Exhibit 1

Declaration of Paul Blanch

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

CITY OF BOSTON, DELEGATION	)	
	)	**DOCKET NO. 16-1081**
	)	**consolidated with**
	)	**16-1098, 16-1103**
TOWN OF DEDHAM, MASSACHUSETTS	)	
RIVERKEEPER, INC. *et al.* PETITIONERS	)	
v.	)	
FEDERAL ENERGY REGULATORY COMMISSION	)	

DECLARATION OF PAUL M. BLANCH

Pursuant to 28 U.S.C. § 1746, Paul M. Blanch hereby declares as follows:

1. My name is Paul M. Blanch and I reside at 135 Hyde Road, West Hartford CT 06117.

2. I am a registered Professional Engineer (inactive status) with more than 50 years of experience with nuclear safety and the construction and operation of nuclear power plants.[1] As such, I am intimately familiar with all federal regulations governing the design and operation of nuclear power plants.

3. I was a consultant to the Chief Nuclear Officers at Indian Point while its present owner, Entergy, operated it as well as its previous owners, Consolidated Edison and the New York Power Authority.

4. I served as an expert witness for the Attorney General of the State of New York for the Nuclear Regulatory Commission proceedings on the license renewal applications for Indian Point Units 2 and 3.

5. I also have extensive experience as a professional consultant on nuclear issues to the top management of Northeast Utilities, Dominion Nuclear, Millstone Nuclear Power Station, and Maine Yankee.

[1] See attached CV.

6. The expert opinions I express in this declaration are based on my thorough analysis of Entergy and NRC's calculations, meetings with the NRC, FOIA requests, formal petitions, NRC Petition Review Board meetings, conference calls with the NRC and with PHMSA, and my review of hundreds of documents related to the AIM project.

7. On September 27, 2014, I formally submitted my expert opinions to FERC related to the potential impact of the proposed Algonquin Incremental Market (AIM) pipeline expansion (FERC Docket No. CP14-96-000) on the safe operation of the Indian Point Nuclear Plant.

8. While I agree that Congress has given the NRC exclusive jurisdiction over nuclear power plant safety, here the NRC is not properly fulfilling its mandate to protect the public and has never presented any reliable analysis to FERC supporting their conclusions that the safety risk that placing the AIM pipeline next to the Indian Point nuclear power plant is acceptable.

9. The NRC issues Regulatory Guides to provide acceptable means of satisfying the requirements of its regulations (10 CFR). For the identified external hazard as applied in this case, the NRC issued Regulatory Guide 1.91 (RG 1.91) entitled "Evaluations of Explosions Postulated To Occur At Nearby Facilities And On Transportation Routes Near Nuclear Power Plants", which was last revised in 2013.[2] The intent of this guidance document is to ensure that adequate protection is provided to the public from harm and radiation exposure from external events. This guide discusses how to calculate a blast radius from a nearby gas pipeline, the probability of a catastrophic gas pipeline failure, the impact of vapor clouds, heat generated and jet fires from a gas line failure. References are included in the RG for more detailed evaluations. There are no other methodologies approved by the NRC for evaluating the impact of a gas line release other than RG 1.91.

10. ALOHA is a computer program developed by EPA for use in assessing the impact of chemical releases including releases from gas lines. However, the EPA specifically prohibits the use of this program for modeling a "gas release from a pipe that has broken in the middle and is leaking from both broken ends", which is the scenario that the NRC and Entergy analyzed in the ALOHA program.[3] The ALOHA program is not mentioned or referenced in RG 1.91 as an acceptable method for calculating blast radius and risk, thus unapproved for this postulated event.

11. All analyses conducted by the NRC, Entergy, and its consultant, The Risk Research Group, Inc., of the safety risk of placing the AIM pipeline next to Indian Point, including the confirmatory and bounding analysis, relied primarily upon the

[2] The 2013 version of NRC RG 1.91 is available on the NRC website at ADAMS database accession number: ML12170A980.

[3] EPA Aloha User's Manual (February 2007) at 146, available at https://nepis.epa.gov

use of the ALOHA program. However, they have never provided a basis for deviating from the methods approved by the NRC in Regulatory Guide 1.91.

12. A summary of the risk analysis was submitted by Entergy to the NRC on August 14, 2014[4] and includes the following statement:

NL-14-106
Docket Nos. 50-247 and 50-286
Page 3 of 4

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

Release of Natural Gas from the Proposed New AIM 42" Pipeline Taking a Southern Route Near IPEC and an Analysis of the Causes of and (2) Determination of Exposure Rates Associated with a Failure of the Proposed AIM 42" Natural Gas Pipeline Near IPEC (also enclosed and collectively referred to as the "Hazards Analyses"). Both supporting analyses were prepared for Entergy by The Risk Research Group, the consultant that prepared the hazards analysis for the existing pipelines near IPEC.

13. Contrary to the requirements of RG 1.91, the Risk Research study[5] performed for Entergy projected a maximum impact radius from a jet fire of between 1,155 feet and 1,266 feet for damaging blast effects based solely on the prohibited ALOHA program.

14. RG 1.91 provides the following clear and simple equation for determining the blast radius from a gas line rupture. Again, the NRC has no other acceptable equation for the calculation of a blast radius

$$R_{min} = Z * W^{\frac{1}{3}} \quad (1)$$

where

R_{min} = distance from explosion where P_{so} will equal 1.0 psi (6.9 kPa) (feet or meters)
W = mass of TNT (pounds or kilograms (kg))
Z = scaled distance equal to 45 ($ft/lb^{1/3}$) when R is in feet and W is in pounds
Z = scaled distance equal to 18 ($m/kg^{1/3}$) when R is in meters and W is in kilograms

A safe distance from a source of potential explosion to critical plant structures would be equal to or greater than R_{min}.

15. This NRC equation states that the damaging blast radius is proportional to the amount of gas or energy released during the event. The amount of gas released (W in the equation above) is calculated by multiplying the gas release flow rates by the amount of time the gas continues to flow before the rupture is isolated and then by the 5% yield number used by NRC and the conversion of kilograms of methane to TNT. Therefore, if the gas release is terminated immediately, the

[4] Letter from Entergy, NL-14-106, dated August 21, 2014.

[5] "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 The Risk Research Group. Inc., 18 Dogwood Road, West Orange. NJ, Dated August 19, 2014".

blast radius will be small. If the release continues for a prolonged period, the blast radius will be much greater.

16. I obtained a copy of Entergy's and the NRC's calculations under the Freedom of Information Act. The calculations performed by Entergy and the NRC both assumed that the gas flow in the AIM pipeline could be isolated and terminated within 3 minutes. However, as explained in more detail in the Declaration of pipeline safety expert Richard Kuprewicz, there is no basis for this unrealistic assumption.

17. The NRC stated in response to a FOIA request[6] that the flow rates for gas released from a rupture of the AIM pipeline will be 376,000 kilograms per minute for the first minute, 200,000 kilograms per minute for the next minute, and 100,000 kilograms per minute until the gas line is isolated. This statement originated[7] from the Risk Research study dated August 19, 2014.

18. However, if one uses the flow rate numbers provided by NRC along with the NRC's assumption that the gas flow will terminate within 3 minutes, the calculation using the RG 1.91 equations results in a blast radius of about 1,905 feet rather than the 1,155-1,266 foot blast radius calculated by Risk Research Group using the ALOHA program. The NRC relied on this much less conservative and unreliable blast radius in its safety assessment rather than the blast radius that would have been calculated using its own regulatory guidance and stated assumptions.

19. My calculation using the above flow rates provided by the NRC and a realistic gas flow isolation time of 60 minutes in the equation from RG 1.91 results in a blast radius of greater than 4,000 feet, which would encompass the entire nuclear plant site. Even assuming a less realistic isolation time of 30 minutes, the blast radius would be 3,255 feet, encompassing both reactor units 1 and 3 and most of reactor unit 2.

---

6 NRC internal email dated April 27, 2015:

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

7 Risk Research Group, Inc Analysis dated August 19, 2014

[23] Based on an average release rate of (b)(7)(F) This rate comprises the release of (b)(7)(F) in the first minute (from ALOHA), a release (b)(7)(F) in the next two minutes (accounting for the pressure drop) and (b)(7)(F) after valve closure. This last will take an additional 3 minutes after the valves are closed (from ALOHA).

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

The Risk Research Group, Inc. 23 August 19, 2014

20. A blast radius in the range of 3,000 to 4,000 feet would likely disable structures, systems and components (SSCs) that are necessary to prevent core melting and major radioactive releases to the environment. The impact on the Indian Point site may disable all safety systems similar to the catastrophic nuclear event at Fukushima. None of the safety systems at Indian Point have been designed or analyzed to withstand the projected blast effects.

21. On March 24, 2015, NRC Chairman Burns testified before Congress and was questioned by Congresswoman Lowey as to why the EPA's ALOHA program was used for this analysis rather than the methodology required by RG 1.91.[8] Chairman Burns stated that RG 1.91 could not be used for this analysis because it did not address "vapor cloud" explosions and heat flux. This is an inaccurate statement to a member of Congress by the NRC Chairman. RG 1.91 discusses "vapor clouds" and their impact 10 times in RG 1.91. References provided in the RG provide other guidance for addressing heat flux. None of the references suggest the use of ALOHA for evaluating the risk of a gas line release.

22. As a direct result of inquiries from Congressional Representatives to the NRC Chairman questioning the NRC's assumption of a 3-minute valve isolation time, the NRC conducted a "bounding" analysis assuming a gas release for one hour. This bounding analysis used an energy release inconsistent with previous values[9] provided by the NRC and also used the prohibited ALOHA program. If the NRC had used its published release rates in the RG 1.91 equation the blast radius after 60 minutes is calculated to be about 4,000 feet.

23. At the Turkey Point Nuclear facility in Florida, the NRC properly using RG 1.91 analyzed the safety risk of a 22-inch gas line with an operating pressure of 722 PSI.[10] This analysis projected a blast radius of 3,097 feet. Comparatively, the AIM project involves a significantly larger pipeline (42 inches) with a higher design pressure of 850 psi and yet the NRC projected a blast radius of only about 1,200 feet (less than half of the blast radius they calculated for a smaller diameter and lower pressure pipeline near Turkey Point).

24. NRC Regulatory Guide 1.91 specifies the probability of a catastrophic gas pipeline failure that the NRC finds to be acceptable to meet the NRC regulations. This regulatory guide clearly states that if the probability of a pipeline event occurs at a frequency of less than 1 in 10 million per year ($1x10^{-7}$ per year) then this risk is acceptable. I consider this risk to be reasonable if it is reliably calculated in accordance with accepted engineering principles.

25. The NRC and Entergy both claim that the probability of a pipeline accident near

---

8 See video of testimony, available at https://www.youtube.com/watch?v=umWpVZTqoJE.

9 Internal NRC email from David Beaulieu dated April 27, 2015.

10 See attached Turkey Point Units 6 & 7 COL Application Part 2 – FSAR at 2.2-23 – 2.2-25.

Indian Point is acceptable because they have calculated it to be less than 1 in 10 million per year (or 1 x 10^{-7} per year). However, it is my expert opinion that the actual failure probability of the AIM pipeline is in the range from 1 in 1000 to 1 in 10,000 per year, which is completely unacceptable and inconsistent with the requirements of 10 CFR Part 100 and RG 1.91. Put in perspective, according to NTSB statistics, there are approximately 37 million commercial airline flights per year with about 10 fatal crashes per year, or 1 crash in 3,700,000 commercial flights per year. The probability of a nuclear event at Indian Point due to a gas line failure is in the range of 1 in 1000 to 1 in 10,000 events per year, which is significantly greater than those of the commercial airline industry. This probability is completely unacceptable for a nuclear plant and ignores the NRC's mandate to protect the public.

26. The NRC's calculation of the probability of a pipeline explosion states:

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

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

27. The above clearly states that the failure rate, according to PHMSA data and the FEMA, DOT and EPA Handbook of Chemical Hazards Analysis Procedures, Section 11 (Reference 5) is projected to be 1.5 pipeline failures in 1000 per year (1.5 x 10^{-3}) within the proximity of Indian Point, a number that exceeds the NRC's acceptable probability rate by a factor of more than 1000 times.

28. Without any reliable basis, the NRC and Entergy then reduced this unacceptable probability by citing Reference 5, Section 11 of RG 1.91 as a justification. The number they used for the failure rate for pipelines greater than 20 inches in diameter is accurate however the probability reductions citing 1 percent for a complete break, a 5 percent ignition rate, and a further reduction of at least an

order of magnitude for an underground pipe are not discussed in Reference 5 and are otherwise unsupported. Pipeline safety expert, Richard Kuprewicz, explains in more detail in his Declaration why these assumptions are unrealistic.

29. A nuclear facility in Eunice, New Mexico was proposed to be located within 1.8 miles of a 16-inch gas line operating at a pressure of less than 50 psi. This pipeline in New Mexico has less than 5% of the capacity (flow) of the new AIM pipeline. The AIM pipeline will operate at a pressure 50 times greater than the pressure of the New Mexico pipeline found to present an unacceptable risk. This line is located at a significantly greater distance away from the Indian Point nuclear facility. A study required by the NRC determined that the consequences of a pipeline explosion near the proposed nuclear facility were unacceptable and not in compliance with NRC regulations.[11] This event was analyzed using the same RG 1.91 requirements that should have been used for analyzing the AIM pipeline.

30. In conclusion, the NRC has underestimated the probability of a gas line accident impacting the Indian Point nuclear plant by at least a factor of 1000. Moreover, the NRC and Entergy have failed to provide any supportable documentation that Indian Point can safely shut down the plants in the event of a gas line rupture, and Entergy has no emergency procedures in place at Indian Point to respond to a gas line rupture. The blast radius from a gas line rupture would likely encompass the entire Indian point site, disabling all vital equipment required to prevent core damage and major radioactive releases to the environment.

31. It is my expert opinion that once gas is introduced into the AIM pipeline there will be a grave and imminent danger to the surrounding area and residents. The consequences of a nuclear event at Indian Point may impact millions of lives in the Hudson Valley and New York City and cause social and economic impacts in the trillions of dollars range.[12]

32. It is my professional expert opinion that a transparent and independent risk analysis must be conducted consistent with NRC regulations 10 CFR Part 50, Regulatory Guide 1.91, and the requirements of DOT/PHMSA 49 CFR §192.935 and ASME B31.8(S) prior to pressurized gas being introduced into the AIM pipeline.

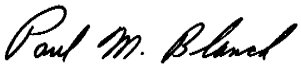
---

[11] See attached Framatome ANP Calculation 32-2400572-02, "Natural Gas Pipeline Hazard Risk Determination" dated January 19, 2004.

[12] This estimate is based on the contamination and land condemnation resulting from the Fukushima accident, recovery and disposal costs, and the estimated property values in the areas surrounding Indian Point.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on September 16, 2016.



_____

Paul M. Blanch

1. P. Blanch CV
2. Entergy to NRC re: Safety Evaluation Prepared in Response to AIM Project (August 21, 2014) Indian Point Safety Evaluation prepared by Energy (August 21, 2014).
3. Hazards Analysis: Consequences of Postulated Fire and Explosion Following Release of Natural Gas From Proposed AIM Pipeline, prepared for Entergy by Risk Research Group (August 19, 2014).
4. NRC Internal Email from D. Beaulieu to D. Pickett (April 27, 2015).
5. Turkey Point Units 6 and 7 COL Application, Part 2 -FSAR at 2.2.2-2.2.-25
6. Attachment 2: Calculation 32-2400572-02, “Natural Gas Pipeline Hazard Risk Determination” by Framatome ANP

P. Blanch CV

Resume

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

OVERVIEW

A 50+ year professional consulting to the top management of Northeast Utilities, Dominion Nuclear, Millstone Nuclear Power Station, Indian Point and Maine Yankee and with a distinguished career as an engineer, engineering manager and project coordinator for the construction and operation of nuclear power plants. Intimately familiar with all regulations governing the design and operation of commercial Nuclear Power Plants

An expert witness having provided research and testimony for numerous plaintiffs including the State of New York Attorney General, Three Mile Island, Vermont Yankee, Saint Lucie, Millstone, Seabrook, Indian Point and Davis Besse.

Provided testimony on behalf of federal and private nuclear workers before State and Federal Courts and the Merit Systems Protection Board (MSPB).

Developed computer research tools and programs to access, search and analyze publically available documents from the Nuclear Regulatory Commission (NRC).

EXPERIENCE

EXPERT WITNESS FOR RIVERKEEPER RELATED TO THE SAFETY AND FEASIBILITY OF COOLING TOWERS FOR INDIAN POINT UNITS 2 AND 3. --2015 T0 PRESENT

Provided expert testimony before the New York State court about the safety of Indian Point be required to install cooling towers in lieu of present once through cooling.

CONSULTANT TO NUMEROUS PUBLIC INTEREST GROUPS RELATED TO THE PROPOSED INSTALLATION OF A NEW NATURAL GAS LINE IN THE CLOSE PROXIMITY TO THE INDIAN POINT POWER PLANTS--2013 TO PRESENT

I continue to work with public interest groups, US Senators, Congresspersons, and other elected officials about the potential impact of a new 42-inch natural gas line crossing the Indian Point property. I am working with the NRC and have met with the NRC Chairman and other Commissioners for the purpose of conducting a risk assessment should a malfunction of the new gas line occur. Also working with the Department of Transportation (PHMSA), and the Federal Energy Regulatory

Commission (FERC) and the NY Governor's office.

EXPERT WITNESS FOR NEW STATE ATTORNEY GENERAL SUPPORTING NEW YORK'S POSITION RELATED TO THE RELICENSING OF INDIAN POINT UNITS 2 AND 3 (IP 2&3) –April 2007 to 2012

Provided expert witness research and testimony on behalf of the State of New York on the relicensing of the Indian Point units. Researched the design basis for IP 2&3 and provided the basis for age related contentions submitted on behalf of the State of New York to the NRC within the scope of the relicensing requirements of 10 CFR 54. The Atomic Safety Licensing Board accepted four out of five contentions related to buried piping systems, inaccessible cable qualification and the life management of vital transformers.

EXPERT WITNESS FOR VARIOUS PUBLIC INTEREST GROUPS SUPPORTING THEIR POSITION RELATED TO THE RELICENSING OF THE SEABROOK NUCLEAR PLANT -2010 to present

Provided expert witness research and testimony on behalf of various public interest groups opposing the relicensing of Seabrook.

EXPERT WITNESS FOR NEW ENGLAND COALITION (NEC) vs. ENTERGY NUCLEAR REVIEWING THE EXTENDED POWER UPRATE AND RELICENSING OF VERMONT YANKEE—2004 to present

Provided pro bono expert witness research and testimony on behalf of NEC opposing the 20% Extended Power Uprate (EPU) for Vermont Yankee (VY). Researched the design basis for VY and provided testimony before the Vermont Public Service Board, Public Service Commission, Atomic Safety and Licensing Board (ASLB) and the Advisory Committee for Reactor Safety (ACRS). Participated in meetings with Vermont Governor Douglas, Senators Leahy and Jeffords. Petitioned the NRC under 10 CFR 2.206 to request VY and the NRC identify any and all non-compliances with present NRC regulations and evaluate risks associated with identified non-compliances to the General Design Criteria of 10 CFR 50 Appendix A and other applicable NRC regulations.

EXPERT WITNESS FOR PLAINTIFFS IN FINESTONE vs. FLORIDA POWER AND LIGHT -AUGUST 2003 to JANUARY 2006

Provided expert witness and conducted extensive historical research to determine the quality and quantity of unmonitored releases from the St. Lucie nuclear plant. Discovered that the plant had significant unmonitored discharges to the environment in excess of those allowed by 10 CFR 20. Case dismissed via summary judgment in 2006.

EMPLOYEE CONCERNS AND SAFETY CONCIOUS WORK ENVIRONMENT CONSULTANT -- February 2001 to February 2002

Consultant reporting to the Chief Nuclear Officer at Indian Point Unit 2 assisting in the evaluation of the plant's Employee Concerns Program and an assessment of the Safety Conscious Work Environment. (SCWE) Work also includes assisting investigations of allegations related to employee discrimination and other technical and safety issues. Developed and implemented training programs for ECP and other site personnel.

EMPLOYEE CONCERNS AND SAFETY CONCIOUS WORK ENVIRONMENT CONSULTANT -- September 2000 to 2001

Consultant, reporting to the President of Maine Yankee Atomic Power Company. Primary responsibilities include the re-establishment of a Safety Conscious Work Environment (SCWE) and to act as an independent facilitator to resolve differences between employees and management. Evaluated the Employee Concerns Program making recommendations for improvement to the President. Conducted independent investigations of allegations received internally and referral allegations from the NRC.

EMPLOYEE CONCERNS AND SAFETY CONCIOUS WORK ENVIRONMENT CONSULTANT -- February 1997 to 2001

Consultant reporting to the President of Northeast Nuclear Energy Company assisting in the recovery of the three Millstone Units shut down due to safety problems. Primary responsibilities include the establishment of a Safety Conscious Work Environment (SCWE) and to act as an independent facilitator to resolve differences between employees and management. Coordinate many different groups at Millstone including executive management, legal, human resources and the Employee Concerns organization.

Resolve differences at the lowest possible management level. Coordinate with ECP to investigate safety, technical and alleged harassment issues and review outcomes, to assure the investigation was conducted in an unbiased, fair and equitable manner. Coordinate corrective action with the appropriate management, legal and technical organizations.

Worked closely with top management and corporate communications to coordinate efforts to regain public confidence with the operation and management of the Millstone site. Provide assistance with regulatory compliance issues and interface with various public interest groups in the Millstone area including State oversight and groups critical of the Millstone operations. Provide both formal and informal feedback to the

NRC about the recovery of Millstone and the establishment of a Safety Conscious Work Environment.

Conducted training and made presentations to top nuclear executives about the need to maintain a Safety Conscious Work Environment when requested by the Nuclear Energy Institute and the Nuclear Regulatory Commission.

Made regular presentations to public interest groups, State of Connecticut oversight organizations and the Nuclear Regulatory Commission as to my personal assessment of the work environment at Millstone and the status of corrective actions.

Worked as a team member with other Millstone management providing overall strategic direction to the President to assist in the recovery of Millstone with specific emphasis on public confidence and the establishment of a SCWE.

Provide routine advice to outside legal organizations and other nuclear utility management with respect to dealing with employees raising safety concerns.

Conducted presentations (September 1999 and September 2000) to the Employee Concerns Program Forum providing a perspective on "whistleblower" issues and what management needs to do to properly address these issues.

Conducted presentation in September 2000, along with NRC Chairman Meserve, to the NRC and the NRC's Inspector General's staff on a proposal to resolve "High profile whistleblower" situations.

EXPERT WITNESS FOR PLAINTIFFS RELATED TO THE THREE MILE ISLAND 1979 ACCIDENT-1995 to 1998

Provided expert witness and conducted extensive historical research to determine the quality and quantity of unmonitored releases from the Three Mile Island plant. Discovered that the actual releases were more than 5 times the amount published by the NRC and the operator of TMI.

ENERGY CONSULTANT -- 1993 to 1997

Provided expert witness testimony and worked with the NRC to change Federal Regulations for the protection of individuals identifying safety issues at nuclear licensed facilities.

Worked with the Office of the Inspector General of the NRC to provide major input to a revision of the recently passed federal "Energy Bill" providing additional protection to Nuclear Whistleblowers. Some personnel within the NRC have referred this to as “the Blanch Amendment”.

Provided advice to both attorneys and their clients to gain an understanding of the NRC and Department of Labor regulations governing the protection of whistleblowers under the Energy Reorganization Act

NORTHEAST UTILITIES -- 1972 to 1993

Supervisor of Electrical Engineering (Instrument and Control Engineering Branch)
Responsible for programs to assure plant reliability and compliance with NRC regulations. Conducted periodic training of employees and contractors to maintain continued cognizance of all corporate and station procedures and regulations. Worked as both a supervisor of an engineering organization and directed the efforts of Stone and Webster and Bechtel to assure safety and compliance during the design and construction of Millstone Units 2 & 3. Primary interface between NU, Westinghouse and Stone and Webster for the conceptual design of electrical and process instrumentation systems during construction of Millstone Unit 3. Assured compliance with all NRC electrical standards and design criteria. Member of the Millstone Nuclear Review Board responsible to the president to assure compliance with all applicable regulations.

ACCOMPLISHMENTS

Directed the development of the first real time instrumentation monitoring system for practical use in commercial nuclear plants to assess the overall safety status of the plant and to provide information to remote facilities during emergency events. This effort resulted in the identification of many instrumentation problems not previously recognized or considered “undetectable failures." As a result of these efforts, and in face of strong opposition Rosemont and the nuclear industry, the NRC issued a Bulletin (90-01) requiring all utilities to monitor Rosemount transmitters used in safety applications. A supplement to the Bulletin was issued at the end of 1992.

Recognized the inability of condensate pots to function under de-pressurization events as a direct result of NU's computerized instrument monitoring system. This is one of the most significant safety issues identified in the nuclear industry. Developed a water injection system into the reference legs that precluded the absorption of these gases. This solution was adopted by the entire nuclear industry.

Developed a program to reduce or eliminate the need for periodic calibration of analog instrumentation and the elimination of the need for pressure transmitter response time testing. The formation of an ISA Standard activity (ISA 67.06) for the development of a standard for Performance Monitoring of Safety Related Instruments in Nuclear Power Plants was a direct result of these efforts.

Received a "First Use" award from Electric Power Research Institute (EPRI) for the application of Signal Validation for the identification of failed sensors during accident, as a direct result of developing and implementing signal validation for emergency computer systems.

Worked closely with the US General Accounting Office conducting its study related to the NRC's handling of whistleblower issues in the nuclear industry and buried piping degradation.

Electrical plant and Reactor operator and Leading Petty Officer aboard the Nuclear Powered Submarine USS Patrick Henry (SSBN-599). Qualified electrical plant and reactor operator and instructor at Navy prototype reactor (S1C).

SPECIAL QUALIFICATIONS

Actively participated and contributed to studies conducted by the NRC and NU addressing the cultural problems at Northeast Utilities. Collaborated with the Fundamental Cause Assessment Team and the NRC's Millstone Independent Review Group and provided insights as to the root causes of the problems effecting the NU nuclear organization.

Named Utility Engineer of the Year (1993) by Westinghouse Electric and Control Magazine for advancing the safety of nuclear power.

Publicly recognized in October 1992 by the Chairman of the NRC (Ivan Selin) for significant contributions to nuclear safety, related to the identification of the condensate pot problems on Boiling and Pressurized Water Reactors.

Testified before the US Senate Subcommittee about the failure of the NRC's regulatory practices and the NRC's mistreatment of Nuclear Whistleblowers. Instrumental in developing Connecticut's Nuclear Whistleblower Law effective October 1, 1992 which is the strongest Whistleblower Protection Law in the country. Discussed in Time Magazine (March 4, 1996) as a contributor to nuclear safety.

Featured on Page 1 of the Wall Street Journal (03/12/1998) as a Nuclear Safety Advocate assisting the successful recovery of Millstone Units 2 and 3.

EDUCATION

BS Electrical Engineering, Magna Cum Laude, 1972, University of Hartford
Graduate courses in Mechanical and Thermodynamic Engineering
US Navy Submarine School, 1968
US Navy Nuclear Power School, 1965
US Navy Electronics Technician School, 1964

PROFESSIONAL ASSOCIATIONS

Vice Chairman, Institute of Nuclear Power Operations (INPO) Two Standards Activities in response to Three Mile Island including Post Accident Monitoring requirements.

Member of the ANS Standards Committee responsible for developing the requirements for seismic monitoring systems for nuclear power plants. (ANS 6.8.1 and ANS 6.8.2)

Worked with NEI (NUMARC) on the resolution of the common mode failures of Rosemont pressure transmitters.

Worked with the NRC and discovered (1992) a significant design error impacting all BWR's. This was a deficiency in the design of level transmitters that would have produced non-conservative reactor level errors. These errors may have exceeded 35 feet. As a result, every BWR was required to make extensive modifications to resolve this major issue.

Chairman of Two Committees for the Institute for Nuclear Power Operations (INPO) related to Three Mile Island post accident monitoring requirements and emergency response facilities.

Member of ISA 67.04 for the development of Instrument Setpoints for Nuclear Power Plants

Registered Professional Engineer - California

Entergy to NRC re: Safety Evaluation
Prepared in Response to AIM Project (August 21, 2014)
Indian Point Safety Evaluation
prepared by Energy (August 21, 2014).

Entergy

Entergy Nuclear Northeast
Indian Point Energy Center
450 Broadway, GSB
P.O. Box 249
Buchanan, NY 10511-0249
Tel (914) 254-2055

Fred Dacimo
Vice President
Operations License Renewal

SECURITY-RELATED INFORMATION – WITHHOLD UNDER 10 CFR 2.390

NL-14-106

August 21, 2014

U.S. Nuclear Regulatory Commission
Document Control Desk
11545 Rockville Pike, TWFN-2 F1
Rockville, MD 20852-2738

SUBJECT: 10 C.F.R. 50.59 Safety Evaluation and Supporting Analyses Prepared in Response to the Algonquin Incremental Market Natural Gas Project
Indian Point Nuclear Generating Unit Nos. 2 & 3
Docket Nos. 50-247 and 50-286
License Nos. DPR-26 and DPR-64

REFERENCES:

1. *Algonquin Gas Transmission, LLC*, Abbreviated Application of Algonquin Gas Transmission, LLC for a Certificate of Public Convenience and Necessity and For Related Authorizations, Docket No. CP14-96-000 (Feb. 28, 2014) ("Certificate Application").

2. Algonquin Incremental Market Project *Draft Environmental Impact Statement* Algonquin Gas Transmission, LLC, August 6, 2014, Docket No. CP14-96-000, FERC/EIS-0254D

3. MOTION TO INTERVENE AND COMMENTS OF ENTERGY NUCLEAR INDIAN POINT 1, LLC, ENTERGY NUCLEAR INDIAN POINT 2, LLC, ENTERGY NUCLEAR INDIAN POINT 3, LLC AND ENTERGY NUCLEAR OPERATIONS, INC. Algonquin Gas Transmission, LLC) Docket No. CP14-96-000, April 8, 2014

Dear Sir or Madam:

As the Nuclear Regulatory Commission ("NRC") is aware, Algonquin Gas Transmission, LLC ("AGT") has proposed to construct and operate a new natural gas pipeline near the Indian Point Entergy Center ("IPEC"). The Project, known as the Algonquin Incremental Market Project ("AIM Project"), involves the construction and operation of about 37 miles of natural gas pipeline and associated facilities to expand natural gas transportation service to Connecticut, Rhode Island, and Massachusetts. The majority of the pipeline facilities would replace existing

IE47
NRR

SECURITY-RELATED INFORMATION – WITHHOLD UNDER 10 CFR 2.390

Algonquin pipelines, but the Project also includes the installation of new 42-inch diameter pipeline near the southern boundary of IPEC to replace the existing 26-inch pipeline in vicinity of IPEC which will remain in place but idled. On February 28, 2014, AGT filed a formal application with the Federal Energy Regulatory Commission ("FERC" or "Agency") related to the AIM Project (Reference 1).

On August 6, 2014, FERC issued the draft environmental impact statement ("EIS") for the AIM Project (Reference 2). As it relates to IPEC, the draft EIS states as follows:

> Based on our consultation with NRC, Entergy is required to assess any new safety impacts on its IPEC facility and provide that analysis to the NRC. Algonquin has coordinated with Entergy to provide information about its proposed pipeline, and Entergy is currently performing a Hazards Analysis. To ensure that no new safety hazards would result from the AIM Project, we are recommending that Algonquin file the final conclusions regarding any potential safety-related conflicts with the IPEC based on the Hazards Analysis performed by Entergy.

FERC's conclusions in the draft EIS were based, in part, on comments Entergy submitted to FERC to assist the Agency in identifying issues for evaluation in the EIS (Reference 3). Entergy noted in its comments to FERC that the existing AGT system has been operating safely next to IPEC for several decades, and evaluations of the potential hazards posed by the existing pipelines, conducted pursuant to NRC regulations and guidance, establish that the existing pipelines do not impair the safe operation of IPEC. The proposed AIM Project, however, expands the existing AGT system, including pipeline capacity and pressure. Thus, the potential for increased nuclear safety risks, including in terms of the probability and consequences of a potential malfunction or failure of the expanded natural gas pipeline near IPEC, must be evaluated and found to be acceptable in accordance with applicable NRC regulations. Accordingly, while such occurrences are unlikely, Entergy must analyze any increased risk and consequences of such events prior to FERC's approval of the project. Entergy further noted that, depending on the results of the analysis, prior NRC review and approval of the new hazards analysis could be required before the project can be approved by FERC. FERC received numerous other scoping comments from members of the public and government officials concerning the safety of the Project and its proximity to IPEC. Thus, there is significant public interest in this project and its potential impacts on IPEC.

As noted in the EIS, Entergy has worked closely with AGT to better understand the scope of the project and confer regarding means to avoid any potential adverse impacts to IPEC. As a direct result of those efforts, Entergy and AGT have agreed to a comprehensive set of design and installation enhancements for piping routed near IPEC. These enhancements include, but are not limited to, thicker piping, thicker corrosion protection, greater burial depth, and installation of protective reinforced concrete mats to impede access to the buried piping.

Consistent with applicable NRC regulations and guidance, Entergy prepared the enclosed 10 C.F.R. § 50.59 Safety Evaluation related to the proposed AIM Project. Entergy also prepared two supporting evaluations; (1) Consequences of a Postulated Fire and Explosion Following the

SECURITY-RELATED INFORMATION – WITHHOLD UNDER 10 CFR 2.390

Release of Natural Gas from the Proposed New AIM 42" Pipeline Taking a Southern Route Near IPEC and an Analysis of the Causes of and (2) Determination of Exposure Rates Associated with a Failure of the Proposed AIM 42" Natural Gas Pipeline Near IPEC (also enclosed and collectively referred to as the "Hazards Analyses"). Both supporting analyses were prepared for Entergy by The Risk Research Group, the consultant that prepared the hazards analysis for the existing pipelines near IPEC.

As documented in the attached Hazards Analyses, Entergy has concluded that based on the proposed routing of the 42-inch pipeline further from safety related equipment at IPEC and accounting for the substantial design and installation enhancements agreed to by AGT, the proposed AIM Project poses no increased risks to IPEC and there is no significant reduction in the margin of safety. Accordingly, as documented in the enclosed 10 C.F.R. § 50.59 Safety Evaluation, Entergy has concluded that the change in the design basis external hazards analysis associated with the proposed AIM Project does not require prior NRC approval.

Entergy's comments on the AIM Project draft EIS are due to be filed with FERC by September 29, 2014. Given the current status of the AIM Project, Entergy believes this is the last opportunity as a matter of right for Entergy to inform FERC as to the results of the Hazards Analysis, whether additional mitigation is necessary, and whether prior NRC review and approval is required. In addition, FERC requested that AGT file the final conclusions regarding any potential safety-related conflicts with IPEC based on the Hazards Analysis performed by Entergy by that same date.

As noted above, Entergy has determined that there are no increased risks to Indian Point and, pursuant to 10 CFR § 50.59, has concluded that prior NRC review and approval is not required. In our submittal to FERC we plan to point out that as part of the routine inspection program NRC always has the right to review and challenge any analysis done pursuant to 10 CFR 50.59. Unless NRC chooses to perform such a review we cannot guarantee that they would ultimately concur with our position. Therefore we will suggest that prior to approving the Project, FERC should consider conferring with the NRC before reaching a conclusion regarding the potential hazards posed by the AIM project on IPEC and whether any additional mitigation is necessary. Accordingly, we are forwarding to the NRC the enclosed Safety Evaluation and Hazards Analyses and are prepared to answer any questions NRC may have on the Analyses or support inspections of the same.

Please withhold the hazards analysis (Enclosure 2) under 10 CFR 2.390 as security related information.

SECURITY-RELATED INFORMATION – WITHHOLD UNDER 10 CFR 2.390

If you have any questions, or require additional information, please contact Mr. Robert Walpole, Regulatory Assurance Manager, at [914] 254-6710.

Sincerely,

FRD/sp

Enclosures: 1. 10 C.F.R. 50.59 Safety Evaluation

2 Hazards Analysis (**SECURITY-RELATED INFORMATION – WITHHOLD UNDER 10 CFR 2.390**

cc: Mr. Douglas Pickett, Senior Project Manager, NRC NRR DORL
Mr. William M. Dean, Regional Administrator, NRC Region 1
NRC Resident Inspector
Mr. John B. Rhodes, President and CEO, NYSERDA w/o Enclosure 2
Ms. Bridget Frymire, New York State Dept. of Public Service w/o Enclosure 2

ENCLOSURE 1 TO NL-14-106

10 C.F.R. 50.59 SAFETY EVALUATION

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

r

I. OVERVIEW / SIGNATURES[1]

Facility: IP2/IP3 **Evaluation # / Rev. #:**

Proposed Change / Document: Installation of a New 42" Natural Gas Pipeline South of IPEC

Description of Change: Installation of New 42" Natural Gas Pipeline South of Gypsum Plant and crossing IPEC Property Near Switchyard / GT2/3 Fuel Oil Storage Tank.

Summary of Evaluation:

The proposed pipeline was evaluated under the criteria of 10 CFR 50.59 and the evaluation shows that current Nuclear Regulatory Commission criteria were satisfied that would permit the pipeline to be installed without a license amendment requiring NRC approval

Background

The Indian Point Energy Center (IPEC) is traversed by two natural gas pipelines owned and operated by Spectra Entergy. The pipelines are 26 in. and 30 in. in diameter and operated at a pressure of 600-650 psig and 600-750 psig, respectively. The two gas pipelines traverse the owner-controlled area and are physically located closer to Indian Point Unit 3 (IP3) than Indian Point Unit 2 (IP2). The two lines are buried about 3 ft. deep in a trench formed in excavated rock. Portions of the pipelines at the shoreline of the Hudson River exit the trench and are above ground. The nearest approach of the buried portion of the pipelines to safety related structures, systems and components (SSC) is about 400 ft. The nearest above ground portion is approximately 800 ft. from the nearest safety-related structure (diesel generator building).

The initial licensee and the Atomic Energy Commission considered the hazards posed by these pipelines during the initial licensing process of IP3, and determined that the presence of the gas pipelines did not endanger the safe operation of IP3 (Reference 1). Section 2.2 of the AEC's safety evaluation report (SER) for IP3 describes the Staff's conclusions regarding this analysis that the rupture of these gas pipelines would not impair the safe operation of IP3 (Reference 2).

On September 27, 1997 the New York Power Authority (NYPA) submitted the Individual Plant Examination of External Events (IPEEE) report for IP3 (Reference 3). In that report, it evaluated the susceptibility of IP3 to damage to the pipelines from seismic events. NYPA concluded that the probability of occurrence was low enough that the pipelines could be screened out as a seismic vulnerability. NYPA also considered pipeline ruptures from other causes, such as an inadvertent overpressure condition. Although NYPA stated that a vapor cloud rupture scenario could subject some IP3 structures to overpressures exceeding 1 psi, it concluded that the probability of an accidental leak from the line leading to such an event was extremely low. The NRC Staff's evaluation of the IP3 IPEEE did not identify any concerns with that approach (Reference 4).

In March 2003, questions were raised regarding the safety of the existing natural gas pipelines that pass through the Indian Point site, and suggested that they could be subject to sabotage. At the request of NRC Region I, the NRC Staff reviewed the prior evaluations of the lines and associated potential external hazards to the safe operation of the facility. The Staff's review is documented in an

[1] Signatures may be obtained via electronic processes (e.g., PCRS, ER processes), manual methods (e.g., ink signature), e-mail, or telecommunication. If using an e-mail or telecommunication, attach it to this form.

April 25, 2003 NRC internal memorandum (Reference 5). The NRC Staff made an assessment of the risks associated with the potential for large releases of natural gas from the pipelines in the vicinity of IP3 given the statements made in the IP3 IPEEE, and the focus of prior external hazards evaluations on the likelihood of an accidental pipe rupture. The NRC Staff also considered intentional acts to damage the line(s) in its gas pipeline hazard assessment, which is not available to the public for security-related reasons. The NRC's April 25, 2003 memorandum states: "For a large rupture and resulting fire, the staff found that safety-related structures would not be significantly affected. For unconfined vapor cloud ruptures, the staff found that the factors involved to achieve a rupture creating sizeable overpressures make the probability for occurrence very low. However, the NRR staff believes that this aspect should be further evaluated by the Office of Nuclear Safety and Incident Response (NSIR) in conjunction with Region I"

In March 2008, the NRC Staff requested information from Entergy as a result of a concern from a member of the public that there are "weak spots" in the IPEC security defense/structure, including a National Guard security position known as "Point 8." That request included any analyses or calculations supporting Entergy's conclusions regarding the vulnerability of Point 8. In an April 23, 2008 letter (ENOC-08-00021) to the NRC, Entergy explained that Point 8 encompasses the above-ground pressurized gas piping and valves that are part of the Algonquin natural gas pipelines in the Owner Controlled Area (OCA) at IPEC. It noted that although the IPEEE had examined an accidental rupture of the gas pipelines, no evaluation of sabotage on the gas pipelines within Point 8 previously had been performed. Entergy further explained that it had implemented additional compensatory measures to minimize the potential for such an event while it performed the additional assessment requested by NRC. Those measures are described in Entergy's April 23, 2008 letter.

As a follow-up to the Request for Information, Entergy completed an evaluation in August 2008 of the consequences of an assumed rupture of the two gas pipelines as a result of a sabotage on Point 8. IPEC Engineering completed that evaluation using inputs from an analysis performed by Risk Research Group, Inc. In that analysis, which Entergy submitted to the NRC on September 30, 2008 (see ENOC-08-00046), Entergy considered the following hazards created by a postulated breach and rupture of the pressurized aboveground portions of the pipelines: (1) potential missiles, (2) an over-pressurization event, (3) a vapor cloud (or flash) fire, (4) a hypothetical vapor cloud explosion, and (5) a jet fire. Entergy's August 2008 evaluation concluded that "[t]he concern that an attack on Point 8 would result in a lot of damage and casualties is not substantiated to the extent the Security Plan and Safe Shutdown capabilities of the plants remain assured in the event of an attack and rupture of the exposed portions of the Algonquin natural gas pipelines within Point 8." The IP3 Updated Final Safety Analysis Report (UFSAR), Rev. 3, Section 2.2.2, discusses the pipelines and lists the 2008 report as a reference.

On October 25, 2010, a member of the public filed a 10 C.F.R. § 2.206 petition requesting that the NRC order Entergy to demonstrate that it has the capability to protect the public in the event of a rupture, failure, or fire on the gas pipelines that cross the Indian Point site. The petition also requested that the NRC review all available information, and request any necessary information from Entergy to ensure compliance with all NRC regulatory requirements related to external hazards. In a letter to the petitioner dated March 31, 2011, the NRC stated that it had reviewed previous licensee and NRC reports related to this issue and "did not identify any violations of NRC regulations or any new information that would change the staff's previous conclusion that the pipelines do not endanger the safe or secure operation of IP2 or IP3."

Proposed AIM Pipeline Expansion Project

Spectra Energy Transmission LLC / Algonquin Gas Transmission, LLC (hereinafter Spectra or AGT)has filed with FERC a proposal to expand its natural gas transmission capacity, discussed above, by installing a new 42 inch diameter pipeline that transmits gas at higher pressures than the current pipelines described above. For purposes of this evaluation, once installed the existing 26 inch pipeline and 30 inch pipeline are assumed to remain in use. The 42 inch pipeline is currently proposed to cross the Hudson River south of Indian Point, be routed on the west side of Broadway where it enters the IPEC owner controlled area before passing under Broadway and near the IPEC switchyard and the Gas Turbine 2/3 Fuel Oil Storage Tank (GT 2/3 FOST) and eventually joining with the existing natural gas pipelines. The proposed routing is referred to in this evaluation as the 'southern route" (The term "southern route" is the term used by Spectra to describe the final selected pipe routing for the new 42 inch pipeline). Only natural gas would be transmitted through these pipelines (Reference 6). In response to certain issues identified by Entergy with regard to the proposed routing of the new 42-in pipeline near IPEC, Spectra has stated that it would take additional design and construction measures on a 3935 foot section of the new pipeline to further limit the potential for adverse effects on the continued safe operation of Indian Point.

While the proposed 42 inch pipeline is further from IP2 and IP3 structures, systems and components (SSC) within the Security Owner Control Area (SOCA) used to control access to the main plant area than the existing pipelines, the new pipeline has a larger diameter than the existing lines and operates at a higher pressure, and therefore is a change to the current licensing basis for external hazards located near IP2 and IP3. The potential effects of the proposed pipeline on IP2 and IP3 have been evaluated using current NRC guidelines. Specifically, the Standard Format and Content Regulatory Guide 1.70 identifies the information to be provided for offsite events that could create a plant hazard. The NUREG 0800 Standard Review Plan (SRP) sections 2.2.1 to 2.2.3 (Rev 3) further discuss information to be assessed against current regulations and the descriptions and evaluations to be considered for acceptability. RG 1.91 Rev 2 provides guidance on how the evaluation should be performed and states the evaluation is to consider structures, systems and components (SSC) important to safety as well as safety related SSCs.

Design and Construction

1) Design

As discussed further below, the proposed southern routing must consider potential adverse effects on SSCs important to safety nearer to the southern route, including the GT 2/3 Fuel Oil Storage Tank (FOST), electrical switchyard (includes lines to and from Indian Point), Emergency Operations Facility (EOF)/ meteorological tower, and the city water tank. Additional features also considered, include the FLEX Storage Building, IP2 and IP3 Steam Generator Mausoleums, and the fuel oil tanker. The design of the 42 inch gas pipeline is to use X-52 to X-65 steel, to require a wall thickness of 0.469 to 0.510 inches, and to bury the pipeline underground with a minimum of 3 feet to the surface from the top of the pipeline (References 7 and 8). Spectra Energy however, has indicated (Reference 8) that, in the area where a postulated pipeline rupture could adversely affect IPEC SSCs ITS, about 3935 feet of the pipeline would be of enhanced design and construction to further limit the already very low potential for a gas pipeline rupture. The pipeline design will incorporate the following additional design and construction features:

- The Pipe Grade will be upgraded to X-70, (70,000 psig minimum yield strength and 82,000 psig minimum tensile strength) and manufactured to API 5L standards like all pipeline.

The 0.720 inch wt (thickness in inches), X-70 material operating at the maximum operating pressure (MAOP) of 850 psi is over 40% greater wt than required by the United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration Natural Gas Pipeline Minimum Federal Safety Standards (49 CFR Part 192) (the "DOT Code"). The resulting wt exceeds Class 4 requirements, the most stringent DOT Code classification. The actual length of the enhanced portion of the gas pipeline will be subject to field survey verification of the proposed Algonquin Gas Transmission, LLC (AGT) 42 inch diameter AIM Project pipeline shown in the enclosed report "Consequences of a Postulated Fire and Explosion Following the Release of Natural Gas from the Proposed New AIM 42 inch Pipeline Taking a Southern Route Near IPEC" (hereinafter called Report).

