.
Casing Isolation Testing	2-2100	This procedure describes the tests for electrical short circuits between casings and the carrier pipe at cased pipeline locations.

Document Title	Document Number	Description
Insulating Joint Isolation - Design Considerations and Testing	2-2110	This procedure describes the design considerations and testing requirements for isolation joints for maintaining electrical isolation between a pipeline and other metallic structures.
Interference Testing and Mitigation	2-2120	This procedure describes the detection, measurement and mitigation of stray current interference from foreign sources, such as nearby pipeline cathodic protection systems, direct current powered transit systems and mining operations.
Close Interval Survey	2-2130	The survey involves measuring the pipe-to-soil potentials at varying distance intervals directly over a pipeline.
Current Requirement Testing	2-2140	This procedure describes the determination of the approximate amount of current required to cathodically protect a section of pipeline or any other underground metallic structure.
Grounding Cell Inspection	2-2150	Grounding cells are protective devices which prevent high voltage AC fault currents or high voltage surges from damaging insulating joints and coated pipelines in high voltage transmission line rights-of-way.
Coating Systems for Buried or Submerged Piping	2-2160	This procedure describes the application and maintenance of coatings for buried or submerged piping.
Critical Bond Inspection	2-2170	A bond is an intentional metallic path between two or more metallic structures capable of conducting electrical current flow.
Annual Corrosion Control Surveys	2-2180	This procedure describes how to conduct the Annual Corrosion Control Survey of Company pipelines and structures.
Measuring IR Drop	2-2190	This procedure describes how to apply and interpret the IR drop. IR drop caused by current flow in the soil/coating is termed "electrolytic IR drop;" IR drop caused by current flow in the pipe (metal) circuit is termed "metallic IR drop."
Application of Cathodic Protection Criteria	2-2200	Meeting any criterion or combination of criteria in this section is evidence that adequate cathodic protection has been achieved.

Document Title	Document Number	Description
Induced AC – Safety and Corrosion	2-2210	How to measure and mitigate induced AC.
Earth Gradient Measurement	2-2220	This procedure describes methods used to perform cell-to-cell and side drain surveys.
Cathodic Protection System Design	2-2230	This procedure describes requirements for cathodic protection design.
Coating Fault Detection Surveys	2-2240	This procedure describes how to use voltage gradient techniques to locate coating defects on buried pipelines.
IR Drop/Coupling Surveys	2-2250	The survey involves measuring IR drop potentials at varying distance intervals with probe rods in direct connection to the coupled pipeline. This survey is employed to determine continuity of bonds on coupled pipelines.
Coating Resistance Measurement	2-2260	This procedure describes testing methods for obtaining coating resistance measurements.
Pipeline Current Mapper (PCM) for Current Attenuation	2-2270	A Current Attenuation (CA) survey (also known as an Electromagnetic Survey or a Pipeline Current Mapper (PCM) Survey) is used to determine the relative coating condition of a buried metallic pipeline.
Pipeline Current Mapper (PCM) A-Frame For Alternating Current Voltage Gradient (ACVG)	2-2280	Alternating Current Voltage Gradient (ACVG) is a survey technique used to detect flaws or holidays in buried pipeline coatings.
Assessment of Pipeline Coating Using Direct Current Voltage Gradient (DCVG)	2-2290	This SOP describes the process used to assess the condition of underground pipeline coating using Direct Current Voltage Gradient (DCVG) survey techniques to identify coating flaws (holidays).
Pin Brazing	2-2300	How to perform a pin brazing connection.
Internal Corrosion Monitoring and Mitigation	2-2310	Contains requirements and guidelines for inspection, evaluation, monitoring and mitigation of internal corrosion on distribution, transmission, storage and jurisdictional gathering lines within the Company pipeline system.
Evaluation of Remaining Strength of Pipe with Metal Loss	2-4020	This procedure describes the details of those evaluation methods currently approved to determine the remaining strength of pipe with metal loss.