The following information was provided by Spectra (Reference 8) regarding the design enhancements:.

- The 0.720 inch X-70 piping is virtually impervious to one of the most frequent causes of pipe rupture (excavation). The Pipeline Research Committee International (PRCI) report "Modified Criteria to Evaluate the Remaining Strength of Corroded Pipelines" documents the size of defect required to cause a pipeline rupture, based upon over 100 pipe defect burst tests. ASME B31G "Manual for Determining Remaining Strength of Corroded Pipelines" is a guideline used in the pipeline industry that applies this research to predict pipe defect rupture pressure, including the Modified B31G equation. There is also a PRCI report (PR-244-9729) "Reliability Based Prevention of Mechanical Damage to Pipelines" which is available to the public through the Center for Frontier Engineering Research (C-FER), and Section 6 provides a model, based upon excavator data, which can be used to predict the force required to puncture a pipeline. Puncture force is calculated from Equation 6.4 on p.28 of the referenced PRCI report (PR-244-9729), using a very conservatively low sample ultimate tensile strength of 79,300 psi and a relatively sharp excavator tooth of 0.5 x 1.5 inches. The weight of the excavator is based upon Figure 6.3 on p.31 of the PRCI report, but the required excavator weight to damage the proposed enhanced piping is so great that it must be extrapolated well beyond the end of the graph. If the curved relationship were continued, it would never reach the 508 kN (kilo newton) force required to puncture the 0.720 inch wall pipe, but by projecting an over-conservative straight line to continue the upper right slope of the curve, an excavator weight of 193 tons at 508 kN would be necessary to damage the enhanced piping. The probability of excavator size comes from Figure 6.1 on p.30 of the PRCI report. This type excavator has not been seen at IPEC as can be demonstrated by the fact the largest Caterpillar backhoe (385CL) is less than half that size at 94 tons

- The criterion for whether a defect fails as a leak versus a rupture comes from NG-18 research. The "Through Wall Collapse" (TWC) equation was developed many years ago from analyses of numerous full-scale pressure tests of pipe by Dr. Kiefner and others at Battelle. A puncture is nowhere close to the leak-rupture line, so it is very apparent that a puncture of the pipe wall would only cause a leak and would not rupture the pipe.

The Modified B31G equation is:

(b) Modified B31G. For $z \leq 50$,

$$M = (1 + 0.6275z - 0.003375z^2)^{1/2}$$

For $z > 50$,

$$M = 0.032z + 3.3$$

$$S_F = S_{flow}\left[\frac{1 - 0.85(d/t)}{1 - 0.85(d/t)/M}\right]$$

$$z = L^2/Dt$$

Inputting a 70% depth defect with length of 20' into the above equation produces a minimum failure pressure S_F = 1121 psig, whereas the maximum operating pressure of the pipeline is only 850 psig.

- All 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.

- Standard coating for all the pipe will be Fusion Bond Epoxy (FBE) coating 16 mils (thousands of an inch) nominal; 12 -14 mils is industry standard. Coating for the enhanced pipe will be a dual layer with FBE and Abrasion Resistant Overlay ("ARO"). AGT will specify 25 mils of coating, consisting of 16 mils of FBE and 9 mils of ARO. ARO will provide for enhanced protection during installation and provide additional external corrosion protection. Internal corrosion protection will also be provided (1.5 mils of FBE).

- A physical barrier to impede access to the buried piping will be installed above the enhanced pipe. Installation will include two (2) parallel sets of fiber-reinforced concrete slabs with dimensions of 3 feet wide by 8 feet long by 6 inch thick (a cross-sectional view of the proposed design is provided in Appendix B, Exhibit C of the attached report). Yellow warning tape will be placed at the top of the concrete slabs and another layer 1 foot above the pipe.

- The latest state of the art cathodic protection will be used on the pipeline.

Piping was or will be purchased to AGT Pipe standards ES-PP3.11 and/or ES-PP3D.3. Mill inspection will follow standards IS-IP1.1, IS-IC1.1, and IS-IC2.1. Non-Destructive Examination ("NDE") will follow APL-5L PSL-2 requirements as well as AGT Standards in the mill. All pipe is tested in the mill in accordance with AGT Standards,

2) Construction

The construction of the new pipeline is not going to result in any issues affecting plant operation. The construction pathway will result in construction under the power lines from the switchyard, but appropriate protective measures will be used to prevent interference with the

power lines. The construction pathway will not require construction above the existing gas pipeline and (per Reference 8):

- There will be no blasting for rock removal in the region of the enhanced design pipe.
- The Broadway crossing on the west side of the tank will be made using an open cut installation method. Spectra will ensure that traffic flow is maintained during construction, and access to the Indian Point facility is not impeded.
- Work near electrical power lines will follow industry standard practices and OSHA regulations.
- The enhanced gas pipeline would be buried to a minimum greater depth of 4 feet from the top of the pipeline to the surface and buried 5 feet under Broadway.
- The pipeline coatings will be inspected electronically as the enhanced pipeline is lowered into the ground. A coating fault test is normally performed to detect any faults prior to backfill. In addition a Direct Current Voltage Gradient (DCVG) survey will be performed to ensure coating integrity following enhanced pipe installation and partial backfill.

Spectra pipe installation welders must be qualified by destructive testing. To maintain their qualification, they must have a qualifying weld inspected via non-destructive testing and found to be acceptable at intervals not exceeding 6 months. A welder must re-qualify via destructive testing every 2 years. The welder's qualifications and continuation of qualification must be documented. All pipeline/piping welding procedures shall be qualified by destructive testing. All welding (including temporary welds) will be in compliance with approved welding procedures and performed by an AGT approved qualified welder.

All field welds for enhanced gas pipeline shall also undergo Non Destructive Examination which will include as a minimum 100% radiography of all field butt welds for Class Locations 1. The normal radiography requirement is 10% of all butt welds. All installed pipe will also undergo a full hydrostatic test in the field after installation to verify pipe integrity per the DOT Code requirements and AGT standards.

3) Ongoing Pipeline Maintenance and Monitoring Activities
Spectra monitors the cathodic protection levels on its pipeline system in accordance with the 49 CFR § 192.465(a): "Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine the cathodic protection meets the requirements of 49 CFR § 192.463." Spectra also performs an assessment of its pipeline system in high consequence areas in accordance with 49 CFR § 192.921, which will include IPEC. Subsequent reassessments are done at a maximum of 7 years in accordance with 49 CFR § 192.939. Cathodic protection surveys will confirm, at test sites installed along the pipeline, that cathodic protection voltage potentials are maintained at levels necessary to prevent corrosion. Sophisticated inline inspection tools will be run through the pipeline at least once every seven years to identify internal and external corrosion, and other defects. These inspection tools continue to advance and can detect, size and locate pipe anomalies with high accuracy. Any defect noted by a tool run are tracked and corrected as necessary.

The methods used to prevent pipeline overpressure have been successful for many decades at compressor stations. Spectra has stated that it never had a pipeline rupture attributable to over-pressuring a pipeline. There are multiple levels of protection:

- The first level of protection is a precautionary alarm at 5 psi below the maximum allowable operating pressure (MAOP) to alert the Gas Control center in Houston to determine if any action needs to be taken and to ensure conditions are under control.

- The automated control system for the compressor unit is set to ensure that the discharge pressure does not exceed the pipeline MAOP.

- It is extremely rare that pressure ever exceeds MAOP, but if this were to happen, a "critical" alarm would alert the local station attendant and the Gas Control center in Houston to take immediate manual control measures (e.g., slowing or shutting down compressors, adjusting conditions at nearby facilities, etc.) to reduce pressure. These personnel are trained on how to respond to abnormal operating conditions.

- The Stony Point station control system is set to automatically shut down the unit and close the unit isolation valves when pipeline pressure reaches MAOP for 305 consecutive seconds.

- The Stony Point station control system is set to automatically shut down the unit and close the unit isolation valves when pipeline pressure reaches MAOP + 1psig for 10 consecutive seconds.

- The turbine compressor units also have a manufacturer-installed, automatic shutdown system to protect the equipment from damage and the set point on this device is lowered to trigger at 15 psi above MAOP.

- In the very unlikely event that the pressure were to continue to climb, the standard over pressure protection ("OPP") system is in place to automatically shut down all compressors at the station, and this is set at the OPP limit specified in the DOT Code 49 CFR § 192.169 (or 34 psi above MAOP for the new 42 inch pipeline).

- Relief valves are also in place at most compressor stations, as noted, but are part of an older operating strategy and are not relied upon as the primary means of overpressure protection (gas emissions and noise from relief valves are undesirable).

- The pressure control and overpressure devices are reliable, and the accuracy of set points is verified at periodic time intervals in accordance with the DOT Code. Maintenance records are audited by internal teams as well as the United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration auditors to ensure compliance.

4) Actions in the event of a rupture

The existing pipeline automation and control system, which will be used for the proposed new 42 inch pipeline near IPEC, does not provide for an automatic isolation of the closest upstream and downstream mainline valves upon the detection of a pipeline rupture. The two closest actuated valves are located at mile post 2.61 on the west side of the Hudson River and at mile post 5.47 just east of IPEC. They would require an operator to take action to close these valves. The system, however, is monitored 24 hours a day and an alarm would immediately alert the control point operator, located in Houston, Texas, of an event and isolation would be initiated. This would result in all the gas between these valves at the time of closure being able to vent or burn. The estimated time to respond to the alarm (less than one minute) and the

closure time of the valves (about one minute) was used as the basis for an assumed closure time of three minutes for the analysis performed in the attached report.

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

Evaluation Criteria

The Standard Format and Content Guide (RG 1.70) requires in Section 2.2.3.1 (Determination of Design Basis Events) that design basis events external to the nuclear plant be defined as those accidents that have a probability of occurrence on the order of about $1x10^{-7}$ per year or greater and have potential consequences serious enough to affect the safety of the plant to the extent that Part 100 guidelines could be exceeded. It further states:

- "The determination of the probability of occurrence of potential accidents should be based on an analysis of the available statistical data on the frequency of occurrence for the type of accident under consideration and on the transportation accident rates for the mode of transportation used to carry the hazardous material. If the probability of such an accident is on the order of 10^{-7} per year or greater, the accident should be considered a design basis event, and a detailed analysis of the effects of the accident on the plant's safety-related structures and components should be provided."

- Ruptures – Accidents involving detonations of high explosives, munitions, chemicals, or liquid and gaseous fuels should be considered for facilities and activities in the vicinity of the plant where such materials are processed, stored, used, or transported in quantity. Attention should be given to potential accidental ruptures that could produce a blast overpressure on the order of 1 psi or greater at the plant, using recognized quantity-distance relationships. Missiles generated in the rupture should also be considered.

- Flammable Vapor Clouds (Delayed Ignition) – Accidental releases of flammable liquids or vapors that result in the formation of unconfined vapor clouds should be considered. Assuming that no immediate rupture occurs, the extent of the cloud and the concentrations of gas that could reach the plant under "worst-case" meteorological conditions should be determined. An evaluation of the effects on the plant of detonation and deflagration of the vapor cloud should be provided. Missiles generated in the rupture should also be considered.

- Fires – Accidents leading to high heat fluxes or to smoke, and nonflammable gas- or chemical-bearing clouds from the release of materials as the consequence of fires in the vicinity of the plant should be considered. Fires in adjacent industrial and chemical plants and storage facilities and in oil and gas pipelines, brush and forest fires and fires from transportation accidents should be evaluated as events that could lead to high heat fluxes or to the formation of such clouds.

- Missiles Generated by Events near the Site – Identify all missile sources resulting from accidental ruptures in the vicinity of the site. The presence of and operations at nearby industrial, transportation, and military facilities should be considered. Missile sources that should be considered with respect to the site include, among others, pipeline ruptures.

NUREG 0800 is the NRC Standard Review Plan (SRP) which provides the NRC review criteria and acceptance criteria. The current revision of SRP Section 2.2.3 acceptance criteria states

"Specific SRP acceptance criteria acceptable to meet the relevant requirements of the NRC's regulations identified above are as follows for the review described in this SRP section. The SRP is not a substitute for the NRC's regulations, and compliance with it is not required. However, an applicant is required to identify differences between the design features, analytical techniques, and procedural measures proposed for its facility and the SRP acceptance criteria and evaluate how the proposed alternatives to the SRP acceptance criteria provide acceptable methods of compliance with the NRC regulations.

1. Event Probability

   The identification of design-basis events resulting from the presence of hazardous materials or activities in the vicinity of the plant or plants is acceptable if all postulated types of accidents are included for which the expected rate of occurrence of potential exposures resulting radiological dose in excess of the 10 CFR 50.34(a)(1) as it relates to the requirements of 10 CFR Part 100 is estimated to exceed the NRC staff objective of an order of magnitude of 10-7 per year.

   If data are not available to make an accurate estimate of the event probability, an expected rate of occurrence of potential exposures resulting in radiological dose in excess of the 10 CFR 50.34(a)(1) as relates to the requirements of 10 CFR Part 100, by an order of magnitude of 10-6 per year is acceptable if, when combined with reasonable qualitative arguments, the realistic probability can be shown to be lower.

2. Design-Basis Events

   The effects of design-basis events have been adequately considered, in accordance with 10 CFR 100.20(b), if analyses of the effects of those accidents on the safety-related features of the plant or plants have been performed and measures have been taken (e.g., hardening, fire protection) to mitigate the consequences of such events.

The SRP says that the "technical rationale for application of these acceptance criteria to the areas of review addressed by this SRP section is discussed in the following paragraphs:

1. Offsite hazards that have the potential to cause onsite accidents leading to the release of significant quantities of radioactive fission products, and thus pose an undue risk of public exposure, should have a sufficiently low probability of occurrence and should fall within the scope of the low-probability-of-occurrence required by 10 CFR 100.20(b) based on criterion of 10 CFR 50.34(a)(1) as it relates to the requirements of 10 CFR Part 100.

2. Data are often not available to enable the accurate calculation of probabilities because of the low probabilities associated with the events under consideration. Accordingly, the expected rate of occurrence of potential exposures in excess of the 10 CFR 50.34 (a)(1) requirements as they relate to the requirements of 10 CFR Part 100 guidelines by an order of magnitude of 10-6 per year is acceptable if, when combined with reasonable qualitative arguments, the realistic probability can be shown to be lower.

Regulatory Guide ("RG") 1.91 describes methods for nuclear power plant licensees that the NRC Staff finds acceptable for evaluating postulated failures at nearby facilities and transportation routes. One method includes the calculation of minimum safe distance based on estimates of TNT-equivalent mass of potentially explosive materials. Once blast load effects are calculated, the safe distances can

be based on peak positive incident overpressure below one pound per square inch, or 1.0 psi for which no significant damage would be expected. The RG goes on to say "If the facility with potentially explosive materials or the transportation routes are closer to SSCs important to safety than the distances computed using Equation (1), the applicant or licensee may show that the risk is acceptably low on the basis of low probability of failures. A demonstration that the rate of exposure to a peak positive incident overpressure in excess of 1.0 psi (6.9 kPa) is less than $1x10^{-6}$ per year when based on conservative assumptions, or $1x10^{-7}$ per year when based on realistic assumptions, is acceptable. Due consideration should be given to the comparability of the conditions on the route to those of the accident database. If the facility with potentially explosive materials or the transportation routes are closer to SSCs important to safety than the distances computed using Equation (1), the applicant may show through analysis that the risk to the public is acceptably low on the basis of the capability of the safety-related structures to withstand blast and missile effects associated with detonation of the potentially explosive material."

Results of Evaluation of Proposed Southern Route

Pipeline Rupture Event

The potential failure of the proposed new 42 inch pipeline along the more-distant (from IP2 and IP3) southern route has been evaluated for both exposure rates and effects.

The NRC noted in the discussion in RG 1.91, Rev 2, that "The NRC staff determined that if the probability of an failure at a nearby facility or the exposure rate, based on the theory in the Federal Emergency Management Agency's *Handbook of Chemical Hazard Analysis Procedures*, November 2007 (Ref. 11) for material in transit, can be shown to be less than 1x10-7 per year, then the risk of damage caused by failures is sufficiently low" Chapter 11.0 "Probability Analysis Procedures," Section 11.6 "Transportation of Hazardous Materials By Pipeline," has developed a formula for estimating the frequency of pipeline releases considering the size of the pipeline ($\geq$ 20 inches diameter applies to this pipeline), the length of pipe under consideration (about 3935 feet) to exclude damage to the switchyard and the GT 2/3 FOST), and size of the breach (guillotine breaks are considered which is 20% of all breaks).

For the proposed pipeline, the FEMA "Handbook of Chemical Hazard Analysis Procedures" identifies (page 11-28) the accident rate for pipelines with diameters greater than or equal to 20 inches is 5E-4 releases per year-mile. The length of pipe that could affect the SSC important to safety is greater than the enhanced gas pipeline of 3935 feet or 0.745 miles. This length corresponds to the probability of 3.73E-4. This value is not used to assess the 42 inch gas pipeline but is used to conclude that the rupture of the gas pipeline must be considered as a design basis event under NRC guidance. The value is not used to assess the gas pipeline because the data base from which frequency is determined is not applicable to this gas pipeline (it includes mostly pipelines of steel but also considers pipes of other materials, considers pressure of up to several thousand pounds per square inch (psi), pipes of various different diameters, and pipes of older and less rigorous design).

Consideration of the gas pipeline rupture as a design basis event requires a hazard analysis to be prepared. The hazard analysis must consider the location of safety related and important to safety structures, systems and components (SSCs) relative to the gas pipeline. The acceptance criteria for the hazard analysis considers; if the probability of a gas pipeline rupture is sufficiently low the event may be excluded; if the rupture does not damage the safety related or ITS SSCs then the rupture is acceptable; or, if the safety-related SSCs remain available to safely shutdown the plant and the risk of damage to the SSCs is low, then the risk to the public can be considered acceptable.

If the gas pipeline distances are sufficient to limit overpressure to less than 1.0 psi, the continued capability of safety related structures to withstand the effects of a gas pipeline rupture can be shown.

This hazards analysis considers the effects of the gas pipeline rupture to involve the approximately 3 miles of pipeline between isolation valves and considers the event to be terminated by manual action within 3 minutes after any pipeline rupture event by closing the closest isolation valves and limiting the event to the gas between these valves. Further, local fire departments have been trained in large gasoline fires of the type postulated for IPEC security events and will therefore have the ability to address any secondary fires and fire damage that will be of a lesser size when the gas pipeline flow has been terminated.

Evaluation of significance to margin of safety

The effects on safety related and important to safety (ITS) SSCs from a postulated gas pipeline failure could come from (1) potential missiles, (2) an over-pressurization event, (3) a vapor cloud (or flash) fire, (4) a hypothetical vapor cloud explosion, and (5) a jet fire. The attached analysis of the effects of a postulated gas pipeline failure and explosion along the southern route near IPEC is consistent with NRC guidance and demonstrates that there will be no damage to safety-related SSCs. However, the attached analysis also shows that certain SSCs important to safety (i.e., Switchyard with associated transmission lines, Gas Turbine 2/3 Fuel Oil Storage Tank (GT 2/3 FOST), City Water Tank, and Emergency Operations Facility (EOF) and meteorological tower) have to be evaluated for loss under certain postulated rupture scenarios. Entergy is also considering potential impacts to the FLEX Storage Building, the fuel oil tanker, and the IP2 and IP3 steam generator mausoleums.

Regulatory Guide (RG) 1.91 Rev 2 defines an acceptable method for establishing the distances beyond which no adverse effect would occur based on a level of peak positive incident overpressure. The peak overpressure of 1.0 psi (6.9 kPa) is considered to define this distance and can be calculated by

$$R_{min} = Z * W^{1/3}$$

where

Rmin = distance from explosion where P_{so} will equal 1.0 psi (6.9 kPa) (feet or meters)
W = mass of TNT (pounds or kilograms (kg))
Z = scaled distance equal to 45 ($ft/lb^{1/3}$) when R is in feet and W is in pounds
Z = scaled distance equal to 18 ($m/kg^{1/3}$) when R is in meters and W is in kilograms

The attached report contains the hazard evaluation which calculates the minimum safe distances from a vapor cloud explosion using the RG 1.91 formula (Table 10). The hazard evaluation also conservatively assumed damage to SSC important to safety from thermal radiation of 12.6 kW/m^2 (Table 4) due to a jet fire (immediate ignition of the release produces a jet fire anchored on the pipeline) and calculated the distance to achieve this value. The hazard analysis also defines the missile hazard based on historical industry pipeline failure data and demonstrates the delayed vapor cloud explosion (deflagration) is not a concern. The hazard evaluation is considered to be very conservative since the methodologies used for calculating the overpressure distance and the selection of the thermal radiation of 12.6 kW/m^2 (the distance that plastic melts / piloted ignition of wood are well below the thermal radiation for building damage) The attached hazard analysis identifies distances beyond which damage is not postulated even in worst case ruptures as follows:

Type of Effect Evalulated	Exclusion Distance	Basis
Jet fire	1266 ft (386 m)	A heat flux of 12.6 kW/m^2 was chosen as a basis for limiting postulated damage
Vapor Cloud explosion (detonation)	1155 ft (352 m)	A 1.0 psi overpressure will not occur at greater distance
Missile	900 ft (274 m)	The maximum distance that missiles have been observed

The first assessment assumes that these SSCs ITS could be damaged by a postulated explosion and evaluates whether there would be a significant reduction in the margin of safety. The assessment is to quantify potential effects assuming a postulated gas pipeline rupture and does not consider the frequency of a gas pipeline rupture and explosion or the capability of SSC. The assessments are based on the closest distances from the enhanced and unenhanced pipeline, as follows:

SSC ITS	Closest distance from enhanced gas pipeline	Closest distance non-enhanced gas pipeline
Switchyard	115 ft (35 m)	>1266 ft (386 m)
GT2/3 fuel tank	105 ft (32 m)	>1266 ft (386 m)
City water tank	1336 ft (407 m)	>1266 ft (386 m)
Meteorological tower	Not applicable	551 ft (168 m)
EOF	1002 ft (305 m)	>1266 ft (522 m)
SOCA	1580 ft (482 m)	>1580 ft (482 m)
Backup Meteorological tower	1844 ft (562 m)	>1266 ft (386 m)
SSC of Interest		
FLEX Building Unit 2 SG Mausoleum Unit 3 SG Mausoleum	1033 ft (315 m) 1440 ft (439 m) Not Applicable	1162 ft (354 m) >1266 ft (386 m) 477 ft (145 m)

The following assessment discusses the safety significance of a postulated loss of SSCs ITS from a postulated gas pipeline rupture. It concludes a loss of the SSCs important to safety would not result in a significant decrease in the margin of safety provided for public health and safety except for the assumed loss of the switchyard and GT 2/3 FOST which are more significant SSCs ITS.

- A postulated gas pipeline rupture near the switchyard could cause total loss of the switchyard of the type that could occur with low probability events such as extreme natural phenomena (e.g., earthquake, tornado winds / missiles, hurricanes, etc.) that the switchyard is not protected against. The potential loss of the switchyard can result in loss of offsite power to the plant and result in a generator or turbine trip with or without fast bus transfer to the turbine generator bus. This is considered a relatively high probability event and is analyzed in the Updated Final Safety Analysis Report (UFSAR). The loss of offsite power would result in automatic operation of the Emergency Diesel Generators (EDG) to provide essential power to cool down and shutdown each plant. The loss of offsite power is also considered as an initiator of the station blackout event (SBO) where the three EDG (three for IP2 or three for IP3) at one plant are postulated to fail to start. Both IP2 and IP3 have a separate SBO diesel generator for such an event. The IP2 SBO diesel has a fuel oil supply in the Unit 1 turbine building but depends upon the city water storage tank for initial cooling. The IP3 SBO diesel has local fuel oil supplies and has radiator cooling. The SBO event considers the ability to restore the switchyard in determining the duration for which a SBO is evaluated. However, loss of the switchyard for an extended period of time due to a postulated pipeline rupture does

not need to be considered for the SBO. NRC acceptance criteria for SBO (NUMARC 87-00) do not require consideration of low probability events such as severe natural phenomena or pipeline rupture for SBO. Therefore there would be no significant reduction in margin of safety due to loss of the switchyard from the contribution of a switchyard failure due to a gas pipeline rupture.

- A postulated gas pipeline rupture near the GT 2/3 FOST could cause loss of the tank. The purpose of the tank is to provide a supply of fuel oil to the IP2 and IP3 EDG so that they would have an overall 7 day supply of fuel oil (it is presumed that additional fuel oil as well as backup generators could be made available in that time). The function of the GT 2/3 FOST is backed up by the ability to provide fuel oil from outside the plant. The gas pipeline rupture that could cause loss of the GT 2/3 FOST could also result in loss of the switchyard due to their close proximity. This will require the backup fuel oil from offsite to be provided as the primary means of achieving a 7 day fuel oil supply. The gas pipeline rupture could also cause loss of the main access gate to the site directly across from the switchyard but there are other access gates for delivery of the fuel oil. The gate several hundred feet further south (it used to access IP3 when the two units were independent) could be blocked by the rupture since it is not too far from the GT 2/3 FOST. This gate has been blocked with two concrete barriers (a crane could be used to remove them). To the north about 1850 feet is the gate used for access to IP2 when the two sites were independently owned and this gate is expected to be available. It is easily accessible by opening the gates in the owner controlled fence and manually opening the blocking bar used in place of concrete barriers. Although access is feasible, the dependency on the offsite delivery results in a reduction in the margin of safety for the safety related EDG to provide the power for plant shutdown. The tanker that is stored onsite to transport fuel oil from the GT 2/3 FOST is within the damage range but will be relocated to assure availability for all cases where the GT 2/3 FOST remains available. Therefore it is concluded that the reduction in the margin of safety is more significant assuming a pipeline failure that results in the loss of both the switchyard and GT 2/3 FOST. But as discussed below, the substantial additional design and construction enhancements for the pipeline near IPEC make this a very low frequency event and, per NRC acceptance criteria, does not pose a concern to the safe operation of IP2 or IP3.

- A postulated gas pipeline rupture will not cause loss of the city water tank because the distance from the gas pipeline is sufficient to prevent loss of the tank (see above table) since the peak positive incident overpressure will not exceed 1.0 psi and the heat flux will not exceed 12.6 kW/m^2. The city water tank functions as alternate water supply to the IP2 and IP3 Auxiliary Feedwater Systems. It also serves as a backup for other SSCs, including the IP2 Appendix R / SBO diesel. The rupture of the gas pipeline is not caused by severe natural phenomena or by any postulated plant event and is therefore, not coincident with any plant event requiring the city water tank. Therefore there is no significant reduction in the margin of safety.

- A postulated gas pipeline rupture could cause loss of the important to safety Emergency Operations Facility (EOF) because it can see a heat flux of 12.6 kW/m^2 and be exposed to an overpressure in excess of 1 psi, as well as loss of the meteorological tower which is also within both exclusion distances. The function of the EOF is to act as a central command post for a plant emergency that meets the criteria for emergency responders to assemble. The function of the meteorological tower is to provide weather information in the event of a plant emergency that requires activation of the emergency response organization, it contains instrumentation for Entergy activation of the siren system and communications with the offsite assessment team. No gas pipeline rupture will cause any plant damage meeting the criteria for emergency

planning to assemble in the EOF. The EOF is activated for Alert Emergency Level declaration or above. An Unusual Event would likely be declared in the event of a pipeline rupture that results in switchyard failure (Loss of all offsite AC power to 480 V safeguards buses (5A, 2A/3A, 6A) for > 15 min) but the Alert Emergency Level criteria criteria would not be reached. The failure that does damage the meteorological tower would not result in damage to the switchyard. Also, there is a backup meteorological tower (it does not contain the 60 meter and 122 meter instruments), normal means to activate the siren systems from the counties, alternate communications with the assessment teams, and a backup EOF that would not be affected by the rupture. There would therefore be no significant reduction in the margin of safety since the EOF and meteorological tower functions would not be required and backups are available.

- There is no damage to the SOCA which is beyond the exclusion distance for which the effects of the gas pipeline explosion are considered for damage to SSCs. The SOCA boundary was identified for evaluation since the plant safety related SSCs are within the SOCA boundary and the SOCA represents the outer security boundary. Therefore there is no damage to safety related or security required SSCs.

In addition to the SSCs important to safety discussed above, other features have been considered.

- The building for storage of FLEX equipment (used for beyond design basis events) is required to address Fukushima orders. The building is constructed of reinforced concrete and was designed for a tornado overpressure. It does not have a damage potential from vapor cloud detonation because the overall structural capability of the building is designed for 3.0 psi overpressure compared to the predicted overpressure which is only slightly over 1 psi. The FLEX storage building is outside the postulated distance for a missile. The building is within the heat flux distance but the heat flux will not be great enough to affect the concrete and there is no other equipment to be affected.

- The storage of the steam generators replaced on IP2 and IP3 is in mausoleum buildings. The Unit 3 mausoleums are subject to potential damage since they are within the exclusion distance for heat flux, missile damage and overpressure. The Unit 3 building has 3 foot thick reinforced concrete walls supported by a pile foundation with reinforced concrete pile, an 18 inch (average) thick reinforced concrete roof supported by metal decking and steel beams, and an 8 inch thick reinforced concrete grade slab. Although the structure contains radioactive material, analyses have demonstrated the failure of the structure would not result in releases exceeding the limits in 10 CFR 20 (10 CFR 50.59 analysis dated May 1987). The Unit 2 mausoleum is outside the exclusion distances and a postulated rupture would have no effect.

A rupture of the buried gas pipeline due to a sabotage event is not considered deterministically or in the evaluation of frequency because the NRC regulations do not require the postulation of sabotage on facilities that are not part of the power plant and due to the substantial difficulty of intentionally causing an rupture of underground piping coupled with the extra design features that have been included in the proposed enhanced pipeline design. A gas pipeline rupture of exposed (above-ground) portions of the pipeline due to sabotage, however, has been postulated at IPEC in the past in response to a concern, although there is no regulatory requirement to do so. Consistent with this precedent, a sabotage event is postulated, but limited to considerations of potential sabotage of above ground piping. The above ground piping, however, is sufficiently far from any SSC important to safety so that all SSCs are outside the exclusion areas of the hazard analysis.

A gas pipeline rupture due to natural phenomena was also evaluated and is not considered to represent a credible threat to the pipeline. Tornadoes and hurricanes do not present a threat to the buried pipeline due to winds or missiles. Missile impacts are resisted by the strength of the piping and the 3 to 4 foot depth of the soil. Additionally, the effects of tornado missiles are not part of the IP2 design basis and are restricted to a single missile at IP3. A seismic event has the potential to cause loss of supporting soils due to the potential liquefaction of the underlying soils and susceptibility to other damage that could cause loss of the pipeline. However, due to the rocky soil in this area at relatively shallow depths combined with low seismicity, liquefaction of the underlying soil is not likely (Reference 9). As a result, the pipeline will be continuously supported along the entire length of burial by the soil and will tend to move in phase with the soil during an earthquake resulting in low stresses. The primary risks from ground movement hazards come from active seismic faults, landslides, long wall mine subsidence, and frost heaves in areas with deep frozen ground, none of which apply along the pipeline in the area near the Indian Point Facility. Therefore, a seismic event is not postulated to adversely affect the buried portion of the pipe.

The potential exists where the 26 / 30 inch pipeline will come together with the 42 inch pipeline for an explosion in one of the three pipelines to cause an explosion in one or more of the other lines. This would be possible in the above ground portion of the pipeline but the blasts would be sequential and this distances are great enough that the effects would be acceptable. Experience has shown that the rupture of one underground pipe would not affect another since the forces are upward. Also the lines are not close enough to even create this possibility until they reach the area where they are brought above ground. Therefore, a postulated simultaneous failure of the buried portions of the existing 26 / 30 inch pipelines and new 42 inch pipeline is not a credible event.

Frequency of Events

The prior discussion indicates that the new gas pipeline represents no potential damage to safety related SSC but a gas pipeline rupture could cause potential damage to SSCs ITS closer to the proposed southern route. The discussion also assesses the effects on the safety margin for protection of the public for a postulated gas pipeline rupture. The following information shows that the frequency of postulated gas pipeline ruptures that could damage SSCs ITS are, based in part on the enhanced design and installation features, sufficiently low and do not result in a significant reduction in the margin of safety. This is because they are excluded from consideration in accordance with NRC guidance due to the very low frequency of a gas pipeline rupture that could damage these SSCs ITS and because the frequency is sufficiently low that the undamaged safety related SSCs can be credited with safely shutting down the plant, or because the SSCs are not within the distance where they could be damaged. The one exception to this being the Meteorological Tower, which is above 10-6/yr. however, there is a backup Meteorological Tower and other means of obtaining meteorological data (e.g., NOAA)

The frequency of a pipeline explosion was evaluated using industry data and correlating it to more recent data. The frequency of a pipeline rupture and enhanced pipeline rupture is 1.32E-5 per mile-year and 1.98E-6 per mile-year, respectively. These are considered conservative values. The frequency of damage to the various SSCs ITS is calculated by the length of pipeline exposure and the frequency of occurrence of the types of events. The results are as follows:

SSC ITS	Event	Frequency / year
Switchyard	Jet fire	7.23E-7
	Vapor Cloud explosion	5.52E-8
	Missile	1.32E-7
GT2/3 fuel tank / switchyard	Jet fire	5.20E-7

	Vapor Cloud explosion	4.25E-8
GT2/3 fuel tank	Missile	1.51E-8
City water tank	Jet fire	Outside damage distance
	Vapor Cloud explosion	Outside damage distance
	Missile	Outside damage distance
Meteorological tower	Jet fire	1.86E-6
	Vapor Cloud explosion	1.51E-7
	Missile	2.06E-9
EOF	Jet fire	4.02E-7
	Vapor Cloud explosion	2.79E-8
	Missile	Outside damage distance
SOCA	Jet fire	Outside damage distance
	Vapor Cloud explosion	Outside damage distance
	Missile	Outside damage distance
Backup Meteorological tower	Jet fire	Outside damage distance
	Vapor Cloud explosion	Outside damage distance
	Missile	Outside damage distance
City Water Tank	Jet fire	Outside damage distance
	Vapor Cloud explosion	Outside damage distance
	Missile	Outside damage distance
Other SSC of Interest		
FLEX Building	Jet fire	No exposed instruments for 12.kW/m^2 to damage
	Vapor Cloud explosion	Overpressure 1.19 psi building design for 3.0 psi
	Missile	Outside damage distance
Unit 2 SG Mausoleum	Jet fire	Outside damage distance
	Vapor Cloud explosion	Outside damage distance
	Missile	Outside damage distance
Unit 3 SG Mausoleum	Jet fire	1.38E-6 (for thermal radiation that would damage the building)
	Vapor Cloud explosion	1.95E-7
	Missile	3.83E-8

Conclusion

Based on the considerations discussed above, the potential for an increase in risk to the public is acceptably low on the basis of:

- there is no damage to safety related SSC or plant security from a postulated pipeline rupture;
- the effect on SSCs ITS of a postulated gas pipeline rupture would not have a significant effect on plant safety because:
    - The SSCs ITS have been shown to be sufficiently far away from a postulated gas pipeline failure so as to be unaffected by the failure, or

- Based on the agreed-upon pipeline design and construction enhancements, the low frequency of a gas pipeline rupture would preclude consideration of rupture with damage to SSC ITS, with the exception of the Meteorological Tower where frequency is greater that 10E-6. The meteorological tower, is not required for shutdown and the undamaged safety related SSCs can be credited with safely shutting down the plant. The meteorological tower also has backup capability and other means of obtaining meteorological data are available (e.g., NOAA).

Therefore there is no significant reduction in the margin of safety with regard to public safety.

References

(1) Preliminary Safety Analysis Report (PSAR) for IP3, dated August 30, 1968, ADAMS Accession No. ML093480204 ("Gas Pipeline Fire" describing the design and construction of the gas lines., operation and maintenance practices, postulated failure modes, and standoff distances provided to determine safety-related structures would not be affected).

(2) Safety Evaluation Report dated September 21, 1973, ADAMS Accession No. ML072260465.

(3) New York Power Authority letter to NRC (IPN-97-132) Regarding Indian Point 3 Nuclear Power Plant – Individual Plant Examination of External Events (IPEEE), dated September 26, 1997.

(4) Letter to M Kansler regarding "Review of Individual Plant Examination of External Events (TAC NO. M83632),"' dated February 15, 2001

(5) Memorandum from Richard J. Laufer, Chief, Section 1, Project Directorate 1, Division of Licensing Project Management Office of Nuclear Reactor Regulation, NRC, to Peter Eselgroth, Chief, Branch 2, Division of Reactor Projects, Region 1, NRC, "Subject: Review of Natural Gas Hazards, Indian Point Nuclear Generating Unit Nos. 2 and 3 (TAC Nos. MB8090 and MB8091)" (Apr. 25, 2003) (ADAMS Accession No. ML11223A040).

(6) Berk Donaldson, Algonquin Gas Transmission, LLC letter to Ms Kimberly D Bose, FERC regarding *Algonquin Gas Transmission, LLC*, Docket No. CP14-96-000, Abbreviated Application for a Certificate of Public Convenience and Necessity and for Related Authorizations, dated February 28, 2014

(7) Timothy C O'Brien, Spectra, E mail to Charles A. Moore, Morgan Lewis& Brockius, LLP, dated July 29, 20124

(8) Spectra Energy (Algonquin Gas Transmission) memorandum to Energy regarding Response to Entergy Document entitled "Pipeline Enhancements Being Evaluated to Mitigate a Pipeline Failure" dated July 29, 2014.

(9) "Enercon Report of Liquefaction Potential Assessment" dated June 26, 2014 (IP-RPT-14-00010)

Is the validity of this Evaluation dependent on any other change? ☐ **Yes** ☒ **No**

If "Yes," list the required changes/submittals. The changes covered by this 50.59 Evaluation cannot be implemented without approval of the other identified changes (e.g., license amendment request). Establish an appropriate notification mechanism to ensure this action is completed.

Based on the results of this 50.59 Evaluation, does the proposed change require prior NRC approval? ☐ **Yes** ☒ **No**

Preparer: Stephen Prussman / 8-18-2014
Name (print) / Signature / Company / Department / Date

Reviewer: John Skonieczny / / ENTERGY / KONE / 8-19-2014
Name (print) / Signature / Company / Department / Date

OSRC: John Kirkpatrick/ 8/21/14
Chairman's Name (print) / Signature / Date

Meeting 14-13 on 8-18-2014
OSRC Meeting #

II. 50.59 EVALUATION

Does the proposed Change being evaluated represent a change to a method of evaluation ONLY? If "Yes," Questions 1 – 7 are not applicable; answer only Question 8. If "No," answer all questions below.

☐ Yes
☒ No

Does the proposed Change:

1. Result in more than a minimal increase in the frequency of occurrence of an accident previously evaluated in the UFSAR?

☐ Yes
☒ No

BASIS:

Currently, a 26 inch and 30 inch pipeline traverse the site along a route just south of the protected area and the effects of a rupture of that pipeline has been evaluated. The addition of a 42 inch pipeline south of the IPEC property that crosses IPEC property near the GT 2/3 Fuel Oil Storage Tank (FOST) and Buchanan substation creates the possibility of a gas pipeline rupture. Gas pipelines have a low frequency of rupture. The new gas pipeline has been designed with the latest methodology and a significant portion has been enhanced with additional features (e.g., deeper burial, thicker pipe, stronger materials, positive means to prevent excavation and abrasion resistance coating) intended to further reduce the frequency of gas pipeline rupture in the area of Structures Systems and Components (SSC) important to safety (ITS). The frequency is sufficiently low that the new gas pipeline will not result in more than a minimal increase in the frequency of occurrence of an accident (gas pipeline rupture) currently evaluated in the UFSAR.

2. Result in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system, or component important to safety previously evaluated in the UFSAR?

☐ Yes
☒ No

BASIS:

A rupture of the new gas pipeline could be the cause of a malfunction of a SSC previously evaluated. The new gas pipeline has been routed where a gas pipeline rupture could not cause malfunction of a safety related SSC or security provisions and therefore there would be no increase in the likelihood of damage to those SSC. The routing is where a postulated rupture could cause a malfunction of SSC's ITS (Switchyard with associated transmission lines, Gas Turbine 2/3 Fuel Oil Storage Tank (GT 2/3 FOST), and Emergency Operations Facility (EOF) and meteorological tower) due to proximity. The likelihood of a gas pipeline rupture causing malfunction of SSC ITS will be minimized by the gas pipeline design and maintenance as well as the enhancement of a substantial portion of that gas pipeline routed near the SSC ITS. The increase in likelihood of a gas pipeline rupture affecting the SSCs ITS has been determined to have a very low frequency. As a result, this new pipeline is not considered to result in a more than minimal increase in the likelihood of occurrence of a malfunction of a SSCs important to safety previously evaluated in the UFSAR.

3. Result in more than a minimal increase in the consequences of an accident previously evaluated in the UFSAR?

☐ Yes
☒ No

BASIS:

The rupture of the gas pipeline previously considered in the UFSAR assessed if it could result in loss of safety related SSCs. This is the rupture of the 26 inch and 30 inch gas pipelines which were previously evaluated as acceptable during the original Licensing stage, and as during the performance of the IPEEE as of acceptably low probability. It was evaluated for an aboveground rupture as a potential security event and the evaluation concluded the effects were acceptable. The evaluation of the consequences of these prior ruptures showed there was no damage to safety related SSCs. The effects of a gas pipeline rupture of the new 42 inch gas pipeline were evaluated to determine whether the consequences of the previous evaluations were increased. The evaluation showed there was no damage to safety related SSCs due to gas pipeline rupture and therefore there is no increase in consequences. The evaluation, performed using methodologies consistent with the current NRC guidance, looked at the effects on SSC important to safety as well as safety related SSC. The evaluation shows that, due to the proximity of the proposed southern route to SSCs ITS, there was a potential for damage. However, it also showed that the damage frequency was sufficiently low, according to NRC criteria, that it was acceptable. Additionally, the evaluation of SSCs ITS was not an accident previously considered. Therefore there is no increase in consequences since the safety related SSCs are not damaged and the effects of damage to SSCs ITS were not previously evaluated and are acceptable. As a result, it can be concluded that this activity will not result in a more than minimal increase in the consequence of previously evaluated accidents.

4. Result in more than a minimal increase in the consequences of a malfunction of a structure, system, or component important to safety previously evaluated in the UFSAR?

☐ Yes
☒ No

BASIS:

The effects of a rupture in the new 42 inch gas pipeline have been evaluated to determine the effects on SSCs ITS. The evaluation shows the frequency of a rupture affecting a SSCs ITS have been reduced to where a rupture will have no more than a minimal increase in the consequences of malfunction of the SSCs ITS affected. Natural phenomena with a probability greater than the rupture of the gas pipeline can damage the SSCs ITS that the postulated gas pipeline rupture can affect. The ability of the plant to safely shutdown and maintain cold shutdown has been assessed with this damage. There is a minimal increase in the consequence of a malfunction of the SCCs since a gas pipeline rupture has the lower frequency. Therefore, this activity will not result in a more than minimal increase in the consequences of a malfunction of a SSCs important to safety previously evaluated in the UFSAR.

5. Create a possibility for an accident of a different type than any previously evaluated in the UFSAR?

☐ Yes
☒ No

BASIS:

The previously considered rupture of the 26 and 30 inch pipelines is considered a similar accident. A rupture of the new 42 inch gas pipeline has been evaluated and would not result in damage to a safety related SSC but could result in damage to SSC important to safety (Buchanan switchyard, the GT2/3 storage tank, and the EOF / meteorological tower). Loss of these components could not create the possibility of an accident of a different type than previously evaluated since their loss has previously been evaluated. There are no other changes to the plant operations, operating procedures or site activities that could possibly create an accident of a different type than previously evaluated. As a result, this activity does not create a possibility for an accident of a different type than previously evaluated in the UFSAR.

6. Create a possibility for a malfunction of a structure, system, or component important to safety with a different result than any previously evaluated in the UFSAR? ☐ Yes ☒ No

BASIS:

A rupture of the new 42 inch gas pipeline has been evaluated and would not result in damage to a safety related SSC but could result in damage to SSCs ITS. The potential for damage could not result in a malfunction with a different result that any previously considered in the UFSAR because the potential damage is not different than previously evaluated and there is no damage to safety related SSC. Rupture of the pipeline is postulated to occur in normal operation since it is not postulated to occur as a result of a plant accident or natural phenomena. The malfunction of SSCs ITS that could be affected by the gas pipeline is no different than those previously considered in the UFSAR. That failure is just a loss of the component since there is no interface with safety related SSC. Therefore the malfunction of the affected components would not have a different result than the rupture of these components as previously evaluated.

7. Result in a design basis limit for a fission product barrier as described in the UFSAR being exceeded or altered? ☐ Yes ☒ No

BASIS:

A rupture of the new 42 inch gas pipeline has been evaluated and would not result in damage to a safety related SSC and damage to a ITS would not affect the ability to safely shutdown. The postulated rupture of the new 42" gas pipline has no impact on fission product barriers. Therefore there will be no fission product barrier design basis limit approached.

8. Result in a departure from a method of evaluation described in the UFSAR used in establishing the design bases or in the safety analyses? ☐ Yes ☒ No

BASIS:

This activity installs a new gas pipeline routed south of the IPEC plant and partially on IPEC property. The UFSAR describes past evaluations of pipeline rupture but does not discuss the methodology. The new evaluation of the potential for rupture uses methodology consistent with past evaluations and approved by NRC and evaluates the frequency of rupture using methodology consistent with the NRC criteria. Therefore, it is concluded there is no departure from past methodologies used for the plant and does not depart from a method of analysis contained in the UFSAR.

If any of the above questions is checked "Yes," obtain NRC approval prior to implementing the change by initiating a change to the Operating License in accordance with NMM Procedure EN-LI-103.

Hazards Analysis: Consequences of Postulated Fire and Explosion Following Release of Natural Gas From Proposed AIM Pipeline, prepared for Entergy by Risk Research Group (August 19, 2014).

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

~~Security Related Information - Withhold Under 10 CFR 2.390~~

ATTACHMENT 9.1 VENDOR DOCUMENT REVIEW STATUS
Sheet 1 of 1

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

Document No.: IP-RPT-14-00013	Rev. No.0
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	
EC No.: 52291 (N/A for NP)	Purchase Order No.

STATUS NO:
1. ☒ ACCEPTED, WORK MAY PROCEED
2. ☐ ACCEPTED AS NOTED RESUBMITTAL NOT REQUIRED, WORK MAY PROCEED
3. ☐ ACCEPTED AS NOTED RESUBMITTAL REQUIRED
4. ☐ NOT ACCEPTED

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.

	Print Name	Signature	Date
Responsible Engineer	John Skonieczny		8-19-14
Engineering Supervisor	Rich Drake		8-20-14

THE RISK RESEARCH GROUP, INC.

~~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

The Risk Research Group, Inc.
18 Dogwood Road
West Orange, NJ 07072

Under Contract 10391690

Author: David J. Allen, Ph.D, P.Eng.

David J. Allen

8/19/2014

~~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 [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). 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 [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 [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 [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, [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.