Document Title	Document Number	Description
Inline Tool Pipeline Inspection	2-4030	Describes inline inspection with magnetic flux leakage (MFL) technology.
Buried Pipe Inspections	2-4040	How to inspect buried pipelines for coating deterioration or external corrosion.
Shorted Casing Repair and Mitigation	2-4050	This procedure provides guidelines for remedial action to be taken at shorted casings which have been verified to be shorted using an approved test method.
Physical Observations and Collection of Liquid and Solid Samples	2-4060	Samples are for determining if internal corrosion is present.
Bacterial Corrosion Tests	2-4070	This procedure describes testing for the presence of Sulfate Reducing Bacteria (SRB) and/or Acid Producing Bacteria (APB).
Corrosion Control Remedial Action	2-4080	Used when existing corrosion controls must be altered.
Gas Sampling	2-4090	Samples are for determining if internal corrosion is present.
Water Detection	2-4100	How to test for the presence of water in a liquid sample.
Alkalinity Testing of Liquids	2-4110	How to test for total alkalinity of a liquid sample.
Dissolved CO2 Testing in Water	2-4120	How to test for carbon dioxide in a liquid sample.
Dissolved H2S Testing in Water	2-4130	How to test for hydrogen sulfide in a liquid sample.
Sulfide and Carbonate Testing of Solids	2-4140	How to test a sold for sulfides and carbonates.
Coupon Installation and Removal	2-4150	How to install, remove, and analyze corrosion coupons.
Aboveground Coating Systems	2-5010	This procedure describes coatings for aboveground piping and equipment, such as aerial markers, casing vents, milepost markers, pig traps, and valves and fittings located in the Company right-of-way outside and including the station suction and discharge valves.
Atmospheric Pipe Inspection	2-5020	How to inspect above ground piping for coating deterioration or pipe corrosion.
SOP's for Emergency Response and for Common Procedures		

Document Title	Document Number	Description
Action Item Summary Sheet	5-1010	Frequency that various emergency response procedures should be conducted or maintained.
Area Emergency Response Procedures	5-2010	This procedure provides the foundation for responding to emergencies by Transmission (Operations) Foundation elements include the SET US Operations Crisis Management Plan and Incident Command Structure.
Emergency and Security Event Simulation	5-2020	This procedure describes the requirements for preparing and conducting emergency and security event simulations.
Investigation of Failures	5-2030	This procedure and the SET U.S. Operations Crisis Management Plan are to be implemented together to enable Company personnel to analyze a system failure or accident.
Safety-Related Conditions Reporting	5-2040	This procedure list the conditions related to leaks, damage or defects that would potentially be reported as a safety-related condition. It also explains the tests, which should be administered to determine if a reportable condition does exist, and defines the reporting responsibilities.
Response to Abnormal Operations	5-2050	This procedure describes how to respond in instances of abnormal operations.
DOT/BOEMRE Incident Reporting	5-2060	This procedure describes the requirements for making verbal and written notification to the National Response Center (NRC), DOT, BOEMRE, and state agencies on Incidents (onshore or offshore) and offshore damages.
Above Ground Facility – Minimum Security Practices	5-2070	This document specifies the minimum security practices for Compressor stations, Processing plants, Main line block valve, launcher and receiver sites, Meter and regulator (M&R) stations, Reservoir and cavern storage wells, and Aerial pipeline crossings.
Releasing Security Sensitive Information	5-2080	The purpose of this document is to specify the requirements for processing the release of sensitive information to Federal, State and local government officials and agencies as well as private companies and individuals. This document also specifies information that is acceptable to distribute to the public without review.

Document Title	Document Number	Description
Internal DOT Audit Procedure	5-2090	This procedure provides a program outline for a comprehensive team based pipeline safety compliance audit program. This program will include an audit guide for compliance and SOP application review at each Region and Area Office on a systematic periodic basis.
Region Hurricane Response Plan	5-2100	This procedure defines the guidelines for the regions, which are affected by hurricanes, to develop hurricane response plans.
TSB/NEB Incident Reporting	5-2140	This procedure describes the steps and responsibilities for reporting incidents, accidents and occurrences to the Transportation Safety Board of Canada (TSB).
Purging	5-3010	This procedure describes purging requirements for pipelines, compressor station piping, meter station piping and other related equipment. There are three reasons to purge a pipeline. 1) Purging is performed to remove natural gas from a pipeline and replace it with nitrogen or air. 2) Purging is performed to remove air or nitrogen from the pipeline and subsequently replace it with natural gas. Purging is necessary to minimize inert constituents in the gas and eliminate a potentially combustible mixture of gas and air inside the pipeline. 3) Purging is also performed to evacuate gas away from a pipeline tie-in.
Filter (Pipeline - Operations, Maintenance & Inspection)	5-3040	This procedure describes safe standard procedures for inspecting and/or removing and installing gas pipeline filter elements.
Pressure Testing	5-3050	This procedure describes how pressure testing substantiates the Maximum Allowable Operating Pressure (MAOP) and verifies the integrity of steel pipelines.
Pipe-Type and Bottle-Type Holders	5-3060	This procedure describes provisions for the routine testing of pipe-type or bottle-type holders as defined in O&M Plan, Section 3.0. Pipe-type or bottle-type holders must be monitored for adequate cathodic protection levels to mitigate possible external corrosion and must be checked for dew point of vapors contained in the stored gas, that if condensed might cause internal

Document Title	Document Number	Description
		corrosion.
Hazardous Energy Control (Lockout/Tagout)	5-3070	This procedure is designed to meet requirements established in OSHA 29CFR 1910.147. This purpose of this procedure is to provide guidance to safely perform service and/or maintenance on equipment where the unexpected energizing, startup or release of stored energy may occur.
Verification and Certification of Test Equipment	5-3080	This procedure describes inspection, verification and certification requirements for test equipment to maintain operability and required accuracy.
Collection of Liquid and Solid Samples and Physical Observations	5-3090	This procedure describes the steps for obtaining and handling samples of liquids, and/or solids for internal corrosion evaluation and /or gas measurement purposes.
Third Party Damage	5-4020	This procedure describes third party damage which includes, but is not limited to, any damages inflicted upon the pipeline and its facilities by the encroachment of foreign construction equipment, vehicular traffic, welding operations, or nearby blasting. This procedure is required to protect and maintain the serviceability of the pipelines and facilities.
Valve Inspection and Maintenance	5-5010	This procedure describes the activities associated with valve inspection and maintenance. It also describes the safe and proper operation of valves.
Valve Actuators (Automatic) - Maintenance/ Inspection	5-5020	This procedure describes the safe and proper maintenance of automatic valve actuators.
Remotely Controlled Valves Inspection and Maintenance	5-5030	This procedure describes the methods of inspecting and maintaining the equipment that remotely control mainline valves.

Document Title	Document Number	Description
Overpressure Protection and Capacity Verification	5-6010	This procedure describes the methodology utilized for protecting both the Maximum Allowable Operating Pressure (MAOP) and MAOP plus the build-up allowed for operation of pressure limiting and control devices for all compressor stations, mainline piping, and measurement and regulating stations per the pipeline regulations and other incorporated references.
Relief Valves - Testing, Inspection and Maintenance	5-6020	This procedure describes the testing and inspection (T&I), and maintenance of relief valves used in natural gas, air and storage tank service.
Regulators and Control Valves	5-7010	This procedure describes the requirements for inspection, testing, maintenance and repair of pressure regulators, pressure monitors, and flow control valves.
Controllers	5-7020	This procedure describes the inspection, testing, maintenance and repair of pneumatic and electronic controllers.
Vault Inspection and Maintenance	5-7030	This procedure describes the activities associated with vault inspection.
Hot Work Permits	5-8010	This procedure describes the activities associated with welding, cutting, and electric power tools or other spark-producing equipment in a classified work area.
Methanol Injection	5-9010	This procedure describes the method for injecting methanol into the pipeline at a measuring station.
Gas Control and Pipeline Operation Procedures		
Initial Notification of Potential Emergency	8-2010	This procedure describes the requirements and the sequence of actions to be taken by Gas Control in the event of an initial notification of a potential emergency condition on the pipeline.
Emergency Response	8-2020	Emergencies include pipeline rupture
Alarm Management	8-2030	How to manage alarms received through the SCADA system
Outage Management	8-2040	An Outage is any pipeline facility that becomes unavailable for any reason.
Early Notification Disaster Recovery	8-2050	How to prepare for and conduct Disaster Recovery when given sufficient notification.
Short Notification Disaster Recovery	8-2060	How to conduct Disaster Recovery with no notice.