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

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

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

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

(b)(7)(F)

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 (b)(7)(F) 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, (b)(7)(F) (b)(7)(F) 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 (b)(7)(F) This rate comprises the release of (b)(7)(F) in the first minute (from ALOHA), a release (b)(7)(F) in the next two minutes (accounting for the pressure drop) and (b)(7)(F) 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) [redacted]. 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) [redacted] 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) [redacted] 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.

---

[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 [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 [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 [redacted] adjoining the pipeline right of way, [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)

(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) (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.

References

1. Indian Point Unit 3 Nuclear Power Plant, Individual Plant Examination of External Events (IPEEE), September 26, 1997.

2. "Consequences of Fire and Explosion Following the Release of Natural Gas from Pipelines Adjacent to Indian Point", Study performed for Entergy, Indian Point Energy Center, August 14, 2008.

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.

4. Congram, G. E., "Continuous Inspection Needed to Tame Pipeline Corrosion", Pipeline and Gas Journal, December 1994, pp 30-34.

5. Sax, N. Irving and Lewis, Richard J., Sr., "Hazardous Materials Desk Reference", Van Nostrand Reinhold, New York, 1987.

6. Center for Chemical Process Safety, "Guidelines for Vapor Cloud Explosion, Pressure Burst, BLEVE and Flash Fire Hazards", 2nd edition, New York, 2010.

7. US Nuclear Regulatory Commission, "Fire Dynamics Tools", NUREG-18-5, December 2004.

8. Lees, Frank P., "Loss Prevention in the Process Industries", Butterworth-Heinemann, Boston, 1996.

9. "Oil and gas Fires", UK Health and Safety Executive, OTI 92 596, 1992.

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

11. Dennis P. Nolan, "Handbook of Fire and Explosion Protection Engineering Principles for Oil, Gas, Chemical and Related Facilities", Elsevier, 2010.

12. J. K. Thomas, M. L. Goodrich and R. J. Duran, "Propagation of a Vapor Cloud Explosion from a Congested Area into an Uncongested Area", Process Safety Progress, Vol. 32, No. 2, pp 199-206, 2013.

13. R. J. Harris and Wickens (1989) as quoted in [6] and [8].

14. Yoshitomo Inaba, Tetsuo Nishihara, Mark A. Groethe and Yoshikazu Nitta, 'Study on explosion characteristics of natural gas and methane in semi-open spaces for the HTTR

hydrogen production system", Nuclear Engineering and Design, Volume 232, Issue 1, July 2004, Pages 111-119.

15. W. W. Lewis, J. P. Lewis and P. M. Outrim, "LNG Facilities, the Real Risks", Gas Tech 2002.

16. FM Global, Property Loss Prevention Data Sheets 7-42, October 2013.

17. Scott G. Davis, et al., "2005 Buncefield Vapor Cloud Explosion: Unraveling the Mystery of the Blast", GexCon Paper.

18. Will Gray, "Impossible explosion: the Buncefield blast explained", New Scientist, April 5, 2012.

19. Buncefield Major Incident Investigation Board, "Explosion Mechanism Advisory Group Report", UK Government, August 2007.

20. Indian Point Unit 3 Nuclear Power Plant, Final Safety Analysis Report.

21. US Nuclear Regulatory Commission, "Nuclear Fuel Cycle Facility Accident Analysis Handbook", NUREG/CR-6410, March 1998.

22. US Environmental Protection Agency, "Risk Management Program Guidance", EPA 550-B-99-009, March 2009.

23. NOAA, EPA and DOT, "Technical documentation and software quality assurance for project Eagle-ALOHA", February 2006.

24. Hanna, S. R., J. C. Chang, and D. G. Strimaitis, 1993: Hazardous response modeling uncertainty. ESL-TR-91-28, US Air Force Engineering and Service Laboratory.

25. Neil Schultz, "Fire and Flammability Handbook", Van Nostrand Reinhold, New York, 1985.

26. John L. Woodward, "Estimating the Flammable Mass of a Vapor Cloud", Center for Chemical Process Safety, New York 1998.

27. US Federal Emergency Management Agency, "Reference Manual to Mitigate Potential Terrorist Attacks Against Buildings", FEMA-426, December 2003.

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. [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

---

[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

---

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 [redacted] 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]

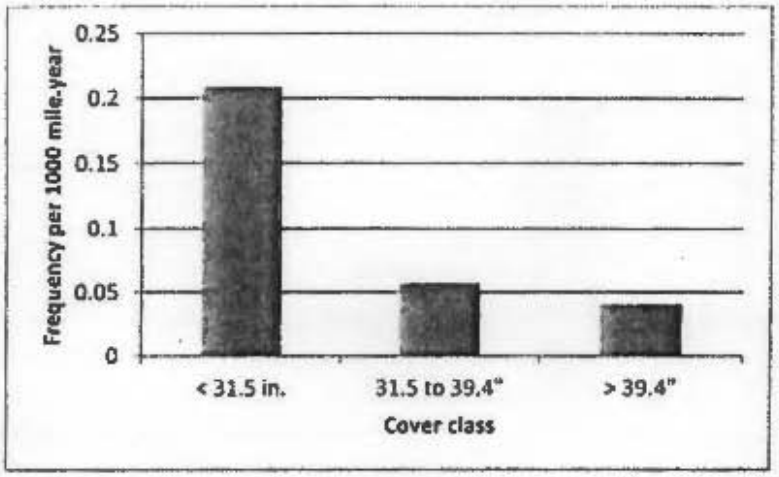


Figure B-2

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

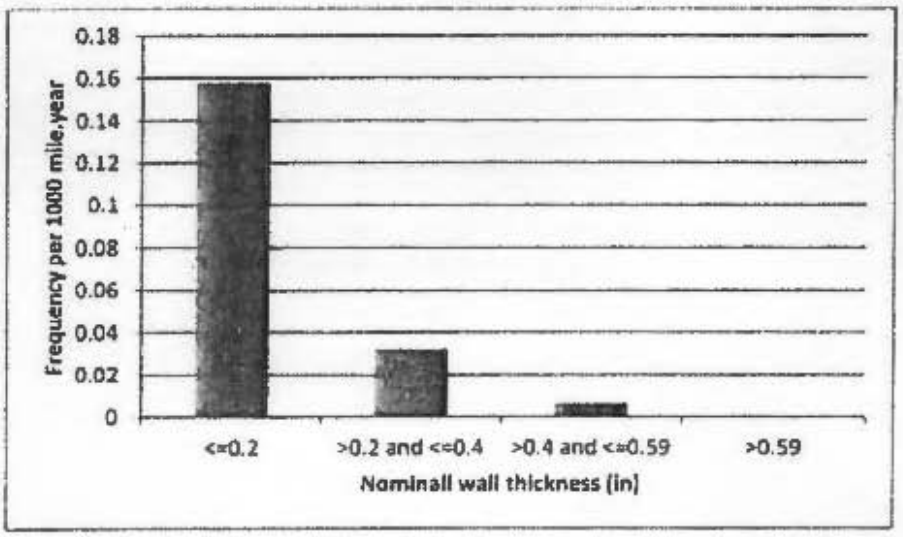
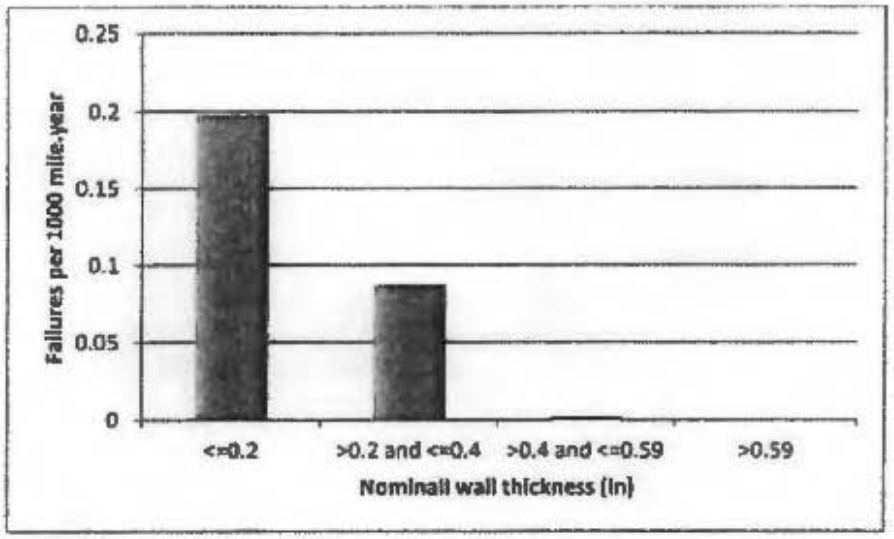


Figure B-3

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]

[redacted]

[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)	[redacted]		1.98×10^{-6}	1.32×10^{-5}	[redacted]	1.95×10^{-7}

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).

---

[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) length of enhanced 42" pipeline within (b)(7)(F) 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 x 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) length of unenhanced 42" pipeline and (b)(7)(F) length of enhanced 42" pipeline. An exposure rate for rupture followed by ignition of 1.86 x 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) (b)(7)(F) length of unenhanced 42" pipeline and a 203 m (666 ft) length of enhanced 42" pipeline within (b)(7)(F) 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 x 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) length of unenhanced 42" pipeline. An exposure rate for rupture followed by ignition of 1.38 x 10^{-6}/yr can be predicted for this length (Table B-3).

---

[14] The (b)(7)(F) 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) 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)			1.98×10^{-6}	1.32×10^{-5}	(b)(7)(f)	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.

[

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)

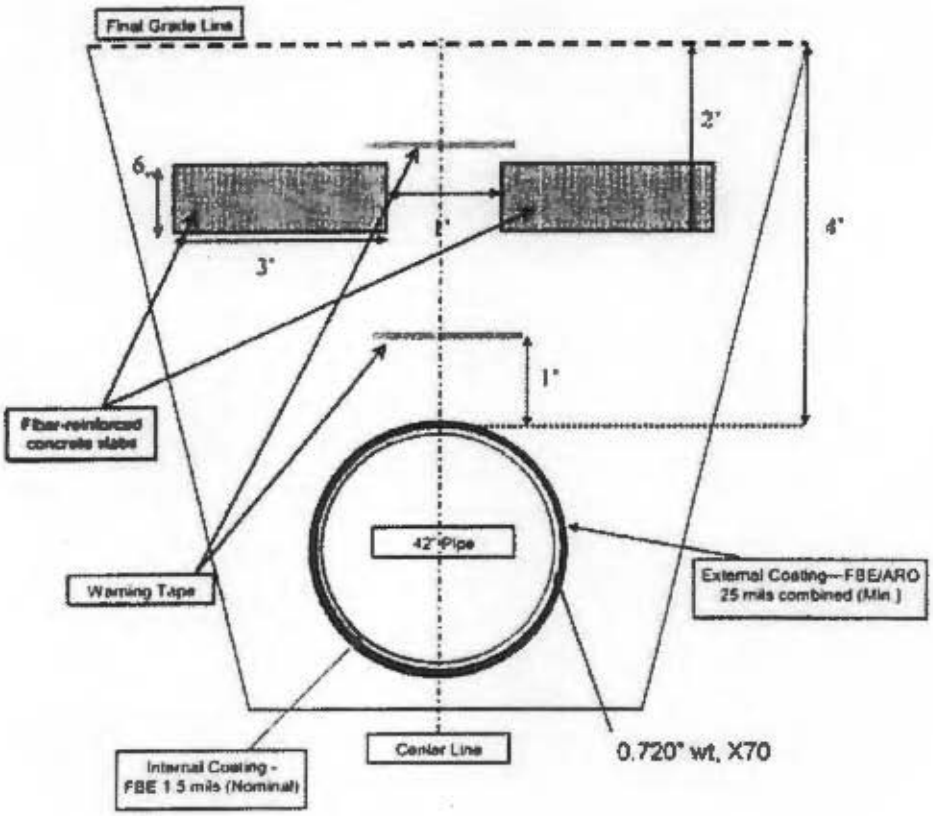
Question	Typical Gas Pipeline Installation/design	IPEC Enhanced Installation/design	Remarks
	will be repaired.	to installation of concrete slabs and any coating faults will be repaired.	
Mitigation of AC induced current from high voltage power lines.	Provisions for AC Mitigation	AGT is in the process 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



FOIA/PA REQUEST
Case No.: 2015-0076
Date Rec'd: 12/4/14
Specialist: Dennis
Related Case:

FOIA Resource

From: Susan Van Dolser (b) (6)
Sent: Thursday, December 04, 2014 8:41 AM
To: FOIA Resource
Subject: WWW Form Submission

Below is the result of your feedback form. It was submitted by

Susan Van Dolsen (b) (6) on Thursday, December 04, 2014 at 08:41:27

through the IP (b) (6)

using the form at http://www.nrc.gov/reading-rm/foia/foia-submittal-form.html

and resulted in this email to foia.resource@nrc.gov

Company/Affliation: None

Address1: (b) (6)

Address2:

City (b)

State (b)

Zip (b) (6)

Country: United_States

Country-Other:

Phone (b) (6)

Desc: Requesting these documents:

ML14253A340, Enclosure 2 to NL-14-106- Hazards Analysis ML14245A111, Enclosure 2 to NL-14-106: Hazards Analysis ML14329A189, Blast Analysis for 42-Inch Natural Gas Pipeline at Indian Point ML14307B748, Indian Point Energy Center, Units 2 and 3, Plant Modifications, IP 71111.18, Pipeline Analysis

FeeCategory: Personal_Noncommercial

MediaType:

MediaType_Other_Description:

Expedite_ImminentThreatText:

Expedite_UrgencyToInformText:

Waiver_Purpose:

Waiver_ExtentToExtractAnalyze:

Waiver_SpecificActivityQuals:

Waiver_ImpactPublicUnderstanding:

Waiver_NatureOfPublic:

Waiver_MeansOfDissemination:

Waiver_FreeToPublicOrFee:

Waiver_PrivateCommericalInterest:

NRC Internal Email from D. Beaulieu to D. Pickett
(April 27, 2015)

Heater, Keith

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

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

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

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

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

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

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

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

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

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

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

A-4

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

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

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

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

A different section of the Oak Ridge Report states:

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

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

Turkey Point Units 6 and 7 COL Application,
Part 2 - FSAR at 2.2.2-2.2.-25

SECTION 2.2:
NEARBY INDUSTRIAL, TRANSPORTATION, AND MILITARY FACILITIES
TABLE OF CONTENTS

SECTION 2.2 LIST OF TABLES

SECTION 2.2 LIST OF FIGURES

2.2 NEARBY INDUSTRIAL, TRANSPORTATION, AND MILITARY FACILITIES

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

PTN COL 2.2-1

The purpose of this section is to establish whether the effects of potential accidents onsite or in the vicinity of the site from present and projected industrial, transportation, and military installations and operations should be used as design basis events for plant design parameters related to the selected accidents. Facilities and activities within the vicinity, 5 miles, of Turkey Point Units 6 & 7 were considered to meet the guidance in RG 1.206. Facilities and activities at greater distances are included as appropriate to their significance.

STD DEP 1.1-1

Subsection 2.2.1 of the DCD is renumbered as Subsection 2.2.4 and moved to the end of Section 2.2. This is being done to accommodate the incorporation of RG 1.206 numbering conventions for Section 2.2.

2.2.1 LOCATIONS AND ROUTES

PTN COL 2.2-1
PTN COL 3.5-1
PTN COL 3.3-1

Potential hazard facilities and routes within the vicinity (5 miles) of Units 6 & 7, and airports within 10 miles of Units 6 & 7 are identified along with significant facilities at a greater distance in accordance with RG 1.206, RG 1.91, RG 4.7, and relevant sections of 10 CFR Parts 50 and 100.

An investigation of the potential external hazard facilities and operations within 5 miles of Units 6 & 7 concluded there is one significant industrial facility associated with a military installation identified for further analysis. An evaluation of major transportation routes within the vicinity of Units 6 & 7 identified one natural gas transmission pipeline system and one navigable waterway for assessment (References 204, 206, 207, and 208).

Potential hazard analysis of internal events includes Units 1 through 5 and onsite chemical and chemical storage facilities associated with Units 6 & 7 along with an onsite transportation route.

A site vicinity map (Figure 2.2-201) details the following identified facilities and road and waterway transportation routes:

Significant Industrial and Military Facilities Within 5 Miles

- Turkey Point Units 1 through 5
- Homestead Air Reserve Base

Transportation Routes Within 5 Miles

- Onsite transportation route
- Miami to Key West, Florida Intracoastal Waterway
- Florida Gas Transmission Company, Turkey Point Lateral Pipeline and Homestead Lateral Pipeline

An evaluation of nearby facilities and transportation routes within 10 miles of Units 6 & 7 revealed that there are no additional facilities significant enough to be identified as potential hazard facilities. (References 207, 224, and 225)

Potential hazard analyses of airports within 10 miles of Units 6 & 7 are identified along with airway and military operation areas. There are two airports within 10 miles of the plant and one airway identified whose centerline is located approximately 5.98 miles from the plant identified for further analysis. (References 209, 210, 223, and 240)

Figure 2.2-202 illustrates the following identified airports and airway routes within 10 miles of Units 6 & 7, including:

Airport and Airway Routes Within 10 Miles

- Turkey Point Heliport
- Homestead Air Reserve Base
- Ocean Reef Club Airport
- Airway V-3

There are no identified hazard facilities, routes, or activities greater than 10 miles that are significant enough to be identified (References 207, 223, 224, 225, and 240).

Items illustrated in Figures 2.2-201 and 2.2-202 are described in Subsection 2.2.2.

2.2.2 DESCRIPTIONS

Descriptions of the industrial, transportation, and military facilities located in the vicinity of Units 6 & 7 and identified in Subsection 2.2.1 are provided in the subsequent subsections in accordance with RG 1.206.

2.2.2.1 Description of Facilities

In accordance with RG 1.206, two facilities, along with the onsite chemical and chemical storage facilities associated with Units 6 & 7, were identified for review:

- Turkey Point Units 1 through 5
- Homestead Air Reserve Base

Table 2.2-201 provides a concise description of each facility, including its primary function and major products, as well as the number of people employed.

2.2.2.2 Description of Products and Materials

A more detailed description of each of these facilities, including a description of the products and materials regularly manufactured, stored, used, or transported, is provided in the following subsections. In accordance with RG 1.206, chemicals stored or situated at distances greater than 5 miles from the plant do not need to be considered unless they have been determined to have a significant impact on the proposed facilities.

The South Florida Regional Planning Council, Emergency Management Division, was contacted to obtain information regarding offsite chemical storage. The EPA's Envirofacts/Enviromapper database was also queried to ascertain if other facilities of significance existed in addition to the facilities identified after evaluating the Superfund Amendments and Reauthorization Act (SARA) Title III, Tier II reports obtained from South Florida Regional Planning Council. Other than the Turkey Point Units 1 through 5 site, there was only one identified external facility, Homestead Air Reserve Base, within 5 miles of the Turkey Point site with

hazardous material storage in quantities identified as meeting SARA Title III Tier II reporting requirements. A review of SARA reports encompassing an area extending out from Units 6 & 7 with a minimum radius of 7.24 miles out to a maximum radius of 28.45 miles inclusive of the following zip codes: 33035, 33033, 33032, 33039, and 33037revealed that there are no other facilities or storage locations identified that could have a significant impact on Units 6 & 7. The evaluation for those facilities located greater than 5 miles from Units 6 & 7 was based on identifying whether any of these facilities contained highly toxic, highly volatile chemicals not bounded by the onsite storage of these chemicals with risk management program calculated endpoint distances of at least 25 miles (References 224, 225, and 226). Therefore, further analysis beyond these two facilities and the onsite chemical storage facilities associated with Units 6 & 7 is not required.

2.2.2.2.1 Turkey Point Plant

Units 1 through 5 are located on the approximate 11,000-acre Turkey Point plant property. Units 1 and 2 are gas/oil-fired steam electric generating units; Units 3 and 4 are nuclear powered steam electric generating units; and Unit 5 is a natural gas combined cycle plant. The two 400 MW (nominal) gas/oil-fired steam electric generation units have been in service since 1967 (Unit 1) and 1968 (Unit 2). These units currently burn residual fuel oil and/or natural gas with a maximum equivalent sulfur content of 1 percent. The two 700 MW (nominal) nuclear units are pressurized water reactor units that have been in service since 1972 (Unit 3) and 1973 (Unit 4). Unit 5 is a nominal 1150 MW combined-cycle unit that began operation in 2007 (Reference 244).

Units 6 & 7 are located southwest of Units 1 through 5 as delineated on the site area maps (Figures 2.1-203 and 2.1-205).The center point of the Unit 6 reactor building is approximately 215 feet west and 3625 feet south of the center point of the Unit 4 containment.The chemicals identified for possible analysis and their location associated with Units 1 through 5 and the onsite chemical storage facilities associated with Units 6 & 7 are presented in Table 2.2-202. The disposition of hazards associated with these chemicals is summarized in Tables 2.2-207 and 2.2-208 and the subsequent analysis of these chemicals is addressed in Subsection 2.2.3.

2.2.2.2.2 Homestead Air Reserve Base

The Homestead Air Reserve Base is located approximately 4.76 miles north-northwest of Units 6 & 7 (Figure 2.2-201). Construction of a fully operating

military base (Homestead Army Air Field) began at the current Homestead Air Reserve Base site in September of 1942 to serve as a maintenance and fueling stopover for aircraft headed overseas during World War II.

Today, the 482nd Fighter Wing, the host unit of Homestead Air Reserve Base, continues to support contingency and training operations of U.S. Southern Command and a number of tenant units including Headquarters Special Operations Command South, U.S. Coast Guard Maritime Safety and Security Team, and an air and maritime unit of U.S. Customs and Border Protection. The Homestead Air Reserve Base is a fully combat-ready unit capable of providing F-16C multipurpose fighter aircraft, along with mission ready pilots and support personnel, for short-notice worldwide deployment. In addition, the Homestead Air Reserve Base is home to the most active North American Aerospace Defense Command alert site in the continental United States, operated by a detachment of F-15 fighter interceptors from the 125th Fighter Wing Florida Air National Guard.

The Homestead Air Reserve Base has 2365 total personnel including 267 active-duty personnel, 1245 Air Force Reserve Command and National Guard personnel, 779 civilians, and 74 civilian contractors (References 202 and 203). The chemicals stored at the Homestead Air Reserve Base identified for possible analysis are presented in Table 2.2-203. The disposition of hazards associated with these chemicals is summarized in Table 2.2-209 and the subsequent analysis of these chemicals is addressed in Section 2.2.3.

2.2.2.3 Description of Pipelines

There are two natural gas transmission pipelines operated by Florida Gas Transmission Company within 5 miles of the plant as depicted in Figure 2.2-201. The Florida Gas Transmission Company owns and operates a high-pressure natural gas pipeline system that serves FPL and other customers in south Florida. Two of the pipelines, the Turkey Point Lateral and the Homestead Lateral, are located within 5 miles of Units 6 & 7. A more detailed description of the pipelines are presented in the following subsection, including the pipe size, age, operating pressure, depth of burial, location and type of isolation valves, and type of gas or liquid presently carried. Information pertaining to the various pipelines is also presented in Table 2.2-204.

2.2.2.3.1 Florida Gas Transmission Company/Turkey Point Lateral Pipeline

The Florida Gas Transmission Company Turkey Point Lateral is a 24-inch diameter pipeline that was installed in 1968. The pipeline operates at a maximum

pressure of 722 pound-force per square inch gauge (psig) and provides gas service to Turkey Point's gas-fired power plants. The pipeline is buried to an approximate depth of 42 inches below grade. The nearest isolation valve is located approximately 11.8 miles from the south end of the 24-inch Turkey Point Lateral. The isolation valve is manually operated. At the closest approach to Units 6 & 7, the Turkey Point Lateral pipeline, depicted on Figure 2.2-201, passes within approximately 4535 feet of the Unit 6 auxiliary building. The Turkey Point Lateral transports natural gas and there are not any future plans to transport any other products (Reference 204).

2.2.2.3.2 Florida Gas Transmission Company/Homestead Lateral Pipeline

The Florida Gas Transmission Company Homestead Lateral is a 6.625-inch diameter pipeline that tees off of the 24-inch Turkey Point Lateral approximately 3 miles north of the Turkey Point site and extends in a westward direction to provide gas service to the City of Homestead. The Homestead Lateral was installed in 1985, and also operates at a maximum pressure of 722 psig. This pipeline is buried to an approximate depth of 42 inches below grade. There is a manually operated isolation valve located just downstream of the 24 inch by 6 inch tee at the take-off of the Homestead Lateral. The Homestead Lateral transports natural gas and there are not any future plans to transport any other products (Reference 204). Because of the proximity and diameter of the Turkey Point Lateral pipeline in comparison to the Homestead lateral pipeline, the Turkey Point Lateral pipeline presents a greater hazard, and as such, the Turkey Point Lateral pipeline analysis is bounding and no further analysis of the Homestead Lateral pipeline is warranted.

2.2.2.4 Description of Waterways

Units 6 & 7 are located on the western shore of south Biscayne Bay. Biscayne Bay is a shallow coastal lagoon located on the lower southeast coast of Florida (Reference 258). The bay is approximately 38 miles long, approximately 11 miles wide on average, and has an area of approximately 428 square miles (References 259 and 260). On the southern portion of the Biscayne Bay where Units 6 & 7 are located, the bay is approximately 8 miles wide and 9 miles long and extensive sandbars exist. South Biscayne Bay is separated from Card Sound to the south by a sandbar area encompassing the Arsenicker Keys and Cutter Bank. The nearshore shallow areas of the western side of south Biscayne Bay are generally less than 5 feet deep (Reference 205).

The Biscayne Bay contains the Miami to Key West, Florida Intracoastal Waterway. The only commodity transported on the Miami to Key West, Florida Intracoastal Waterway is residual fuel oil. In 2005, there were 611,000 short tons of residual fuel oil transported, and the entirety of this commodity was delivered to the Turkey Point plant (Table 2.2-205, Reference 206).

The Turkey Point turning basin is approximately 300 feet wide, 1200 feet long and approximately 20 feet deep (Reference 205)The Turkey Point fuel unloading dock is located on the north side of the turning basin. The concrete constructed fuel oil dock at the Turkey Point plant can handle one barge at a time. Residual fuel oil is delivered exclusively by barges that typically are approximately 228 feet long, 54 feet wide, and have a draft of 6.5 feet when loaded. This size barge will transport approximately 18,000 barrels of oil. Residual fuel oil is unloaded from the barges to the two fuel oil storage tanks located north of the unloading dock. In a typical week, five to seven deliveries of oil may be made and each delivery requires about 5 hours to unload. Because the storage of residual fuel oil at the Turkey Point site, two 268,000 barrel tanks, exceeds the quantity transported by a barge, the storage tanks present a greater hazard, and as such, the analysis of residual fuel oil located in the storage tanks is bounding and no further analysis of the residual fuel oil transported by the barge is warranted.

2.2.2.5 Description of Highways

Miami-Dade County is traversed by several highways. Interstate 95, U.S. Highway 1 and the Florida Turnpike (State Road 821) are the major transportation routes for north-south traffic flow in the county. The major route for east-west movement is U.S. Route 41 which crosses the middle of the county (Reference 207). Main access to the Turkey Point site is Palm Drive (SW 344th Street), which runs in an east-west direction along the northern boundary of the Turkey Point site. Palm Drive provides a connection with U.S. Highway 1 and the Florida Turnpike. There are no major highways within 5 miles of Units 6 & 7 (Figure 2.2-201, References 201 and 207).

To ascertain which hazardous materials may be transported on the roadways within 5 miles of Units 6 & 7, the industries that may store hazardous materials—and, hence, have either the materials transported to the site or transported from the site—were identified through SARA Title III, Tier II reports as described in Subsection 2.2.2.2. The only identified chemicals whose transportation route may approach closer than 5 miles to Units 6 & 7 are those chemicals transported onto the Turkey Point plant property. Of these chemicals, gasoline was the only identified roadway transportation event that is not bounded

by an event involving the onsite storage vessel for each identified chemical. Each of the identified onsite chemicals that had the potential to explode, or form a flammable or toxic vapor cloud, is analyzed to determine safe distances.

2.2.2.6 Description of Railroads

There are no railroads in the vicinity (5 miles) of Units 6 & 7 (Figure 2.2-201, Reference 207).

2.2.2.7 Description of Airports

In accordance with RG 1.206 and RG 1.70, Homestead Air Reserve Base is the only identified airport located within the vicinity (5 miles) of Units 6 & 7 other than the Turkey Point Heliport located onsite. Further, RG 4.7 recommends that major airports within 10 miles be identified. The Ocean Reef Club Airport is a small private airport located approximately 7.4 miles from Units 6 & 7 (Figure 2.2-202, References 223 and 240).

A more detailed description of each of these airports is presented in the subsequent sections, including distance and direction from the site, number and type of aircraft based at the airport, largest type of aircraft likely to land at the airport facility, runway orientation and length, runway composition, hours attended, and yearly operations where available. Information pertaining to airports located within 10 miles of the site is presented in tabular form in Table 2.2-206. A screening evaluation of the closest major airport in the region, Miami International Airport, is also included in this table to ascertain whether this airport is or may be of significance in the future.

2.2.2.7.1 Airports

2.2.2.7.1.1 Turkey Point Heliport

The Turkey Point site operates its own corporate heliport. The Turkey Point heliport is located in the southeast corner of the Units 3 & 4 parking lot approximately 3100 feet north of Units 6 & 7. The heliport is an approximate 22-foot by 22-foot concrete pad. The maximum gross weight of the helicopter operated at the site, an Agusta A109E Power Helicopter, is 6600 pounds. There were approximately 79 takeoffs and landing operations in 2007. As described in Subsection 2.2.2.7.2, it is not expected that an aircraft of this weight and size would have an impact on safety-related structures (References 227 and 228). Further, the number of operations at the heliport, especially in comparison with

other aviation facilities is infrequent. Due to the weight of the aircraft (thus low penetration hazard) using the heliport and infrequent operations, no further analysis of the heliport is warranted.

2.2.2.7.1.2 Homestead Air Reserve Base

Homestead Air Reserve Base is located approximately 4.76 miles north-northwest from the proposed Units 6 & 7. The U.S. Air Force owns the airport, and the airport is for private use, with permission required before landing. The airport has a concrete/grooved runway, Runway 05/23, which is 11,200 feet long and 300 feet wide. The runway headings are 50 degrees (Runway 05) and 230 degrees (Runway 23). The traffic pattern for Runway 05 is right and the traffic pattern for Runway 23 is left (Reference 209).

The Homestead Air Reserve Base has approximately 36,429 annual operations and this projection is not expected to change over the period of the license duration (Reference 208). Consistent with RG 1.206, the Homestead Air Reserve Base located approximately 4.76 miles from the site, was considered because the plant-to-airport distance is less than 5 miles.

Homestead Air Reserve Base indicated that the military aircraft onsite consisted of F-16Cs with a wingspan of 32 feet 10 inches and F-15As with a wingspan of 42 feet 9 inches. The reported number of military operations was 24,902 per year. The Homestead Air Reserve Base also indicated that there were 7430 operations per year from U.S. Customs Border Patrol aircraft along with 4097 transient aircraft operations per year (Reference 208).

2.2.2.7.1.3 Ocean Reef Club Airport

Ocean Reef Club Airport is a privately owned airport located 7.41 miles south southeast from Units 6 & 7. The airport is an amenity associated with the Ocean Reef Club. All aircraft must be registered and permission is required before landing. There is no scheduled airline service associated with the airport and the airport is unattended (Reference 242).

The airport has an asphalt runway that is 4500 feet long and 70 feet wide. The runway headings are 40 degrees (Runway 04) and 220 degrees (Runway 22). The landing pattern is to the left. There are approximately 25 aircraft based on the site, 15 single-engine planes and 10 multi-engine planes. The plant-to-airport distance criteria in accordance with NUREG-0800 is $500D^2$, where D is the distance in statute miles from the site, for airports located within 5 to 10 statute miles from the site, giving the airport a significance factor of 27,454 operations per

year. The airport is an unattended private facility with just 25 aircraft based on the field with no control tower (References 209 and 210). To reach a significance factor of 27,454 operations, each aircraft would need to average approximately 1,098 operations per year. Therefore, it is reasonably assumed that the airport operations at this facility meet the plant-to-airport distance/annual operations criteria and no further evaluation is warranted.

2.2.2.7.2 Aircraft and Airway Hazards

There is one airport, Homestead Air Reserve Base, located approximately 4.76 miles from Units 6 & 7. The Homestead Air Reserve Base has approximately 36,429 annual operations and this projection is not expected to change over the period of the license duration (Reference 208). As required by RG 1.206, an aircraft hazard analysis should be provided for all airports with a plant-to-airport distance less than 5 statute miles from the site.

The Units 6 & 7 site meets acceptance criteria 1.B. of Section 3.5.1.6 of NUREG-0800—there are no military training routes or military operations areas within 5 miles of the site. The centerline of the closest military training route, IR-53, is approximately 11.5 nautical miles, 13.2 statute miles, from Units 6 & 7, while the closest military operations area, Lake Placid military operations area, is approximately 115 nautical miles or 132.3 statute miles from Units 6 & 7 (Reference 223).

The Units 6 & 7 site is located closer than 2 statute miles to the nearest edge of a federal airway. The site is approximately 5.98 statute miles from the centerline of airway V3/G439 as depicted in Figure 2.2-202. The width of a federal airway is typically 8 nautical miles, 4 nautical miles (4.6 statute miles) on each side of the centerline, placing the airway approximately 1.4 statute miles to the nearest edge (Reference 211). The edge of the closest high altitude airway is located further than 2 statute miles from Units 6 & 7 (Reference 240). Because of the proximity of airway V3/G439 to Units 6 & 7, criteria 1.C. set in Section 3.5.1.6 of NUREG-0800 that the plant is at least 2 statute miles beyond the nearest edge of a federal airway is not met.

Therefore, a calculation to determine the probability of an aircraft accident that could possibly result in radiological consequences to the site was performed following NUREG-0800 and DOE-STD-3014-96 to determine whether the accident probability rate is less than an order of magnitude of 1E–07. The probability of an aircraft crashing into the plant and its impact frequency evaluation are estimated using a four-factor formula that considers: (1) the number of

operations; (2) the probability that an aircraft will crash; (3) given a crash, the probability that the aircraft crashes into a 1-square-mile area where the facility is located; and (4) the size of the facility. In order to estimate aircraft crash frequencies, this method applies the four-factor formula to two different flight phases, near-airport activities or airport operations that considers takeoffs and landings, and non-airport activities or in-flight phase operations (Reference 212). This assessment of impact frequency assumes that all impacts will lead to facility damage and a possible release of radioactive material.

Mathematically, the four-factor formula is:

$$F = \Sigma N_{ijk} * P_{ijk} * f_{ijk}(x,y) * A_{ij} \qquad \text{(Equation 1)}$$

Where,

F	=	estimated annual aircraft crash impact frequency for the facility of interest (no./year)
N_{ijk}	=	estimated annual number of site-specific aircraft operations for each applicable summation parameter (no./year)
P_{ijk}	=	aircraft crash rate (per takeoff or landing for near-airport phases and per flight for the in-flight (non-airport) phase of operation for each applicable summation parameter)
$f_{ijk}(x,y)$	=	aircraft crash location conditional probability (per square mile) given a crash evaluated at the facility location for each applicable summation parameter
A_{ij}	=	the site-specific effective area for the facility of interest that includes skid and fly-in effective areas (square miles) for each applicable summation parameter, aircraft category or subcategory, and flight phase for military aviation
i	=	(index for flight phases): i=1, 2, and 3 (takeoff, in-flight, and landing)
j	=	(index for aircraft category or subcategory): j=1, 2, …, 11
k	=	(index for flight source): k=1, 2, …, k
Σ	=	$\Sigma k\ \Sigma j\ \Sigma i$
ijk	=	site-specific summation over flight phase, i; aircraft category or subcategory, j; and flight source, k

Effective Area

The effective area was calculated using the method provided in the DOE Standard, DOE–STD-3014-96 (Reference 212). For the AP1000 design, the

safety-related structures are contained on the nuclear island which consists of the containment or shield building and the auxiliary building. To calculate a conservative estimate of the effective target area, a bounding building was used in accordance with the DOE standard with the following assumptions:

- The total footprint area of the safety-related structures was obtained to estimate the equivalent width/length (W, L) of a bounding building, and thus the building diagonal length, R.
- For the AP1000 design, when determining the length, L of the bounding building, the actual length of the auxiliary building, 254 feet, was used.
- The total volume of the bounding building is obtained in order to estimate the equivalent height of the rectangular bounding building.
- In this calculation, the 78-foot wingspan was conservatively chosen to represent military aircraft wingspan. Homestead Air Reserve Base indicated that the military aircraft on site consisted of F-16Cs with a wingspan of 32 feet 10 inches and F-15As with a wingspan of 42 feet 9 inches (Reference 208).

Based on those assumptions, the effective areas for general aviation, air carrier, air taxi and commuter, large military (takeoff), large military (landing), small military (takeoff), and small military (landing) type of aircraft are 0.01730, 0.04309, 0.03859, 0.03775, 0.03660, 0.02166, and 0.02824 square miles, respectively.

Airport Operations Impact Frequency

Using the four-factor formula, the total impact frequency from airport operations, which includes near airport activities and considers takeoffs and landings, into the plant was determined to be 2.56E-07 per year. Even though most of the airport operations are attributed to small military aircraft operations, the calculated impact frequency was dominated by general aviation operations. The lower impact frequency attributed to Homestead Air Reserve Base is largely due to the orientation of the runway at Homestead Air Reserve Base. Crash location probability values are primarily distributed about the x-axis, the extended runway centerline—for military aircraft, this distribution is also dependent on the pattern side of the runway. When the x-axis is placed along the center of the runway, the Units 6 & 7 site lies nearly on the y-axis, accounting for the low crash location probabilities for airport operations. In determining the airport operation frequency, the following assumptions were formulated:

- Based on data received from Homestead Air Reserve Base, it was assumed that for each aircraft category, 75 percent of the operations occurred on Runway 05 and 25 percent of the operations occurred on Runway 23, resulting in:
  - 18,678 small military operations for Runway 05
  - 6,226 small military operations for Runway 23
  - 5,574 large military operations for Runway 05
  - 1,858 large military operations for Runway 23
  - 3,074 general aviation operations for Runway 05
  - 1,026 general aviation operations for Runway 23

Non-Airport Operations Impact Frequency

For non-airport operations, or the in-flight phase, methods provided in DOE Standard DOE-STD-3014-96 were used and the total impact frequency from non-airport operations into the plant was determined to be 3.61E-06 per year (Reference 212).

The determined impact frequency using this methodology is heavily weighted towards general aviation aircraft due to the large probability, N * P * f(x,y), of general aviation crashes throughout the continental United States. The analysis of non-airport operations impact frequency was based on the four-factor formula, as used for airport operations for the class of aircraft *j*:

$$F_j = N_j * P_j * f_j (x,y) * A_j$$

Where, the product NP represents the expected number of in-flight crashes per year; f(x,y) is the probability, given a crash, that the crash occurs in a 1-square-mile area surrounding the facility of interest, and A is the effective area of the facility (Reference 212). For this calculation, the values of N * P * f(x,y) selected are the continental U.S. averages.

Total Impact Frequency

This assessment led to a total impact frequency of 3.86E-06 per year when considering both the airport and non-airport operations, which is greater than an order of magnitude of 1E-07 per year. Therefore, consideration of whether the

damage from the aircraft crash may result in radiological releases in excess of the exposure guidelines in 10 CFR Part 100 was considered for general aviation and commercial aircraft categories. The General Aviation category dominates the impact frequency results. Studies of General Aviation and Commercial Aircraft categories conclude that impacts from these categories are not likely to result in core damage. In these instances (General Aviation and Commercial Aircraft categories), crash probabilities are multiplied by appropriate conditional probabilities of a radioactive material release exceeding 10 CFR Part 100 guidelines to obtain the consequence probabilities of such a release. The impact of aircraft and aircraft missiles on substantial concrete structures has been extensively studied and a core damage probability can reasonably be applied to the calculated total impact frequency for the General Aviation and Commercial Aircraft categories (References 227 and 228). NUREG/CR-4839 cites a conditional core damage probability of 0.1 as a conservative estimate. Therefore, for this calculation, a conditional core damage probability of 0.1 was conservatively applied to the General Aviation and Commercial Aircraft categories. Conservatively, a conditional core damage probability of 1.0 was applied to the small and large military aviation categories.

Taking into account the conditional core damage probability, the rate of aircraft accidents that could lead to radiological consequences in excess of the exposure guidelines of 10 CFR 50.34(a)(1) is 4.86E-07 crashes per year. This includes the following inherent conservatisms:

- Shielding by adjacent structures, topographical features, and barriers was not credited. The skid distance would virtually be eliminated, reducing the effective area, if this were credited, because the nuclear island is shielded on three sides and partially on the fourth side by other structures.

- A conservative value of the conditional core damage probability was used. General Aviation aircraft was not screened out, that is, a core damage probability of zero was not applied to the general aviation class, even though studies have shown they are not considered a significant hazard to nuclear power stations because of their low weight and low penetration hazard.

- DOE methodology has conservatisms built in. One example is in determining the effective area of the bounding building where the heading of the crashing aircraft with respect to the facility is assumed to be the worst case which is perpendicular to the diagonal of the bounding rectangle regardless of direction of actual flights.

Therefore, a value of 4.86E-07 aircraft crashes per year that may lead to radiological consequences meets the guidance in NUREG-0800, Section 3.5.1.6 which states that 10 CFR 100.1, 10 CFR 100.20, 10 CFR 100.21, 10 CFR 52.17, and 10 CFR 52.79 requirements are met if the probability of aircraft accidents resulting in radiological consequences greater than the 10 CFR Part 100 exposure guidelines is less than an order of magnitude of 1E-07 per year. The value of 4.86E-07 aircraft crashes per year that may lead to radiological consequences also meets RG 1.206 guidance, which states that plant design should consider aircraft accidents that could lead to radiological consequences in excess of the exposure guidelines of 10 CFR 50.34(a)(1) and 10 CFR 52.79 with a probability of occurrence greater than an order of magnitude of 1E–07 per year.

2.2.2.8 Projections of Industrial Growth

The Units 6 & 7 site is located in unincorporated Miami-Dade County, Florida. Miami-Dade County has adopted a Comprehensive Development Master Plan to meet the requirements of the Local Government Comprehensive Planning and Land Development Regulation Act, Chapter 163, Part II, Florida Statutes, and Chapter 9J-5, Florida Administrative Code. The Comprehensive Development Master Plan was last revised in October 2006.

The Comprehensive Development Master Plan Map illustrates the locations of major institutional uses, communication facilities, and utilities of metropolitan significance. The 2025 expansion area boundary delineated on the Land Use Plan Map does not depict any future industrial area expansion within 5 miles of Units 6 & 7 (Reference 213).

Thus, a review of Miami-Dade County's Comprehensive Development Master Plan does not indicate any future projections of new major industrial, military, or transportation facilities located within the vicinity of the Units 6 & 7 site (Reference 213).

2.2.3 EVALUATION OF POTENTIAL ACCIDENTS

An evaluation of the information provided in Subsections 2.2.1 and 2.2.2, for potential accidents that should be considered as design basis events, and the potential effects of those identified accidents on the nuclear plant in terms of design parameters (e.g., overpressure, missile energies) and physical phenomena (e.g., concentration of flammable or toxic clouds outside building structures), was performed in accordance with the criteria in 10 CFR Parts 20,

52.79, 50.34, 100.20, and 100.21, using the guidance contained in RG 1.78, 1.91, 4.7, and 1.206.

2.2.3.1 Determination of Design-Basis Events

RG 1.206 states that design basis events, internal and external to the nuclear plant, are defined as those accidents that have a probability of occurrence on the order of magnitude of 1E-07 per year or greater with potential consequences serious enough to exceed the guidelines in 10 CFR Part 100 affecting the safety of the plant. The following accident categories are considered in selecting design basis events: explosions, flammable vapor clouds (delayed ignition), toxic chemicals, fires, collisions with the intake structure, and liquid spills. On the basis of the identification of industrial, transportation, and military facilities presented in Subsections 2.2.1 and 2.2.2, the postulated accidents within these categories are analyzed at the following locations:

- Onsite chemical storage (Units 1 through 5)
- Onsite chemical storage (Units 6 & 7)
- Nearby chemical and fuel storage facilities (Homestead Air Reserve Base)
- Nearby transportation routes (Florida Gas Transmission Company (Turkey Point Lateral-natural gas transmission pipeline), and an onsite transportation route)

2.2.3.1.1 Explosions

Accidents involving detonations of explosives, munitions, chemicals, liquid fuels, and gaseous fuels are considered for facilities and activities either onsite or within the vicinity of the plant, where such materials are processed, stored, used, or transported in quantity. NUREG-1805 defines explosion as a sudden and violent release of high-pressure gases into the environment. The strength of the wave is measured in terms of overpressures (maximum pressure in the wave in excess of normal atmospheric pressure). Explosions come in the form of detonations or deflagrations. A detonation is the propagation of a combustion zone at a velocity that is greater than the speed of sound in the un-reacted medium. A deflagration is the propagation of a combustion zone at a velocity that is less than the speed of sound in the un-reacted medium (Reference 214).

The effects of explosions are a concern in analyzing structural response to blast pressures. The effects of blast pressure from explosions from nearby railways,

highways, navigable waterways, or facilities to safety-related plant structures are evaluated to determine if the explosion would have an adverse effect on plant operation or would prevent safe shutdown of the plant.

2.2.3.1.1.1 Explosions /Trinitrotoluene Mass Equivalency

The onsite chemicals (Units 1 through 5 [Table 2.2-207] and Units 6 & 7 [Table 2.2-208]), offsite chemical storage (Homestead Air Reserve Base [Table 2.2-209]), hazardous materials transported in pipelines (Turkey Point Lateral [Table 2.2-210]), and hazardous materials potentially transported on roadways (Table 2.2-210) were evaluated to ascertain which hazardous materials had a defined flammability range, upper (UFLs) and lower (LFLs) flammability limits, with a potential to explode upon detonation. Whether an explosion is possible depends in large measure on the physical state of a chemical. In the case of liquids, flammable and combustible liquids often appear to ignite as liquids. However, it is actually the vapors above the liquid source that ignite. For flammable liquids at atmospheric pressure, an explosion will occur only if the non-oxidized, energized fluid is in the gas or vapor form at correct concentrations in air. The concentrations of formed vapors or gases have an upper and lower bound known as the UFL and the LFL. Below the LFL, the percentage volume of fuel is too low to sustain propagation. Above the UFL, the percentage volume of oxygen is too low to sustain propagation (Reference 215).

The postulated accidents, involving those hazardous materials determined to have the potential to explode, involve the rupture of a vessel whereby the entire contents of the vessel are released and an immediate deflagration/detonation ensues. That is, upon immediate release, the contents of the vessel are assumed to be capable of supporting an explosion upon detonation (e.g., flammable liquids are present in the gas/vapor phase between the UFL and LFL). The trinitrotoluene (TNT) mass equivalency methodology employed for determining the safe distances, the minimum separation distance required for an explosive force to not exceed 1 psi peak incident pressure, involve a compilation of principles and criterion from RG 1.91, NUREG-1805, National Fire Protection Association (NFPA) Code, and pertinent research papers.