Document Title	Document Number	Description
Abnormal Operating Conditions	8-2070	How to respond to abnormal operations
Shift Change	8-2080	This procedure describes the requirements and sequence of actions necessary to adequately brief the incoming control room personnel after a shift change.
Change Management	8-2090	Change Management of the equipment or operations of the pipeline.
Inspection, Testing, and Repair Specifications and Procedures		
In-Line Tool Pipeline Inspection	9-2010	An overview of inline inspection in the company.
External Corrosion Direct Assessment (ECDA)	9-2020	The purpose of this procedure is to describe the process of performing External Corrosion Direct Assessment (ECDA) surveys on identified pipeline segments. This procedure is written in accordance with NACE SP 0502, "Pipeline External Corrosion Direct Assessment Methodology".
Dry Gas Internal Corrosion Direct Assessment (ICDA)	9-2030	The purpose of this procedure is to describe the process of performing the Dry Gas Internal Corrosion Direct Assessment (DG-ICDA) methodology on specified pipeline segments carrying normally dry gas. This procedure is in accordance with Federal Rulemaking on integrity management for gas pipelines (49 CFR Part 192 and ASME/ANSI B31.8S-2001) and NACE SP 0206, "Internal Corrosion Direct Assessment (ICDA) Methodology for Pipelines Carrying Normally Dry Gas".
Stress Corrosion Cracking Direct Assessment (SCCDA)	9-2040	The purpose of this procedure is to describe the process that the Company uses to perform Stress Corrosion Cracking Direct Assessment (SCCDA) on identified pipeline segments. This procedure is written in accordance with NACE RP0204-2004, "Stress Corrosion Cracking Direct Assessment Methodology".
Hydrostatic Testing for Stress Corrosion Cracking	9-2050	This procedure details the Company's methods and requirements for conducting hydrostatic testing to verify the integrity of a pipeline by testing sections that have shown evidence of stress corrosion cracking (SCC) as leaks or failures, Category 2, 3 and 4 SCC found during direct examination of the pipeline, or may

Document Title	Document Number	Description
		have a higher vulnerability to SCC due to historical operating conditions.
Direct Examination	9-2060	The purpose of this procedure is to describe the process of performing the Direct Examination (DE) methodology on specified pipeline segments carrying natural gas.
Assessment of Pipeline Segments Using Guided Wave UT	9-2070	This SOP describes the process to assess the integrity of pipeline segments using the guided wave ultrasonic testing process (GWUT). GWUT may be used to assess above ground, buried, or cased pipe.
Response to In-Line Inspection	9-3010	This procedure describes the process for evaluating anomalies that are detected by in-line inspection tools, the process to determine which anomalies will be selected for direct examination, and a prioritized schedule for conducting the excavation.
Monitoring and Mitigation (ECDA)	9-3020	This procedure outlines the requirements for conducting an external corrosion direct assessment on certain segments of the Company's pipeline system. Contained within this SOP are plans for addressing immediate, scheduled and monitored indications which were identified as part of the assessment process.
Defect Assessment & Repair Options for Internal Corrosion	9-4010	This document covers guidelines for the evaluation of internal corrosion for pipelines carrying natural gas to ensure pipeline integrity. The methodology is applicable to pipelines which are in gas service and can only be inspected manually, or with automated instrumentation, from the exterior of the pipe.
Defect Assessment & Repair Options for External Corrosion	9-4020	This procedure describes the process for examining and evaluating external corrosion anomalies. This procedure describes details of those evaluation methods currently approved to determine the remaining strength of pipe with metal loss.

Document Title	Document Number	Description
Direct Examination & Repair Options for Stress Corrosion Cracking	9-4030	This procedure provides guidance to personnel performing direct examination (nondestructive examination and assessment) of exposed underground pipelines for stress corrosion cracking (SCC).
Defect Assessment & Repair Options for Dents and Mechanical Damage	9-4040	This procedure defines a methodology for field assessment of plain dents and dents interacting with other defects in natural gas pipelines. Provisions of ASME B31.8-2007 §851.41 - §851.43 are incorporated.
Defect Assessment & Repair Options for Miscellaneous Defects	9-4050	This procedure provides guidance for the assessment of exposed pipelines for miscellaneous defects. Miscellaneous defects are generally the result of pipe manufacturing defects, construction damage, or obsolete construction practices.
Magnetic Particle Inspection of Pipelines for Surface Cracks	9-4060	This procedure contains recommendations for performing Magnetic Particle Testing (MT) inspection for the purposes of detecting pipeline surface cracks including all forms of SCC. The recommended method for inspecting Company pipelines is the water based, wet visible black-on-white contrast method.
Ultrasonic Inspection of Line Pipe	9-4070	Either manual or automated ultrasonic inspection (UT) can be used to identify and quantify corrosion on line pipe.
CorrEval Software & User's Guide	9-4110	The CorrEval spreadsheet provides a method for calculating the failure pressure levels of longitudinally oriented part-through flaws of varying depths in pressurized pipe. The method is applicable to blunt defects such as corrosion-caused metal loss.
Mechanical Damage Assessment Software & User's Guide	9-4120	The Company developed Excel spreadsheet programs utilizing ASME B31.8-2007 equations for dent curvature strain assessment, and calculating maximum allowable grinding repair lengths.
Pipeline Repair Procedures	9-5010	This procedure outlines the approved pipeline repair methods available for existing pipelines and details the steps required to perform each repair method for damaged or defective pipe. Area Management shall supervise all repairs to ensure that the work is done in accordance with Company procedures.