The allowable and actual safe distances for hazardous materials transported or stored were determined in accordance with RG 1.91, Revision 1. RG 1.91 cites 1 psi (6.9 kilopascal) as a conservative value of positive incident over pressure below which no significant damage would be expected. RG 1.91 defines this safe distance by the Hopkinson Scaling Law Relationship:

$$R \geq kW^{1/3} \qquad \text{(Equation 2)}$$

Where R is the distance in feet from an exploding charge of W pounds of equivalent TNT and k is the scaled ground distance constant at a given overpressure (for 1 psi, the value of the constant k is 45 ft/lb$^{1/3}$).

The methodology for calculating, W, and hence the safe distance, R, is dependent on the phase—solid, atmospheric liquid, or pressurized or liquefied gas—of the chemical during storage and/or transportation.

Solids

For a solid substance not intended for use as an explosive but subject to accidental detonation, RG 1.91 states that it is conservative to use a TNT mass equivalent (W) in Equation 2 equal to the cargo mass.

Atmospheric Liquids

RG 1.91 states that it is *limited to solid explosives and hydrocarbons liquefied under pressure,* and the guidance provided in determining W, the mass of the substance that will produce the same blast effect as a unit mass of TNT, is specific to solids. Therefore, the guidance for determining the TNT mass equivalent, W, in RG 1.91, where the entire mass of the solid substance is potentially immediately available for detonation, is not applicable to atmospheric liquids, where only that portion in the vapor phase between the UFL and LFL is available to sustain an explosion.

The methodology employed conservatively considers the maximum gas or vapor volume within the storage vessel as explosive. Thus, for atmospheric liquid storage, this maximum gas or vapor would involve the container to be completely empty of liquid and filled only with air and fuel vapor at UFL conditions in accordance with NUREG-1805. Therefore, for atmospheric liquids, the TNT mass equivalent, W, was determined following guidance in NUREG-1805, where

$$W = (M_{vapor} * \Delta H_c * Y_f) / 2000 \qquad \text{(Equation 3)}$$

Where M_{vapor} is the flammable vapor mass (lbs), ΔH_c is the heat of combustion of the substance (Btu/lb), 2000 is the heat of combustion of TNT (Btu/lb), and Y_f is the explosion yield factor. The yield factor is an estimation of the explosion efficiency, or a measure of the portion of the flammable material participating in the explosion. Conservatively, an explosion yield factor of 100 percent was applied to account for a confined

explosion (NUREG-1805). In reality, only a small portion of the vapor within the flammability limits would be available for combustion and potential explosion, and a 100 percent yield factor is not achievable (Reference 216).

Pressurized or Liquefied Gases

For liquefied and pressurized gases, the entire mass is conservatively considered as a flammable gas/vapor because a sudden tank rupture could entail the rapid release and mixing of a majority of the contents and a confined explosion could possibly ensue. For example, in the case of liquefied gases, the liquefied gas would violently expand and mix with air while changing states from the liquid phase to a vapor/aerosol phase. Therefore, in the case of pressurized or liquefied gases, the entire mass is conservatively considered as available for detonation, and the equivalent mass of TNT, W, is calculated in accordance with NUREG-1805 (Equation 3) where the M_{vapor} is the flammable mass (pounds) and the entire mass of the pressurized or liquefied gas is considered flammable. Again, an explosion yield factor of 100 percent was conservatively assumed to account for a confined explosion (NUREG-1805).

2.2.3.1.1.2 Boiling Liquid Expanding Vapor Explosions

A boiling liquid expanding vapor explosion (BLEVE) is an additional concern with closed storage tanks that contain substances that are gases at ambient conditions but are stored in a vessel under pressure in its saturated liquid/vapor form. The NFPA defines a BLEVE as the failure of a major container into two or more pieces, occurring at a moment when the contained liquid is at a temperature above its boiling point at normal atmospheric pressure. If the chemical is above its boiling point when the container fails, some or all of the liquid will flash-boil, that is, instantaneously become a gas. This phase change forms blast waves with energy equivalent to the change in internal energy of the liquid/vapor. This phenomenon is called a BLEVE. If the chemical is flammable, a burning gas cloud called a fireball may occur if a significant amount of the chemical flash-boils. Because thermal radiation impacts a greater area than the overpressure, it is the more significant threat, and therefore, thermal heat flux values are presented for substances capable of producing a BLEVE (NUREG-1805).

The onsite chemicals (Units 1 through 5 [Table 2.2-207] and Units 6 & 7 [Table 2.2-208]), offsite chemical storage (Homestead Air Reserve Base, [Table 2.2-209]), hazardous materials transported in pipelines (Turkey Point Lateral [Table 2.2-210]), and hazardous materials potentially transported on

roadways (Table 2.2-210) were evaluated to ascertain which hazardous materials had a defined flammability range, upper and lower flammability limits, with a potential to produce a BLEVE. That is, those chemicals stored in their saturated liquid form but are gases at ambient conditions. The Areal Locations of Hazardous Atmospheres (ALOHA) model was used to model the worst-case accidental BLEVE for each chemical identified as capable of producing a BLEVE, calculated as the thermal heat flux at the nearest safety-related structure. To model the worst-case BLEVE in ALOHA, the meteorological conditions presented in Table 2.2-212 were used as inputs and the determined worst-case meteorological case for each substance was used as site atmospheric input for the BLEVE analysis.

Other inputs/assumptions for the BLEVE analysis using the ALOHA model include:

- "Open Country" was selected for the ground roughness. The degree of atmospheric turbulence influences how quickly a pollutant cloud moving downwind will mix with the air around it and be diluted. In the case of a BLEVE, the movement of a vapor cloud is not a consideration.

- The "Threat at Point" function was selected with no crosswind in the ALOHA modeling runs. This effectively models the chemical release as a direct-line source from the spill site to the point of concern, the nearest safety-related structure for Units 6 & 7.

- The "Level of Concern" selected was 5.0 kilowatts per square meter (kW/m^2). At 5.0 kW/m^2, second-degree burns are expected to occur within 60 seconds (Reference 217). Further, the EPA has selected 5.0 kW/m^2 for 40 seconds as its level of concern for heat from fires in EPA's Risk Management Program Guidance for Offsite Consequence Analysis (Reference 220). Regarding damage to structures, as a point of reference, the ignition threshold for wood is 40 kW/m^2 (NUREG-1805)

In each of the explosion scenario analyses in the subsequent subsections, the described TNT mass equivalency methodology or BLEVE methodology was employed to determine the safe distances. The effects of these explosion events from both internal and external sources are summarized in Table 2.2-213, and are described in the following subsections relative to the release source.

2.2.3.1.1.3 Onsite Chemical Storage/Units 1 through 5

Units 6 & 7 are located close to the existing Units 1 through 5 chemical storage locations. The hazardous materials stored on site that were identified for further analysis with regard to explosion potential were acetylene, ammonium hydroxide, hydrazine, hydrogen, and propane. A conservative analysis using the TNT equivalency methods described in Subsection 2.2.3.1.1.1 was used to determine safe distances for the identified hazardous materials. The results indicate that the safe distances are less than the minimum separation distance from the nearest safety-related structure, the Unit 6 auxiliary building, to each storage location. The safe distance for acetylene is 1416 feet; for ammonium hydroxide, 296 feet; for hydrazine, 170 feet; for hydrogen, 1098 feet; and for propane, 1299 feet (Table 2.2-213). Acetylene is stored approximately 4300 feet; ammonium hydroxide approximately 5079 feet; hydrazine approximately 2727 feet; hydrogen approximately 3966 feet; and propane 4168 feet; from the nearest safety-related structure for Units 6 & 7—the Unit 6 auxiliary building.Therefore, an explosion from any of the onsite hazardous materials evaluated will not adversely affect the safe operation or shutdown of Units 6 & 7.

Additionally, propane was identified for further analysis with regard to its potential for forming a BLEVE. The propane tank located at Turkey Point site is determined to bound propane storage at the Homestead Air Reserve Base due to the large distance separating propane storage at the Homestead Air Reserve Base and Units 6 & 7. A conservative analysis using the ALOHA model described in Subsection 2.2.3.1.1.2 is used to determine the safe distance—the distance to the thermal heat flux of 5 kW/m^2 from the formation of a fireball. Inputs to the ALOHA model also included the dimensions of the propane tank with a diameter of 3.08 feet and a length of 9.92 feet.The safe distance for propane is 603 feet.Propane is stored 4168 feet from the nearest safety-related structure for Units 6 & 7—the Unit 6 auxiliary building. The thermal radiation heat flux at the nearest safety-related structure is 0.0878 kW/m^2 and the calculated burn duration is 5 seconds. Therefore, the thermal radiation heat flux resulting from a BLEVE from the storage of propane will not adversely affect the safe operation or shutdown of Units 6 & 7.

2.2.3.1.1.4 Onsite Chemical Storage/Units 6 & 7

The chemicals associated with Units 6 & 7 that were identified for further analysis with regard to explosion potential were methanol, hydrazine, morpholine, and the hydrogen storage banks. A conservative analysis using the TNT equivalency methods described in Subsection 2.2.3.1.1.1 was used to determine safe

distances for the identified hazardous materials. The results indicate that the safe distances are less than the minimum separation distance from the nearest safety-related structure—the Unit 6 or Unit 7 auxiliary building—to each storage location. The safe distance for methanol is 344 feet; for hydrazine, 153 feet; for morpholine 136 feet; and for hydrogen, 544 feet (Table 2.2-213). Methanol is stored at the FPL reclaimed water treatment facility approximately 5581 feet from the nearest safety-related structure for Units 6 & 7—the Unit 7 auxiliary building. Hydrazine and morpholine are stored approximately 218 feet; and hydrogen approximately 560 feet from the nearest safety-related structure for Turkey Point Units 6 & 7—the Unit 6 or Unit 7 auxiliary building. Therefore, an explosion from any of the onsite hazardous materials evaluated will not adversely affect the safe operation or shutdown of Units 6 & 7.

2.2.3.1.1.5 Nearby Facilities/Homestead Air Reserve Base

The Homestead Air Reserve Base, located approximately 4.76 miles (25,133 feet) from the nearest safety-related structure for Units 6 & 7, the Unit 6 auxiliary building, is the identified facility of concern within the vicinity of the Turkey Point site as determined in Subsection 2.2.2.2.2. The hazardous materials stored at the Homestead Air Reserve Base identified for further analysis were: gasoline, hydrazine, jet fuel, and propane. A conservative analysis using the TNT equivalency methods described in Subsection 2.2.3.1.1.1 is used to determine safe distances for the identified hazardous materials.The results indicate that the safe distances are less than the minimum separation distances from the Unit 6 auxiliary building to the storage locations for any of the identified chemicals (Table 2.2-213). Propane resulted in the largest safe distance, 5,513 feet, which is less than the distance of 4.76 miles (25,133 feet) to the nearest safety-related structure for Units 6 & 7. Therefore, damaging overpressures from an explosion resulting from a complete failure of the total stored quantity for each chemical evaluated at Homestead Air Reserve Base would not adversely affect the operation or shutdown of Units 6 & 7.

2.2.3.1.1.6 Transportation Routes/Roadways

The safety-related structure located closest to identified transportation routes/roadways, the Unit 6 auxiliary building, is located approximately 2054 feet (at its closest point of approach) from the onsite transportation delivery route for gasoline. As detailed in Subsections 2.2.3.1.1.4 and 2.2.3.1.1.5, deliveries of chemicals to the site were screened and determined to be bounded by the evaluation performed for the onsite storage quantities. The maximum quantity of gasoline assumed to be transported is 50,000 pounds (9,000 gallons) in

accordance with RG 1.91. An evaluation was conducted using the TNT equivalency methodologies described in Subsection 2.2.3.1.1.1 The results indicate that the safe distance for this quantity of gasoline is 266 feet, which is less than the minimum separation distance from the Unit 6 auxiliary building identified above and in Table 2.2-213. Therefore, an explosion from potentially transported hazardous materials on site will not adversely affect the safe operation or shutdown of Units 6 & 7.

2.2.3.1.1.7 Transportation Routes/Pipelines

As described in Subsection 2.2.2.3, the Florida Gas Transmission Company owns and operates a high-pressure natural gas transmission pipeline system that serves FPL and other customers in south Florida. Two of the pipelines in this system are located within 5 miles of Units 6 & 7. The closest pipeline, the Turkey Point Lateral, represents the bounding condition. The nearest safety-related structure, the Unit 6 auxiliary building, is 4535 feet away from the analyzed release point, the closest approach of the nearest natural gas transmission pipeline.

Experiments conducted in Germany (Reference 218) and by the Institution of Gas Engineers (Reference 219) have indicated that detonations of mixtures of methane (greater than 85 percent) with air do not present a credible outdoor explosion event (Reference 216). Further, there have been no reported vapor cloud explosions involving natural gas with high methane content—there have been numerous reports of vapor clouds igniting resulting in flash fires without overpressures (Reference 216). In evaluating similar research, Y. -D. Jo and Ahn report that when leaked natural gas is not trapped and immediate ignition occurs, only a jet fire will develop. Thus, the dominant hazards from natural gas pipelines are from the heat effect of thermal radiation from a sustained jet fire and from explosions where the natural gas vapor cloud becomes confined either outside or by migration inside a building (Reference 245). Even though the immediate ignition of natural gas resulting in overpressure events resulting from a ruptured gas pipeline is considered an unlikely event, an evaluation was conservatively conducted to evaluate a potential explosion from the natural gas transmission pipeline.

The worst case scenario considered the immediate deflagration/detonation of the released natural gas. That is, upon immediate release, the contents of the pipeline are assumed to be capable of supporting an explosion upon detonation (i.e., the gas is present in concentrations between the UFL and LFL). In this scenario, it was assumed that the pipe had burst open, leaving the full cross-sectional area of

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

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

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

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

where

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

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

decrease significantly immediately after the break occurs. The amount of gas released was then determined by:

$$\text{Mass (lb)} = Q_{max}\ \text{(lb/s)} \times \text{time (s)} \qquad \text{(Equation 5)}$$

Using the flammable mass calculated by the above methodologies, the equivalent mass of TNT can be calculated using Equations 2 and 3.

The results indicate that the safe distance, the distance to 1 psi, is less than the minimum separation distance from the Unit 6 auxiliary building to the pipeline break (Table 2.2-213). The safe distance of 3097 feet is less than the minimum separation distance to the pipeline, 4535 feet. Therefore, the overpressure at the nearest safety related structure, the Unit 6 auxiliary building, resulting from an explosion due to immediate deflagration of natural gas vapor resulting from a pipeline rupture is not significant. The results indicate that overpressures from an explosion from a rupture in the Florida Gas Transmission Company Turkey Point Lateral natural gas transmission pipeline will not adversely affect the safe operation or shutdown of Units 6 & 7.

2.2.3.1.2 Flammable Vapor Clouds (Delayed Ignition)

Flammable materials in the liquid or gaseous state can form an unconfined vapor cloud that can drift towards the plant before an ignition event. When a flammable chemical is released into the atmosphere and forms a vapor cloud, it disperses as it travels downwind. The portion of the cloud with a chemical concentration within the flammable range (i.e., between the LFL and UFL) may burn if the cloud encounters an ignition source. If the cloud burns fast enough to create a detonation, an explosive force is generated. The speed at which the flame front moves through the cloud determines whether it is considered a deflagration or a detonation. Two possible events are evaluated—thermal radiation effects from either a flash fire resulting from the ignition of a flammable vapor cloud or a jet fire resulting from the rapid release of gas from a pipeline, and pressure effects resulting from a vapor cloud explosion.

2.2.3.1.2.1 Flammable Vapor Cloud—Thermal Radiation

The onsite chemicals, Units 1 through 5 (Table 2.2-207) and Units 6 & 7 (Table 2.2-208); offsite chemical storage, Homestead Air Reserve Base, (Table 2.2-209); hazardous materials transported in pipelines, Turkey Point Lateral (Table 2.2-210); and hazardous materials potentially transported on roadways (Table 2.2-210), were evaluated to ascertain which hazardous materials

had the potential to form flammable vapor clouds. In each scenario, those chemicals with an identified flammability range, the ALOHA Version 5.4.1, air dispersion model was used to determine the distances that the vapor cloud could exist in the flammability range, thus presenting the possibility of ignition and potential thermal radiation effects (Reference 217). The safe distance for flammable vapor clouds was measured as the distance to the outer edge of the LFL section of the cloud.

Conservative assumptions were used in the ALOHA analyses regarding both meteorological inputs and identified scenarios (Tables 2.2-211 and 2.2-212). Each postulated event was evaluated under a spectrum of meteorological conditions to determine the worst-case meteorological condition. The spectrum of meteorological parameters chosen for the meteorological sensitivity analysis was selected based on the defined Pasquill meteorological stability classes (Table 2.2-212). The meteorological sensitivity analysis includes the most stable meteorological class, F, allowable with the ALOHA model. More stable meteorological classes and lower wind speeds will prevent a formed chemical vapor cloud from dispersing before reaching safety-related structures or the control room.The inclusion of this selection of meteorological conditions in the meteorological sensitivity analysis is conservative for Units 6 & 7 because the joint frequency wind distribution classes at F stability, which contain windspeeds less than 2 meters/second, occur at a frequency of approximately 3 percent annually.

Other assumptions for the ALOHA model include:

- “Open Country” was selected for the ground roughness with the exception of those chemicals stored north of Units 1 through 4 (ammonium hydroxide); those chemicals stored at the PGS bulk gas storage area (hydrogen); and those chemicals stored inside the turbine building (hydrazine and morpholine), where “Urban or Forest” was selected. The degree of atmospheric turbulence influences how quickly a pollutant cloud moving downwind will mix with the air around it and will be diluted. Friction between the ground and air passing over it is one cause of atmospheric turbulence. The rougher the ground surface, the greater the ground roughness and the greater the turbulence that develops. A chemical cloud generally travels farther across open country than over an urban area or forest. The selection of “Open Country” is conservative because the Turkey Point site meets the criteria for “Urban or Forest”—an area with many friction-generating roughness elements, such as trees or small buildings (e.g., industrial areas). The site layout and location of the chemicals stored north of Units 1 through 4 and those stored at the PGS in relation to Units 6 &

7 would entail a vapor cloud travel through or around plant structures, thus "Urban or Forest" was selected for the determined worst-case meteorological conditions. In the case of the chemicals store inside the turbine building, the formed vapor clouds would need to travel through various friction generating surface elements such as building components and a ventilation system, thus, "Urban or Forest" is the appropriate selection.

- The "Threat at Point" function was selected with no crosswind in the ALOHA modeling runs. This effectively models the chemical release as a direct-line source from the spill site to the point of concern, the nearest safety-related structure for Units 6 & 7. These results represent the worst-case hazard levels that could develop at that distance directly downwind of the source rather than accounting for the prevailing meteorological conditions.

- For each of the identified chemicals in the liquid state, it was conservatively assumed that the entire contents of the vessel leaked, forming a 1-centimeter-thick puddle. This provided a significant surface area from which to maximize evaporation and the formation of a vapor cloud.

- For each of the identified chemicals in the gaseous state, it was conservatively assumed that the entire contents of the vessel/pipeline are released over a 10-minute period into the atmosphere as a continuous direct source (40 CPR 68.25).

Guidance concerning flammable vapor clouds indicates that it is appropriate to consider the distance to the LFL as the safe distance for flammable vapor clouds. Generally, for flash fires the controlling factor for the amount of damage that a receptor will suffer is whether the receptor is physically within the burning cloud. This is because most flash fires do not burn very hot and the thermal radiation generated outside of the burning cloud will generally not cause significant damage due to the short duration (References 229 and 243). However, with the exception of those chemicals stored inside the turbine building, conservatively, the thermal radiation heat flux was calculated for each formed vapor cloud capable of ignition resulting in a flash fire. Those chemicals stored inside the turbine building were not evaluated because a fire in the turbine building does not affect safe shutdown capability. Fire areas located in the turbine building are separated from the safety-related areas of the nuclear island by a 3-hour fire barrier wall.

For this calculation, all of the mass of the vapor cloud is considered flammable and at the upper explosive limit. This is a conservative assumption because the upper explosive limit represents the highest percentage of fuel by volume in air

(molar fraction) that can propagate a flame (Reference 215). The resulting incident heat flux on the nearest safety-related structure is calculated using the following equation presented in the Society of Fire Protection Engineers Handbook of Fire Protection Engineering (Reference 221):

$$q = \frac{\bar{v} f \tau g^{1/2} \rho_f h_f V_f^{5/6}}{4\pi r^2}$$ (Equation 6)

Where,

q	=	incident heat flux, kW/m²
$\bar{v}$	=	normalized dimensionless heat transfer rate
f	=	fraction of combustion energy radiated to the environment
τ	=	atmospheric transmissivity
g	=	acceleration due to gravity, m/s²
ρ_f	=	vapor density, kg/m³
h_f	=	heat of combustion, kJ/kg
V_f	=	initial vapor volume of fuel, m³
r	=	the distance between the fireball center and the nearest safety-related structure, m—calculated as:

$$r = \left[x^2 + (Z - h)^2\right]^{1/2}$$ (Equation 7)

Where,

χ	=	horizontal separation of fireball center and nearest safety-related structure, m
Z	=	height of fireball center above ground, m
h	=	nearest safety-related structure height above ground, m

The following assumptions are used when calculating the radiant heat flux from a resulting flash fire:

- The temperature is assumed to be 40˚F, the mean extreme annual dry bulb temperature for nearby Homestead Air Reserve Base (Reference 222). This results in a conservative assumption as a lower ambient air temperature corresponds to a denser fuel upon release and thus a larger fuel mass.

- The initial vapor cloud before ignition is assumed to be spherical and located at the lower explosive limit distance away from the point of release—the closest point that the vapor cloud can reach the nearest safety-related structure and still burn.

- The transmissivity of air is conservatively assumed to be one. This is conservative because the water vapor and carbon dioxide will absorb thermal radiation and depreciate the incident heat flux on the nearest safety-related structure. Making the assumption that the transmissivity of air is one results in neglecting those losses.

- The fraction of combustion energy radiated to the environment is assumed to be 20 percent (Reference 221).

- The normalized dimensionless heat transfer rate, $\overline{\nu}$ is assumed to be 0.0005, the point at which η, non-dimensionless time, becomes asymptotic (Reference 221).

- The nearest safety-related structure is conservatively assumed to be a blackbody—it absorbs all incident radiation.

- It is assumed that once the maximum fireball diameter and height are reached, they are maintained for the duration of the fireball.

2.2.3.1.2.2 Flammable Vapor Cloud—Explosions

Those identified chemicals with the potential to detonate are then evaluated to determine the possible effects of a flammable vapor cloud explosion. ALOHA was used to model the worst-case accidental vapor cloud explosion for the identified chemicals, including the safe distances and overpressure effects at the nearest safety-related structure. To model the worst-case vapor cloud explosion in ALOHA, detonation was chosen as the ignition source. The evaluation was conducted using the identical assumptions presented in Subsection 2.2.3.1.2.1 for the ALOHA model. The safe distance was measured as the distance from the spill site to the location where the pressure wave is at 1 psi overpressure.

The effects of flammable vapor clouds and vapor cloud explosions from internal and external sources are summarized in Table 2.2-214 and are described in following subsections relative to the release source.

2.2.3.1.2.3 Onsite Chemical Storage/Units 1 through 5

The hazardous materials stored on site that were identified for further analysis with regard to forming a flammable vapor cloud capable of delayed ignition following an accidental release of the hazardous material are acetylene, ammonium hydroxide, hydrazine, hydrogen, and propane. As described in Subsection 2.2.3.1.2.1, the ALOHA dispersion model was used to determine the distance a vapor cloud could travel to reach the LFL boundary once a vapor cloud has formed from an accidental release of the identified chemical. It was conservatively assumed that the entire contents of the ammonium hydroxide, hydrazine, and liquid propane vessels leaked forming a one-centimeter-thick puddle; while, for acetylene and hydrogen, it was assumed that the entire contents of the tank are released over a 10-minute period as a continuous direct source. The results indicate that any plausible vapor cloud that could form and mix sufficiently under stable atmospheric conditions would be below the LFL boundary before reaching the nearest safety-related structure—the Unit 6 auxiliary building. The distance to the LFL boundary for acetylene is 909 feet; for ammonium hydroxide, 525 feet; for hydrazine, 42 feet; for hydrogen, 720 feet; and for propane, the distance to the LFL boundary is 714 feet. Acetylene is stored approximately 4300 feet; ammonium hydroxide, approximately 5079 feet; hydrazine, approximately 2727 feet; hydrogen, approximately 3966 feet; and propane approximately 4168 feet from the Unit 6 auxiliary building (Table 2.2-214).

Further, as described in Subsection 2.2.3.1.2.1, the associated heat flux for each flammable vapor cloud was determined from the point at which the vapor cloud reaches the LFL to the nearest safety-related structure. The maximum incident heat flux for acetylene is 0.162 kW/m^2; for ammonium hydroxide, 0.900 kW/m^2; for hydrazine, 0.271 kW/m^2; for hydrogen, 0.033 kW/m^2 and for propane the maximum incident heat flux is 0.090 kW/m^2. These results are less than 5 kW/m^2 level of concern defined by the EPA.

A vapor cloud explosion analysis was also completed following the methodology as detailed in Subsection 2.2.3.1.2.2 in order to obtain safe distances. The results concluded that the safe distance, the minimum distance required for an explosion to have less than a 1 psi peak incident pressure, are less than the shortest distance to the nearest safety-related structure for Units 6 & 7, the Unit 6 auxiliary building, and the storage location of these chemicals. The safe distance for the acetylene cylinders is 1242 feet; for ammonium hydroxide, 1407 feet; for one hydrogen tube trailer, 828 feet; and for liquid propane, 1416 feet. For hydrazine, no explosion occurs because the vapor pressure for hydrazine is sufficiently low

that not enough vapor is released from the spill for a vapor cloud explosion to occur. Each of these chemicals is stored at a greater distance from the nearest safety-related structure than the calculated safe distance.

Therefore, a flammable vapor cloud with the possibility of ignition or explosion formed from the onsite chemical storage for Units 1 through 5 analyzed will not adversely affect the safe operation or shutdown of Units 6 & 7 (Table 2.2-214).

2.2.3.1.2.4 Onsite Chemical Storage/Units 6 & 7

The hazardous materials stored on site that were identified for further analysis with regard to forming a flammable vapor cloud capable of delayed ignition following an accidental release of the hazardous material are methanol, hydrazine, morpholine, and hydrogen. As described in Subsection 2.2.3.1.2.1, the ALOHA dispersion model was used to determine the distance a vapor cloud could travel to reach the LFL boundary once a vapor cloud has formed from an accidental release of the identified chemical. Because hydrazine and morpholine are located inside the turbine building in a room with curbing, it was conservatively assumed that the entire contents of the largest vessel for each identified scenario leaked forming a puddle with the same area as the bermed area of the chemical storage room. Further, for the chemicals located inside the turbine building, the vapor cloud explosion analyses were conservatively modeled as if no building is present. For the hydrogen storage banks, it was assumed that the entire contents of all tubes in one bank are released over a 10-minute period as a continuous direct source.

The results indicate that any plausible vapor cloud that could form and mix sufficiently under stable atmospheric conditions would be below the LFL boundary before reaching the nearest safety-related structure—the Unit 6 auxiliary building. The distance to the LFL boundary for methanol is 177 feet; for hydrazine, less than 33 feet; for morpholine, less than 33 feet; and for hydrogen, 351 feet. Methanol is stored at the FPL reclaimed water treatment facility approximately 5581 feet; hydrazine and morpholine are stored approximately 218 feet; and hydrogen is stored approximately 560 feet from the nearest safety-related structure—either the Unit 6 or Unit 7 auxiliary building (Table 2.2-214).

Further, as described in Subsection 2.2.3.1.2.1, for those chemicals stored outside the turbine building, the associated heat flux for each flammable vapor cloud was determined from the point at which the vapor cloud reaches the LFL to the nearest safety-related structure. The maximum incident heat flux for methanol

is 0.592 kW/m^2; and for hydrogen is 2.344 kW/m^2. These results are less than 5 kW/m^2 level of concern defined by the EPA.

A vapor cloud explosion analysis was also completed as detailed in Subsection 2.2.3.1.2.2 to obtain safe distances. The results concluded that the safe distance, the minimum distance required for an explosion to have less than a 1 psi peak incident pressure, are less than the shortest distance to the nearest safety-related structure for Units 6 & 7, the Unit 6 auxiliary building, and the storage location of these chemicals. The safe distance for the methanol is 444 feet; for hydrazine, no detonation; for morpholine, no detonation; and for hydrogen, 528 feet. For hydrazine and morpholine, no detonation/explosion occurs because the vapor pressures are sufficiently low that not enough vapor is released from the spill for a vapor cloud explosion to occur. Each of these chemicals is stored at a greater distance from the nearest safety-related structure than the calculated safe distance. Therefore, a flammable vapor cloud with the possibility of ignition or explosion formed from the storage of the onsite chemical storage for Units 6 & 7 analyzed will not adversely affect the safe operation or shutdown of Units 6 & 7 (Table 2.2-214).

2.2.3.1.2.5 Nearby Facilities/Homestead Air Reserve Base

The Homestead Air Reserve Base, located approximately 4.76 miles, 25,133 feet, from the nearest safety-related structure, the Unit 6 auxiliary building, operates within the vicinity of the Turkey Point site. The hazardous materials stored at Homestead Air Reserve Base that were identified for further analysis with regard to the potential for delayed ignition of a flammable vapor cloud formed following the accidental release of a hazardous material are gasoline and propane. For gasoline, it was conservatively assumed that the entire contents of the vessel leaked and formed a 1-centimeter-thick puddle. Because solutions such as gasoline cannot be modeled in the current version of ALOHA, as recommended by the EPA, gasoline was modeled for flammable vapor cloud and vapor cloud explosion analysis by selecting n-Heptane as a surrogate for gasoline in ALOHA's chemical library. This selection is appropriate as the evaporation curves over a range of temperatures for n-Heptane and gasoline are shown to be similar, and at temperatures below 80°C, the evaporation of n-Heptane occurred at a faster rate (Reference 246). In the case of propane, the entire contents of the tank are assumed to be released over a 10-minute period as a continuous direct source. The results using the methodology described in Subsection 2.2.3.1.2.1 concluded that any plausible vapor cloud that could form and mix sufficiently under stable atmospheric conditions is below the LFL boundary before reaching the Units 6 & 7

site (Table 2.2-214). The greatest distance to the LFL boundary, 2190 feet, was for propane, while the distance to the LFL boundary for gasoline was 396 feet.

Further, as described in Subsection 2.2.3.1.2.1, the associated heat flux for each flammable vapor cloud was determined from the point at which the vapor cloud reaches the LFL to the nearest safety-related structure. The maximum incident heat flux for gasoline is 0.051 kW/m^2; and for propane the maximum incident heat flux is 0.078 kW/m^2. These results are less than 5 kW/m^2 level of concern defined by the EPA (Table 2.2-214).

Because each of the identified chemicals has the potential to explode, a vapor cloud explosion analysis was also performed as described in Subsection 2.2.3.1.2.2. The results of the vapor cloud explosion analysis concluded that the safe distance, the minimum distance required for an explosion to have less than a 1 psi peak incident pressure, is less than the minimum separation distance between the Unit 6 auxiliary building and the release point at Homestead Air Reserve Base. The largest determined safe distance was for propane, 4770 feet, while the determined safe distance for gasoline was 1260 feet. (Table 2.2-214)

Therefore, a flammable vapor cloud with the possibility of ignition or explosion from the storage of chemicals at offsite facilities will not adversely affect the safe operation or shutdown of Units 6 & 7.

2.2.3.1.2.6 Transportation Routes/Roadways

The nearest safety-related structure for Units 6 & 7, the Unit 6 auxiliary building, is located approximately 2054 feet at its closest point of approach from the onsite transportation delivery route for gasoline. The methodology presented in Subsection 2.2.3.1.2.1 was used for determining the distance from the accidental release site where the vapor cloud is within the flammability limits. It was conservatively estimated that the vessel carried and released 50,000 pounds, 9000 gallons, of gasoline. The results for the 9000-gallon gasoline tanker concluded that any plausible vapor cloud that can form and mix sufficiently under stable atmospheric conditions will have a concentration less than the LFL before reaching the nearest safety-related structure. The distance to the LFL boundary for gasoline is 222 feet.

Further, as described in Subsection 2.2.3.1.2.1, the associated heat flux for the formed flammable vapor cloud was determined from the point at which the vapor cloud reaches the LFL to the nearest safety-related structure. The maximum

incident heat flux for the 9000-gallon gasoline tanker is 2.776 kW/m^2. These results are less than 5 kW/m^2 level of concern defined by the EPA.

Gasoline was also evaluated using the methodology presented in Subsection 2.2.3.1.2.2 to determine the effects of a possible vapor cloud explosion. The safe distance, the minimum separation distance required for an explosion to have less than a 1 psi peak incident pressure impact from the drifted gasoline vapor cloud, is less than the shortest distance to the onsite gasoline delivery route. The safe distance for this quantity of gasoline was determined to be 780 feet (Table 2.2-214).

Therefore, a flammable vapor cloud ignition or explosion from a 9000-gallon gasoline tanker transported on site will not adversely affect the safe operation or shutdown of Units 6 & 7.

2.2.3.1.2.7 Transportation Routes/Pipelines

The Florida Gas Transmission Company owns and operates a high-pressure natural gas transmission pipeline system that serves FPL within the vicinity of Units 6 & 7. At its closest distance, the Turkey Point Lateral pipeline passes within approximately 4535 feet of the nearest safety-related structure for Units 6 & 7—the Unit 6 auxiliary building. To conservatively evaluate the consequences from a potential flammable vapor cloud or vapor cloud explosion from a natural gas transmission pipeline, a worst-case scenario was considered involving the release of natural gas directly into the atmosphere resulting in a vapor cloud. Two scenarios were considered for the postulated natural gas pipeline rupture. The first scenario considered a formed vapor cloud that traveled toward Units 6 & 7. As the vapor cloud travels towards Units 6 & 7, it is plausible that the cloud concentration could become flammable along its path. As described in Subsection 2.2.3.1.2.1, the ALOHA dispersion model was used to determine the distance a vapor cloud could travel to reach the LFL boundary once a vapor cloud has formed from an accidental release of natural gas (as methane) from the pipeline. The pipeline release source module was selected in the ALOHA program to model the natural gas release. The pipeline characteristics presented in Table 2.2-204 and the gas pipeline temperature for the Turkey Point Lateral, 78°F, are used as inputs to the ALOHA model. It was conservatively assumed that the pipeline was “connected to an infinite tank source” and that the roughness of the pipeline was “smooth” to model the break. The results concluded that under this scenario, the plausible vapor cloud that could form will be below the LFL boundary before reaching the nearest safety related structure for Units 6 & 7—the Unit 6 auxiliary building.

Because of the possibility that the natural gas vapor cloud may become confined either outside or by migration inside a building, a vapor cloud explosion analysis was performed as described in Subsection 2.2.3.1.2.2 and the ALOHA pipeline inputs from the preceding paragraph. The results of the vapor cloud explosion analysis concluded that the safe distance, the minimum distance required for an explosion to have less than 1 psi peak incident pressure, of 3033 feet, is less than the separation distance, 4535 feet, between the Unit 6 auxiliary building and the pipeline break.

As described in Subsection 2.2.3.1.1.7, when leaked natural gas is not trapped and immediate ignition occurs, a jet fire will develop. A jet fire occurs when a flammable chemical is rapidly released from an opening in a vessel or pipeline and an immediate ignition occurs. The jet fire stabilizes to a point that is close to the source of the release and continues to burn until the fuel source is stopped. Thus, the jet fire scenario should be considered for determining safety distances in the vicinity of natural gas pipelines. This is because in addition to producing thermal radiation, the jet fire causes considerable convective heating in the region beyond the flame tip. Additionally, the high velocity of the escaping gas into the jet causes more efficient combustion to occur than in pool fires. Therefore a much higher heat transfer rate could occur for a jet fire than in a pool fire flame.

The safe distance for a jet fire is measured as the distance from the fire to the point where the thermal heat flux reaches 5.0 kW/m^2. For the natural gas pipeline, ALOHA was used to model the worst-case accidental release from a pipeline resulting in a jet fire, including the safe distances and thermal heat flux effects on the nearest safety related structure.

The thermal effect of a jet fire strongly depends on atmospheric conditions and the impact radius for thermal radiation is primarily affected by wind speed, and increases with decreasing wind speed. Thermal radiation is also affected by atmospheric transmittivity. Atmospheric transmittivity is the measure of how much thermal radiation from a fire is absorbed and scattered by water vapor and other components in the atmosphere. To model the jet fire scenario in ALOHA, the worst case meteorological conditions determined from the vapor cloud flammability and explosion analyses for the pipeline was used as site atmospheric input for the jet fire analysis. Because humidity is used to determine the atmospheric transmittivity in the ALOHA model, the humidity levels were varied to determine the atmospheric worst case in ALOHA for the jet fire scenario. The results of the jet fire analysis concluded that the safe distance, the distance to 5 kW/m^2, of 1035 feet, is less than the separation distance, 4535 feet, between the Unit 6 auxiliary

building and the pipeline break. The maximum thermal radiation effects at the nearest safety related structure for modeled jet fire scenario is 0.261 kW/m^2.

Therefore, a jet fire or flammable vapor cloud ignition or explosion from a rupture in the Turkey Point Lateral natural gas transmission pipeline will not adversely affect the safe operation or shutdown of Units 6 & 7 (Table 2.2-214).

2.2.3.1.3 Toxic Chemicals

Accidents involving the release of toxic or asphyxiating chemicals from onsite storage facilities and nearby mobile and stationary sources were considered. Toxic chemicals known to be present on site or in the vicinity of the Turkey Point site, or to be frequently transported in the vicinity, were evaluated.

The onsite chemicals, Units 1 through 5 (Table 2.2-207) and Units 6 & 7 (Table 2.2-208); offsite chemical storage, Homestead Air Reserve Base, (Table 2.2-209); hazardous materials transported in pipelines, Turkey Point Lateral (Table 2.2-210); and hazardous materials potentially transported on roadways (Table 2.2-210) were evaluated to ascertain which hazardous materials should be analyzed with respect to their potential to form a toxic or asphyxiating vapor cloud following an accidental release.

The ALOHA air dispersion model was used to predict the concentrations of toxic or asphyxiating chemical clouds as they disperse downwind for all facilities and sources except for the Turkey Point Lateral natural gas pipeline. In the case of a toxic vapor cloud, the maximum distance a cloud can travel before it disperses enough to fall below the *Immediately Dangerous to Life and Health* (IDLH) or other determined toxicity limit concentration in the vapor cloud was determined using ALOHA. Asphyxiating chemicals were evaluated to determine if their release resulted in the displacement of a significant fraction of the control room air—defined by the Occupational Safety and Health Administration's (OSHA) definition of an oxygen-deficient atmosphere.)

The IDLH is defined by the National Institute of Occupational Safety and Health (NIOSH) as a situation that poses a threat of exposure to airborne contaminants when that exposure is likely to cause death or immediate or delayed permanent adverse health effects, or prevent escape from such an environment. The IDLHs are determined by NIOSH so that workers are able to escape such environments without suffering permanent health damage. Where an IDLH was unavailable for a toxic chemical, the time-weighted average or threshold limit value, promulgated

by OSHA or adopted by the American Conference of Governmental Hygienists, was used as the toxicity concentration level.

The ALOHA model was also used to predict the concentration of the chemical in the control room following a chemical release to ensure that, under worst-case scenarios, control room operators will have sufficient time to take appropriate action. ALOHA is a diffusion model that permits temporal as well as spatial variations in release terms and concentrations in the control room. The concentrations in the control room are limited to a 60-minute period because, as indicated in RG 1.78, the probability of a plume remaining within a given sector for a long period of time is quite small.

The toxicity/asphyxiation analyses conducted using the ALOHA model was run under a spectrum of standard meteorological conditions (selected stability class, wind speed, time of day, and cloud cover) based on the defined Pasquill meteorological stability classes (Tables 2.2-211 and 2.2-212). The meteorological sensitivity analysis includes the most stable meteorological class, F, allowable with the ALOHA model. The more stable the meteorological class and the lower the wind speed, the less turbulence is generated, and therefore less mixing and dilution of the formed pollutant cloud should occur. This is conservative for the Turkey Point site because the joint frequency wind distribution classes at F stability which contain wind speeds less than 2 meters/second, occur at a frequency of approximately 3 percent annually.

Other atmospheric inputs/assumptions for the ALOHA model include:

- “Open Country” was selected for the ground roughness with the exception of those chemicals stored north of Units 1 through 4 (ammonium hydroxide and sodium hypochlorite); those chemicals stored at the PGS bulk gas storage area (nitrogen, hydrogen, and carbon dioxide); and those chemicals stored inside the turbine building (hydrazine, morpholine, and sodium hypochlorite), where “Urban or Forest” was selected. The degree of atmospheric turbulence influences how quickly a pollutant cloud moving downwind will mix with the air around it and will be diluted. Friction between the ground and air passing over it is one cause of atmospheric turbulence. The rougher the ground surface, the greater the ground roughness and the greater the turbulence that develops. A chemical cloud generally travels farther across open country than over an urban area or forest. The selection of “Open Country” is conservative because the Turkey Point site meets the criteria for “Urban or Forest”—an area with many friction-generating roughness elements, such as trees or small buildings (e.g., industrial areas). The site layout and location of the chemicals stored

north of Units 1 through 4 and those stored at the PGS in relation to Units 6 & 7 would entail a vapor cloud travel through or around plant structures, thus "Urban or Forest" was selected for the determined worst-case meteorological conditions. In the case of the chemicals stored inside the turbine building, the formed vapor clouds would need to travel through various friction generating surface elements such as building components and a ventilation system, thus, "Urban or Forest" is the appropriate selection.

- The "Threat at Point" function was selected with no crosswind for the ALOHA modeling runs. This selection effectively models the chemical release as a direct-line source from the spill site to the point of concern, the control room intake. This is conservative because all of the chemicals, with the exception of the onsite chemicals associated with Units 6 & 7, are stored to the north of Units 6 & 7, and the predominant annual wind direction is from the east with an annual frequency of approximately 17 percent—and when deriving the toxicity level in the control room, RG 1.78 provides an allowance for taking into account the prevailing meteorological conditions at the site.

- Except for those chemicals stored inside the turbine building, for each of the identified chemicals, it was conservatively assumed that the entire contents of the vessel leaked, forming a 1-centimeter-thick puddle.

- For those identified hazardous materials in the gaseous state, it was conservatively assumed that the entire contents of the vessel or pipeline are released over a 10-minute period into the atmosphere as a continuous direct source (40 CFR 68.25).

- For chemicals located inside the turbine building, the toxicity analyses are conservatively modeled as if no building is present.

The effects of toxic chemical releases from internal and external sources are summarized in Table 2.2-215 and are described in the following subsections relative to the release sources.

2.2.3.1.3.1 Onsite Chemical Storage/Units 1 through 5

The hazardous materials stored onsite that were identified for further analysis with regard to the potential of the formation of toxic vapor clouds formed following an accidental release are acetylene (asphyxiant), ammonium hydroxide, argon (asphyxiant), carbon dioxide, chlorine, hydrazine, hydrogen (asphyxiant), muriatic acid, nitrogen gas (asphyxiant), liquid nitrogen (asphyxiant), oxygen (may create

an oxygen enriched environment), propane, and sodium hypochlorite.As described in Subsection 2.2.3.1.3, the identified hazardous materials were analyzed using the ALOHA dispersion model to determine whether the formed vapor cloud would reach the control room intake and what the concentration of the toxic chemical may reach in the control room following an accidental release. Acetylene, argon, carbon dioxide, chlorine, hydrogen, nitrogen, and oxygen concentrations were determined at the control room following a 10-minute release from the largest storage vessel. For each chemical in the liquid phase (ammonium hydroxide, hydrazine, muriatic acid, liquid nitrogen, propane, and sodium hypochlorite), the worst-case release scenario in each of the analyses included the total loss of the largest vessel, resulting in an unconfined 1-centimeter-thick puddle. In the case of each the asphyxiants or toxic gases, the maximum concentration, under the determined worst-case meteorological conditions, at the control room—45.9 parts per million (ppm) acetylene, 10.8 parts per minute (ppm) argon, 93.3 ppm carbon dioxide, 0.824 ppm chlorine, 53.9 ppm hydrogen, 144 ppm nitrogen, 122 ppm liquid nitrogen, and 14.9 ppm oxygen—would not displace enough oxygen for the control room to become an oxygen-deficient, or in the case of oxygen an oxygen enriched, environment, nor would they be otherwise toxic at these concentrations. Consistent with RG 1.78, asphyxiating chemicals should be considered if their release results in a displacement of a significant fraction of control room air—in accordance with the definition of oxygen-deficient atmosphere provided by the OSHA. (Reference 230) The remaining chemical analyses concluded that the control room will remain habitable for the determined worst-case release scenario—239 ppm ammonium hydroxide (urban), 8.52 ppm hydrazine, 0.966 ppm muriatic acid, 5.83 ppm propane, and 0.00467 ppm sodium hypochlorite (urban). (Table 2.2-215) Therefore, the formation of a toxic vapor cloud following an accidental release of the analyzed hazardous materials stored on site will not adversely affect the safe operation or shutdown of Units 6 & 7.

2.2.3.1.3.2 Onsite Chemical Storage/Units 6 & 7

The hazardous materials stored on site that were identified for further analysis with regard to the potential of the formation of toxic vapor clouds formed following an accidental release are methanol, sodium hypochlorite (storage at FPL reclaimed water treatment facility, cooling tower, and the turbine building), hydrazine, morpholine, liquid nitrogen (asphyxiant), nitrogen (asphyxiant), hydrogen (asphyxiant), liquid carbon dioxide, and carbon dioxide. As described in Subsection 2.2.3.1.3, the identified hazardous materials were analyzed using the ALOHA dispersion model to determine whether the formed vapor cloud would reach the control room intake and what the concentration of the toxic chemical

may reach in the control room following an accidental release. Liquid carbon dioxide, carbon dioxide, hydrogen, and nitrogen concentrations were determined at the control room following a 10-minute release from the largest storage vessel. For each chemical stored in the turbine building in the liquid phase (hydrazine, morpholine, and sodium hypochlorite) each of the analyses included the total loss of the largest vessel, resulting in a puddle release whose area is equivalent to the bermed area in the chemical storage room in the turbine building. For remaining chemicals stored in the liquid phase, the worst-case release scenario included the total loss of the largest vessel, resulting in an unconfined 1-centimeter-thick puddle. In the case of each of the asphyxiants or toxic gases, the concentration under the determined worst-case meteorological conditions at the control room—1380 ppm carbon dioxide, 1400 ppm liquid carbon dioxide, 521 ppm hydrogen, 363 ppm nitrogen, and 885 ppm liquid nitrogen—would not displace enough oxygen for the control room to become oxygen-deficient, nor would they be otherwise toxic at these concentrations. The remaining chemical analyses indicate that the control room would remain habitable for the determined worst-case release scenario—76.8 ppm methanol, 30.7 ppm hydrazine, 18.3 ppm morpholine, 0.0412 ppm sodium hypochlorite (FPL reclaimed water treatment facility), 0.349 ppm sodium hypochlorite (cooling tower), and 0.0454 ppm sodium hypochlorite (turbine building) (Table 2.2-215). Therefore, the formation of a toxic vapor cloud following an accidental release of the analyzed hazardous materials stored on site would not adversely affect the safe operation or shutdown of Units 6 & 7.

2.2.3.1.3.3 Nearby Facilities/Homestead Air Reserve Base

The Homestead Air Reserve Base is approximately 4.76 miles, 25,133 feet, from the Turkey Point site. The hazardous materials stored at Homestead Air Reserve Base that are identified for further analysis with regard to the potential for forming a toxic vapor cloud following an accidental release and traveling to the control room are Halon 1301, oxygen (potential for creating an oxygen enriched environment), gasoline, and propane.For Halon 1301 and gasoline, the worst-case release scenario included the total loss of the largest vessel, resulting in an unconfined 1-centimeter-thick puddle. Because solutions such as gasoline cannot be modeled in the current version of ALOHA as recommended by the EPA, gasoline was modeled for toxicity analysis by selecting n-Heptane as a surrogate for gasoline in ALOHA's chemical library. This selection is appropriate as the evaporation curves over a range of temperatures for n-Heptane and gasoline are shown to be similar, and at temperatures below 80°C, the evaporation of n-Heptane occurred at a faster rate (Reference 246). Oxygen and Propane

concentrations are determined outside the control room following a 10-minute release of the total quantity onsite. In the case of oxygen, the maximum concentration under the determined worst-case meteorological condition at the control room—5.31 ppm—would not displace enough air for the control room to become an oxygen enriched environment. The chemical analysis indicates that the distance the Halon 1301, gasoline, or propane vapor cloud could travel before falling below the selected toxicity limit was less than the distance to the control room for each meteorological condition analyzed (Table 2.2-215). Therefore, the formation of a toxic vapor cloud following an accidental release of the analyzed hazardous materials stored at an offsite facility will not adversely affect the safe operation or shutdown of Units 6 & 7.

2.2.3.1.3.4 Transportation Routes/Roadways

The nearest control room for Units 6 & 7 is approximately 2084 feet at its closest point of approach, from the onsite transportation delivery route for gasoline. As detailed in Subsection 2.2.2.5, delivery of chemicals other than gasoline to the Units 1 through 5 site are screened and determined to be bounded by the evaluation performed for the Units 1 through 5 onsite storage quantities. The methodology presented in Subsection 2.2.3.1.3 was used for determining the distance from the release site to the point where the toxic vapor cloud reaches the IDLH boundary. For gasoline, the time-weighted average toxicity limit was conservatively used because no IDLH is available for this hazardous material. The time-weighted average is the average value of exposure over the course of an 8-hour work shift. Gasoline was modeled for toxic analysis by selecting n-Heptane in ALOHA's chemical library. The maximum concentration of gasoline attained in the control room during the first hour of the release was determined. In this scenario, it was conservatively estimated that the transport vehicle lost the entire contents—50,000 pounds, or 9000 gallons. The results concluded that any vapor cloud that forms following an accidental release of gasoline at the closest approach from the onsite transportation delivery route, and travels toward the control room, will not achieve an airborne concentration greater than the time-weighted average in the control room(Table 2.2-215). Therefore, the formation of a toxic vapor cloud following an accidental release of gasoline transported onsite will not adversely affect the safe operation or shutdown of Units 6 & 7.

2.2.3.1.3.5 Transportation Routes/Pipelines

The Florida Gas Transmission Company owns and operates a high pressure natural gas transmission pipeline system that serves FPL. At its closest distance,

the Turkey Point Lateral pipeline passes within approximately 4535 feet of the nearest control room for Units 6 & 7, the Unit 6 control room. Natural gas or its main constituent, methane, is not considered toxic and there is no IDLH or other toxicity limit identified. However, natural gas is considered an asphyxiant. Therefore, an analysis is necessary for the natural gas transmission pipeline to determine whether an oxygen-deficient environment exists in the control room from the displacement of air. Utilizing the methodology and inputs described in Subsections 2.2.3.1.3 and 2.2.3.1.2.7, natural gas (as methane) was analyzed using the ALOHA dispersion model to determine whether the formed vapor cloud would reach the control room intake and whether the concentration of the asphyxiating chemical may reach levels in the control room which would displace enough oxygen. The concentration under the determined worst-case meteorological conditions at the control room—523 ppm will not displace enough oxygen for the control room to become an oxygen-deficient atmosphere.

2.2.3.1.4 Fires

Accidents were considered in the vicinity of the Turkey Point site that could lead to high heat fluxes or smoke, and nonflammable gas or chemical-bearing clouds from the release of materials as a consequence of fires. Fires in adjacent industrial plants and storage facilities—chemical, oil and gas pipelines; brush and forest fires; and fires from transportation accidents—are evaluated as events that could lead to high heat fluxes or to the formation of such clouds.

The nearest industrial site is the Homestead Air Reserve Base, located approximately 4.76 miles from Units 6 & 7. Each of the chemicals stored at Units 1 through 7 and the Homestead Air Reserve Base along with the nearest natural gas transmission pipeline, the Turkey Point Lateral, are evaluated in Subsection 2.2.3.1.2 for potential effects, including heat fluxes where appropriate, of accidental releases leading to a delayed ignition and/or explosion of any formed vapor cloud. For each of the stored or transported hazardous materials evaluated, the results concluded that any formed vapor cloud will dissipate below the LFL before reaching the control room.Further, an evaluation of the heat flux from the formed vapor cloud capable of ignition concluded that the resulting heat flux from a flash fire or jet fire (Florida Gas Transmission pipeline) will be below the 5 kW/m^2 threshold (Table 2.2-214). Therefore, it is not expected that there will be any hazardous effects to Units 6 & 7 from fires or heat fluxes associated with the operations at these facilities, transportation routes, or pipelines.

Further, the potential for an onsite fire from the residual fuel oil storage facilities located at the Turkey Point site was evaluated to estimate the resulting heat flux.

Subsection 2.2.3.1.2 does not include an evaluation of the heat flux from the formation of a vapor cloud because the low vapor pressure of residual fuel oil makes this a non-credible event. The incident heat flux was calculated using the solid flame model presented in NUREG-1805. The solid flame model is based on the assumption that the fire is a solid vertical cylinder that emits thermal radiation laterally.The incident heat flux calculated from the solid flame model requires that the average emissive power at the flame surface (kW/m^2) and the configuration factor along with the flame height be calculated. The methodology used to calculate the average emissive power, flame height, configuration factor and resultant incident heat flux is as follows:

Emissive Power

The emissive power (E) is the total surface radiation of the fire per unit area per unit time (NUREG-1805).

$$E(kW/m^2) = 58\ (10^{-0.00823D}) \qquad \text{(Equation 8)}$$

Where, D is the effective diameter of the pool fire for a noncircular pool and is calculated from the surface area of the pool (A_f) and is given by the following equation:

$$D = (4A_f/\pi)^{1/2} \qquad \text{(Equation 9)}$$

Flame Height

For open pool burning with no fire growth, the following correlation can be used to determine the flame height of the fire (NUREG-1805).

$$H_f(m) = 0.235\ Q^{0.4} - 1.02\ D \qquad \text{(Equation 10)}$$

Where, D is the effective diameter of the fire (m) and Q is the heat release of the fire determined by the following relationship:

$$Q = m^n\ \Delta H_{c,eff}\ A_f\ (1-e^{-k\beta D}) \qquad \text{(Equation 11)}$$

Where, m^n is the mass loss rate per unit area per unit time (kg/m^2-s); $\Delta H_{c,\ eff}$ is the heat of combustion (kJ/kg); A_f is the surface area of the pool (m^2); and $k\beta$ is an empirical constant (m^{-1}).

Configuration Factor

The configuration factor (F_{1-2}) is a geometric quantity that accounts for the fraction of the radiation leaving one surface that strikes another surface directly. The configuration factor is a sum of the horizontal and vertical vectors and is a value between 0 and 1. The factor approaches 1 as the distance between the point of interest and the flame is decreased (NUREG-1805).

$$F_{1-2} = (F^2_{1-2,H} + F^2_{1-2,V})^{½} \qquad \text{(Equation 12)}$$

Incident Heat Flux

The incident heat flux, Q''_{inc}, to the target is given by (NUREG-1805):

$$Q''_{inc}\ (\text{kW/m}^2) = EF_{1-2} \qquad \text{(Equation 13)}$$

The following inputs and assumptions were used in determining the incident heat flux:

- It was conservatively assumed that the entire contents of one of the residual fuel oil storage tanks, 268,000 barrels, completely ruptures spilling the entire contents into the bermed area.
- The terrain between the fire and the closest plant structure is assumed to be flat with no obstructions.
- It is assumed that it is an open pool fire and the entire surface of the fuel oil in the bermed area is involved. The pool is assumed to be circular with an area equivalent to the bermed area.
- The fire is assumed to be a perfect black body with an emissivity of 1.
- The transmissivity of air is assumed to be 1—this assumes that no thermal radiation is absorbed by air.
- The Unit 6 service building, located 3668 feet from the postulated fuel oil fire, was conservatively used as the separation distance between the fire and nearest building—although the service building is not a safety-related structure, it was conservatively chosen as the structure of concern for Units 6 & 7.

Using the method described above the incident heat flux for a postulated pool fire involving the entire contents of the storage vessel would result in an incident heat

flux of 0.0625 kW/m^2 at the Unit 6 service building—below the selected 5.0 kW/m^2 level of concern for heat from fires. Further, a dispersion analysis study concluded that airborne pollutant concentration levels resulting from the postulated fire will be below established ambient air quality standards before reaching Units 6 & 7.

Brush and forest fires were also considered consistent with RG 1.206. Units 6 & 7 are built on fill material to an elevation of approximately 25-26 feet NAVD 88. The plant area consists of approximately 218 acres providing a cleared area consisting of limited vegetative fuel for a fire of at least 600 feet wide surrounding the Units 6 & 7 site safety-related structures. This provides a substantial defensible zone in the unlikely event of a fire originating as a result of onsite or offsite activities. Additionally, Units 6 & 7 is located south of Units 1 through 5 and are within the cooling canals.These canals, which are approximately 100–150 feet wide, encircle the Units 6 & 7 plant area. The canals are deep, primary return, water canals leading to Units 1 through 4 cooling water intakes. Therefore, the zone surrounding Units 6 & 7 is of sufficient size, especially when considering the canals surrounding the plant area, to afford protection in the event of a fire. The Florida Department of Agriculture and Consumer Services, Division of Forestry recommends a defensible space of 30 feet (minimum) to 100 to 200 feet be maintained around structures for protection against wildfires. In addition, California has adopted regulations requiring a fire break of at least 30 feet and a fuel break to 100 feet (References 231 and 232). The safety zone around Units 6 & 7 greatly exceeds these recommended distances, and therefore, it is not expected that there will be any hazardous effects to Units 6 & 7 from fires or heat fluxes associated with wild fires, fires in adjacent industrial plants, or from onsite storage facilities.

2.2.3.1.5 Collisions with Intake Structure

Because Units 6 & 7 are located near a navigable waterway, an evaluation was performed that considered the probability and potential effects of impacts on the plant cooling water intake structure and enclosed pumps. The Units 6 & 7 makeup water system consists of either reclaimed water provided from the Miami-Dade Water and Sewer Department or saltwater makeup water from the radial collector wells to the circulating water cooling system. The radial collector wells consist of a central reinforced concrete caisson, extending below the Biscayne Bay seabed. The wells are designed to induce infiltration from the nearby surface water source (Biscayne Bay), combining the desirable features of extremely high well yields with induced seabed filtration of suspended particulates. Thus, there is no intake structure associated with either the reclaimed water pipeline or radial collector well system

that would be damaged as a result of navigable waterway activities that would affect the safe shutdown of Units 6 & 7.

2.2.3.1.6 Liquid Spills

The accidental release of oil or liquids that may be corrosive, cryogenic, or coagulant was considered to determine if the potential exists for such liquids to be drawn into the plant's makeup water intake structure and circulating water system or otherwise affect the plant's safe operation. In the event that these liquids would spill into the Biscayne Bay, they would not only be diluted by the large quantity of Biscayne Bay water, but the only material shipped by barge, residual fuel oil, has a specific gravity less than water and would float on top of the water. Therefore, any spill in the Biscayne Bay will not affect the water supplied by the radial collector wells and will not affect the safe operation or shutdown of Units 6 & 7.

2.2.3.1.6.1 Radiological Hazards

The hazard due to the release of radioactive material from Units 3 & 4 as a result of normal operations or an unanticipated event will not threaten safety of the new units. Smoke detectors, radiation detectors, and associated control equipment are installed at various plant locations as necessary to provide the appropriate operation of the systems. Radiation monitoring of the main control room environment is provided by the radiation monitoring system. The habitability systems for Units 6 & 7 are capable of maintaining the main control room environment suitable for prolonged occupancy throughout the duration of the postulated accidents that require protection from external fire, smoke, and airborne radioactivity. Automatic actuation of the individual systems that perform a habitability systems function is provided. In addition, safety-related structures, systems, and components for Units 6 & 7 have been designed to withstand the effects of radiological events and the consequential releases which will bound the contamination from a release from either of these potential sources.

2.2.3.2 Effects of Design Basis Events

As concluded in the previous subsections, no events were identified that had a probability of occurrence on the order of magnitude of 1E-07 or greater; and potential consequences serious enough to affect the safety of the plant to the extent that the guidelines in 10 CFR Part 100 could be exceeded. Thus, there are no accidents associated with nearby industrial, transportation, or military facilities that are considered design basis events.

STD DEP 1.1-1

2.2.4 COMBINED LICENSE INFORMATION

PTN COL 2.2-1

This COL item is addressed in Subsections 2.2 through 2.2.3.

2.2.5 REFERENCES

201. FPL, *Turkey Point Uprate Project, Site Certification Application*, January 18, 2008.

202. U.S. Air Force, Homestead Air Reserve Base. Available at www.homestead.afrc.af.mil/, accessed July 18, 2008.

203. Headquarters Air Force Reserve Command, *Air Installation Compatible Use Zone (AICUZ) Study for the Homestead Air Reserve Base*, Florida, October 2007.

204. Correspondence, Ron Moran, Florida Gas Transmission Company, to David Wagner, Bechtel Power Corporation, Gas Line Operation Parameters, February 15, 2008.

205. FPL, *Turkey Point Plant Operations Manual for Fuel Oil Unloading*, July 2005.

206. U.S. Army Corps of Engineers, Institute of Water Resources, *Waterborne Commerce of the United States, Part 1 — Waterways and Harbors Atlantic Coast*, 2005.

207. Rand McNally, *Miami-Dade County Street Guide*, 2008.

208. Homestead Air Reserve Base, *Response to Freedom of Information Act Request*, FOIA#2008-002, May 2008.

209. Airnav.com. Available at http://www.airnav.com/, accessed February 15, 2008.

210. GCR & Associates, Inc., Airport IQ5010. Available at http://www.gcr1.com/5010web/, accessed February 15, 2008.

211. The National Airspace System. Available at http://www.faa.gov/library/manuals/aviation/instrument_flying_handbook/media/faa-h-8083-15-2.pdf, accessed November 16, 2006.

212. U.S. Department of Energy, *Accident Analysis for Aircraft Crash into Hazardous Facilities*, DOE Standard, DOE-STD-3014-96, October 1996, Reaffirmation May 2006.

213. Miami-Dade.gov, Adopted 2015-2025 Land Use Plan Map. Available at http://www.miamidade.gov/planzone/CDMP_landuse_map.asp, accessed October 23, 2008.

214. National Fire Protection Agency, NFPA 68, *Guide for Venting of Deflagrations*, 2002.

215. National Fire Protection Agency, NFPA 921, *Guide for Fire and Explosion Investigations*, 2008.

216. Factory Mutual Insurance Company, FM Global, *Guidelines for Evaluating the Effects of Vapor Cloud Explosions Using a TNT Equivalency Method*, May 2005.

217. Areal Locations of Hazardous Atmospheres (ALOHA), Version 5.4.1, NOAA, February 2006.

218. Geiger, W., *Generation and Propagation of Pressure Waves Due to Unconfined Chemical Explosions and Their Impact on Nuclear Power Plant Structures*, Nuclear Engineering and Design, Volume 27, 1974.

219. Harris, R.J., and Wickens, M.J., *Understanding Vapor Cloud Explosions — An Experimental Study*, The Institution of Gas Engineers, Special Projects Division, Communication 1408, 55th Autumn Meeting, Kensington Town Hall, November 1989.

220. U.S. EPA, *Risk Management Program Guidance for Offsite Consequence Analysis,* EPA 550-B-99-009, April 1999.

221. DiNenno, P.J., *The SFPE Handbook of Fire Protection Engineering*, 2nd Edition, Society of Fire Protection Engineers, June 1995.

222. American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE), *Design Conditions for Homestead AFB*, FL, USA, WMO# 722025, ASHRAE Handbook-Fundamentals, 2005.

223. U.S. Department of Transportation, Federal Aviation Administration National Aeronautical Charting Office, United States Government *Flight Information Publication IFR Enroute Low Altitude—U.S., Panel L-19*, August 2007.

224. South Florida Regional Planning Council, Emergency Management, Kunish, Donald, *Response to Freedom of Information Act Request, SARA Title III, Tier II reports*, reporting year 2006, March 2008.

225. U.S. EPA Enviromapper database. Available at http://134.67.99.109/wme/myWindow.asp?xl=80.5011043333333&yt=25.4872705&xr=-80.4531043333333&yb=25.4512705, September 29, 2008 and November 6, 2008.

226. U.S. EPA, Chemical Emergency Preparedness and Prevention Office, James C. Belke, *Chemical accident risks in U.S. industry- A preliminary analysis of accident risk data from U.S. hazardous chemical facilities*, September 25, 2000.

227. Sugano, T., et al., *Local Damage to Reinforced Concrete Structures Caused by Impact of Aircraft Engine Missiles*, Nuclear Engineering and Design 140, pp. 387–423, 1993.

228. Mizuno, et al., *Investigation on Impact Resistance of Steel Plate Reinforced Concrete Barriers against Aircraft Impact: Part 3 Analyses of Full-Scale Aircraft Impact*, 18th International Conference on Structural Mechanics in Reactor Technology (SMiRT 18), August 2005.

229. Drs. Uijt de Haag, P.A.M., and Ale, B.J.M., *Guideline for quantitative risk assessment*, “Purple book,” CPR 18E, December 2005.

230. Occupational Safety and Health Administration, *Occupational and Health Standards, Hazardous Materials, Hazardous Waste Operations and Emergency Response Definitions,* Title 29 Code of Federal Regulations Part 1910.120(a)(3), April 3, 2006.

231. Florida Department of Agriculture and Consumer Services, Division of Forestry, Firewise Landscaping. Available at http://www.fl-dof.com/wildfire/firewise_landscaping.html, accessed November 19, 2008.

232. Defensible Space, 2005, California Code of Regulations Title 14 CCR, Division 1.5, Chapter 7 Fire Protection, Subchapter 3, Article 3. *Fire Hazard Reduction Around Buildings and Structures Defensible Space*. § 1299. Available at http://www.fire.ca.gov/CDFBOFDB/pdfs/ DefensibleSpaceRegulationsfinal12992_17_06.pdf, accessed March 22, 2007.

233. National Institute for Occupational Safety and Health (NIOSH), Center for Disease Control and Prevention, NIOSH Pocket Guide to Chemical Hazards, September 2005.

234. United States Coast Guard, *Chemical Hazards Response Information System*, Commandant Instruction 16465.12C, 1999.

235. United States Environmental Protection Agency and the National Oceanic and Atmospheric Administration's Office of Response and Restoration, *Computer-Aided Management of Emergency Operation*.

236. Matheson Tri-Gas, *Liquid Nitrogen Material Safety Data Sheet*, January 2007.

237. Mallinckrodt Baker, Inc., *Sodium Molybdate Material Safety Data Sheet*, August 2005.

238. International Programme on Chemical Safety, *Argon Data Sheet*, May 2003.

239. Seinfeld, J.H., *Atmospheric Chemistry and Physics of Air Pollution*, John Wiley & Sons, Inc., 1986.

240. U.S. Department of Transportation, Federal Aviation Administration National Aeronautical Charting Office, *United States Government Flight Information Publication IFR Enroute High Altitude—U.S., Panel H-8*, May 2007.

241. U.S. Department of Transportation, Federal Aviation Administration, *FAA Terminal Area Forecast: National Forecast 2006 (1)—Airport Operations,*

Miami International. Available at http://tafpub.itworks-software.com/OperationsListPrint.asp?TABLE_NAME=airportOperations&DisplayAll=undefined, accessed February 15, 2008.

242. Ocean Reef Club, ORC Airport. Available at http://www.oceanreef.com/index.cfm?fuseaction=aboutus.airport&, accessed December 16, 2008.

243. Canadian Society for Chemical Engineering, *Risk Assessment-Recommended Practices for Municipalities and Industry,* ISBN No. 0-920804-92-6, 2004.

244. Florida Power & Light, *Ten-Year Power Plant Site Plan 2009–2018*. Miami, Florida. Available at http://www.fpl.com/about/ten_year/pdf/plan.pdf _plan.shtml, accessed May 21, 2009.

245. Jo, Y. -D, and Ahn, B. J., *Analysis of hazard areas associated with high-pressure natural gas pipelines*.

246. Fardad, D. and Ladommatos, N., *Evaporation of hydrocarbon compounds, including gasoline and diesel fuel, on heated metal surfaces*, Department of Mechanical Engineering, Brunel University, Uxbridge, UK, Proc Instn Mech Engrs Vol 213 Part D, 1999.

247. The Chlorine Institute, Inc., *Sodium Hypochlorite Manual Pamphlet 96*, *Edition 2*, May 2000.

248. Accepta Ltd., *Accepta 2047 MSDS: Water Treatment Flocculant: High molecular weight anionic liquid polymer*, January 6, 2004.

249. Accepta Ltd., *Accepta 2065 MSDS: Carbohydrazide based oxygen scavenger boiler water treatment*, January 6, 2004.

250. Accepta Ltd., *Accepta 2090 MSDS: Flocculant: High molecular weight liquid cationic polymer*, January 6, 2004.

251. Nalco Company, *pHREEdom® 5200M Scale/Deposit Inhibitor Product Bulletin*, March 30, 2006.

252. Nalco Company, *3D TRASAR 3DT102 Material Safety Data Sheet*, June 27, 2005.

253. Nalco Company, *3D TRASAR 3DT195 Material Safety Data Sheet*, March 21, 2007.

254. Mallinckrodt Baker, Inc., *Sodium Molybdate Material Safety Data Sheet*, May 19, 2008.

255. Nalco Company, 3D TRASAR 3DT155 Material Safety Data Sheet.

256. Chemical Safety Associates, Inc., RoClean P111 NSF MSDS, January 2006.

257. Chemical Safety Associates, Inc., RoClean P303 NSF MSDS, October 2007.

258. Langevin, C. D., *Simulation of Ground-Water Discharge to Biscayne Bay, Southeastern Florida*, Water-Resources Investigations Report 00-4251, U.S. Geological Survey 2001.

259. Wingard, G. L., et. al., *Ecosystem History of Southern and Central Biscayne Bay: Summary Report on Sediment Cove Analyses — Year Two*, Open File Report, U.S. Geological Survey, Report 2004-1312, October 2004.

260. Swarzenski, Peter, et. al., *Novel geophysical and geochemical techniques used to study submarine groundwater discharge in Biscayne Bay, Florida*, U.S. Geological Survey, Fact Sheet 2004-3117, September 2004.

PTN COL 2.2-1

Table 2.2-201
Description of Facilities — Products and Materials

Site	Concise Description	Primary Function	Number of Persons Employed	Major Products or Materials
Units 1 through 5	Units 1 & 2 are gas/oil-fired steam electric generating units; Units 3 & 4 are nuclear powered steam electric generating units; and Unit 5 is a natural gas combined-cycle plant.	Power Production	977	Electrical Power
Homestead Air Reserve Base	Homestead Air Reserve Base is a fully combat-ready unit capable of providing F-16C multipurpose fighter aircraft, along with mission ready pilots and support personnel, for short-notice worldwide deployment.	Military Installation	2365	N/A — Military Installation

Source: References 201, 202, and 203

PTN COL 2.2-1

Table 2.2-202 (Sheet 1 of 5)
Onsite Chemical Storage Units 1 through 7

Material	Toxicity Limit IDLH[(a)]	Maximum Quantity in Largest Container	Primary Storage Location
Units 1 through 5			
Acetylene Gas	Asphyxiant	150 pound cylinders (3,000 pounds total)	Welding Gas House
Ammonium Hydroxide	300 ppm	(2) 20,000 gallon above ground storage tanks	East Side Unit 5 for SCR
Argon Gas	Asphyxiant	150 pound cylinders (3,000 pounds total)	Welding Gas House
Boric Acid	None Established	Fiber drums (66,660 pounds total)	Units 3 & 4 Central Receiving Warehouse/ Boric Acid Room
Carbon Dioxide	40,000 ppm	150 pound cylinders (9,000 pounds total)	Compressed Gas House
Chlorine	10 ppm	150 pound cylinder	Nuclear Sewage Treatment Area
Citric Acid	None Established	500 pounds	Water Treatment Area (Units 1 & 2)
Hydrated Lime (Calcium Hydroxide)	5 mg/m^3[(b)]	35,000 pounds	Fossils Storage Building
Hydrazine	50 ppm	1,100 gallons (2,215 gallons total)	Stores Drum Storage Area (Units 3 & 4)
Hydrogen Gas	Asphyxiant	(2) 45,000 standard cubic feet (2 Hydrogen Tube Trailers)	Stored in two Hydrogen Tube Trailers
Hydrogen Peroxide	75 ppm	5 gallon	Primary Chemical Addition Area
Lead (in battery)	100 mg/m^3 (as lead)	174,000 pounds	Units 1 through 5 Battery Rooms/Land Utilization Fleet Service Shop
Lithium Hydroxide	None Established	5 gallons	Primary Chemical Addition Area
Lube Oil	None Established	14,800 gallon storage tank (122,548 gallons total)	Units 3 & 4 Lube Oil Storage Tank/Lube Oil Reservoirs
Magnesium Oxide	750 mg/m^3	20,000 pounds	Fossils Storage Building
Mineral Oil	2,500 mg/m^3	(2) 16,180 gallons (48,997 gallons total)	Unit 1 Main Transformer/Unit 2 Main Transformer
Muriatic Acid (Hydrochloric Acid)	50 ppm	110 gallons	Units 1 & 2 Water Treatment Area
Nitrogen Gas	Asphyxiant	100,000 cubic feet	Gas House/Trailer

PTN COL 2.2-1

Table 2.2-202 (Sheet 2 of 5)
Onsite Chemical Storage Units 1 through 7

Material	Toxicity Limit IDLH[(a)]	Maximum Quantity in Largest Container	Primary Storage Location
Nitrogen– Liquid	Asphyxiant	3,500 gal	Units 3 & 4 N_2 Dewar Tanks
Number 2 Fuel Oil/Diesel Fuel	None Established	4,300,000 gallon above ground storage tank (4,510,632 total)	Unit 5 Southeast Corner
Number 6 Fuel Oil (Residual Fuel Oil)	None Established	(2) 268,000 barrel (11,256,000 gallon) above ground storage tanks	Fossil Fuel Tank Farm-NE corner of site
Organometallic Magnesium Complex	None Established	134,000 pounds	Units 1 & 2 East Side Chem Feed Area
Oxygen Gas	May displace air and cause an oxygen enriched environment	150 pound cylinders (3,000 pounds total)	Welding Gas House
Propane	2,100 ppm	500 Gallons	Units 1 & 2-NE of Metering Tanks
Silicone	None Established	568 gallons (1,136 gallons total)	Unit 1 Power Potential Transformer/Unit 2 Power Potential Transformer
Sodium Bicarbonate	None Established	50 pound bags (10,000 pounds total)	Unit 1 Boiler Dry Storage Warehouse
Sodium Hydroxide	10 mg/m^3	Fiber drums (1,900 pounds total)	Units 1 & 2 Water Treatment Plant/Units 3 & 4 Central Receiving Warehouse
Sodium Hypochlorite	10 ppm as chlorine	6,000 gallon tank	Unit 5 South of Cooling Tower
Sodium Molybdate	5 mg/m^3 (as Mo)	80 gallons	Unit 3 Condensate Polisher Bldg
Sodium Nitrite	None Established	80 gallons	Unit 3 Condensate Polisher Bldg
Sodium Tetraborate	1 mg/m^3[(b)]	22,000 pounds	Units 3 & 4 Dry Stores
Sulfuric Acid	15 mg/m^3	6,000 gallons (12,500 gallons total)	Units 3 & 4 Water Treatment Plant/ Unit 5 South of Cooling Tower
Sulfuric Acid (Station Batteries)	15 mg/m^3	2,913 pounds	Units 1 & 2 Station Battery Rooms
Trisodium Phosphate-Liquid	None Established	300 gallons	Unit 5- North of Steam Turbine

PTN COL 2.2-1

Table 2.2-202 (Sheet 3 of 5)
Onsite Chemical Storage Units 1 through 7

Material	Toxicity Limit IDLH[a]	Maximum Quantity in Largest Container	Primary Storage Location
Unleaded Gasoline	300 ppm[b]	2,000 gallon split tank (7,000 gallons total)	Vehicle Refueling Area/Land Utilization Vehicular Fuel Tank
Units 6 & 7			
Anionic polymer	None Established	900 gallons	FPL Reclaimed Water Treatment Facility
Ferric Chloride (47% Solution)	1 mg/m^3[c]	90,250 gallons	FPL Reclaimed Water Treatment Facility
Lime ($Ca(OH)_2$)	5 mg/m^3[c]	23,000 gallons	FPL Reclaimed Water Treatment Facility
Sulfuric Acid (93% Solution)	15 mg/m^3	33,600 gallons	FPL Reclaimed Water Treatment Facility/ Cooling Tower/ Turbine Building
Methanol	6,000 ppm	25,000 gallons	FPL Reclaimed Water Treatment Facility
Sodium Hypochlorite (40% Solution)	10 ppm (as chlorine)	20,000 gallons	FPL Reclaimed Water Treatment Facility/ Cooling Tower/ Turbine Building
Alum (49% Solution)	None Established	30,000 gallons	FPL Reclaimed Water Treatment Facility
Sodium Bisulfite (40% Solution)	5 mg/m^3[c]	15,000 gallons	FPL Reclaimed Water Treatment Facility
Sodium Hydroxide	None Established	15,000 gallons	FPL Reclaimed Water Treatment Facility
Polymer (25% Solution)	None Established	275 gallon tote	FPL Reclaimed Water Treatment Facility
Proprietary Scale Inhibitor[d]-Saltwater (Sodium salt of phosphonomethylate diamine)	None Established	10,000 gallons	Cooling Towers
Proprietary Scale Inhibitor[d]-Saltwater (Calcium phosphate, zinc, iron, manganese)	None Established	12,200 gallons	Cooling Towers
Proprietary Scale Inhibitor[d]-Transition from Saltwater to Reclaimed (Silica based scale inhibitor)	None Established	400 gallon tote	Cooling Towers

PTN COL 2.2-1

Table 2.2-202 (Sheet 4 of 5)
Onsite Chemical Storage Units 1 through 7

Material	Toxicity Limit IDLH[a]	Maximum Quantity in Largest Container	Primary Storage Location
Proprietary Scale Inhibitor[d]-Reclaimed (High Stress Polymer with PSO)	None Established	12,000 gallons	Cooling Towers
Proprietary Scale Inhibitor[d] (17.9% phosphoric acid)	1,000 mg/m^3	800 gallons	Turbine Building
Proprietary Dispersant[d] (Calcium phosphate, zinc, iron, manganese)	None Established	800 gallons	Turbine Building
Proprietary Scale Inhibitor[d] (30% phosphoric acid)	1,000 mg/m^3	800 gallons	Turbine Building
Sodium Bisulfite (25% solution)	5 mg/m^3[c]	80 gallons	Turbine Building
Proprietary Reverse Osmosis Cleaning Chemical[d] (EDTA Salt, Percarbonate Salt, Phosphonic Acid, Tetrasodium Salt)	None Established	Fiber Drums	Turbine Building
Proprietary Reverse Osmosis Cleaning Chemical[d] (Hydroxyalkanoic acid, Inorganic phosphate, EDTA Salt)	None Established	Fiber Drums	Turbine Building
Hydrazine (35% solution)	50 ppm	800 gallons	Turbine Building
Carbohydrazide	None Established	800 gallons	Turbine Building
Morpholine	1,400 ppm	800 gallons	Turbine Building
No. 2 Diesel Fuel Oil	None Established	60,000 gallons	Diesel Generator Day Tanks/Diesel Generator Building/Annex Building
Liquid Nitrogen	Asphyxiant	1,500 gallons	Plant Gas Storage Area
Nitrogen Gas	Asphyxiant	58 cubic feet	Plant Gas Storage Area
Hydrogen Gas	Asphyxiant	40,000 standard cubic feet (Tube Trailer)	Plant Gas Storage Area
Liquid Carbon Dioxide	40,000 ppm	6 tons	Plant Gas Storage Area
Carbon Dioxide Gas	40,000 ppm	104,800 standard cubic feet	Plant Gas Storage Area

PTN COL 2.2-1

Table 2.2-202 (Sheet 5 of 5)
Onsite Chemical Storage Units 1 through 7

Material	Toxicity Limit IDLH[(a)]	Maximum Quantity in Largest Container	Primary Storage Location
Sodium Molybdate	5 mg/m^3 (as Mo-TLV)	45 gallons	Turbine Building
Ethylene Glycol	None Established	45 gallons	Turbine Building

(a) Immediately dangerous to life and health.
(b) Threshold limit value/time-weighted average (TLV-TWA).
(c) Time-weighted average (TWA)
(d) Main constituents of proprietary treatment chemicals are listed.

Source: References 233, 234, 235, 236, 237, 248, 249, 250, 251, 252, 253, 254, 255, 256, and 257

PTN COL 2.2-1

Table 2.2-203
Offsite Chemical Storage — Homestead Air Reserve Base

Material	Toxicity Limit (IDLH)	Maximum Quantity in Largest Container[a] (pounds)
Bromotrifluoromethane (Halon 1301)	40,000 ppm	5,440
Diethylene Glycol Monobutyl Ether	None Established	30,625
Diesel Fuel Oil (High Sulfur)	None Established	158,752
Gasoline	300 ppm[b]	137,104
Hydrazine	50 ppm	1,437
Jet Fuel	200 mg/m^3[b]	23,251,606
Nitrogen (gas)	Asphyxiant	21,648
Oxygen	May displace air and cause an oxygen enriched environment	36,561
Propane	2,100 ppm	185,865

(a) Actual amount of compound in these cases is the maximum of the reported range on the SARA Title III, Tier II report. This range envelopes an order of magnitude and represents the greatest amount present at the facility during the reporting period.
(b) Threshold limit value/time-weighted average (TLV-TWA).

Source: References 224, 233, 234, and 235

PTN COL 2.2-1

Table 2.2-204
Units 6 & 7 Pipeline Information Summary

Operator	Product	Pipeline Diameter	Pipeline Age	Operating Pressure	Depth of Burial	Distance Between Isolation Valves
Florida Gas Transmission Company-Turkey Point Lateral	Natural Gas Transmission	24 inches	1968	722 psig	3.5 feet	11.8 miles
Florida Gas Transmission Company-Homestead Lateral	Natural Gas Transmission	6.625 inches	1985	722 psig	3.5 feet	NA[(a)]

(a) Due to the proximity and diameter of the Turkey Point lateral pipeline in comparison to the Homestead lateral pipeline, the Turkey Point lateral pipeline presents a greater hazard, and as such, the Turkey Point lateral pipeline analysis is bounding and no further analysis of the Homestead lateral pipeline is warranted.

Source: Reference 204

PTN COL 2.2-1

Table 2.2-205
Hazardous Chemical Waterway Freight, Intracoastal Waterway, Miami to Key West, Florida

Material	Toxicity Limit (IDLH)	Total Quantity (short tons)
Residual Fuel Oil	None established	611,000

Source: References 206 and 234

PTN COL 2.2-1

Table 2.2-206
Aircraft Operations — Significant Factors

Airport	Number of Operations	Distance from Site	Significance Factor[a]
Turkey Point Heliport	79	0.6 miles	N/A[b]
Homestead Air Reserve Base	36,429	4.76 miles	N/A[b]
Ocean Reef Club Airport[c]	Sporadic	7.41 miles	27,454
Miami International Airport[c]	386,681 (2005 operations) 545,558 (2025 projected)	25.5 miles	651,832

(a) $500d^2$ movements per year for sites within 5 to 10 miles and $1000d^2$ movements per year for sites outside 10 miles.
(b) Consistent with RG 1.206, airports with a plant-to-airport distance less than 5 miles from the site is considered regardless of the projected annual operations.
(c) Because the projected number of operations is less than the calculated significance factor, an evaluation for this airport was not conducted.

Source: References 208, 209, 210, and 241

PTN COL 2.2-1

Table 2.2-207 (Sheet 1 of 3)
Units 1-5 Onsite Chemical Storage — Disposition

Material	Toxicity Limit (IDLH)	Flammability	Explosion Hazard	Vapor Pressure	Disposition
Acetylene Gas	Asphyxiant	2.5–100 percent	Vapor may explode	51.370 psi at –76˚F	Toxicity Analysis—consider as asphyxiant
					Flammability Analysis
					Explosion Analysis
Ammonium Hydroxide	300 ppm (as ammonia)	15–28%	None listed	854,548 Pa at 293.15˚K	Toxicity Analysis
					Flammability Analysis
					Explosion Analysis
Argon Gas	Asphyxiant	Not flammable	None listed	1,044.630 Pa @117.32˚K	Toxicity Analysis—consider as asphyxiant
Boric Acid	None Established	Not flammable	None listed	N/A-solid	No further analysis required
Carbon Dioxide	40,000 ppm	Not flammable	None listed	907.299 psi @ 75˚F	Toxicity Analysis and consider as asphyxiant
Chlorine	10 ppm	Not flammable	None listed	74.040 psi @ 50˚F	Toxicity Analysis
Citric Acid	None Established	0.28 kg/m^3 (dust)–2.29 kg/m^3 (dust)	None listed	N/A-solid	No further analysis required-low vapor pressure[(a)]
Hydrated Lime (Calcium Hydroxide)	5 mg/m^3[(b)]	Not flammable	Noncombustible Solid in solution	Solid—in a solution	No further analysis required[(c)]
Hydrazine	50 ppm	4.7–100 percent	Vapor may explode	14.4 mm Hg @ 77˚F	Toxicity Analysis
					Flammability Analysis
					Explosion Analysis
Hydrogen Gas	Asphyxiant	4.0–75 percent	Vapor may explode	1.231 psi @ –434˚F	Toxicity Analysis—consider as asphyxiant
					Flammability Analysis
					Explosion Analysis
Hydrogen Peroxide	75 ppm	Not flammable	None listed	0.200 psi @ 90˚F	Toxicity—screened from further analysis using criteria in RG 1.78—low volume
Lead (In battery)	100 mg/m^3 (as lead)	Not flammable	None listed	N/A-solid	No further analysis required

PTN COL 2.2-1

Table 2.2-207 (Sheet 2 of 3)
Units 1-5 Onsite Chemical Storage — Disposition

Material	Toxicity Limit (IDLH)	Flammability	Explosion Hazard	Vapor Pressure	Disposition
Lithium Hydroxide	None Established	Not flammable	None listed	N/A-Solid in solution	No further analysis required
Lube Oil	None Established	Combustible-No flammable limits listed	None listed	0.100 psi @ 100˚F	No further analysis required—low vapor pressure[a]
Magnesium Oxide	750 mg/m^3	Not flammable	None listed	N/A-solid	No further analysis required—low vapor pressure[a]
Mineral Oil	2,500 mg/m^3	Combustible-No flammable limits listed	None listed	<0.5mm Hg @ 68˚F	No further analysis required—low vapor pressure[a]
Muriatic Acid (Hydrochloric Acid)	50 ppm	Not flammable	None listed	5.975 psi@ 90˚F	Toxicity Analysis
Nitrogen Gas	Asphyxiant	Not flammable	None listed	1.931 psi @ –344˚F	Toxicity Analysis—consider as asphyxiant
Nitrogen- Liquid	Asphyxiant	Negligible	None listed	1.931 psi @ –344˚F	Toxicity Analysis—consider as asphyxiant
Number 2 Fuel Oil/Diesel Fuel	None Established	1.3–6.0 percent	None listed	0.100 psi @ 100˚F	No further analysis required—low vapor pressure[a]
Number 6 Fuel Oil (Residual Fuel Oil)	None Established	1–5 percent	None listed	0.100 psi @ 100˚F	No further analysis required—low vapor pressure[a]
Organometallic Magnesium Complex	None Established	Not flammable	None listed	N/A-solid	No further analysis required
Oxygen	May displace air and cause an oxygen-enriched environment	Not flammable	None listed	363, 385 Pa at 104.47˚K	Toxicity Analysis—consider for oxygen-enriched environment
Propane	2,100 ppm	2.1–9.5 percent	Vapor may explode	837,489 Pa at 293.15˚K	Toxicity Analysis Flammability Analysis Explosion Analysis/BLEVE
Silicone	None Established	Not flammable	None listed	Not available	No further analysis required
Sodium Bicarbonate	None Established	Not flammable	None listed	N/A-solid	No further analysis required
Sodium Hydroxide	No established IDLH for solution	Not flammable	Noncombustible Solid in solution	Solid—in solution	No further analysis required—low vapor pressure[d]

PTN COL 2.2-1

Table 2.2-207 (Sheet 3 of 3)
Units 1-5 Onsite Chemical Storage — Disposition

Material	Toxicity Limit (IDLH)	Flammability	Explosion Hazard	Vapor Pressure	Disposition
Sodium Hypochlorite	10 ppm as chlorine	Not flammable	None listed	31.1 mmHg @ 89.6˚F (12.5% weight percent)	Toxicity Analysis[e]
Sodium Molybdate	5 mg/m^3 (as Mo)[b]	Not flammable	None listed	N/A-solid	No further analysis required[f]
Sodium Nitrite	None Established	Not flammable	None listed	1.818 psi @ 100˚F	No further analysis required
Sodium Tetraborate	1 mg/m^3[b]	Not flammable	None listed	N/A-solid	No further analysis required[a]
Sulfuric Acid	15 mg/m^3	Not flammable	None listed	0.001 mmHg @ 68˚F	No further analysis required—low vapor pressure[a]
Sulfuric Acid (Station Batteries)	15 mg/m^3	Not flammable	None listed	0.001 mmHg @ 68˚F	No further analysis required—low vapor pressure[a]
Trisodium Phosphate-Liquid	None Established	Not flammable	None listed	Not available	No further analysis required
Unleaded Gasoline[g]	300 ppm[b]	1.4–7.4 percent	Vapor may explode	4,703.3 Pa @ 293.15˚K	No further analysis required[g]

(a) Solids and chemicals with vapor pressures this low are not very volatile. That is, under normal conditions, chemicals cannot enter the atmosphere fast enough to reach concentrations hazardous to people and, therefore, are not considered to be an air dispersion hazard.
(b) Threshold limit value/ time-weighted average (TLV-TWA).
(c) Lime (calcium hydroxide) is listed as a noncombustible solid and with a very low—approximate vapor pressure of 0 mmHg. The toxicity data provided by NIOSH provides the following basis for the standard established by OSHA for general industry: "8 hour time-weighted average 15 mg/m^3, total dust" and "5 mg/m^3, respirable fraction." Thus, this toxicity limit was established for the exposure to the solid form. Therefore, an air dispersion hazard resulting from the formation of a toxic vapor cloud is not a likely route of exposure.
(d) Sodium hydroxide in its pure form is a noncombustible solid and therefore has a very low vapor pressure. The IDLH documentation provided by NIOSH provides the following description of the substance—"colorless to white, odorless solid (flakes, beads, granular form)" and provides the following basis for establishing the 10 mg/m^3 IDLH limit for the solid form—"the revised IDLH for sodium hydroxide is 10-mg/m^3 based on acute inhalation toxicity data for workers [Ott et al. 1977]" where the reference for Ott et. al gives the following description "Mortality among employees chronically exposed to caustic dust". Thus, this toxicity limit was established for the exposure to the solid form is not applicable to the solution. Therefore, an air dispersion hazard resulting from the formation of a toxic vapor cloud is not a likely route of exposure.
(e) Sodium hypochlorite does not have a determined IDLH value listed in NIOSH; however, MSDS have listed a toxicity limit for sodium hypochlorite as 10 ppm—as chlorine. Speculation exists on the exact chlorine species that are present in the vapor. The vapor pressures of sodium hypochlorite solutions are less than the vapor pressure of water at the same temperature. However, because of the potential for sodium hypochlorite to decompose and release chlorine gas upon heating, sodium hypochlorite was conservatively evaluated for toxicity.
(f) Sodium molybdate is a noncombustible solid and therefore has a very low vapor pressure. There is no IDLH or other toxicity limits for sodium molybdate. There are, however, IDLH, PEL and TLVs for Molybdenum. These exposure limits are based upon dusts, inhalable and respirable fractions. Therefore, an air dispersion hazard resulting from the formation of a toxic vapor cloud is not a likely route of exposure.
(g) Onsite Gasoline is bounded by Onsite Transport of Gasoline.