Document Title	Document Number	Description
Repair Sleeve Design	9-5020	This procedure should be used in conjunction with SOP #9-5010, "Pipeline Repair Procedures", and provides the engineering requirements for design of full encirclement, steel repair sleeves used as temporary or permanent repairs of corrosion, mechanical damage, weld defects, or material defects in pipe.
Clock Spring Procedures	9-5030	This procedure presents the requirements and procedures for the installation, inspection and removal of Clock Spring composite wraps and is a supplement to the criteria set forth in Section 4.0 of SOP #9-5010, "Pipeline Repair Procedures".
Specifications and Procedures for Pipeline Projects including Construction, Procurement, and Inspection		
Onshore Pipelines and Meter Stations	CS-PL1.7	Specification for the construction of onshore natural gas pipelines.
Onshore Compressor Stations - Painting And Coating	CS-CS1-14.4	Specification for the coating of above and below ground piping.
Quality Assurance Inspection Plan For Purchase Of API Pipe And FBE Coating	IS-QP1.0	The Spectra Energy Quality Assurance plan for the purchase of line pipe and coatings in the United States of America covers manufacture and testing at the pipe mill, shipping the pipe to the coating mill, coating the pipe at the coating mill, load-out of pipe from coating mill to method of transport.
Valves	IS-IV1.1	Valve inspection procedure at the manufacturer
Ultrasonic Weld Seam Inspection Of ERW Linepipe	IS-IP2.0	This specification is established to outline the responsibilities of the ERW linepipe inspection contractor in fulfilling the requirements for supplemental ultrasonic weld seam inspection. This supplemental inspection is to be performed in addition to all other weld seam inspection conducted by the pipe manufacturer and shall be in accordance with Company requirements and the American Petroleum Institute (API-5L).
Pipe	IS-IP1.1	Pipe inspection procedure at the pipe mill

Document Title	Document Number	Description
General - Material/Equipment Inspection Reporting Requirements	IS-IG2.1	This specification outlines the formats, procedure for submittal and submittal schedule for the inspection reports required by the Company for inspections of material/equipment at a Manufacturer's facility.
General - Material/Equipment Inspection Requirements	IS-IG1.1	This specification outlines the responsibilities and general requirements of the Third Party Inspection Company and its representatives as representatives of Spectra Energy Transmission in a material/equipment inspection capacity at a Manufacturer's facility.
Fabrications	IS-IF2.1	Fittings and flanges inspection at the manufacturer
Fittings And Flanges	IS-IF1.1	Fabricated items inspection at the manufacturer
Coating - Induction Bends, Fusion Bonded Epoxy	IS-IC4.1	Inspection of FBE coated induction bends at the coating yard
Coating - Concrete And Anode	IS-IC3.1	Inspection of the concrete coating and anodes at the coating yard
Coating - Fusion Bonded Epoxy	IS-IC2.1	Inspection of FBE coating on pipe at the coating yard
Coating - Internal	IS-IC1.1	Inspection of the internal coating at the coating yard
Induction Bends	IS-IB1.1	Inspection of induction bends at the bend manufacturer
Pipeline/Plant Construction Inspection Manual - Introduction	IG-CIM.1	An overview of inspection methods and form intended for use on construction projects.
Facility Audit Report	TS-711.0	Form to be used when auditing a supplier or manufacturer
Fabrication Surveillance Inspection Checklist		Form to be used when inspecting equipment at a manufacturer
Assessment Document List		Form requesting data related to safety and quality from a manufacturer
Pipe, Double Submerged Arc Weld	ES-PP3.9	Specification for API 5L pipe
Audit Protocol	AP-AM2.1	How to perform a plant audit of an unapproved manufacturer
Onshore Compressor Stations - Pressure Testing	CS-CS1-19.4	Specification for hydrostatic testing of above and below ground piping.