Source: References 217, 233, 234, 235, 236, 237, and 238

PTN COL 2.2-1

Table 2.2-208 (Sheet 1 of 4)
Units 6 & 7 Onsite Chemical Storage — Disposition

Material	Toxicity Limit (IDLH)	Flammability	Explosion Hazard	Vapor Pressure	Disposition
FPL Reclaimed Water Treatment Facility					
Anionic polymer	None Established	Not Flammable	None Listed	Solution	No further analysis required—skin/eye irritant only.
Ferric Chloride (47% Solution)	1 mg/m^3 [(a)]	Not Flammable	Noncombustible solid	Solid—in a solution	No further analysis required—TWA established for solid salts—not applicable to solution.[(b)]
Lime ($Ca(OH)_2$)	5 mg/m^3 [(a)]	Not Flammable	Noncombustible solid in solution	Solid—in a solution	No further analysis required.[(c)]
Sulfuric Acid (93% Solution)	15 mg/m^3	Not Flammable	None Listed	0.001 mm Hg @ 68°F	No further analysis required.[(d)]
Methanol (Denitrification)	6,000 ppm	6–36 percent	Vapor may explode	96 mmHg @ 68°F	Toxicity Analysis Flammability Analysis Explosion Analysis
Sodium Hypochlorite (40% Solution) Disinfection	10 ppm as Cl_2	Not Flammable	None Listed	31.1 mmHg @ 89.6°F (12.5% Weight Percent)	Toxicity Analysis [(e)]
Alum (49% Solution) (Phosphorus Removal)	None established	Not Flammable	None Listed	Solid—in a solution	No further analysis required.
Sodium Bisulfite (40% Solution) (Dechlorination)	5 mg/m^3 [(a)]	Not Flammable	None Listed	Solid—in a solution	No further analysis required. TWA established for solid—not applicable to solution.[(f)]
Sodium Hydroxide (50% Solution)	10 mg/m^3	Not Flammable	Noncombustible solid in solution	Solid—in a solution	No further analysis required. TWA established for solid—not applicable to solution. [(g)]
Polymer (25% Solution)	None established	Not Flammable	None Listed	Solution	No further analysis required—skin/eye irritant only.
Circulating Water System					
Sodium Hypochlorite—(12 Trade Percent)	10 ppm as Chlorine	Not Flammable	None Listed	31.1 mmHg @ 89.6°F (12.5% Weight Percent)	Toxicity Analysis [(e)]
Sulfuric Acid (93% Solution)—Saltwater	15 mg/m^3	Not Flammable	None Listed	0.001 mm Hg	No further analysis required.[(d)]
Proprietary Scale Inhibitor—Saltwater (Sodium salt of phosphonomethylate diamine)	Does not contain any substance that has an exposure limit	Not Flammable	None Listed	Inhalation not a likely route of exposure	No further analysis required.

PTN COL 2.2-1

Table 2.2-208 (Sheet 2 of 4)
Units 6 & 7 Onsite Chemical Storage — Disposition

Material	Toxicity Limit (IDLH)	Flammability	Explosion Hazard	Vapor Pressure	Disposition
Circulating Water System (cont.)					
Proprietary Scale Inhibitor—Saltwater (Calcium phosphate, zinc, iron, manganese)	None Established	Not Flammable	None Listed	Inhalation not a likely route of exposure	No further analysis required.
Proprietary Scale Inhibitor—Transition from Saltwater to Reclaimed (Silica based scale inhibitor)	None Established	Not expected to burn unless all water is boiled away—remaining organics may be ignitable	None Listed	Solution	No further analysis required.
Proprietary Scale Inhibitor—Reclaimed (High Stress Polymer with PSO)	Does not contain any substance that has an exposure limit	Not Flammable	None Listed	16 mmHg @ 100°F	No further analysis required.
Service Water System					
Sulfuric Acid (93% Solution) (pH Addition)	15 mg/m^3	Not Flammable	None Listed	0.001 mm Hg	No further analysis required.[d]
Proprietary Scale Inhibitor (17.9% Phosphoric Acid)	1,000 mg/m^3	Not Flammable	None Listed	water/phosphoric acid=0.03mmHg	No further analysis required.[h]
Proprietary Dispersant (Calcium phosphate, zinc, iron, manganese)	None Established	Not Flammable	None Listed	Inhalation not a likely route of exposure	No further analysis required.
Sodium Hypochlorite (12 Trade Percent)	10 ppm as Cl_2	Not Flammable	None Listed	31.1 mmHg @ 89.6°F (12.5% Weight Percent)	Toxicity Analysis [e]
Demineralized Water System					
Proprietary Scale Inhibitor—(30% Phosphoric Acid)	1,000 mg/m^3	Not Flammable	None Listed	water/phosphoric acid=0.03mmHg	No further analysis required.[h]
Sodium Bisulfite (25% Solution)	5 mg/m^3 [a]	Not Flammable	None Listed	Solid—in a solution	No further analysis required. TWA established for solid—not applicable to solution.[f]
Sulfuric Acid (93% Solution)	15 mg/m^3	Not Flammable	None Listed	0.001 mm Hg	No further analysis required.[d]
Reverse Osmosis (RO) Cleaning Chemicals					
Proprietary Reverse Osmosis Cleaning Chemical (EDTA Salt, Percarbonate Salt, Phosphonic Acid, Tetrasodium Salt)	None established	Not Flammable	None Listed	Solid—in a solution	No further analysis required.

PTN COL 2.2-1

Table 2.2-208 (Sheet 3 of 4)
Units 6 & 7 Onsite Chemical Storage — Disposition

Material	Toxicity Limit (IDLH)	Flammability	Explosion Hazard	Vapor Pressure	Disposition
Reverse Osmosis (RO) Cleaning Chemicals (cont.)					
Proprietary Reverse Osmosis Cleaning Chemical (Hydroxyalkanoic acid, Inorganic phosphate, EDTA Salt)	None established	Not Flammable	None Listed	Solid—in a solution	No further analysis required.
Steam Generator Blowdown System					
Hydrazine-oxygen scavenger (35% solution)	50 ppm	4.7–100 percent	Vapor may explode	14 mmHg @ 77°F	Toxicity Analysis Flammability Analysis Explosion Analysis
Carbohydrazide—oxygen scavenger (Shut Down)	None established	Not flammable-unless water is boiled away and chemical is heated	None Listed	12 mm Hg @ 20°C	No further analysis required.
Morpholine	1,400 ppm[i]	1.4–11.2 percent	Vapor may explode	6 mmHg @ 68°F	Toxicity Analysis Flammability Analysis Explosion Analysis
Standby Diesel Fuel Oil System					
No. 2 Diesel Fuel Oil-Diesel Generator Day Tank	None Established	1.3–6.0 percent	None Listed	0.100 psi @ 100°F	No further analysis required—low vapor pressure.[k]
No. 2 Diesel Fuel Oil-Ancillary Diesel Generator	None Established	1.3–6.0 percent	None Listed	0.100 psi @ 100°F	No further analysis required—low vapor pressure.[k]
No. 2 Diesel Fuel Oil-Diesel Fire Pump Day Tank	None Established	1.3–6.0 percent	None Listed	0.100 psi @ 100°F	No further analysis required—low vapor pressure.[k]
Fire Protection System					
No. 2 Diesel Fuel Oil	None Established	1.3–6.0 percent	None Listed	0.100 psi @ 100°F	No further analysis required—low vapor pressure.[k]
Plant Gas System					
Nitrogen-Liquid	Asphyxiant	Negligible	None Listed	1.931 psi @ -344°F	Toxicity Analysis—consider as asphyxiant
Nitrogen Gas	Asphyxiant	Not Flammable	None Listed	1.931 psi @ -344F°	Toxicity Analysis—consider as asphyxiant
Hydrogen Gas	Asphyxiant	4.0–75 percent	Vapor may explode	1.231 psi @ -434°F	Toxicity Analysis—consider as asphyxiant Flammability Analysis Explosion Analysis

PTN COL 2.2-1

Table 2.2-208 (Sheet 4 of 4)
Units 6 & 7 Onsite Chemical Storage — Disposition

Material	Toxicity Limit (IDLH)	Flammability	Explosion Hazard	Vapor Pressure	Disposition
Plant Gas System (cont.)					
Carbon Dioxide-Liquid	40,000 ppm	Not Flammable	None Listed	907.299 psi @ 75°F	Toxicity Analysis—consider as asphyxiant
Carbon Dioxide Gas	40,000 ppm	Not Flammable	None Listed	907.299 psi @ 75°F	Toxicity Analysis—consider as asphyxiant
Central Chilled Water System					
Sodium Molybdate (Corrosion Inhibitor)	5 mg/m^3 (as Mo) (l)	Not Flammable	None Listed	Solid in a solution	No further analysis required (m)
Ethylene Glycol	None Established	3.2–15.3 percent	Vapor may explode	0.003 psi @ 90°F	No further analysis required—low vapor pressure.(n)

(a) Time Weighted Average (TWA)
(b) Ferric chloride in its pure form is a noncombustible solid and therefore has a very low vapor pressure. The IDLH documentation provided by NIOSH provides the following basis for establishing the 1 mg/m^3 TWA limit—"The ACGIH…considers the salts to be irritants to the respiratory tract when inhaled as dusts and mists." Thus, this toxicity limit was established for the exposure to the solid form. Note, there is no IDLH established for this chemical. Therefore, an air dispersion hazard resulting from the formation of a toxic vapor cloud is not a likely route of exposure.
(c) Lime (calcium hydroxide) is listed as a noncombustible solid and with a very low– approximate vapor pressure of 0 mmHg. The toxicity data provided by NIOSH provides the following basis for the standard established by OSHA for general industry: "8 hour time-weighted average 15 mg/m^3, total dust" and "5 mg/m^3, respirable fraction." Thus, this toxicity limit was established for the exposure to the solid form. Therefore, an air dispersion hazard resulting from the formation of a toxic vapor cloud is not a likely route of exposure.
(d) Sulfuric acid has a very low vapor pressure and therefore an air dispersion hazard resulting from the formation of a toxic vapor cloud is not a likely route of exposure.
(e) Sodium hypochlorite does not have a determined IDLH value listed in NIOSH; however, MSDS have listed a toxicity limit for sodium hypochlorite as 10 ppm—as chlorine. Speculation exists on the exact chlorine species that are present in the vapor. The vapor pressures of sodium hypochlorite solutions are less than the vapor pressure of water at the same temperature. However, because of the potential for sodium hypochlorite to decompose and release chlorine gas upon heating, sodium hypochlorite was conservatively evaluated for toxicity.
(f) Sodium bisulfite in its pure form is a noncombustible solid and therefore has a very low vapor pressure. The IDLH documentation provided by NIOSH provides the following basis for establishing the 5 mg/m^3 TWA limit—"the 5-mg/m^3 limit was proposed because it represents a limit below that established for physical irritant particulates, and this limit reflects the irritant properties of sodium bisulfite. And, in the judgement of the ACGIH "inhalation of or contact with the dust would result in high local concentrations [of sodium bisulfite] in contact with high local concentrations of sensitive tissue. Thus, this toxicity limit was established for the exposure to the solid form is not applicable to the solution. Note, there is no IDLH established for this chemical. Therefore, an air dispersion hazard resulting from the formation of a toxic vapor cloud is not a likely route of exposure.
(g) Sodium hydroxide in its pure form is a noncombustible solid and therefore has a very low vapor pressure. The IDLH documentation provided by NIOSH provides the following description of the substance—"colorless to white, odorless solid (flakes, beads, granular form)" and provides the following basis for establishing the 10 mg/m^3 IDLH limit for the solid form—"the revised IDLH for sodium hydroxide is 10-mg/m^3 based on acute inhalation toxicity data for workers [Ott et al. 1977]" where the reference for Ott et. al gives the following description "Mortality among employees chronically exposed to caustic dust". Thus, this toxicity limit was established for the exposure to the solid form is not applicable to the solution. Therefore, an air dispersion hazard resulting from the formation of a toxic vapor cloud is not a likely route of exposure.
(h) Phosphoric acid in its pure form is a noncombustible solid and therefore has a very low vapor pressure. The IDLH documentation provided by NIOSH provides the following basis for the original IDLH of 10,000 mg/m^3—according to the Manufacturing Chemists Association, phosphoric acid does not cause any systemic effect and the chance of pulmonary edema from mist or spray inhalation is very remote. And, the basis for the revised IDLH for phosphoric acid, 1,000 mg/m^3, is based on acute oral toxicity data in animals. Therefore, an air dispersion hazard resulting from the formation of a toxic vapor cloud is not a likely route of exposure.
(i) The IDLH documentation provided by NIOSH states that based on health considerations and acute inhalation toxicity data in humans and animals, a value of 2000 ppm would have been appropriate for morpholine. However, the revised IDLH for morpholine is 1400 ppm based strictly on safety considerations (i.e., being 10% of the lower explosive limit of 1.4%)
(j) Not used.
(k) Diesel Fuel has a low vapor pressure and therefore an air dispersion hazard resulting from the formation of a flammable vapor cloud is not a likely route of exposure.
(l) Threshold Limit Value (TLV)
(m) Sodium molybdate is a noncombustible solid and therefore has a very low vapor pressure. There is no IDLH or other toxicity limits for sodium molybdate. There are, however, IDLH, PEL and TLVs for molybdenum. These exposure limits are based upon dusts, inhalable and respirable fractions. Therefore, an air dispersion hazard resulting from the formation of a toxic vapor cloud is not a likely route of exposure.
(n) Ethylene glycol has a low vapor pressure and therefore an air dispersion hazard resulting from the formation of a flammable vapor cloud is not a likely route of exposure.
Source: References 217, 233, 234, 235, 247, 248, 249, 250, 251, 252, 253, 254, 255, 256, and 257

PTN COL 2.2-1

Table 2.2-209
Offsite Chemicals, Disposition — Homestead Air Reserve Base

Material	Toxicity Limit (IDLH)	Flammability	Explosion Hazard	Vapor Pressure	Disposition
Bromotrifluoromethane (Halon 1301)	40,000 ppm	Not flammable	None listed	1,436,150 Pa at 293.15˚K	Toxicity Analysis
Diesel Fuel Oil (High Sulfur)	None Established	1.3–6.0 percent	None listed	0.100 @ 100˚F	No further analysis required-low vapor pressure[a]
Diethylene Glycol Monobutyl Ether	None Established	Not flammable	None listed	0.159 @ 220˚F	No further analysis required
Gasoline	300 ppm[b]	1.4–7.4 percent	Vapor may explode	4,703.3 Pa @ 293.15˚K	Toxicity Analysis
					Flammability Analysis
					Explosion Analysis
Hydrazine[c]	50 ppm	4.7–100 percent	Vapor may explode	14.4 mm Hg @ 77˚F	No further analysis required[c]
Jet Fuel	200 mg/m^3[b]	0.6–4.9 percent	Vapor may explode	0.1 psi @ 100˚F	Explosion Analysis—no flammability/toxicity analysis required low vapor pressure[a]
Nitrogen Gas[c]	Asphyxiant	Not flammable	None listed	1.93 psi @ –344˚F	No further analysis required[c]
Oxygen	May displace air and cause an oxygen enriched environment	Not flammable	None listed	363,385 Pa at 104.47˚K	Toxicity Analysis-consider for oxygen enriched environment
Propane	2,100 ppm	2.1–9.5 percent	Vapor may explode	837,489 Pa at 293.15˚K	Toxicity Analysis
					Flammability Analysis
					Explosion Analysis

(a) Solids and chemicals with vapor pressures this low are not very volatile. That is, under normal conditions, chemicals cannot enter the atmosphere fast enough to reach concentrations hazardous to people and, therefore, are not considered to be an air dispersion hazard.
(b) Threshold limit value/ time-weighted average (TLV-TWA).
(c) Homestead Air Reserve Base storage of hydrazine and nitrogen is bounded by Turkey Point onsite storage of hydrazine and nitrogen.
Source: References 217, 233, 234, and 235

PTN COL 2.2-1

Table 2.2-210
Transportation — Navigable Waterway, Turkey Point Lateral Pipeline, and Onsite Transportation Route — Disposition

Material	Toxicity Limit (IDLH)	Flammability	Explosion Hazard	Vapor Pressure	Disposition
Navigable Waterway					
Residual Fuel Oil	None established	1–5 percent	None listed	0.100 psi @ 100°F	No further analysis required—hazard analysis bounded by residual fuel storage at Units 1–5 [(a) (c)]
Turkey Point Lateral Pipeline					
Natural Gas (methane)	Asphyxiant	5–15 percent	Vapor may explode	258,574.0 mm Hg @ 100°F	Toxicity Analysis-consider as asphyxiant
					Flammability Analysis
					Explosion Analysis
Onsite Transportation Route					
Unleaded Gasoline	300 ppm[(b)]	1.4–7.4 percent	Vapor may explode	4,703.3 Pa @ 293.15°K	Toxicity Analysis
					Flammability Analysis
					Explosion Analysis

(a) Solids and chemicals with vapor pressures this low are not very volatile. That is, under normal conditions, chemicals cannot enter the atmosphere fast enough to reach concentrations hazardous to people and, therefore, are not considered to be an air dispersion hazard.
(b) Threshold limit value/ time-weighted average (TLV-TWA).
(c) As described in Subsection 2.2.2.4, because of the storage of residual fuel oil at the Turkey Point site, (2) 268,000 barrel tanks exceeds the quantity transported by a barge, the analysis of residual fuel oil located in the storage tanks is bounding and, therefore, no further analysis is required.
Source: References 217, 233, 234, and 235

PTN COL 2.2-1

Table 2.2-211
Atmospheric Input data for the ALOHA Model

Menu	Parameter	Input	Basis
Site Atmospheric Data			
Site Data	Number of Air Exchanges	0.391 air exchanges per hour	Outdoor air exchange rate for control room
Site Data	Date and Time	June 21, 2007/ June 20, 2008 See Table 2.2-212 for Times	June 21, 2007/June 20, 2008 at 12 noon was chosen because temperatures are highest in the summer during midday. Higher temperatures lead to a higher evaporation rate and thus a larger vapor cloud. The position of the sun for the date and time is used in determining the solar radiation, thus the summer solstice date will provide the most conservative assumption for solar radiation. June 21, 2007/June 20, 2008 at 5 am was chosen for those Pasquill classes defined as “nighttime.”
Setup/Atmospheric	Wind Measurement Height	10 meters	ALOHA calculates a wind profile based on where the meteorological data is taken. ALOHA assumes that the meteorological station is at 10 meters. The National Weather Service usually reports wind speeds from a height of 10 meters. Wind rose data for this project was also taken at a height of 10 meters. Additionally, the surface wind speeds for determining the Pasquill Stability Class are defined at 10m.
Setup/Atmospheric	Air Temperature	90.4ºF	Air temperature influences ALOHA’s estimate of the evaporation rate from a puddle surface (the higher the air temperature, the more the puddle is warmed by the air above it, the higher the liquid’s vapor pressure is, and the faster the substance evaporates). The maximum annual normal (1% exceedance) annual dry bulb temperature calculated, 90.4˚F, was selected as a conservative value.
Setup/Atmospheric	Inversion Height	None	An inversion is an atmospheric condition that serves to trap the gas below the inversion height thereby not allowing it to disperse normally. Inversion height has no affect on the heavy gas model. And, most inversions are at heights much greater than ground level.
Setup/Atmospheric	Humidity	50%	ALOHA uses the relative humidity values to estimate the atmospheric transmissivity value; estimate the rate of evaporation from a puddle; and make heavy gas dispersion computations. Atmospheric transmissivity is a measure of how much thermal radiation from a fire is absorbed and scattered by the water vapor and other atmospheric components.

Source: References 217 and 240

PTN COL 2.2-1

Table 2.2-212
ALOHA Meteorological Sensitivity Analysis Inputs

Stability Class	Surface Wind Speed (m/s)	Cloud Cover	Date/Time
A	1.5	0%	June 21, 2007/12 noon or June 20, 2008/12 noon
B	1.5	50%	June 21, 2007/12 noon or June 20, 2008/12 noon
B	2	0%	June 21, 2007/12 noon or June 20, 2008/12 noon
C	3	70%	June 21, 2007/12 noon or June 20, 2008/12 noon
E	2	50%	June 21, 2007/5 am or June 20, 2008/5 am
F	2	0%	June 21, 2007/5 am or June 20, 2008/5 am
F	3 (only modeled for vapor clouds taking greater than 1 hour to reach the control room)	0%	June 21, 2007/5 am or June 20, 2008/5 am
C	3	50%	June 21, 2007/12 noon or June 20, 2008/12 noon
D	3	50%	June 21, 2007/5 am or June 20, 2008/5 am
C	5.5	0%	June 21, 2007/12 noon or June 20, 2008/12 noon
D	5.5	50%	June 21, 2007/12 noon or June 20, 2008/12 noon

Source: References 217 and 239

PTN COL 2.2-1

Table 2.2-213
Design Basis Events — Explosions

Source	Chemical Evaluated	Quantity	Heat of Combustion (Btu/lb)	Distance to Nearest Safety-Related Structure	Safe Distance for Explosion to have less than 1 psi of Peak Incident Pressure	Thermal Radiation Heat Flux Resulting from a BLEVE
Road: Onsite Transport	Gasoline	50,000 pounds	18,720 Btu/lb	2,054 feet	266 feet	N/A
Pipeline: Turkey Point Lateral	Natural Gas	30,302 pounds[(b)]	21,517 Btu/lb	4,535 feet	3,097 feet	N/A
Onsite (Includes Units 1 thru through 5)	Acetylene	3,000 pounds	20,747 Btu/lb	4,300 feet	1,416 feet	N/A
	Ammonium Hydroxide	40,000 gallons	7,992 Btu/lb	5,079 feet	296 feet	N/A
	Hydrazine	1,100 gallons	8,345 Btu/lb	2,727 feet	170 feet	N/A
	Hydrogen	110,000 cubic feet[(c)]	50,080 Btu/lb	3,966 feet	1,098 feet	N/A
	Propane	500 gallons	19,782 Btu/lb	4,168 feet	1,299 feet	0.0878 kW/m^2
Onsite (Includes Units 6 & 7)	Methanol	25,000 gallons	8,419 Btu/lb	5,581 feet	344 feet	N/A
	Hydrazine (35% solution)	800 gallons	8,345 Btu/lb	218 feet	153 feet	N/A
	Morpholine	800 gallons	20,000 Btu/lb	218 feet	136 feet	N/A
	Hydrogen[(a)]	13,334 standard cubic feet	50,080 Btu/lb	560 feet	544 feet	N/A
Offsite (Homestead Air Reserve Base)	Gasoline	137,104 pounds	18,720 Btu/lb	25,133 feet	372 feet	N/A
	Jet Fuel	23,251,606 pounds	18,540 Btu/lb		2,232 feet	N/A
	Propane	185,865 pounds	19,782 Btu/lb		5,513 feet	N/A

(a) A simultaneous detonation of all the tubes contained in a 40,000 scf hydrogen tube bank is not a likely scenario. If a rupture and subsequent detonation of a single tube were to occur the event could likely trigger another tube failure and detonation, but these events would occur consecutively, not simultaneously. Therefore, detonation of mass from a single tube in hydrogen bank is the most plausible scenario; however, for conservatism, it was assumed that a catastrophic accident could result such that one-third of the tubes could rupture and detonate simultaneously.
(b) Quantity of natural gas released over 5 seconds after a postulated pipeline rupture.
(c) Conservatively, the total hydrogen gas capacity for Units 1–5 was evaluated in lieu of the volume of the largest container.

PTN COL 2.2-1

Table 2.2-214
Design-Basis Events, Flammable Vapor Clouds (Delayed Ignition) and Vapor Cloud Explosions

Source	Chemical Evaluated & Quantity	Distance to Nearest Safety-Related Structure	Distance to LFL[(a)]	Safe Distance for Vapor Cloud Explosions [(a)]	Thermal Radiation Heat Flux at Nearest Safety-Related Structure
Road: Onsite Transport	Gasoline (50,000 pounds)	2,054 feet	222 feet	780 feet	2.776 kW/m^2
Pipeline: Turkey Point Lateral	Natural Gas	4,535 feet	750 feet	3,033 feet	0.261 kW/m^2[(b)]
Onsite (Includes Units 1 through 5)	Acetylene (3,000 pounds)	4,300 feet	909 feet	1,242 feet	0.162 kW/m^2
	Ammonium Hydroxide (40,000 gal)	5,079 feet	525 feet[(c)]	1,407 feet [(c)]	0.900 kW/m^2
	Hydrazine (1,100 gal)	2,727 feet	42 feet	No Detonation[(d)]	0.271 kW/m^2
	Hydrogen (45,000 scf)	3,966 feet	720 feet	828 feet	0.033 kW/m^2
	Propane (500 gal)	4,168 feet	714 feet	1,416 feet	0.090 kW/m^2
Onsite (Includes Units 6 & 7)	Hydrazine (800 gal) (35% solution)	218 feet	< 33 feet[(c)]	No Detonation [(c)(d)]	N/A
	Hydrogen Tube Bank (40,000 scf)	560 feet	351 feet[(c)]	528 feet[(c)]	2.344 kW/m^2
	Methanol (25,000 gal)	5,581 feet	177 feet	444 feet	0.592 kW/m^2
	Morpholine (800 gal)	218 feet	< 33 feet	No Detonation [(c)(d)]	N/A
Offsite (Homestead Air Force Base)	Gasoline (137,104 lb)	25,133 feet	396 feet	1,260 feet	0.051 kW/m^2
	Propane (185,865 lb)		2,190 feet	4,770 feet	0.078 kW/m^2

(a) Worst-case scenario meteorological condition was F stability class at two meters per second
(b) Thermal radiation heat flux resulting from a jet fire at the pipeline break.
(c) Urban or Forest ground roughness selected
(d) “No detonation" is listed when ALOHA reports that there is no detonation of the formed vapor cloud-that is no part of the cloud is above the LEL at any time.

PTN COL 2.2-1

Table 2.2-215 (Sheet 1 of 2)
Design-Basis Events, Toxic Vapor Clouds

Source	Chemical	Quantity	IDLH[a]	Distance to Nearest Control Room (feet)	Distance to IDLH (feet)	Maximum Control Room Concentration (ppm)
Road: Onsite Transport	Gasoline	50,000 pounds	300 ppm[b]	2,084	1,962	69.9[d]
Pipeline: Turkey Point Lateral	Natural Gas	2,036,620 pounds	Asphyxiant	4,535	3,456	523
Onsite (Includes Units 1 through 5)	Acetylene	3,000 pounds	Asphyxiant	4,331	2,169	45.9[d]
	Ammonium Hydroxide[c]	40,000 gallons	300 ppm	5,110	15,312	239[d][c]
	Argon	3,000 pounds	Asphyxiant	4,001	42	10.8[d]
	Carbon Dioxide	9,000 pounds	40,000 ppm	4,001	672	93.3[d]
	Chlorine	150 pounds	10 ppm	2,994	3,603	0.824[d]
	Hydrazine	1,100 gallons	50 ppm	2,758	2,181	8.52[d]
	Hydrogen	45,000 scf	Asphyxiant	4,001	264	53.9[d]
	Muriatic Acid	110 gallons	50 ppm	4,429	2,175	0.966[d]
	Nitrogen Gas	100,000 scf	Asphyxiant	3,596	396	144[d]
	Nitrogen Liquid	3,500 gallons	Asphyxiant	3,596	831	122[d]
	Oxygen	3,000 pounds	May displace air and cause an oxygen enriched environment	4,329	72	14.9[d]
	Propane	500 gallons	2100 ppm	4,198	1,626	5.83[d]
	Sodium Hypochlorite	6,000 gallons	10 ppm as Chlorine	5,232	90	0.00467[c][d]

PTN COL 2.2-1

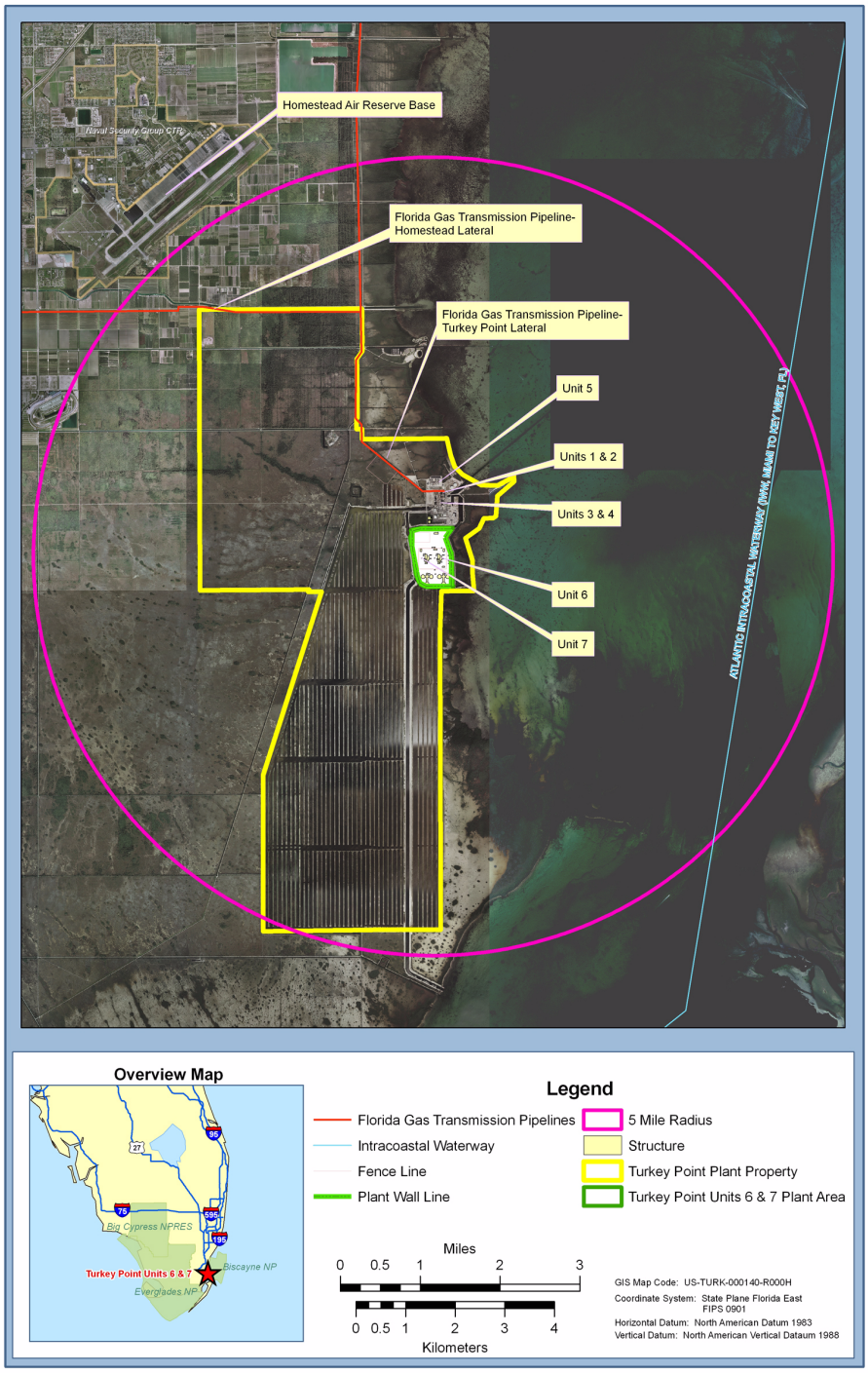
Table 2.2-215 (Sheet 2 of 2)
Design-Basis Events, Toxic Vapor Clouds

Source	Chemical	Quantity	IDLH[a]	Distance to Nearest Control Room (feet)	Distance to IDLH (feet)	Maximum Control Room Concentration (ppm)
Onsite (Includes Units 6 & 7)	Carbon Dioxide	12,160 pounds	40,000 ppm	561 feet	411 feet	1,380 ppm[c][d]
	Carbon Dioxide-Liquid	12,000 pounds	40,000 ppm	561 feet	951 feet	1,400 ppm[c][d]
	Hydrazine (35% solution)	800 gallons	50 ppm	253 feet	432 feet	30.7 ppm[c][d]
	Hydrogen Tube Bank	40,000 standard cubic feet	Asphyxiant	561 feet	N/A	521 ppm[c][d]
	Methanol	25,000 gallons	6,000 ppm	5,660 feet	1,128 feet	76.8 ppm[d]
	Morpholine	800 gallons	1,400 ppm	253 feet	< 33 feet	18.3 ppm[c][d]
	Nitrogen	20,34.2 pounds	Asphyxiant	561 feet	N/A	363 ppm[c][d]
	Nitrogen-Liquid	1,500 gallons	Asphyxiant	561 feet	N/A	885 ppm[c][d]
	Sodium Hypochlorite (Reclaimed Water Treatment Facility)	20,000 gallons	10 ppm as Chlorine	5,660 feet	306 feet	0.0412 ppm[d]
	Sodium Hypochlorite (Cooling Tower)	12,000 gallons	10 ppm as Chlorine	807 feet	240 feet	0.349 ppm[d]
	Sodium Hypochlorite (Turbine Building)	800 gallons	10 ppm as Chlorine	253 feet	< 33 feet	0.0454 ppm[c][d]
Offsite (Homestead Air Reserve Base)	Halon 1301	5,440 pounds	40,000 ppm	25,133 feet	156 feet	0.0154 ppm[e]
	Gasoline	137,104 pounds	300 ppm[b]		3,210 feet	1.12 ppm[f]
	Oxygen	36,561 pounds	May displace air and cause an oxygen enriched environment		243 feet	5.31 ppm[e]
	Propane	185,865 pounds	2,100 ppm		8,448 feet	11.2 ppm[e]

(a) Immediately Dangerous to Life or Health (IDLH)
(b) Threshold Limit Value/ Time-Weighted Average (TLV-TWA)
(c) Calculation was modeling selecting the Urban or Forest for Ground Roughness
(d) Worst-case scenario meteorological condition was F stability class at two meters per second
(e) Worst-case scenario meteorological condition was F stability class at three meters per second
(f) Worst-case scenario meteorological condition was D stability class at 5.5 meters per second

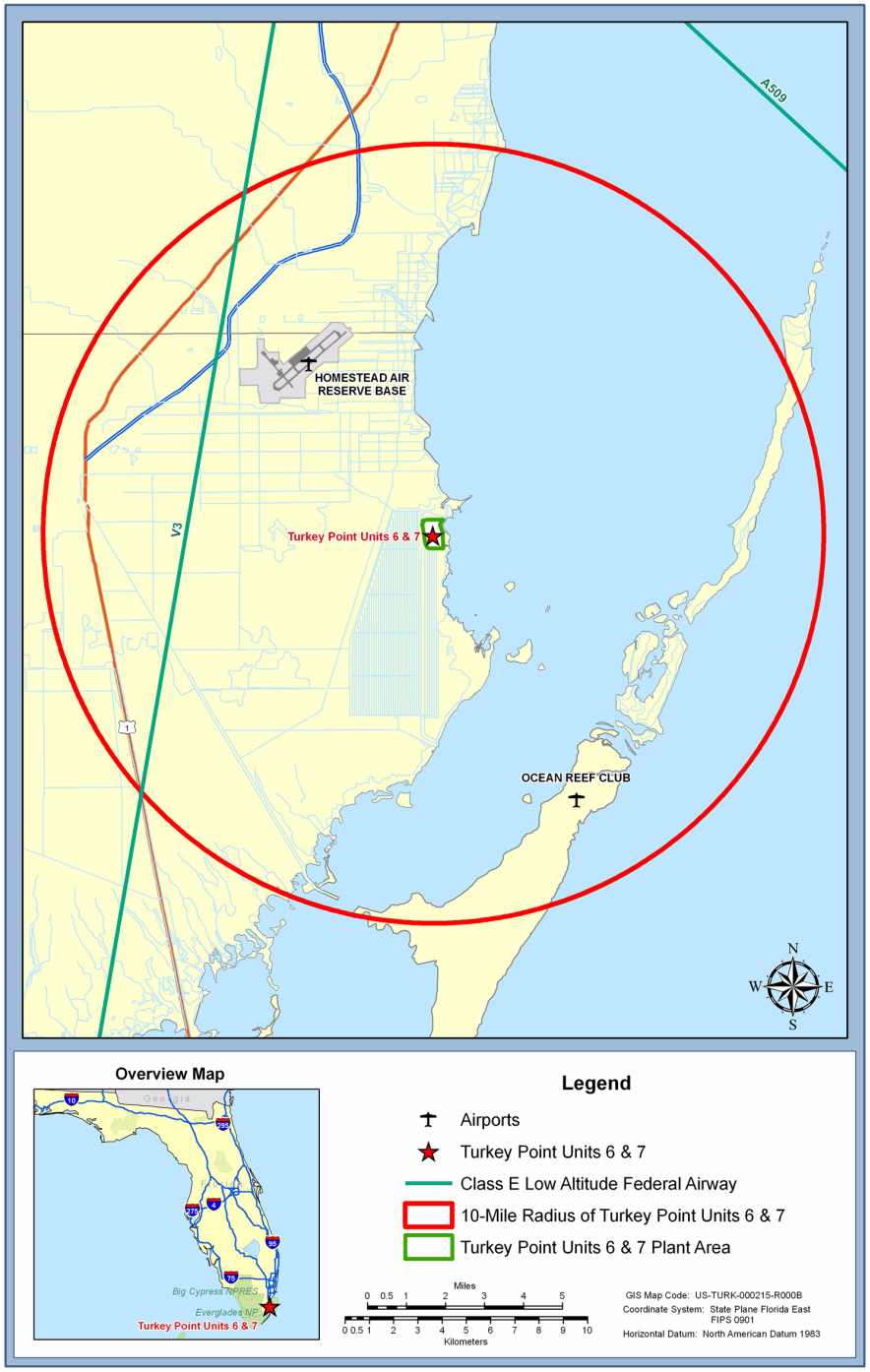
PTN COL 2.2-1

Figure 2.2-201 Site Vicinity Map



PTN COL 2.2-1

Figure 2.2-202 Airport and Airway Map



Attachment 2: Calculation 32-2400572-02,
"Natural Gas Pipeline Hazard Risk Determination"
by Framatome ANP

ATTACHMENT 2

Calculation 32-2400572-02,
"Natural Gas Pipeline Hazard Risk Determination"

20697P-6 (2/2002)

FRAMATOME ANP

CALCULATION SUMMARY SHEET (CSS)

Document Identifier 32 - 2400572 - 02

Title Natural Gas Pipeline Hazard Risk Determination

PREPARED BY:		REVIEWED BY: METHOD: ☒ DETAILED CHECK ☐ INDEPENDENT CALCULATION	
NAME	S.T. Thomson	NAME	J.H. Snooks
SIGNATURE	S.T. Thomson	SIGNATURE	J.H. Snooks
TITLE	Sr Engineer	TITLE	Sr Env Consultant
DATE	1/16/04	DATE	1/19/2004
COST CENTER	41739	REF. PAGE(S)	9
TM STATEMENT: REVIEWER INDEPENDENCE			R C Hayes 1/19/04

PURPOSE AND REASON FOR REVISION 02:

This calculation has been revised to include the natural gas transmission incident data and telephonic incident notifications as an attachment. Also, the number of explosions was increased from six to seven to include an incident where both an ignition ' explosion occurred (i.e., NRC no. 437627). Therefore, the estimated gas line rupture and subsequent hazards yearly ɔability was recalculated and has been revised to 9.44×10^{-6}.

Document Pagination

THE FOLLOWING COMPUTER CODES HAVE BEEN USED IN THIS DOCUMENT:

CODE/VERSION/REV	CODE/VERSION/REV

THE DOCUMENT CONTAINS ASSUMPTIONS THAT MUST BE VERIFIED PRIOR TO USE ON SAFETY-RELATED WORK

☐ YES ☒ NO

Record of Revisions

Affected Section and/or Page(s)	Description (Include changes to calculation attachments, microfiche, and electronic media)
Revision 01	Dated December 12, 2003.
Pg 2	Added Record of Revisions page as required by procedure.
Pg 3	Revised Table of Contents page numbers corresponding to calculation sections and attachments.
Attachment 4 (Pg 21)	Revised Section 6.0 to note use of a computer benchmark test case.
Attachment 10 (Pgs 38-42)	Added ALHOA benchmark test case.
Attachment 11 (Pgs 43-45)	Added Design Verification Checklist as required by procedure, effective 11/26/2003.

Valid and current pages: 1-45

Revision 02	Dated January 16, 2004 – new CSS
Pg 2	Added Record of Revisions associated with Revision 2
TOC, Pg 3	Table of Contents – Revised heading for Attachment 3
Sec. 2.0, Pg 4	1st paragraph, 4th sentence – inserted '(transmitted)' after "being sent".
Sec. 3.0, Pg 5	For equation 'P', changed 'Missile impact' to 'Missile generation'.
Sec. 5.0, Pg 5	Revised Input/Assumption No.3 – deleted 'and hence will be neglected in the probabilistic evaluation' and added the following: 'If a rupture length is not reported, it is assumed to be zero.'
Sec. 6.1, Pg 5	Revised wording for 'I' (i.e., included the word 'rupture').
Sec. 6.1.1, Pg 6	3rd paragraph, 6th sentence –added the following: - '(see Table 1, Note 8)'.
Sec. 6.1.2, Pg 6	1st paragraph, 2nd sentence – added 'be' between 'must' and 'an'. Revised the 1st sentence of 2nd paragraph and revised 'R_{C1}'.
Sec. 6.1.4, Pg 7	Revised '$P_{Explosion}$'.
Sec. 6.2, Pg 8	Last sentence, changed 'detonation' to 'explosion' probability and revised '$P_{missile\ generation}$'.
Sec. 6.4, Pg 8	Revised 'P'
Sec. 7.0, Pg 9	Revised yearly probability from 8.08×10^{-6} to 9.44×10^{-6}, 2nd sentence of last paragraph.
Table 1, Pg 11	Revised table input and Notes 1, 3 and 4. Added Notes 5 through 8.
Attachment 3	Revised Pg 17: added reference source information for the table attachment. Also added pages 17a,b,c,d,e,f,g&h – Incidents and Telephonic Records 1998 – 2001 as well as noted this on Pg 17.
Attachment 11	Replaced the Design Verification Checklist for Revision 1 with that for Revision 2.

Valid and current pages: 1-45, including 17a,b,c,d,e,f,g&h

TABLE OF CONTENTS

1.0 PURPOSE AND OBJECTIVE

This calculation evaluates the hazard at the proposed National Enrichment Facility (NEF) in Eunice, New Mexico due to the presence of a natural gas pipeline.

The evaluation is part of the Integrated Safety Analysis (ISA) for the proposed site, as required by 10 CFR Part 70. It was performed in accordance with the Framatome ANP (FANP) Quality Assurance Program.

2.0 BACKGROUND

A 16-inch natural gas line runs along the southern boundary of Section 32, Township 21 South, Range 38 East, New Mexico Meridian, Lea County, New Mexico. The proposed NEF site (Figure 1) is situated north of New Mexico Highway 234 within Section 32. Sid Richardson Energy Services Co. (SRESCo), located in Jal, New Mexico, operates the pipeline. Information gathered from SRESCo via telephone revealed that the pipeline is a low-pressure line (<50 psi) that carries "wet sour gas," which is unprocessed, field gas from the well being sent (transmitted) for processing (Attachment 5). The gas line is buried to a depth of about 3 feet. The gas composition is approximately 72% methane, 11% ethane, 7% propane, and <1% hydrogen sulfide. The gas line flow is between 200-500 thousand cubic feet per day. It is 14-15 miles in length, with manual block valves at each end and in the middle. There also is a check valve at the connection with the main service line located near Eunice and Highway 234. At its closest approach, the pipeline is about 1800 feet (ft) from the Technical Services Building (TSB), the nearest critical NEF structure (Figures 1 and 2).

Following a postulated rupture of a segment of the gas pipeline shown in Figure 1, natural gas will be discharged into the atmosphere. The released gas mixes with the atmosphere and forms a vapor cloud. Depending on the environmental conditions, this vapor cloud will rise (due to buoyancy effects) and travel away from the rupture location. The vapor cloud may explode (or detonate). When this occurs, the shock wave associated with such an explosion may create an overpressure on plant structures. Also, the dynamic impulse from such an explosion may propel objects or missiles in the vicinity of the explosion towards the NEF structures and may structurally damage critical buildings. Alternatively, the vapor cloud may ignite and form a fireball, resulting in radiant heat that could cause potential structural damage.

Based on the above discussion, the hazards posed by an accidental rupture of the gas pipeline therefore consist of:

a. Overpressure on plant structures due to shock waves generated by detonation or explosion of the gas cloud from mixing of the released gas and the atmosphere.
b. Impact by missiles propelled by air bursts from detonation or explosion of the gas cloud.
c. Radiant heat flux on plant structures due to combustion of the gas/air mixture in the gas cloud (thermal impact).

3.0 METHOD OF ANALYSIS

This calculation uses a hazard model to estimate the likelihood of a gas line rupture and subsequent hazards that could impact NEF plant operations. In its general form, the probability, P, of an incident occurring that affects plant structures is

$$P = P_{Explosion} + P_{Missile\ generation} + P_{Thermal\ impact}$$

4.0 ACCEPTANCE CRITERIA

A natural gas pipeline incident is an external event. In accordance with NUREG-1520, Section 3.4 (Reference 1), an external event is considered not credible if the probability of the event initiation is less than 10^{-6} per year. If the probability is greater than 10^{-6} per year, the event is considered credible and must be evaluated further.

5.0 INPUT & ASSUMPTIONS

The analysis input and assumptions are as follows:

1. The pipeline diameter is 16 inches, with an operating pressure of 50 psi (Attachment 5).

2. The gas released is methane, which is the major constituent of wet sour gas (Attachment 5).

3. Ruptures less than 0.1 foot in length are assumed to be unable to cause a plant hazard. If a rupture length is not reported, it is assumed to be zero.

4. The external walls of the proposed NEF buildings that house critical components are made of concrete (Reference 10) and able to withstand an explosion as determined by the safe separation distance in Regulatory Guide 1.91 (Reference 3).

6.0 ANALYSIS AND RESULTS

6.1 Probability of Pipeline Explosion

The general form for the probability of a pipeline explosion is

$$P = I \times R_C \times D$$

where,

I = gas line rupture incident rate per mile
R_C = conditional probability that a significant incident will occur given an incident
D = exposure distance in miles

6.1.1 Probability of Pipeline Incident (I)

Historical data on pipeline accidents are available through the Office of Pipeline Safety (OPS) official website (Reference 7). Attachment 1 shows the incident summary statistics from 1986 to 2002. Attachment 2 contains the incident summary by cause for years 1998, 1999, 2000, and 2001. Data from these four years will be used to evaluate the yearly probability of a pipe rupture. The annual mileage of natural gas transmission pipelines in the country is given in Attachment 3. Only the "onshore" mileage is used in this evaluation.

Also available from the OPS website (Reference 7) are the detailed account of each reported incident, including incident address, incident date, type of incident and rupture length for a rupture incident as well as telephonic records of incidents involving chemical releases. The telephonic records contain information on incident description, and are used here to determine the number of incidents that involve explosions.

Table 1 synthesizes the information in Attachments 1 through 3, the detailed transmission incident accounts, and the telephonic incident notifications for years 1998 to 2001.* The telephonic records for 1998 and 2001 are only from January to June of each year. The number of on-shore rupture incidents and total mileage for these two years, as a result, are divided by two. The number of incidents that involve an explosion is determined from the telephonic records. If no telephonic records exist, or no mention is made of an explosion for an incident, no explosion is assumed for that incident. This is reasonable since an explosion would be reported if it did occur (see Table 1, Note 8). Also, if a rupture length is not reported, it is assumed to be zero. Only rupture incidents with a rupture length of greater than 0.1 ft are able to cause a plant hazard (Input/Assumption 3).

From Table 1, the annual incident rupture rate is

$$I = 50 \text{ ruptures}/873{,}305 \text{ miles} = 5.73 \times 10^{-5} \text{ ruptures/mile}$$

Hence, the probability of rupture of the pipeline under evaluation is 5.73×10^{-5} ruptures per mile.

6.1.2 Conditional Probability of Significant Incident (R_C)

The conditional probability of a significant incident, R_C, has two parts. Given a pipeline incident, in this case a rupture, there must be an explosion (R_{C1}), and given an explosion it must be substantial (R_{C2}) - i.e., be a detonation to affect plant buildings.