Document Title	Document Number	Description
Pressure Testing	DP-CT1.3	Pipeline specific hydrostatic testing requirements to ensure compliance with DOT requirements.
Non-Destructive Examination	CS-NDE1.0	Minimum requirement for the NDE of welds
Radiography	CS-NDE2.0	Minimum requirement for radiographic inspection of welds
Pressure Testing Of Gas Transmission Facilities	TP-CT-1.5	This procedure provides detailed process requirements for conducting a Pressure Test for Company pipeline or station facilities and provides the criteria for acceptance and documentation of a Pressure Test.

In addition to the above SOP's AGT (Spectra) has stated they will also incorporate the following items during the engineering, procurement and construction of the AIM pipeline project.

a) Quality Assurance/Quality Control (QA/QC) Procedures for the engineering, design, procurement, fabrication and construction.

b) The latest state of the art cathodic protection (CP) systems will be designed and installed by an experienced third party contactor and CP surveys will be conducted in accordance with DOT Part 192 requirements.

c) A robust AC mitigation system will be engineered and installed in areas where the pipeline will be installed adjacent, parallel and crosses high voltage power lines in the area near IPEC.

d) The pipeline coatings will be 100% inspected electronically as the pipeline is lowered into the ground.

e) An Alternating Current Voltage Gradient (ACVG) or Direct Current Voltage Gradient (DCVG) survey will be performed to ensure coating integrity following pipe installation and backfill.

f) Inline inspections (ILI) or smart pig surveys will be conducted as described in the Integrity Management Plan and will be conducted as often as required by Federal Pipeline Integrity Rules and Regulations and ASME B31.8S.

g) The pipeline will be patrolled on a weekly basis per DOT Part 192 to identify possible unapproved encroachments on the ROW.

h) Spectra is also a member of the one-call ("call before you dig") system which is monitored continuously by full-time trained personnel who respond to these calls daily and approved excavations are monitored/supervised by trained inspectors.

i) Operating pressures will be limited to the pipeline maximum allowable operating pressure (MAOP) by the activation of automatic overpressure alarms, shutdown of upstream compressors and isolation devices.

j) Pipeline failures will be detected automatically and immediate alarms will be sent to Spectra's 24/7 control operator who will take the appropriate action in accordance with Spectra's SOP's.

k) 100% of all welds along the segment of pipe near IPEC assets will be radiographed and approved by trained X-ray technicians.

l) The completed pipeline will be subjected to a hydrostatic test continuously for 8 hours in accordance with 49 CFR 192 and Spectra's SOP's.

m) The pipeline will be periodically swept of trapped liquids using swabs or pigs designed for this purpose.

Exhibit B

Pipeline Design Enhancements Proposed by Spectra for IPEC

(in Response to Entergy Questions)

Question	Typical Gas Pipeline Installation/design	IPEC Enhanced Installation/design	Remarks
Pipe pressure safety factors (include national design standard)	49 CFR § 192.111: Class location 1, design factor 0.72 – equates to 72% Specified Minimum Yield Strength ("SMYS"). Class location 3, design factor 0.5 – equates to 50% SMYS.	Pipe to be used for~3935' for Entergy will exceed design factor for Class 4, design factor 0.4 – equates to 40% SMYS. Proposed 0.720" wall thickness ("wt") pipe equates to 36% SMYS.	
Pipe material type (include national design standard)	Pipe Grade will be X-70, 70,000 psi minimum yield strength and 82,000 psi minimum tensile strength, all manufactured to API 5L PSL-2 standards.	Pipe Grade will be X-70. In addition, pipe is procured from vendors who have passed a stringent quality audit, and full-time mill inspection is performed by AGT during pipe production. AGT pipe specifications require additional quality testing and integrity requirements above and beyond API-5L standards.	
Pipe thickness	0.469" wt for Class 1 and 0.510" wt for Class 3	0.720" wt - exceeds Class 1 and Class 3 requirements	Class 4 required wt is 0.6375" for X-70. The proposed 0.720" wt exceeds Class 4