From Table 1, seven ruptures out of the 50 (with a rupture length greater than 0.1 foot) involved explosions. Hence the fraction of explosion events is

$$R_{C1} = 7/50 = 0.14$$

* As of the date of this calculation, transmission data for 2002 to the present was available; however, telephonic incident notifications through 2001 were only available. Therefore, this calculation is based on data between 1998 and 2001.

As stated above, given an explosion it must be significant - i.e., a detonation, but not every explosion is a detonation. Instead, most explosions are deflagrations, which produce much less severe consequences than a detonation. Reference 5 suggests a denotation rate, R_{C2}, given an explosion of 0.28, which is considered conservative (Attachment 7). Therefore, in this calculation,

$$R_{C2} = 0.28$$

6.1.3 Exposure Distance (D)

The exposure distance, D, is a function of the safe separation distance. If an explosion occurs beyond the safe separation distance for a plant critical structure, then the structures will be unaffected.

The exposure distance has two parts: the distance to the gas upper and lower explosion limits (UEL and LEL), D_1, and the safe separation distance, D_2. D_1 is determined by employing the computer program ALOHA (Reference 6) to calculate the concentrations of gas from a postulated gas release along a direct pathway to the NEF. D2 is determined following Regulatory Guide 1.91 (Reference 3) and using the ALOHA results.

As shown in Attachment 4, D_1, the distance to the LEL is 4,095 ft and D_2, the safe separation distance, is 1,471 ft., for a total of 5,566 ft. This means that NEF critical structures must be at least 5,566 ft (1.05 miles) from the point of explosion. Using this distance as a radius, then swinging an arc from the approximate edge of the TSB, intersects the gas pipeline at two points (Figure 1). The distance of the cord between the two points is the exposure distance, D (Figure 1), with the maximum distance possible being two times the radius. Hence, for conservatism,

$$D = 2 \times 1.05 = 2.1 \text{ miles}$$

6.1.4 Final Probability of Pipeline Explosion

The final probability of a pipeline explosion is

$$P_{Explosion} = 5.73 \times 10^{-5} \text{ ruptures (explosions)/mile} \times 0.14 \times 0.28 \times 2.1 \text{ mile} = 4.72 \times 10^{-6} \text{ ruptures (explosions)}$$

6.2 Probability of Missile Hazard

The missile generation hazard depends on the detonation strength (TNT-equivalent weight), the dynamic pressure impulse, the projectile mass, air drag, and the distance between the detonation center and the facility. Since none of these parameters for the proposed enrichment facility has been established, it is conservatively assumed that every detonation will result in a hazard due to missile impact. Accordingly, the probability of a hazard due to missile generation is the same as the explosion probability previously calculated in Section 6.1, or

$$P_{\text{missile generation}} = 4.72 \times 10^{-6} / \text{year}$$

6.3 Probability of Thermal Hazard

The thermal radiation hazard depends on the gas release rate, subsequent motion of the vapor cloud, flame temperature, flame speed, flame emissivity, air transmissivity, and distance between the vapor cloud and the facility. The gas release rate and subsequent motion of the vapor cloud for the present analysis are bounded by similar analysis involving a natural gas pipeline conducted by the Tennessee Valley Authority (TVA) at the Hartsville Nuclear Plants (Reference 9). The pipeline in the TVA analysis had a larger diameter (22 vs. 16 inches) and a higher operating pressure (560 vs. 50 psi). In addition, the TVA analysis used conservative values for flame temperature, flame speed, flame emissivity, and air transmissivity, all of which are applicable to the present evaluation. Lastly, although the distance to the pipeline for the NEF site is less than the TVA analysis (1800 ft vs. 2650 ft), considering other conservatisms as noted above, the TVA results for the radiant heat flux would bound those for a detailed analysis of the pipeline near the NEF.

The worst-case heat flux to critical plant structures in the TVA analysis was less than 800 Btu/ft^2 (page 2.2-12m, Attachment 9). Based on the above argument, the radiant heat flux to the proposed NEF is also expected to be less than 800 Btu/ft^2. This is substantially less than the heat flux expected to cause any damage to the concrete NEF structures. From Reference 9 (page 2.2-12l, Attachment 9), a heat flux of about 1750 Btu/ft^2 would be needed to cause spontaneous ignition of wood. The heat flux that would cause damage to concrete is expected to be much higher. Given the low gas pressure, any fireball would last a very short period of time before the flame front retreated back to the vicinity of the pipe, approximately 1800 ft from the NEF. Hence, there is no need to consider the hazard due to heat exposure from combustion of the gas/air mixture in the gas, resulting in a yearly probability of zero.

6.4 Probability of Hazard due to Gas Pipeline

The final probability of a hazard due to the natural gas pipeline in the vicinity of the proposed NEF site is the sum of the three hazards:

$$P = 4.72 \times 10^{-6} / \text{year} + 4.72 \times 10^{-6} / \text{year} + 0 = 9.44 \times 10^{-6} / \text{year}$$

7.0 RESULTS AND CONCLUSIONS

A postulated rupture of the gas pipeline near the NEF could pose the following the hazards:

- Overpressure on plant structures due to shock waves generated by detonation or explosion of the gas cloud from mixing of the released gas and the atmosphere.
- Impact by missiles propelled by air bursts from detonation or explosion of the gas cloud.
- Radiant heat flux on plant structures due to combustion of the gas/air mixture in the gas cloud.

A hazard model estimated the likelihood of a gas line rupture and the subsequent hazards that could impact NEF plant operations. The yearly probability of these hazards is 9.44×10^{-6} / year. Therefore, the event is considered credible in accordance with NUREG-1520 (Reference 1).

The objective of this calculation has been met.

8.0 REFERENCES

1. NUREG-1520, Standard Review Plan for the Review of a License Application for a Fuel Cycle Facility, Office of Nuclear Material Safety and Safeguards, U.S. Nuclear Regulatory Commission, March 2002.
2. Framatome ANP Document 38-2400064-00, Letter from Mike Lynch dated September 9, 2003, Urenco Authorization of Use of Documents for Design Inputs.
3. Regulatory Guide 1.91, Evaluations of Explosions Postulated to Occur on Transportation Routes Near Nuclear Power Plants, Revision 1, February 1978.
4. Fire Protection Handbook, 17th Edition, 1991, National Fire Protection Association, Quincy, MA. (Attachment 6)
5. Seabrook Station Updated Final Safety Analysis Report (UFSAR), Table 2.2-15. (Attachment 7)
6. ALOHA (Areal Locations of Hazardous Atmospheres) User's Manual, August 1999, U.S. EPA, Chemical Emergency Preparedness and Prevention Office, Washington, D.C. 20460 and National Oceanic Atmospheric Administration, Hazardous Materials Response Division, Seattle, WA, 98115.
7. Office of Pipeline Safety website: http://ops.dot.gov (Attachments 1-3)
8. SFPE Handbook of Fire Protection Engineering, Second Edition, June 1995, Society of Fire Protection Engineers, Boston, MA; National Fire Protection Association, Quincy, MA. (Attachment 8)
9. Tennessee Valley Authority (TVA), Preliminary Safety Analysis Report (PSAR), Hartsville Nuclear Plants, Amendment 30 (Attachment 9).
10. Framatome ANP Document 38-5035284-01, Preliminary Basis of Design.

9.0 QUALITY ASSURANCE

In addition to Urenco supplied design inputs, FANP is also using design inputs supplied by Lockwood Greene. Urenco has authorized FANP in writing (Reference 2) to use design inputs from Lockwood Greene for work in the preparation of the NEF License Application under the context of the FANP QA program.

Table 1
Pipeline Statistic for 1998 to 2001
(Source: Official website of Office of Pipeline Safety: ops.dot.gov, Reference 7)

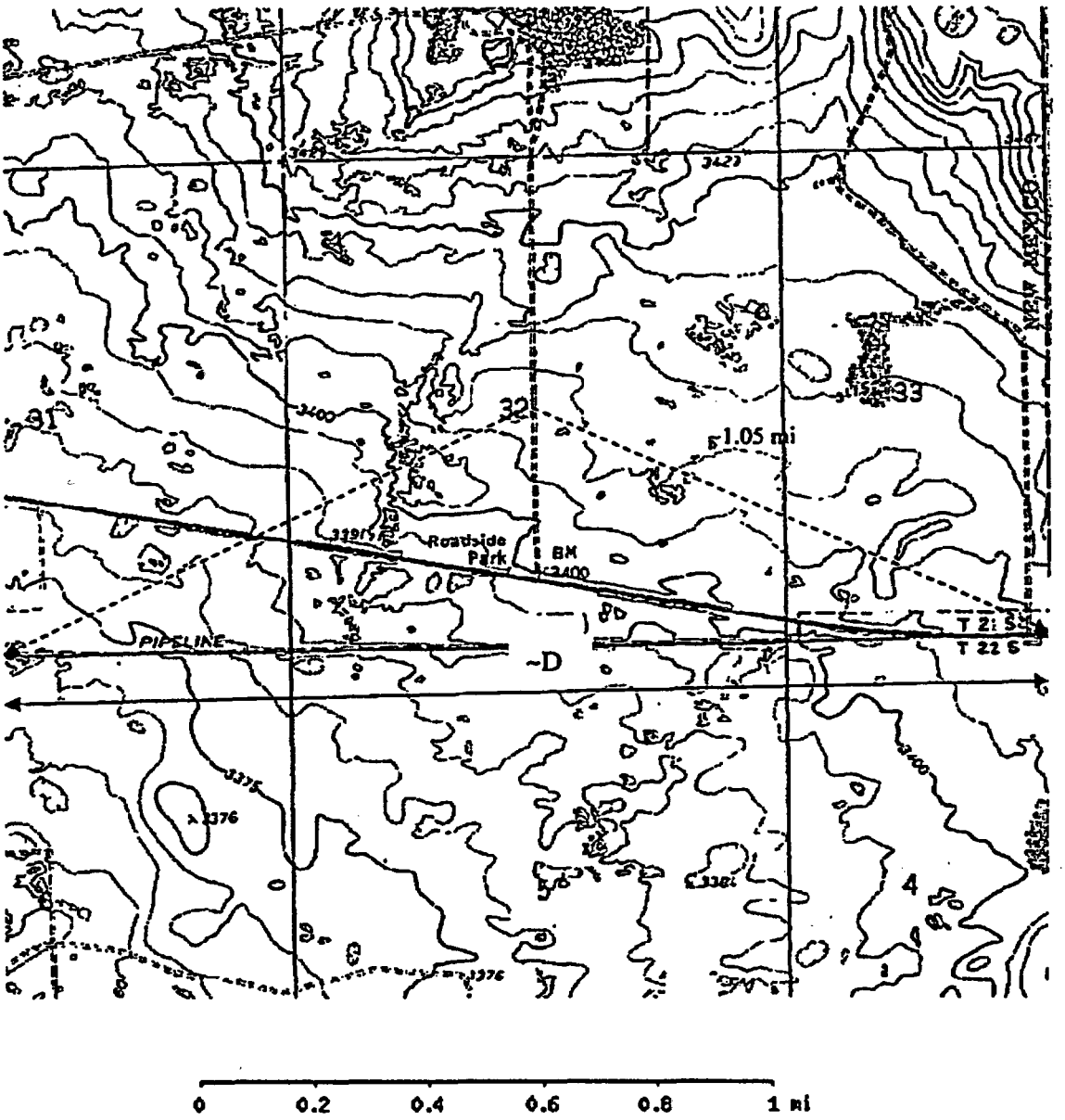
	1998	1999	2000	2001	Total
Rupture	24/2=12	16	24	16/2=8	60
Rupture>0.1'	21/2=11	11	22	11/2=6	50
Total Mileage	295,598/2 = 147,799	290,083	292,957	284,932/2 = 142,466	873,305
No. Ignition	6	5	5	1	17
No. Explosion	3	3	1	0	7

Notes:

1. Only rupture incidents involving rupture lengths greater than 0.1 foot are considered. Unreported rupture lengths are assumed to be zero. (Input/Assumption 3)
2. Information on incident types (i.e., ruptures) is based on natural gas transmission incident data.
3. Information on incidents and explosions is based on telephonic incident notifications. The number of ignitions (fires) is for informational purposes. Ignition incidents include NRC Nos. (1998) 420106, 421437, 427286, 430284, 436523, 437627 (also associated with an explosion), (1999) 474992, 487294, 490844, 498467, 506063, (2000) 527789, 528256, 534705, 548619, 549015 and (2001) 560330.
4. Two ruptures in 1998 (dated 1/26/98 and 3/20/98) were associated with off-shore incidents and not included in the overall rupture total or in the rupture>0.1' total. Also note that in 1998, for one incident, (NRC no. 433654), two pipes ruptured; therefore, this was counted as two pipe ruptures in the rupture and rupture>0.1' totals.
5. Referring to Attachment 3 – Incidents and Telephonic Records 1998 - 2001, note that some incidents were not indicated to be a 'rupture' type incident on the transmission incident data report, although the telephonic incident notifications indicated a rupture occurred. Therefore if a rupture length of >0.1' was associated with an on-shore, non-rupture incident type, it was counted in the rupture and rupture>0.1' totals. This applies to the year 2000 (i.e., NRC No. 520444, dated 2/18/2000 – indicated to be a leak type incident).
6. Reported explosion incidents include NRC Nos. (1998) 424160, 426483, 437627, (1999) 472803, 476123, 491766 and (2000) 551181. Note that for NRC No. (1998) 437627, both a fire (ignition) and explosion were reported.
7. Although it has been assumed that rupture lengths <0.1' are unable to cause a plant hazard and unreported rupture lengths are assumed to be zero, except for NRC No. 476123, six of the seven reported explosions are associated with incident types that have no reported rupture length and/or are not indicated to be ruptures. However, they have been considered in the explosion total and used to determine R_{CI} in Section 6.1.2 without increasing the number of ruptures >0.1' (i.e., 50) in computing R_{CI}. [Note: The other explosion incident indicated to be a rupture is NRC No. 551181; however, it has no reported rupture length.]
8. Referring to Note 3 above, for some of the ignition incidents (i.e., NRC Nos. (1998) 421437, 430284, (1999) 487294, 490844, 498467 and (2000) 528256), the source of the ignition was reported as unknown and/or the incident may have been reported after the ignition started. Considering that no mention is made of an explosion, in addition to various conservatisms used in this evaluation (e.g., determination of $P_{missile\ generation}$ in Section 6.2), it is reasonable not to include these incidents in the explosion total.

Figure 1, Location of Pipeline near the Proposed NEF Site

Source: http://www.topozone.com



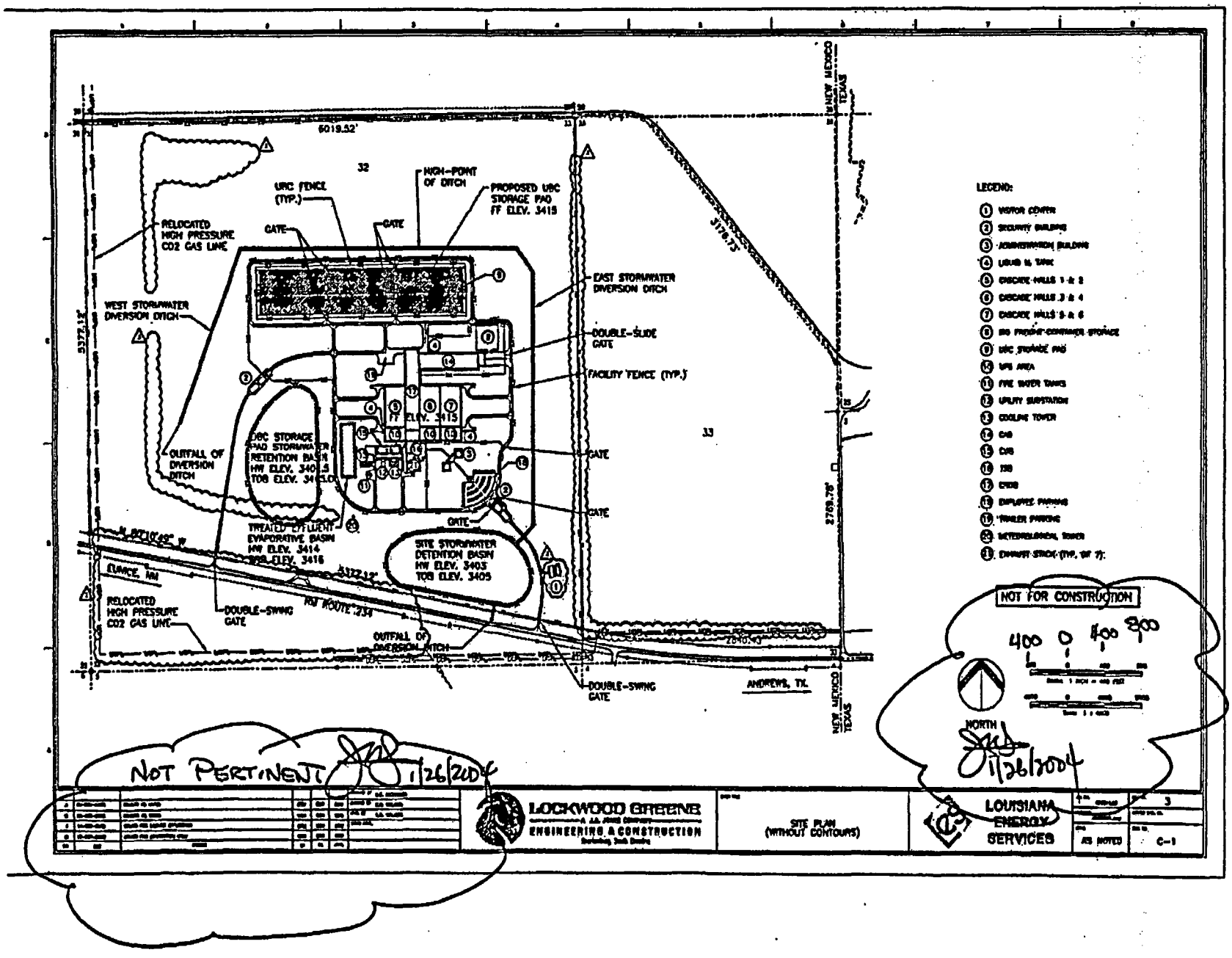


Figure 2, NEF Site Plan

Attachment 1: Incident Summary Statistics from 1986 to 2002

(For Informational Purposes)

OFFICE OF PIPELINE SAFETY
NATURAL GAS PIPELINE OPERATORS
INCIDENT SUMMARY STATISTICS BY YEAR
1/1/1986 - 08/31/2003

TRANSMISSION OPERATORS

Year	No. of Incidents	Fatalities	Injuries	Property Damage
1986	83	6	20	$11,166,262
1987	70	0	15	$4,720,466
1988	89	2	11	$9,316,078
1989	103	22	28	$20,458,939
1990	89	0	17	$11,302,316
1991	71	0	12	$11,931,238
1992	74	3	15	$24,578,165
1993	95	1	17	$23,035,268
1994	81	0	22	$45,170,293
1995	64	2	10	$9,957,750
1996	77	1	5	$13,078,474
1997	73	1	5	$12,078,117
1998	99	1	11	$44,487,310
1999	54	2	8	$17,695,937
2000	80	15	18	$17,868,261
2001	86	2	5	$23,610,883
2002	81	1	5	$24,365,559
Totals	1369	59	224	$324,821,316

Historical totals may change as OPS receives supplemental information on incidents.

Attachment 2: Incident Summary by Cause, 1998, 1999, 2000 and 2001
(For Informational Purposes)

OFFICE OF PIPELINE SAFETY
TRANSMISSION PIPELINE
INCIDENT SUMMARY BY CAUSE
1/1/1998 - 12/31/1998
(Natural Gas)

Cause	No. of Incidents	% of Total Incidents	Property Damages	% of Total Damages	Fatalities	Injuries
CONSTRUCTION/MATERIAL DEFECT	19	19.19	$2,984,361	6.7	0	4
CORROSION, EXTERNAL	8	8.08	$1,289,036	2.89	0	0
CORROSION, INTERNAL	14	14.14	$3,259,500	7.32	0	0
DAMAGE BY OUTSIDE FORCE	37	37.37	$18,673,077	41.97	1	3
OTHER	21	21.21	$18,281,336	41.09	0	4
TOTAL	99		$44,487,310		1	11

Historical totals may change as OPS receives supplemental information on incidents.

OFFICE OF PIPELINE SAFETY
TRANSMISSION PIPELINE
INCIDENT SUMMARY BY CAUSE
1/1/1999 - 12/31/1999
(Natural Gas)

Cause	No. of Incidents	% of Total Incidents	Property Damages	% of Total Damages	Fatalities	Injuries
CONSTRUCTION/MATERIAL DEFECT	8	14.81	$6,654,800	37.6	0	0
CORROSION, EXTERNAL	3	5.55	$465,000	2.62	0	0
CORROSION, INTERNAL	10	18.51	$3,352,000	18.94	0	0
CORROSION, NOT SPECIFIED	1	1.85	$0	0	0	0
DAMAGE BY OUTSIDE FORCE	18	33.33	$5,684,100	32.12	1	2
OTHER	14	25.92	$1,540,037	8.7	1	6
TOTAL	54		$17,695,937		2	8

Historical totals may change as OPS receives supplemental information on incidents.

OFFICE OF PIPELINE SAFETY
TRANSMISSION PIPELINE
INCIDENT SUMMARY BY CAUSE
1/1/2000 - 12/31/2000
(Natural Gas)

Cause	No. of Incidents	% of Total Incidents	Property Damages	% of Total Damages	Fatalities	Injuries
CONSTRUCTION/MATERIAL DEFECT	7	8.75	$591,043	3.3	0	0
CORROSION, EXTERNAL	14	17.5	$3,475,500	19.45	0	0
CORROSION, INTERNAL	16	20	$2,635,086	14.74	12	2
CORROSION, NOT SPECIFIED	1	1.25	$730,000	4.08	0	0
DAMAGE BY OUTSIDE FORCE	20	25	$3,164,161	17.7	3	7
OTHER	22	27.5	$7,272,471	40.7	0	9
TOTAL	80		$17,868,261		15	18

Historical totals may change as OPS receives supplemental information on incidents.

OFFICE OF PIPELINE SAFETY
TRANSMISSION PIPELINE
INCIDENT SUMMARY BY CAUSE
1/1/2001 - 12/31/2001
(Natural Gas)

Cause	No. of Incidents	% of Total Incidents	Property Damages	% of Total Damages	Fatalities	Injuries
CONSTRUCTION/MATERIAL DEFECT	12	13.95	$1,639,070	6.94	0	0
CORROSION, EXTERNAL	7	8.13	$1,961,350	8.3	0	0
CORROSION, INTERNAL	9	10.46	$3,301,200	13.98	0	0
DAMAGE BY OUTSIDE FORCE	36	41.86	$14,807,928	62.71	0	0
OTHER	22	25.58	$1,901,335	8.05	2	5
TOTAL	86		$23,610,883		2	5

Historical totals may change as OPS receives supplemental information on incidents.

ADDED
Pgs 17a,b,c,d,e,f,g & h

Attachment 3: Natural Gas Transmission Pipeline Annual Mileage

Office of Pipeline Safety

Natural Gas Transmission Pipeline Annual Mileage

		Transmission		Gathering	
Year	No. of Records	Onshore	Offshore	Onshore	Offshore
1984	885	277,601	7,353	33,290	3,671
1985	952	282,745	7,719	33,729	1,740
1986	1,008	280,667	9,291	29,737	1,958
1987	963	284,235	7,622	29,654	2,477
1988	1,019	280,252	7,908	28,941	3,101
1989	1,033	279,728	8,198	29,597	2,547
1990	1,105	283,880	8,110	29,266	3,154
1991	1,211	285,295	8,567	29,009	3,704
1992	1,183	283,071	8,397	28,909	3,720
1993	1,131	285,043	8,220	28,431	3,625
1994	1,229	293,438	8,107	27,392	3,912
1995	1,267	288,846	8,101	26,657	4,262
1996	1,247	285,338	6,848	24,844	4,761
1997	1,352	287,745	6,625	28,234	6,161
1998	1,164	295,598	7,108	23,480	5,673
1999	1,176	290,083	6,017	26,348	5,916
2000	1,158	292,957	5,241	21,706	5,682
2001	1,306	284,932	5,536	17,659	3,865
2002	1,389	301,312	6,212	15,968	3,355

Source: http://ops.dot.gov/stats/GTANNUAL2.htm - Pipeline Statistics, Transmission Annual Mileage Totals (1984 – 2002).

Incidents and Telephonic Records 1998 - 2001

NRC No.	Incident Date	Offshore?	Incident Type	Rupture Length	Description of Incident
418580	19980105	No	OTHER		20IN NATURAL GAS PIPELINE / LINE WAS RUPTURED WHEN A CONTRACTOR STRUCK IT WITH A GRADER
NONE	19980108	No	RUPTURE	0.35	No telephonic record
	19980109	Yes	LEAK		N/A, offshore
	19980111	Yes	LEAK		N/A, offshore
419522	19980113	No	RUPTURE	8.5	U/G 10 INCH NATURAL GAS TRANSMISSION LINE PIPE/RUPTURED DUE TO UNKNOWN CAUSES
420106	19980116	No	OTHER		NATURAL GAS COMPRESSOR / COMPRESSOR CAUGHT FIRE
420030	19980116	No	RUPTURE		20 INCH NATURAL GAS TRANSMISSION PIPELINE / CAUSE OF RELEASE UNKNOWN ATTIME OF REPORT
420718	19980121	No	RUPTURE	15	5 INCH NATURAL GAS TRANSMISSION LINE / LINE STRUCK BY HOWARD COUNTY ROAD DEPT. VEHICLE
	19980126	Yes	RUPTURE	5	N/A, offshore
	19980126	Yes	LEAK		N/A, offshore
421437	19980127	No	RUPTURE	92	NATURAL GAS TRANSMISSION LINE / GAS IS BEING RELESED FROM THE PIPELINE AND BURNING / CAUSE OF RELEASE IS UNKNOWN
	19980130	Yes	OTHER	5	N/A, offshore
424160	19980207	No	LEAK		GAS HEATER/EXPLODED-CORROSION RELATED PROBLEM
425454	19980220	No	LEAK		SUBTERRANEAN 20 INCH NATURAL GAS PIPELINE LEAK/ UNKNOWN CAUSE.
425942	19980225	No	OTHER		20 INCH PIPELINE / THE LINE RUPTURED
426217	19980226	No	LEAK		24 INCH NATURAL GAS PIPELINE (TRANSMISSION LINE) / UNKNOWN....DEVELOPEDA LEAK
426463	19980301	No	LEAK		EXPLOSION AT MLNP FIRST AND INGRIA STREETS / MAY BE NATURAL GAS RELATEDCOMPANY IS STILL INVESTIGATING
427286	19980307	No	OTHER	0	CAR DROVE OVER 2" FEEDOFF LINE TO DISTRIBUTION SYSTEM; REGULATOR VALVE BROKEN OPEN RELEASING GAS WHICH IGNITED, SETTING CAR AFIRE.
427385	19980308	No	OTHER		8 INCH METER STATION / LIGHTNING STRUCK METER
	19980320	Yes	LEAK		N/A, offshore
429154	19980320	No	LEAK	0	NATURAL GAS PIPELINE (TRANSMISSION LINE) / A CONTRACTOR STRUCK AND RUPTURED PIPELINE
NONE	19980324	No	LEAK		No telephonic record
	19980327	Yes	RUPTURE	13	N/A, offshore
	19980328	Yes	LEAK		N/A, offshore
430284	19980329	No	RUPTURE	159	FIRE WAS DISCOVERED BY LOCAL POLICE ALONG PIPLINE AREA / CAUSE OF BREAKIS STILL UNKNOW
430957	19980402	No	LEAK		SOURCE: 26" PIPELINE/CAUSE: POSSIBLE CORROSION TO THE PIPELINE CAUSE THE RELEASE
430914	19980402	No	RUPTURE	8	16IN BELOW GROUND NATURAL GAS PIPE/ UNKNOWN CAUSE/ TRANSMISSION LINE INTERSTATE PIPELINE/ COMPANY LINE NAME 2-AD
431768	19980406	No	LEAK		12 IN TRANSMISSION PIPELINE / LEAK UNDERWATER IN INTERCOASTAL WATERWAY (Note: Although it appears from the telephonic record that this incident is associated with an off-shore (underwater) leak, the incident data indicates it is not.)
431743	19980408	No	RUPTURE	16	16 INCH NATURAL GAS TRANSMISSION PIPELINE / LINE FAILURE CAUSED RUPTURE
432039	19980410	No	LEAK		4 INCH NATURAL GAS TRANSMISSION LINE / CAUSE UNKNOWN
433267	19980420	No	LEAK		NATURAL GAS PIPELINE (SIZE & TYPE UNKNOWN) / UNKNOWN....AN OVERFLIGHT OBSERVED WHAT APPEARED TO BE A LEAKING PIPELINE
433654	19980422	No	RUPTURE	700	2 PIPES (TYPE UNKNOWN)/ LANDSLIDE CAUSED PIPES TO RUPTURE (Note: There is only one incident listed for this date in the incident data report. However, the telephonic incident notification report also has a listing for NRC no. 433655 (same city as NRC no. 433654). No. 433655 also pertains to a pipe rupture due to a landslide on the same date [i.e., per the telephonic records: No. 433655 - PIPELINE / LANDSLIDE CAUSED PIPE TO RUPTURE]. Thus, it appears that no. 433655 is not associated with a natural gas pipeline.)
	19980504	Yes	LEAK		N/A, offshore
	19980505	Yes	LEAK		N/A, offshore
435589	19980506	No	RUPTURE	30	30 INCH UNDERGROUND TRANSMISSION LINE / RUPTURED DUE TO UNKNOWN CAUSES
435986	19980508	No	LEAK		22 INCH STEEL PIPELINE / LEAK IN PIPELINE DUE TO UNKNOWN CAUSES RELEASED NATURAL GAS TO THE ATMOSPHERE / LINE: TRANSMISSION LINE
	19980511	Yes	LEAK		N/A, offshore
436523	19980512	No	OTHER		22 INCH TRANSMISSION LINE / WHILE REPAIRING A RELEASE AN IGNITION OCCURRED RESULTING IN AN INJURY TO AN EMPLOYEE
	19980516	Yes	LEAK		N/A, offshore

ATTACHMENT 3 SHT 17a/45
CALC. NO. 32-2400572-02

Incidents and Telephonic Records 1998 - 2001

NRC No.	Incident Date	Offshore?	Incident Type	Rupture Length	Description of Incident
	19980519	Yes	LEAK		N/A, offshore
437627	19980519	No	OTHER		ABOVE GROUND TRANSMISSION LINE(SIZE UNKNOWN)AT METERING FACILITY/DURINGREPAIR WORK AN EXPLOSION OCCURED FOLLOWED BY A FIRE
439300	19980530	No	RUPTURE	30	10 INCH PIPELINE/CAUSE UNKNOWN
439772	19980602	No	OTHER		30 INCH NATURAL GAS PIPELINE / IMPROPER VALVE SEQUENCE CAUSED A RELEASE OF NATURAL GAS
	19980606	No	OTHER		No telephonic record
	19980606	No	LEAK		No telephonic record
	19980615	Yes	LEAK		N/A, offshore
	19980619	No	OTHER		No telephonic record
	19980706	No	LEAK		No telephonic record
	19980707	No	LEAK		No telephonic record
	19980707	No	OTHER		No telephonic record
	19980711	No	OTHER		No telephonic record
	19980715	No	LEAK		No telephonic record
	19980715	No	OTHER		No telephonic record
	19980717	No	LEAK		No telephonic record
	19980717	No	LEAK		No telephonic record
	19980721	No	OTHER		No telephonic record
	19980723	No	LEAK		No telephonic record
	19980723	Yes	LEAK		N/A, offshore
	19980723	Yes	LEAK		N/A, offshore
	19980727	No	OTHER		No telephonic record
	19980802	No	LEAK		No telephonic record
	19980802	No	LEAK		No telephonic record
	19980803	No	OTHER		No telephonic record
	19980808	No	LEAK		No telephonic record
	19980814	No	OTHER		No telephonic record
	19980818	No	OTHER		No telephonic record
	19980825	No	OTHER		No telephonic record
	19980826	Yes	LEAK		N/A, offshore
	19980826	No	LEAK		No telephonic record
	19980826	No	RUPTURE	2	No telephonic record
	19980903	No	RUPTURE	20	No telephonic record
	19980906	No	RUPTURE	15	No telephonic record
	19980917	Yes	LEAK		N/A, offshore
	19980920	Yes	LEAK		N/A, offshore
	19980923	Yes	LEAK		N/A, offshore
	19980923	No	LEAK		No telephonic record
	19980929	No	OTHER		No telephonic record
	19980929	Yes	OTHER		N/A, offshore
	19980930	Yes	LEAK		N/A, offshore
	19981002	Yes	OTHER		N/A, offshore
	19981006	No	RUPTURE		No telephonic record
	19981006	Yes	LEAK		N/A, offshore
	19981008	No	LEAK		No telephonic record
	19981012	No	OTHER		No telephonic record
	19981012	No	RUPTURE	10	No telephonic record
	19981026	No	OTHER		No telephonic record
	19981029	No	RUPTURE		No telephonic record
	19981114	No	RUPTURE	55	No telephonic record

ATTACHMENT 3 SHT 176/45
CALC. NO. 32-2400572-02

NRC No.	Incident Date	Offshore?	Incident Type	Rupture Length	Description of Incident
	19981123	No	LEAK		No telephonic record
	19981130	Yes	LEAK		N/A, offshore
	19981202	No	OTHER		No telephonic record
	19981206	No	RUPTURE	80	No telephonic record
	19981207	No	RUPTURE	33	No telephonic record
	19981210	No	RUPTURE	1	No telephonic record
	19981210	No	OTHER		No telephonic record
	19981213	No	RUPTURE	1	No telephonic record
	19981216	No	OTHER		No telephonic record
	19981217	No	RUPTURE	29	No telephonic record
	19981221	No	LEAK		No telephonic record
469388	19990102	No	RUPTURE		22 INCH PIPELINE / THE MATERIAL RELEASED DUE TO AN UNKNOWN FAILURE ON THE LINE
469420	19990103	No	OTHER		8 INCH TRANSMISSION PIPELINE / UNKNOWN
NONE	19990113	No	LEAK		No telephonic record
NONE	19990117	No	LEAK		No telephonic record
	19990117	Yes	LEAK	0	N/A, offshore
471824	19990125	No	LEAK		20 INCH GAS PIPELINE / CORROSION OF LINE (Note: include even though city differs between the incident and telephone records)
472364	19990130	No	LEAK	0	22 INCH STEEL BELOW GROUND TRANSMISSION PIPELINE / COUPLING FAILED
472803	19990202	No	OTHER		INSIDE PLUMBING OF BUILDING/PLUMBING CONTRACTOR TURNED GAS VALVE ON TO PURGE PLUMBING LINES CAUSING EXPLOSION WHEN PLUGGING IN WATER HEATERS
472833	19990202	No	RUPTURE	0	OPERATOR ID 19136 / 20 INCH TRANSMISSION PIPELINE / THE CAUSE HAS NOT YET BEEN DETERMINED / THERE WAS NO FIRE OR EXPLOSION
474992	19990224	No	LEAK		COMPRESSOR STATION / FAILURE OF COMPRESSOR ENGINE GAS RELEASE AND FIRE / 24 INCH PIPELINE
475272	19990226	No	RUPTURE		26INCH NATURAL GAS TRANSMISSION PIPELINE / FAILURE DUE TO UNKNOWN CAUSE
475494	19990228	No	LEAK		18 INCH NATURAL GAS TRANSMISSION PIPELINE / DOT REGULATED / NO SERVICESAFFECTED / FLANGE GASKET ON LINE LEAKED
475747	19990303	No	LEAK		BELOW GROUND 36IN TRANSMISSION PIPELINE/UNKNOWN DOT REGULATED PIPELINE
476123	19990307	No	RUPTURE	16.5	12 INCH TRANSMISSION LINE RUPTURED AND EXPLODED
	19990323	Yes	LEAK		N/A, offshore
483495	19990512	No	OTHER		3 INCH TRANSMISSION NATURAL GAS PIPELINE / THE LINE WAS STRUCK BY A 3RDPARTY CONTRACTOR / THERE WAS NO FIRE OR EXPLOSION
NONE	19990513	No	LEAK		No telephonic record
	19990520	Yes	LEAK		N/A, offshore
485403	19990528	No	RUPTURE	2	8 INCH TRANSMISSION LINE / CAUSE:UNKNOWN / LINE IS REGULATED BY THE DOT
487294	19990613	No	RUPTURE	10	SOURCE UNKNOWN/ IGNITION AT PIPELINE STATION/ UNDER INVESTIGATION UNKNOWN SIZE OF LINE/STATION IGNITION/NO INJURIES/NO BUILDINGS DAMAGED
490844	19990710	No	RUPTURE	35	NATURAL GAS PIPELINE /NGPL 30INCH GULF COAST LINE RUPTURED CAUSING FIREUNDERGROUND TRANSMISSION LINE / DOT REGULATED LINE
491766	19990718	No	OTHER		METER STATION EQUIPMENT FAILURE RESULTED IN A BUILDING EXPLOSION/ALSO A PIPELINE IS RUPTURED INCIDENTS ARE POSSIBLY RELATED
494775	19990811	No	RUPTURE	4	12 INCH NATURAL GAS PIPELINE /CAUSE UNK / RELEASED NATURAL GAS INTO ATMOSPHERE
495259	19990814	No	OTHER		PURGING 20 INCH PIPELINE / LINE RUPTURED IN TWO PLACES DURING PURGING LINE IS DOT REGULATED
495123	19990815	No	LEAK		6 INCH PIPELINE/DREDGING OPERATION
496056	19990816	No	LEAK		ABOVE GROUND 2IN PIPING WITHIN PLANT/POSSIBLY DUE TO CRACK IN WELD
496023	19990823	No	RUPTURE	43	16IN BELOW GROUND PIPELINE / CAUSE OF RELEASE IS UNDETERMINED TRANSMISSION LINE / NO SERVICE INTERRUPTED
NONE	19990826	No	LEAK		No telephonic record
497288	19990901	No	OTHER		DOT REGULATED TRANSMISSION PIPELINE / RELEASE FROM A 6 INCH BLOW OFF/ 6 INCH LINE COMES OFF A 26 INCH LINE / ABOVE GROUND PIPELINE
497979	19990908	Yes	LEAK		N/A, offshore

ATTACHMENT 3 SHT 17c/45
CALC. NO. 32-2400572-02

NRC No.	Incident Date	Offshore?	Incident Type	Rupture Length	Description of Incident
498467	19990912	No	RUPTURE	25	THERE IS A RUPTURE IN A 24 INCH PIPELINE/ CAUSE OF THE RUPTURE IS UNKNOWN/ GAS IGNITED AS A RESULT OF THE RUPTURE/ DOT REGULATED LINE
498554	19990913	No	RUPTURE		6 INCH GAS TRANSMISSION LINE / LINE HIT BY FARMING EQUIPMENT / RELEASEDNATURAL GAS INTO ATMOSPHERE "DOT REG" LINE NO. 20007"
499423	19990920	No	RUPTURE	1	SEMI TRUCK ROLLED INTO NATURAL GAS FACILITY AND BROKE A SMALL PIPELINE SIZE OF PIPE UNK / NO FIRE/NO INJURIES
	19990923	Yes	LEAK		N/A, offshore
499904	19990923	No	RUPTURE	29	26 INCH NATURAL GAS PIPELINE RUPTURE/ REASON FOR RUPTURE IS UNKNOWN/ THIS IS A DOT REGULATED TRANSMISSION LINE
	19990925	Yes	LEAK		N/A, offshore
501339	19991005	No	OTHER		8 INCH STEEL TRANSMISSION GAS PIPELINE / DOT REGULATED / CONTRACTOR STRUCK WITH BACKHOE
505595	19991016	Yes	LEAK		N/A, offshore
	19991026	Yes	LEAK		N/A, offshore
503884	19991027	No	LEAK		24 INCH NATURAL GAS PIPELINE(GATHERING LINE) / UNKNOWN...LINE WAS DISCOVERED LEAKING
NONE	19991103	No	OTHER		No telephonic record
505133	19991109	No	RUPTURE		24 INCH BELOW GROUND PIPELINE / RELEASE OCCURRED DUE TO UNKNOWN CAUSES
507411	19991111	No	LEAK		A 12 INCH PIPELINE WAS RUPTURED BY A THIRD PARTY
505495	19991111	No	RUPTURE	6	10 INCH TRANSMISSION NATURAL GAS PIPELINE / THE LINE WAS STRUCK BY A 3RD PARTY CAUSING THE LINE TO BLOW OUT / TWO EMPLOYEES ARE MISSING
505500	19991111	No	OTHER		8 INCH TRANSMISSION NATURAL GAS PIPELINE / A BULLDOZER GOUGED THE LINE CAUSING A RELEASE / THERE WAS NO FIRE OR EXPLOSION
NONE	19991113	No	LEAK		No telephonic record
506063	19991117	No	LEAK		4.5 INCH TRANSMISSION NATURAL GAS PIPELINE / THE LINE WAS STRUCK BY A CONTRACTOR CAUSING A RELEASE / A FIRE RESULTED
506839	19991124	No	OTHER		No telephonic record
508490	19991209	No	LEAK		8 INCH.TRANSMISSION NATURAL GAS PIPELINE / A LEAK IN A VENT UNDER A HIGHWAY WAS DISCOVERED / THE CAUSE HAS NOT BEEN DETERMINED
508805	19991210	No	OTHER		12 INCH PIPELINE / THE MATERIAL RELEASED DURING MAINTENANCE WORK
509409	19991218	No	RUPTURE	0.25	NATURAL GAS PIPELINE / 3RD PARTY CONTRACTOR STRUCK LINE WITH BACKHOE / TRANSMISSION LINE / DOT REG. LINE (Note: Same state in incident and telephonic records but different city; conservative to include)
509538	19991220	No	LEAK	0	10 INCH NATURAL GAS TRANSMISSION PIPELINE / A THIRD PARTY STRUCK THE LINE CAUSING A RELEASE / THERE WAS NO FIRE OR EXPLOSION
515184	19991222	No	LEAK		BELOW GROUND 42IN DOT REGULATED PIPELINE/PIPELINE WAS DUG UP TO REPAIR ND IT WAS DISCOVERED THAT PIPELINE NEEDS TO BE BLOWN DOWN PRIOR TO REP
515880	19991231	Yes	LEAK		N/A, offshore
515947	20000101	No	LEAK	0	UNKNOWN UNDERGROUND PIPELINE BREAK
516665	20000111	No	OTHER		THE MATERIAL RELEASED OUT OF A 20 INCH NATURAL GAS PIPELINE DUE TO THIRY DAMAGE. THERE WAS NO FIRE OR EXPLOSION
517700	20000124	No	OTHER		PRESSURE STATION CAME OFF LINE WHICH CAUSED A VALVE TO RELEASE NATURAL E TO HIGH PRESSURE
517943	20000127	No	RUPTURE	2	20 INCH GAS LINE RUPTURED
518022	20000127	No	RUPTURE	770000	20 INCH NATURAL GAS PIPELINE / LINE BLEW OUT CAUSING RELEASE
518173	20000129	No	RUPTURE	50	NATURAL GAS PIPELINE RUPTURE OCCURRED
518468	20000201	No	RUPTURE	5	CALLER STATED THAT THERE HAS BEEN A RELEASE A 24 INCH TRANSMISSION LINEO UNKNOWN CAUSES (Note: telephonic record for 2/2/2000)
518475	20000202	No	RUPTURE	40	30 INCH TRANSMISSION PIPELINE / LINE RUPTURED FOR UNKNOWN REASONS
518851	20000205	No	LEAK		TRANSMISSION PIPELINE RUPTURE
519574	20000211	No	LEAK		THE CALLER STATES THAT TEXAS KEYSTONE COMPANY HIT A 12 INCH NATURAL GAS LINE WHICH WAS OWNED BY CNG TRANSMISSION WITH A BULLDOZER, RUPTURING
520444	20000218	No	LEAK	5	THE MATERIAL SPILLED DUE TO A CRACK ON A WELD IN A 24 INCH PIPELINE
520406	20000218	No	OTHER		16 INCH HIGH PRESSURE STEEL PIPELINE / PIPELINE DAMAGED BY 3RD PARTY

ATTACHMENT 3 SHT 17d / 45
CALC. NO. 32-2400572-02

Incidents and Telephonic Records 1998 - 2001

NRC No.	Incident Date	Offshore?	Incident Type	Rupture Length	Description of Incident
520905	20000223	No	LEAK		A 24 INCH PIPELINE DEVELOPED A LEAK DUE TO UNKNOWN CAUSES AT THIS TIME
520825	20000223	No	RUPTURE	12	NATURAL GAS PIPELINE RUPTURED DUE TO UNKNOWN CAUSES. (Note: In the telephonic records, NRC no. 520806 is also indicated to have occurred in the same state (MI) as NRC no. 520825 and on the same date [i.e., per the telephonic record, no. 520806 is: 12 INCH PIPELINE "TRANSMISSION LINE" / RUPTURE IN LINE DUE TO UNKNOWN CAUSES]. However, in the incident report, there is only one listing for the state of MI on this date. Thus, it appears that no. 520806 is not associated with a natural gas pipeline. Therefore, this is considered one incident.)
NONE	20000225	No	OTHER		No telephonic record
521265	20000227	No	RUPTURE	300	24" TRANSMISSION LINE HAD A RUPTURE
522377	20000308	No	OTHER		A CONTRACTOR HIT A 16 INCH STEEL HIGH PRESSURE LINE, RUPTURING THE LINE AND RELEASED THE MATERIAL
523063	20000315	No	LEAK	0	BELOW GROUND 18 INCH TRANSMISSION LINE RELEASED NATURAL GAS FOR UNKNOWN REASONS
523107	20000316	No	LEAK		UNKNOW PIPELINE/ CAUSE UNKNOWN
523820	20000322	No	LEAK		10 INCH NATURAL GAS TRANSMISSION LINE / POSSIBLE CORROSION
523850	20000322	No	RUPTURE	200	PIPELINE RUPTURE DUE TO UNKNOWN CAUSES
524202	20000327	No	RUPTURE	102	26 INCH STEEL TRANSMISSION PIPELINE / CAUSE UNKNOWN
524643	20000330	No	LEAK		VALVE ON PIPELINE AT PRESSURE LIMITING STATION WAS STRUCK BY A TRUCK CAUSING THE RELEASE.
526947	20000424	Yes	LEAK		N/A, offshore
527237	20000426	Yes	LEAK		N/A, offshore
527789	20000502	No	OTHER		DURING WELDING GAS THAT WAS PRESENT IN THE AREA IGNITED
528256	20000507	No	OTHER		CALLER SAYS THERE WAS A FIRE NEAR A NATURAL GAS PIPELINE
NONE	20000513	No	OTHER		No telephonic record
529301	20000518	No	OTHER		20 INCH KA PIPELINE STRUCK BY MINING COMPANY
NONE	20000603	No	LEAK		No telephonic record
532311	20000614	No	OTHER		THIRD PARTY DAMAGE ON 16 INCH GASLINE CAUSED RELEASE OF MATERIAL/TRACTOR RIPPED HOLE IN LINE
532481	20000617	Yes	LEAK		N/A, offshore
532694	20000619	Yes	LEAK		N/A, offshore
533053	20000622	No	RUPTURE	25	No telephonic record
533867	20000628	No	RUPTURE	6	8 INCH PIPELINE "TRANSMISSION" / UNKNOWN CAUSES
533922	20000629	Yes	LEAK		N/A, offshore
534181	20000702	No	LEAK		30 INCH NATURAL GAS PIPELINE / CAUSE:UNKNOWN
534468	20000702	No	RUPTURE	9	MATERIAL WAS RELEASED FROM A SIX INCH NATURAL GAS PIPELINE DUE TO UNKNOWN CAUSE.
534097	20000703	No	RUPTURE	36	NATURAL GAS LINE HAS BROKEN VALVE AND IS RELEASING MATERIAL (telephonic record dated 7/1/00)
534444	20000705	No	RUPTURE	22	TUG BOW STRUCK GAS LINE CAUSING A RELEASE
	20000705	Yes	LEAK		N/A, offshore
534705	20000707	No	LEAK		A FIRE AT A METER STATION CAUSED A RELEASE OF NATURAL GAS
534686	20000707	Yes	LEAK		N/A, offshore
NONE	20000715	No	OTHER		No telephonic record
535726	20000718	No	OTHER		LINE BLOCKAGE TO MAIN DISTRIBUTION LINE. CALLER BELIEVES A VALVE WAS LEFT SHUT
536155	20000721	No	OTHER		THE MATERIAL RELEASED OUT OF A 16IN NATURAL GAS PIPELINE DUE TO A THIRD PARTY PIECE OF CONSTRUCTION EQUIPMENT STRIKING THE LINE.
536098	20000721	Yes	LEAK		N/A, offshore
537404	20000802	No	RUPTURE	3	THE MATERIAL WAS RELEASING FROM A 16 INCH STEEL PIPELINE DUE TO THE PIPELINE RUPTURING.
NONE	20000804	No	LEAK		No telephonic record
538593	20000814	No	LEAK		PIPELINE LEAK
538917	20000816	Yes	LEAK		N/A, offshore
538990	20000816	No	LEAK		THE CALLER STATED THAT A PIPE CAME OUT OF A COUPLING DUE TO THE LINE BEING PRESSURED UP
539215	20000819	Yes	LEAK		N/A, offshore
539219	20000819	No	RUPTURE	59	30 INCH NATURAL GAS PIPELINE HAS A RUPTURE IN IT DUE TO UNKNOWN CAUSE
539897	20000825	No	LEAK		12 INCH "TRANSMISSION LINE" LINE IS LEAKING NATURAL GAS FOR UNKNOWN REASONS.
540289	20000828	No	LEAK		BELOW GROUND 30 IN MAIN GAS LINE RELEASED MATERIAL. FARMER SPOTTED DARK SPOT ON HIS LAND. SRP INVESTIGATED AND DISCOVERED LEAK.