Exhibit B

Pipeline Design Enhancements Proposed by Spectra for IPEC

(in Response to Entergy Questions)

Question	Typical Gas Pipeline Installation/design	IPEC Enhanced Installation/design	Remarks
			requirements, the most stringent DOT Code classification.
Coating material and design details, include specifications	Standard coating to be Fusion Bond Epoxy ("FBE") coating, 16 mils (one thousandth of an inch) nominal (14 mils is industry standard).	Enhanced coating will be dual layer FBE and Abrasion Resistant Overlay ("ARO") with a nominal thickness of 24 mils. AGT will specify 40 mils of coating consisting of 16 mils of FBE and 24 mils of ARO.	ARO will provide for enhanced protection during installation and provide additional corrosion protection. Spectra has indicated this will be changed to a combined thickness of 25mils (min.). See Exhibit C.
Depth of pipe, show via sketch mats, over lay, etc.	3' cover typical and required by the DOT Code (49 CFR § 192.327)	4' cover along with physical concrete mat barrier protection installed 2' below grade (to bottom of slab).	See Exhibit C
Concrete mat cover details, width, thickness, composition, etc.	Not required	2 parallel sets of fiber reinforced concrete slabs (dimensions 3'x 8'x 6") along the pipeline with a 1' separation over the center of pipe.	See Exhibit C
Seismic considerations	Spectra's design takes into account seismic considerations (Note additional	The accelerations from earthquakes in the range experienced in the eastern United States do not pose a risk for high-strength	Note that the worst earthquakes in the eastern United States are of much lower magnitude than the quakes on the west

Exhibit B

Pipeline Design Enhancements Proposed by Spectra for IPEC

(in Response to Entergy Questions)

Question	Typical Gas Pipeline Installation/design	IPEC Enhanced Installation/design	Remarks
	response received from Spectra for this item shown on the last page of this Exhibit B)	welded steel pipelines.	coast where the gas transmission pipelines have proven to operate safely using the same pipeline design methods.
Radiography of welds	10% for Class 1; 100% for Class 3	100% for Class 1 and Class 3	
Additional misc. safety features i.e., safety tape	Not Required	Yellow warning tape will be placed in two layers – one layer at the top of concrete slabs and another layer 1' above the pipe. Warning ribbons will be a minimum of 18" wide.	See Exhibit C
Backfill details, color, material, etc.	Standard AGT Construction Specifications for backfill.	Install physical concrete mat barrier protection 2' below grade (to bottom of slab). Other backfill will be in accordance with AGT Construction Specifications.	
Coating integrity assessment following pipeline installation (such as ACVG & DCVG)	A coating fault test ("Jeeping") of pipe will be performed prior to backfill and any coating faults	In addition to Jeeping, AGT will conduct a DCVG survey, following partial backfill, prior	

Exhibit B Pipeline Design Enhancements Proposed by Spectra for IPEC (in Response to Entergy Questions)			
Question	**Typical Gas Pipeline Installation/design**	**IPEC Enhanced Installation/design**	**Remarks**
	will be repaired.	to installation of concrete slabs and any coating faults will be repaired.	
Mitigation of AC induced current from high voltage power lines.	Provisions for AC Mitigation	AGT is in the process of modeling the AC interference along the proposed pipeline route. An AC mitigation design will include the ~ 4,290 feet of pipe in this area to address any AC corrosion or personnel safety concerns.	
Minimization/Mitigation of internal corrosion	No special measures required	The proposed pipe will contain an internal coating.	Historically, the existing pipeline system runs quite dry and has never exhibited any signs of internal corrosion problems. Quality of gas at receipt points is monitored to ensure the absence of corrosive components. Cleaning pigs are run on a regular basis to remove any accumulated material.

Additional response from Spectra regarding seismic considerations:

"The potential for geologic hazards, including seismic events, to significantly affect construction or operation of the proposed Project facilities is low. Although the Ramapo Fault has been linked to recent earthquake occurrence in the area, the design of the pipeline takes into consideration site-specific conditions, including earthquakes. The recorded magnitude of earthquakes in the Project area is relatively low and the ground vibration would not pose a problem for a modern welded-steel pipeline"

Exhibit C

AGT Pipe Enhancement Cross-Section for Entergy
NOT TO SCALE