ATTACHMENT 3 SHT 17e, 45
CALC. NO. 32-2400572-02

Incidents and Telephonic Records 1998 - 2001

NRC No.	Incident Date	Offshore?	Incident Type	Rupture Length	Description of Incident
540327	20000829	No	LEAK		THE CALLER STATED THAT A NATURAL GAS PIPELINE WAS RELEASING MATERIAL DUE TO CORROSION.
541917	20000912	No	OTHER		THE MATERIAL IS RELEASING DUE TO A PLANNED BLOWDOWN IN AN 8 INCH PIPELINE. THE BLOWDOWN HAD TO OCCUR TO AVERT A RUPTURE. THIS IS AN EMERG (Note: Although the cities are not the same in the incident and telephonic reports, conservatively include)
543279	20000926	No	RUPTURE		THE MATERIAL RELEASED FROM A 12" GAS PIPELINE DUE TO UNKNOWN CAUSES.
543441	20000927	No	LEAK		THE MATERIAL RELEASED FROM A NATURAL GAS PIPELINE DUE TO UNKNOWN REASONS.
543746	20000929	No	RUPTURE	83.5	THE MATERIAL WAS RELEASED FROM A RUPTURED 30 INCH PIPELINE DUE TO UNKNOWN CAUSES.
544293	20001003	No	OTHER		2 INCH WKM GATE VALVE, "SAFETY SEAL", THE BOLTS ON THE BONNET FAILED.
545019	20001012	No	LEAK		THE MATERIAL RELEASED OUT OF A 24 INCH PIPE LINE DUE TO AN UNDETERMINED CAUSE.
546637	20001026	No	LEAK		THE CALLER STATED THAT A PIPELINE VALVE IS RELEASING GAS. THE CAUSE IS UNKNOWN.
546628	20001030	Yes	LEAK		N/A, offshore
548069	20001113	No	OTHER		THE CALLER STATED THAT A NATURAL GAS DISTRIBUTION SYSTEM HAS LOST SERVICE TO SOME CUSTOMERS. THE CAUSE FOR THE SYSTEM FAILURE IS UNKNOWN.
548441	20001116	Yes	LEAK		N/A, offshore
548619	20001118	No	LEAK		FIRE IN TOWN BOARDER STATION IN THE HEATER. NATURAL GAS DISTRIBUTION CENTER
548759	20001120	No	OTHER		THE MATERIAL RELEASED FROM A RELIEF VALVE ON AN EMERGENCY SHUTDOWN DEVICE DUE TO UNKNOWN CAUSES.
549015	20001123	No	OTHER		THE CALLER IS REPORTING A FIRE IN A COMPRESSOR BUILDING DUE TO UNKNOWN CAUSES. THERE WAS NO EXPLOSION.
549118	20001125	No	LEAK		LEAK IN A 22 INCH NATURAL GAS LINE
549266	20001127	No	LEAK		THE CALLER STATED THAT A GAS LINE MAY HAVE A LEAK IN IT, AND THERE IS BUBBLE COMING FROM THE WATER (NOTE: Same state in incident and telephonic records; conservative to include)
NONE	20001128	No	OTHER		No telephonic record
549612	20001130	No	RUPTURE	28	THE PIPELINE WAS DAMAGE DUE TO A THIRD PARTY. (POSSIBLY AN EMPLOYEE OR CONTRACTOR OF VALLEY TELEPHONE)
549947	20001204	No	RUPTURE	26.25	A 30 INCH TRANSMISSION LINE HAS RUPTURED DUE TO A UNDETERMINED CAUSE CAUSING NATURAL GAS TO RELEASE FROM THE LINE INTO THE ATMOSPHERE.
550268	20001206	No	LEAK		THE MATERIAL IS LEAKING FROM A 30" BALL VALVE DUE TO UNKNOWN CAUSES.
550498	20001209	No	RUPTURE	76	A NATURAL GAS PIPELINE RUPTURED. THE CAUSE IS UNKNOWN.
551181	20001216	No	RUPTURE		EXPLOSION DUE UNKNOWN CAUSES AT AN UNDERGROUND STORAGE FACILITY
551911	20001226	No	NO DATA		CALLER STATED SRP DUG INTO A 32 INCH GAS TRANSMISSION LINE, THE SRP WAS GRADING FOR A STREET
552219	20001229	No	RUPTURE	40	26 INCH NATURAL GAS PIPILINE RUPTURED DUE TO UNKNOWN CAUSE
552464	20010103	No	LEAK		A TRACKHOE HIT A 16 INCH NATURAL GAS PIPELINE BY ACCIDENT WHILE EXCAVATING FOR ANOTHER LINE
552627	20010104	No	RUPTURE	120	THE CALLER REPORTS A RUPTURE OF A 22 INCH NATURAL GAS PIPELINE.
552669	20010104	No	LEAK		THE MATERIAL WAS RELEASED FROM A RUPTURED 16 INCH GAS LINE DUE TO UNKNOWN CAUSES. THE CAUSE FOR THE RELEASE IS UNDER INVESTIGATION
553568	20010115	No	OTHER		THE CALLER STATED THAT A FRONT END LOADER WENT OFF THE ROAD AND HIT A 20 INCH HIGHT PRESSURE GAS LINE. PART OF AN ABOVE GROUND SPAN. GAS RELE
553737	20010116	No	LEAK		THE CALLER REPORTS A LEAKING NATURAL GAS PIPELINE POSSIBLY DUE TO SUSPECTED CORROSION.
553780	20010116	No	OTHER		RELEASE DUE TO AN UNKNOWN CAUSE
554695	20010125	No	LEAK		16 INCH PIPELINE "FLOWLINE" LINE DEVELOPED A PINHOLE leak DUE TO UNKNOWN CAUSES
555048	20010129	No	LEAK		THE CALLER STATED THAT A 12 INCH NATURAL GAS TRANSMISSION PIPELINE RUPTURED, THE CAUSE IS UNKNOWN.
	20010203	Yes	LEAK		N/A, offshore
555725	20010204	No	RUPTURE	1	A THIRD PARTY CONTRACTOR STRUCK A UNDERGROUND 8 INCH NATURAL GAS TRANSMISSION LINE WITH A BACK HOE CAUSING NATURAL GAS TO RELEASE FROM THE LI
NONE	20010206	No	LEAK		No telephonic record
556117	20010228	Yes	OTHER		N/A, offshore
558599	20010305	No	LEAK		THE MATERIAL WAS RELEASED FROM A PIPLINE DUE TO A GASKET FAILURE. (Note: Same state but different cities in the incident and telephonic reports; conservatively include)
559149	20010310	Yes	LEAK		N/A, offshore
NONE	20010313	No	LEAK		No telephonic record (Note: none of the cities and/or counties match between the incident and telephonic reports)

ATTACHMENT 3 SHT 17 OF 45
CALC. NO. 32-2400572-02

Incidents and Telephonic Records 1998 - 2001

NRC No.	Incident Date	Offshore?	Incident Type	Rupture Length	Description of Incident
559926	20010317	No	OTHER		BLOW DOWN VALVE AT A COMPRESSOR STATION DID NOT SHUT DUE TO EQUIPMENT PROBLEMS / COMPRESSOR STATION IS PART OF A PIPELINE (Note: telephonic record for 3/18/2001)
559987	20010319	No	OTHER		No telephonic record (Note: No matching NRC no. in the telephonic record for given date)
560330	20010322	No	OTHER		NATURAL GAS WAS RELEASED FROM A TRANSMISSION PIPELINE, DUE TO A SCHEDULED BLOW-DOWN. THE GAS CAUGHT FIRE.
561008	20010328	No	RUPTURE	0.66	THE MATERIAL RELEASED OUT OF A 6 INCH STEEL TRANSMISSION PIPELINE DUE TO AN EXCAVATOR DAMAGING THE PIPELINE.
NONE	20010329	No	RUPTURE		No telephonic record (Note: none of the Texas cities and/or counties match between the incident and telephonic reports)
NONE	20010329	No	LEAK		No telephonic record (Note: none of the Texas cities and/or counties match between the incident and telephonic reports)
561310	20010330	No	LEAK		A PIPELINE LEAK WAS DETECTED BY A MOTORIST
561806	20010404	No	OTHER		THE CALLER IS REPORTING THAT THE SUSPECTED RESPONSIBLE PARTY TOOK THE COVER OFF A 10 INCH PIPELINE AND PUNCTURED THE LINE WITH A DOZER BLADE
561798	20010404	No	OTHER		A CONTRACTOR HIT THE RESPONSIBLE PARTY'S EIGHT INCH PIPELINE WITH A BULL DOZER CAUSING A RELEASE OF GAS.
561742	20010404	No	OTHER		A RELIEF VALVE ON TRANSMISSION LINE RELEASED GAS DUE TO OVER PRESSURIZATION.
561893	20010405	No	LEAK		THE MATERIAL WAS RELEASED FROM A PIPELINE DUE TO A LEAK IN THE LINE FROM UNKNOWN CAUSES.
561915	20010405	No	OTHER		No telephonic record (Note: No matching NRC no. in the telephonic records for given date.)
562056	20010406	Yes	LEAK		N/A, offshore
562463	20010407	No	OTHER		No telephonic record (Note: No matching NRC no. in the telephonic records for given date.)
563110	20010416	No	LEAK		THE MATERIAL IS LEAKING FROM A CRACKED 36 INCH UNDERGROUND TRANSMISSION PIPE.
564100	20010425	No	OTHER		A 12 INCH TRANSMISSION LINE WAS STRUCK BY A PIECE OF CONSTRUCTION EQUIPMENT CAUSING NATURAL GAS TO RELEASE FROM THE LINE INTO THE ATMOSPHERE.
564274	20010427	No	LEAK		THE MATERIAL RELEASED OUT OF THE TWENTY FOUR INCH UNDERGROUND NATURAL GAS PIPE DUE TO AN UNDETERMINED CAUSE AT THIS TIME.
565631	20010504	No	RUPTURE	18	THE MATERIAL RELEASED OUT OF A 20 INCH PIPELINE DUE TO A VALVE FAILURE. (Note: Description is associated with NRC no. 565031. It appears that the NRC no. of 565631 listed in the incident report, may be a typo.)
565794	20010511	No	LEAK		TRACTOR WITH DITCHING DEVICE STRUCK 12 INCH PIPELINE
565922	20010513	Yes	LEAK		N/A, offshore
567330	20010521	No	LEAK		LEAK ON AN INTERSTATE GAS PIPELINE DUE TO PIPE DAMAGE.
567182	20010524	Yes	LEAK		N/A, offshore
567198	20010524	No	RUPTURE		THE CALLER STATED THAT COUNTY ROAD GRADER HIT A NATURAL GAS PIPELINE AND CAUSED A LEAK.
569368	20010613	No	RUPTURE		No telephonic record
569577	20010614	No	LEAK		No telephonic record
NONE	20010616	No	OTHER		No telephonic record
570128	20010619	No	LEAK		No telephonic record
570250	20010620	No	LEAK		No telephonic record
NONE	20010630	No	LEAK		No telephonic record
572288	20010708	No	OTHER		No telephonic record
574018	20010723	No	LEAK		No telephonic record
NONE	20010724	No	OTHER		No telephonic record
NONE	20010725	No	LEAK		No telephonic record
NONE	20010725	No	OTHER		No telephonic record
NONE	20010729	No	LEAK		No telephonic record
575297	20010803	No	LEAK		No telephonic record
575940	20010809	No	LEAK		No telephonic record
576119	20010811	No	RUPTURE	19	No telephonic record
576520	20010814	No	LEAK		No telephonic record
576787	20010814	No	LEAK		No telephonic record
573077	20010815	No	OTHER		No telephonic record
NONE	20010820	No	LEAK		No telephonic record

ATTACHMENT 3 SHT 17 of 45
CALC. NO. 32-2400572-02

NRC No.	Incident Date	Offshore?	Incident Type	Rupture Length	Description of Incident
577245	20010821	No	RUPTURE		No telephonic record
577758	20010826	Yes	LEAK		N/A, offshore
577808	20010826	Yes	LEAK		N/A, offshore
NONE	20010831	No	LEAK		No telephonic record
578944	20010903	No	RUPTURE	10	No telephonic record
579144	20010907	No	RUPTURE	1	No telephonic record
580005	20010917	No	LEAK		No telephonic record
NONE	20010920	Yes	LEAK		N/A, offshore
580493	20010921	No	LEAK		No telephonic record
580834	20010925	No	RUPTURE	9	No telephonic record
582452	20011009	No	LEAK		No telephonic record
NONE	20011012	No	RUPTURE	4	No telephonic record
583347	20011016	No	LEAK		No telephonic record
583615	20011018	Yes	LEAK		N/A, offshore
584230	20011023	No	OTHER		No telephonic record
NONE	20011024	Yes	LEAK		N/A, offshore
NONE	20011105	No	OTHER		No telephonic record
585264	20011106	No	OTHER		No telephonic record
585408	20011107	No	OTHER		No telephonic record
585912	20011113	No	LEAK		No telephonic record
586663	20011121	Yes	LEAK		N/A, offshore
587965	20011206	No	LEAK		No telephonic record
587925	20011206	No	LEAK		No telephonic record
588102	20011207	No	LEAK		No telephonic record
588053	20011207	No	RUPTURE	10	No telephonic record
585285	20011210	No	OTHER		No telephonic record
588431	20011212	No	LEAK		No telephonic record
588473	20011212	No	RUPTURE		No telephonic record
588825	20011216	No	RUPTURE	610	No telephonic record

Notes: 1) For some incidents (e.g., 1998 through 5/20/1999 and various others), no NRC number is given in the incident data report. Therefore, a comparison of the city, county and/or state information between the incident data report and telephonic incident notification records was made to determine the NRC number.

2) Above information was compiled from the Office of Pipeline Safety website: http://ops.dot.gov - from the Online Library - Accident & Incident Data, Natural Gas Transmission Incident Data - mid 1984 to 2001 and from the Online Library - Telephonic Incident Notification, 1995-1998 & 1999-2001 Telephonic Incident Notifications.

3) Rupture length units are assumed to be in feet (i.e., units are not indicated in the transmission incident data report).

ATTACHMENT 3 SHT 17b/45
CALC. NO. 32-2400572-02

Attachment 4: Calculation of Distances D_1 and D_2

1.0 PURPOSE AND OBJECTIVE

Calculate the exposure distance, D, which has two parts, the distance to the gas upper and lower explosion limits (UEL and LEL), D_1, and the safe separation distance, D_2.

2.0 METHOD OF ANALYSIS

Employ the computer program ALOHA (Reference 6) to calculate the concentrations of natural gas from a postulated gas release along a direct pathway to the NEF. Use the model results to determine the distance to the upper and lower explosion limits (UEL and LEL), which is D_1. Then estimate the safe separation distance, D_2 from an explosion following Regulatory Guide 1.91 (Reference 3).

ALOHA was developed jointly by the U.S. Environmental Protection Agency (EPA) and the National Oceanic Atmospheric Administration (NOAA). The program predicts the rates at which chemical vapors may escape into the atmosphere from broken gas pipes, leaking tanks, and evaporating puddles. It also predicts how the gas cloud disperses in the atmosphere after an accidental release.

3.0 INPUT AND ASSUMPTIONS

The following assumptions were made relating to the dispersion and transport of the pipeline gas:

- The gas released is methane, which is the major constituent of wet sour gas (Attachment 5).
- The postulated gas release is a guillotine pipeline break such that the break hole size equals the pipe diameter.
- The pipe is connected to an infinite source because there are no automatic shut-off valves in the pipeline (Attachment 5).
- The gas release is 1 hour; the maximum expected time before emergency crews arrive to shut off the source at a manual shut-off valve (Attachment 5).
- The pipe length is 200 times the pipe diameter, which is the minimum allowed by ALOHA and considered to be very conservative.
- A delayed explosion from a drifting plume 1 hour after release is more severe than an in-place explosion because the gas plume is closer to the plant.
- The atmosphere is stable, with minimal dispersion and effects due to elevation change.

- The distance from the gas release location to the plant is the "straight-line" distance, which is the shortest distance between the source and the plant measured on a plain surface that excludes intervening ground elevation changes and building surfaces.
- The TNT equivalent weight of an exploding material is represented by the SFPE Handbook method (Reference 8).

4.0 ANALYSIS

The safety of structures from an explosion is evaluated by determining the safe separation distance between the explosion and the structure. If there is sufficient separation such that structural damage is minimized, then the structure is assumed safe.

The method used to establish the safe separation distance is from Regulatory Guide 1.91 (Reference 3), which is based on a level of peak positive incident overpressure, conservatively chosen at 1 pound per square inch (psi), and TNT equivalent energy in the form

$$R = 45\,W^{1/3}$$

where,

R = the safe separation distance in feet (ft), and

W = the TNT equivalent weight of the exploding material in pounds (lbs).

To calculate the safe separation distance, therefore, requires the TNT equivalent of the mass of methane volume released. For a continuous release such as postulated, this is the mass of methane between its lower explosion limit (LEL) and upper explosion limits (UEL) of 5 – 15 % by volume (Reference 8). Note that 5% by volume is equivalent to 50,000 parts per million (ppm) and 15 % by volume is equivalent to 150,000 ppm. Theses values are used as input to ALOHA (see Tables A2 and A1, respectively).

4.1 Methane Explosion Release Mass

The mass of methane released in its explosion range is calculated by using the "Sustained Release Rate" determined by ALOHA and the distance/time relationship to reach the UEL and LEL such that

$$M = S\,(T_{LEL} - T_{UEL})$$

where,

M = mass of methane in pounds (lbs)
S = sustained release rate in pounds per minute (lbs/min)
T_{UEL} = time to reach the UEL in minutes (min)
T_{LEL} = time to reach the LEL in minutes (min)

From ALOHA output Tables A1 and A2, the Sustained Release Rate of methane at 50 psi (i.e., the maximum gas pipeline pressure) is 5,820 lbs/min. The respective distances to the UEL and LEL (referred to as the "LOC" on the printout) are 727 yards (2181 ft), and 1365 yards (4095 ft). At the ALOHA input wind speed of 1 meter/second (m/s), or 3.28 feet per second (ft/s), the time to UEL and LEL is

T_{UEL} = 2181 ft / 3.28 ft/s / 60 s/min = 11.08 min, and

T_{LEL} = 4095 ft / 3.28 ft/s / 60 s/min = 20.81 min

Therefore,

M = 5,820 lbs./min x (20.81 min – 11.08 min) = 56,629 lbs.

4.2 Methane Mass to Equivalent TNT

From the SFPE Handbook, Section 3, Chapter 16, Equations 12 and 13 (Reference 8), the TNT equivalent weight can be expressed as

$$W_{TNT} = \frac{\alpha(\Delta H_c)(M_f)}{4500}$$

where,

W_{TNT} = TNT equivalent mass in kilograms (kg).
α = yield, which is the fraction of available combustion energy.
ΔH_c = theoretical net heat of combustion in kilo-Joules per kilogram (kJ/kg).
M_f = mass of flammable vapor released in kg.

From Reference 4 (Attachment 6), Table A-2, ΔH_c is conservatively chosen to be the gross heat of combustion, which is 55.50 MJ/kg, or 55,500 kJ/kg; M_f = 56,629 lbs/ 2.2 lbs/kg = 25,740 kg; and from Reference 8 (Attachment 8), the blast yield, α, is assumed to be 5%. Substituting,

$$W_{TNT} = \frac{0.05\left(55{,}500\,\frac{KJ}{kg}\right)(25{,}740\,kg)}{4500} = 15{,}873\,kg = 34{,}921 \text{ lbs}$$

4.3 Safe Separation Distance

From above, the safe separation distance, R, is

$R = 45\,(34{,}921)^{1/3} = 1{,}471$ ft

This means that plant critical structures must be at least 1,471 ft from the point of explosion.

5.0 CONCLUSION

The value of D_1 is 4,095 ft (1,365 yards), which is shown in ALOHA output Table A1 and is the distance from the gas release point to the LEL. The value of D_2 is 1,471 ft, which is the safe separation distance.

6.0 COMPUTER PROGRAM BENCHMARK

Attachment 10 demonstrates that ALOHA, version 5.2.3, is correctly predicting results on the installed computer, an IBM-compatible PC (ID#3W2BZ1) using Microsoft Windows XP® Professional, Version 2002, operating system with a Pentium(R) 4 processor.

Table A1
ALOHA Output, Methane UEL

Text Summary ALOHA® 5.2.3

```
SITE DATA INFORMATION:
  Location: EUNICE, NEW MEXICO
  Building Air Exchanges Per Hour: 0.50 (enclosed office)
  Time: October 10, 2003  1042 hours MDT (using computer's clock)

CHEMICAL INFORMATION:
  Chemical Name: METHANE          Molecular Weight: 16.04 kg/kmol
  TLV-TWA: -unavail-              IDLH: -unavail-
  Footprint Level of Concern: 150000 ppm
  Boiling Point: -258.68° F
  Vapor Pressure at Ambient Temperature: greater than 1 atm
  Ambient Saturation Concentration: 1,000,000 ppm or 100.0%

ATMOSPHERIC INFORMATION: (MANUAL INPUT OF DATA)
  Wind: 1 meters/sec from s at 10 meters
  No Inversion Height
  Stability Class: F (user override)
  Air Temperature: 70° F
  Relative Humidity: 5%           Ground Roughness: open country
  Cloud Cover: 0 tenths

SOURCE STRENGTH INFORMATION:
  Pipe Diameter: 16 inches        Pipe Length: 267 feet
  Pipe Temperature: 70° F         Pipe Press: 50 lbs/sq in
  Pipe Roughness: smooth          Hole Area: 201 sq in
  Unbroken end of the pipe is connected to an infinite source
  Release Duration: ALOHA limited the duration to 1 hour
  Max Computed Release Rate: 7,640 pounds/min
  Max Average Sustained Release Rate: 5,820 pounds/min
     (averaged over a minute or more)
  Total Amount Released: 348,998 pounds

FOOTPRINT INFORMATION:
  Dispersion Module: Gaussian
  User-specified LOC: 150000 ppm
  Max Threat Zone for LOC:  727 yards
```

Table A2
ALOHA Output, Methane LEL

Text Summary ALOHA® 5.2.3

```
SITE DATA INFORMATION:
  Location: EUNICE, NEW MEXICO
  Building Air Exchanges Per Hour: 0.50 (enclosed office)
  Time: October 10, 2003  1042 hours MDT (using computer's clock)

CHEMICAL INFORMATION:
  Chemical Name: METHANE          Molecular Weight: 16.04 kg/kmol
  TLV-TWA: -unavail-              IDLH: -unavail-
  Footprint Level of Concern: 50000 ppm
  Boiling Point: -258.68° F
  Vapor Pressure at Ambient Temperature: greater than 1 atm
  Ambient Saturation Concentration: 1,000,000 ppm or 100.0%

ATMOSPHERIC INFORMATION: (MANUAL INPUT OF DATA)
  Wind: 1 meters/sec from s at 10 meters
  No Inversion Height
  Stability Class: F (user override)
  Air Temperature: 70° F
  Relative Humidity: 5%           Ground Roughness: open country
  Cloud Cover: 0 tenths

SOURCE STRENGTH INFORMATION:
  Pipe Diameter: 16 inches        Pipe Length: 267 feet
  Pipe Temperature: 70° F         Pipe Press: 50 lbs/sq in
  Pipe Roughness: smooth          Hole Area: 201 sq in
  Unbroken end of the pipe is connected to an infinite source
  Release Duration: ALOHA limited the duration to 1 hour
  Max Computed Release Rate: 7,640 pounds/min
  Max Average Sustained Release Rate: 5,820 pounds/min
     (averaged over a minute or more)
  Total Amount Released: 348,998 pounds

FOOTPRINT INFORMATION:
  Dispersion Module: Gaussian
  User-specified LOC: 50000 ppm
  Max Threat Zone for LOC:  1365 yards
```

Attachment 5: Gas Line Telephone Chronology

TELEPHONE CHRONOLOGY
REGULATORY COMPLIANCE PROGRAMS- MARLBOROUGH

Call With	See Below	**Date**	See Below
Phone #	See Below	**Time**	See Below
By	J.H. Snooks	**PID**	
Subject	LES-NM: Gas Lines		

DISCUSSION:

6/30/2003 Reviewed gas line maps and was able to identify the closest gas line as the 16" Fullerton Loop Line, which nearly parallel to NM Rte 234-Tx Rte 176. Called "One Call" (800-321-2537) to get info on gas line owner. Dispatcher named three companies: Trinity CO2, Texaco, and Sid Richardson Energy Services. Requested number for SR since gas maps were labeled as SR. Called SR (505-395-2116), but no one available.

7/1/2003 Called SR again, spoke w/ Royce, who gave me general info. The gas line is low pressure (< 50 psi) and carries "wet sour gas," which is unprocessed, field gas from the well being sent for processing. The gas line is buried to about 36", but could vary more or less in sandy soil due to the wind. Royce said he would have someone get back to me on characteristics of gas, e.g., percent methane, etc.

7/10/2003 Returned Royce Dunn's call. RD had additional info on gas line specs and gas characteristics as follows: methane = 72%, ethane = 11%, propane = 7%, H2S = 695ppm (<1%). The gas line flow is between 200-500 thousand cubic feet per day. It is 14-15 miles in length, with manual block valves at each end and in the middle. There also has a check valve at the connection with the main service line located near Eunice and Hwy 176. The likelihood of internal rupture is small because of the low pressure (<50psi).

8/8/2003 Called "One Call" (800-321-2537) to place a pipeline location request for Sections 32 and 33. Used town ID# 838. One Call said there were three operators in area: Sid Richardson, Trinity, and Texaco. Companies will call in 2-5 business days with info. One Call confirmation number is 2003323641.

8/8/2003 Goose Armstrong from Sid Richardson responded to the One call inquiry to say they had two pipelines in Sections 32 and 33, both running parallel to the southern boarder along Rte 234/176. One is 14-inch line that is "idle," i.e., in active. The

other is a 16-inch line carrying natural gas. [See 7/1 and 7/10 above for more details.]

8/8/2003 Brent Washington from Conoco-Phillips (505-390-3425) returned my many calls to various Conoco offices to get info on potential pipelines near Eunice. Brent said there were no known lines, but that he would conduct a site walk down on 8/11 to confirm.

8/11/2003 Brent Washington from Conoco-Phillips (505-390-3425) called to say he walked the site and did not locate any Conoco-Phillips pipelines.

8/13/2003 Lon Briley from Trinity Gas (442-661-0162) responded to the One Call inquiry and said Trinity had one carbon dioxide line crossing Section 32. The line carries liquid CO2 at 2100 psi; the flow is about 15 MMcf per day. Briley said that there manual shut offs about 2 miles north and south of the site and that it would take 45 min to 1 hr to close the values. There also is an electronic shut down system, but it would still take about 45 min to 1 hr to shut off supply and "bleed the system." Alternate contact is Barry Petty (who Ed Maher has spoken to.) His tele no is 432-683-8262.

9/4/2003 Called Royce Dunn at Sid Richardson (505-395-2116) to ask if SR had a DOT risk report in case of a leak like Trinity CO2 gas. RD didn't know of any; he said there wouldn't be a fire or "blowout" explosion, like might occur in the CO2 line because SR gas line is low pressure. RD gave the web site of the state agency responsible for oil sites: www.emnrd.state.nm.us/ocd/.

Attachment 6: Fire Protection Handbook

Fire Protection Handbook™

Seventeenth Edition

Arthur E. Cote, P.E.
Editor-in-Chief

Jim L. Linville
Managing Editor

NFPA National Fire Protection Association
Quincy, Massachusetts

A-2 TABLES AND CHARTS

TABLE A-1. *Heats of Combustion and Related Properties For Pure, Simple Substances* (continued)*

Material	Composition	W Molecular Weight	Δh_c° Gross (MJ/kg)	Δh_c^i Net (MJ/kg)	$\Delta h_c^i/r_o$ (MJ/kg O_2)	r_o Oxygen-fuel Mass ratio	T_b Boiling temp. (°C)	Δh_v Latent Heat of Vaporization (kJ/kg)	C_{pl} Liquid Heat Capacity (kJ/kg-°C)	C_{pv} Vapor Heat Capacity (kJ/kg-°C)
cyclopropane	C_3H_6	42.08	49.70	46.57	13.61	3.422	−32.9	—	1.92	1.33
(decahydronaphthalene) → cis-decalin										
cis-decalin	$C_{10}H_{18}$	138.24	45.49	42.63	12.70	3.356	195.8	309	1.67	1.21
n-decane	$C_{10}H_{22}$	142.28	47.64	44.24	12.69	3.486	174.1	276	2.19	1.65
diacetylene	C_4H_2	50.06	46.60	45.72	15.89	2.877	10.3	—	—	1.47
(diamine) → hydrazine										
diborane	H_6B_2	27.69	79.80	79.80	23.02	3.467	−92.5	—	—	1.75
dichloromethane	CH_2Cl_2	84.94	6.54	6.02	10.65	0.565	39.7	330	1.18	0.60
diethyl cyclohexane	$C_{10}H_{20}$	140.26	46.30	43.17	12.58	3.422	174.		1.87	
diethyl ether	$C_4H_{10}O$	74.12	36.75	33.79	13.04	2.590	34.6	360	2.34	1.52
(2,4 diisocyanotoluene) → toluene diisocyanate										
(diisopropyl ether) → iso-propyl ether										
dimethylamine	C_2H_7N	45.08	38.66	35.25	13.24	2.662	6.9	—	—	1.60
(dimethyl aniline) → xylidene										
dimethylidecalin	$C_{12}H_{22}$	166.30	45.70	42.79	13.15	3.254	220.	260		
(dimethyl ether) → methyl ether										
1,1-dimethylhydrazine (UDMH)	$C_2H_8N_2$	60.10	32.95	30.03	14.10	2.130	25.	576	2.73	
dimethyl sulfoxide	C_2H_6SO	78.13	23.88	22.19	15.30	1.843	189.	677	1.89	1.14
1,3 dioxane	$C_4H_8O_2$	88.10	26.57	24.58	9.68	2.543	105.	404		
1,4 dioxane	$C_4H_8O_2$	88.10	26.63	24.84	9.77	2.543	101.1	406	1.74	1.07
ethane	C_2H_6	30.07	51.87	47.49	12.75	3.725	−88.6	—	—	1.75
ethanol	C_2H_6O	46.07	29.67	26.81	12.87	2.084	78.5	837	2.43	1.42
(ethene) → ethylene										
ethyl acetate	$C_4H_8O_2$	88.10	25.41	23.41	12.83	1.816	77.2	367	1.94	1.29
ethyl acrylate	$C_5H_8O_2$	100.12	27.44	25.69	13.39	1.918	100.	290		1.14
ethylamine	C_2H_7N	45.08	38.63	35.22	13.23	2.662	16.5	—	2.89	1.61
ethyl benzene	C_8H_{10}	106.16	43.00	40.93	12.93	3.165	136.1	339	1.75	1.21
ethylene	C_2H_4	28.05	50.30	47.17	13.78	3.422	−103.9	—	2.33	1.55
ethylene glycol	$C_2H_6O_2$	62.07	19.17	17.05	13.22	1.289	197.5	800	2.43	1.56
ethylene oxide	C_2H_4O	44.05	29.85	27.65	15.23	1.816	10.7	—	1.97	1.10
(ethylene trichloride) → trichloroethylene										
(ethyl ether) → diethyl ether										
formaldehyde	CH_2O	30.03	18.76	17.90	16.23	1.068	−19.3	—	—	1.18
formic acid	CH_2O_2	46.03	5.83	4.58	13.15	0.348	100.5	476	2.15	0.98
furan	C_4H_4O	68.07	30.61	29.32	13.86	2.115	31.4	398	1.69	0.96
α-D-glucose†	$C_6H_{12}O_6$	180.16	15.65	14.08	13.21	1.066	—	—	—	—
(glycerine) → glycerol										
glycerol	$C_3H_8O_3$	92.10	17.95	16.04	13.19	1.216	290.0	800	2.42	1.25
(glycerol trinitrate) → nitroglycerin										
n-heptane	C_7H_{16}	100.20	48.07	44.56	12.68	3.513	98.4	316	2.20	1.66
n-heptene	C_7H_{14}	98.18	47.44	44.31	12.95	3.422	93.6	317	2.17	1.58
hexadecane	$C_{16}H_{34}$	226.43	47.25	43.85	12.70	3.452	286.7	226	2.22	1.64
hexamethyldisiloxane	$C_6H_{18}Si_2O$	162.38	38.30	35.80	15.16	2.364	100.1	192	2.01	—
(hexamethylenetetramine) → methenamine										
n-hexane	C_6H_{14}	86.17	48.31	44.74	12.68	3.528	68.7	335	2.24	1.66
n-hexene	C_6H_{12}	84.16	47.57	44.44	12.89	3.422	63.5	333	2.18	1.57
hydrazine	H_4N_2	32.05	22.06	19.34	49.40	0.998	113.5	1180	3.08	1.65
hydrazoic acid	HN_3	43.02	15.28	14.77	79.40	0.186	35.7	690	—	1.02
hydrogen	H_2	2.00	141.79	120.00	16.35	8.000	−252.7	—	—	14.42
(hydrogen azide) → hydrazoic acid										
hydrogen cyanide	HCN	27.03	13.86	13.05	8.82	1.480	25.7	933	2.61	1.33
hydrogen sulfide	H_2S	34.08	48.54	47.25	16.77	2.817	−60.3	548	—	1.00
maleic anhydride†	$C_4H_2O_3$	74.04	18.77	18.17	14.01	1.297	202.0	—	—	—
melamine†	$C_3H_6N_6$	126.13	15.58	14.54	12.73	1.142	—	—	—	—
methane	CH_4	16.04	55.50	50.03	12.51	4.000	−161.5	—	—	2.23
methanol	CH_4O	32.04	22.68	19.94	13.29	1.500	64.8	1101	2.37	1.37
methenamine†	$C_6H_{12}N_4$	140.19	29.97	28.08	13.67	2.054	—	—	—	—
2-methoxyethanol	$C_3H_8O_2$	76.09	24.23	21.92	13.03	1.682	124.4	583	2.23	—
methylamine	CH_5N	31.06	34.16	30.62	13.21	2.318	−6.3	—	—	1.61
(2-methyl 1-butanol) → iso-amyl alcohol										
(methyl chloride) → dichloromethane										
methyl ether	C_2H_6O	46.07	31.70	28.84	13.84	2.084	−24.9	—	—	1.43
methyl ethyl ketone	C_4H_8O	72.10	33.90	31.46	12.89	2.441	79.6	434	2.30	1.43
1-methylnaphthalene	$C_{11}H_{10}$	142.19	40.68	39.33	12.85	3.038	244.7	323	1.58	1.12

Attachment 7: Seabrook Station UFSAR

SEABROOK UPDATED FSAR

TABLE 2.2-15

PUFF RELEASE ANALYSIS PARAMETER VALUES

Probability that a release will occur (P1)*	10^{-4} spills/year
Probability Ignition will be delayed (P2)**	0.24 delayed ignitions per spill
Probability of Ignition at a critical point (P5)	1.0
Probability of unacceptable damage per critical Ignition for a deflagration (P6)	1.0
Probability of a detonation occurring per critical ignition, for a detonation (P6')***	0.28
Site Temperature	104°F
Propane Mass Release	2.35×10^5 lb.
Flashing Fraction	0.478
Propane Puff Weight (M)	1.12×10^5 lb.
Propane Vapor density at 104°F (Pga)	0.107 lb./ft^3
Detonability Limits of Propane	3.0 - 6.8% (Ref. 96)

* Reference 70 gives an upper bound for boiler failures of 10^{-5} per year and Reference 98 gives the failure rate for fixed location chlorine tanks as 10^{-5} per year, excluding seismic events. A value of 10^{-4} per year is conservatively assumed.

** Study of rail car spills (Reference 70) shows that 76 percent of the spills ignited within 100 ft of the release, hence, a value of 0.24 delayed ignitions per spill.

*** Reference 71 suggests a detonation rate giving ignition of 0.28, which is considered conservative.

Attachment 8: SFPE Handbook of Fire Protection Engineering

SFPE Handbook of Fire Protection Engineering

Second Edition

Editorial Staff

Philip J. DiNenno, P.E., Hughes Associates, Inc.
Craig L. Beyler, PhD., Hughes Associates, Inc.
Richard L. P. Custer, Custer Powell, Inc.
W. Douglas Walton, P.E., National Institute of Standards and Technology
John M. Watts, Jr., PhD., The Fire Safety Institute
Dougal Drysdale, PhD., University of Edinburgh
John R. Hall, Jr., PhD., National Fire Protection Association

NFPA® National Fire Protection Association
Quincy, Massachusetts

Society of Fire Protection Engineers
Boston, Massachusetts

TABLE 2-9.1 *Summary of Limits of Flammability, Lower Temperature Limits (T_L), and Minimum Autoignition Temperatures (AIT) of Individual Gases and Vapors in Air at Atmospheric Pressure*[a] *(Continued)*

Combustible	Limits of flammability (volume-percent) L_{25}	U_{25}	T_L (°C)	AIT (°C)
Ethylenimine	3.6	45	—	320
Ethylene glycol	[4]3.5	—	—	400
Ethylene oxide	3.6	100	—	—
Furfuryl alcohol	[15]1.8	[16]16	72	390
Gasoline:				
100/130	1.3	7.1	—	440
115/145	1.2	7.1	—	470
Glycerine	—	—	—	370
n-Heptane	1.05	6.7	−4	215
n-Hexadecane	[4]0.43	—	126	205
n-Hexane	1.2	7.4	−26	225
n-Hexyl alcohol	[1]1.2	—	—	—
n-Hexyl ether	[4]0.6	—	—	185
Hydrazine	4.7	100	—	—
Hydrogen	4.0	75	—	400
Hydrogen cyanide	5.6	40	—	—
Hydrogen sulfide	4.0	44	—	—
Isoamyl acetate[1]	1.1	[17]7.0	25	360
Isoamyl alcohol[1]	1.4	[19]9.0	—	350
Isobutane	1.8	8.4	−81	460
Isobutyl alcohol	[1]1.7	[1]11	—	—
Isobutyl benzene	[1]0.82	[10]6.0	—	430
Isobutyl formate	2.0	8.9	—	—
Isobutylene	1.8	9.6	—	465
Isopentane	1.4	—	—	—
Isophorone	0.84	—	—	460
Isopropylacetate	[4]1.7	—	—	—
Isopropyl alcohol	2.2	—	—	—
Isopropyl biphenyl	[4]0.6	—	—	440
Jet fuel:				
JP-4	1.3	8	—	240
JP-6	—	—	—	230
Kerosine	—	—	—	210
Methane	5.0	15.0	−187	540
Methyl acetate	3.2	16	—	—
Methyl acetylene	1.7	—	—	—
Methyl alcohol	6.7	[11]36	—	385
Methyl amine	[4]4.2	—	—	430
Methyl bromide	10	15	—	—
3-Methyl butene-1	1.5	9.1	—	—
Methyl butyl ketone	[5]1.2	[1]8.0	—	—
Methyl cellosolve	[17]2.5	[7]20	—	380
Methyl cellosolve acetate	[8]1.7	—	46	—
Methyl ethyl ether	[4]2.2	—	—	—
Methyl chloride	[4]7	—	—	—
Methyl cyclohexane	1.1	6.7	—	250
Methyl cyclopentadiene	[1]1.3	[1]7.6	49	445
Methyl ethyl ketone	1.9	10	—	—
Methyl ethyl ketone peroxide	—	—	40	390
Methyl formate	5.0	23	—	465
Methyl cyclohexanol	[4]1.0	—	—	295
Methyl isobutyl carbinol	[4]1.3	—	40	—
Methyl isopropenyl ketone	[8]1.8	[8]9.0	—	—
Methyl lactate	[1]2.2	—	—	—
α-Methyl naphthalene	[4]0.8	—	—	530
2, Methyl pentane	[4]1.2	—	—	—
Methyl propionate	2.4	13	—	—
Methyl propyl ketone	1.5	8.2	—	—
Methyl styrene	[4]1.0	—	49	495
Methyl vinyl ether	2.6	39	—	—
Methylene chloride	—	—	—	615
Monoisopropyl bicyclohexyl	0.52	[10]4.1	124	230
2-Monoisopropyl biphenyl	[10]0.53	[10]3.2	141	435
Monomethylhydrazine	4	—	—	—
Naphthalene	[10]0.88	[20]5.9	—	526
Nicotine	[1]0.75	—	—	—
Nitroethane	3.4	—	30	—
Nitromethane	7.3	—	33	—
1-Nitropropane	2.2	—	34	—
2-Nitropropane	2.5	—	27	—
n-Nonane	[21]0.85	—	31	205
n-Octane	0.95	—	13	220
Paraldehyde	1.3	—	—	—
Pentaborane	0.42	—	—	—
n-Pentane	1.4	7.8	−48	260
Pentamethylene glycol	—	—	—	335
Phthalic anhydride	[7]1.2	[22]9.2	140	570
3-Picoline	[4]1.4	—	—	500
Pinane	[23]0.74	[23]7.2	—	—
Propadiene	2.16	—	—	—
Propane	2.1	9.5	−102	450
1,2-Propandiol	[4]2.6	—	—	410
β-Propiolactone	[3]2.9	—	—	—
Propionaldehyde	2.9	17	—	—
n-Propyl acetate	1.8	8	—	—
n-Propyl alcohol	[12]2.2	[1]14	—	440
Propyl amine	2.0	—	—	—
Propyl chloride	[4]2.4	—	—	—
n-Propyl nitrate	[17]1.8	[17]100	21	175
Propylene	2.4	11	—	460
Propylene dichloride	[4]3.1	—	—	—
Propylene glycol	[24]2.6	—	—	—
Propylene oxide	2.8	37	—	—
Pyridine	[11]1.8	[25]12	—	—
Propargyl alcohol	[5]2.4	—	—	—
Quinoline	[4]1.0	—	—	—
Styrene	[26]1.1	—	—	—
Sulfur	[27]2.0	—	247	—
p-Terphenyl	[4]0.96	—	—	535
n-Tetradecane	[4]0.5	—	—	200
Tetrahydrofurane	2.0	—	—	—
Tetralin	[1]0.84	[8]5.0	71	385
2,2,3,3-Tetramethyl pentane	0.6	—	—	430
Tetramethylene glycol	—	—	—	390
Toluene	[1]1.2	[1]7.1	—	460
Trichloroethane	—	—	—	500
Trichloroethylene	[28]12	[28]40	30	420
Triethyl amine	1.2	8.0	—	—
Triethylene glycol	[6]0.9	[29]9.2	—	—
2,2,3-Trimethyl butane	1.0	—	—	420
Trimethyl amine	2.0	12	—	—
2,2,4-Trimethyl pentane	0.95	—	—	415
Trimethylene glycol	[4]1.7	—	—	400
Trioxane	[4]3.2	—	—	—
Turpentine	[1]0.7	—	—	—
Unsymmetrical dimethylhydrazine	2.0	95	—	—
Vinyl acetate	2.6	—	—	—
Vinyl chloride	3.6	33	—	—
m-Xylene	[1]1.1	[1]6.4	—	530
o-Xylene	[1]1.1	[1]6.4	—	465
p-Xylene	[1]1.1	[1]6.6	—	530

[a] T = 100° C.
[1] T = 75° C.
[2] T = 75° C.
[3] Calculated.
[4] T = 25° C.
[5] T = 90° C.
[6] T = 85° C.
[7] T = 140° C.
[8] T = 150° C.
[9] T = 110° C.
[10] T = 175° C.
[11] T = 60° C.
[12] T = 53° C.
[13] T = 85° C.
[14] T = 130° C.
[15] T = 72° C.
[16] T = 117° C.
[17] T = 125° C.
[18] T = 200° C.
[19] T = 78° C.
[20] T = 122° C.
[21] T = 43° C.
[22] T = 195° C.
[23] T = 160° C.
[24] T = 95° C.
[25] T = 70° C.
[26] T = 25° C.
[27] T = 247° C.
[28] T = 30° C.
[29] T = 203° C.

actual quenching of the advancing flame front in large vessels. Some agents provide chemical inhibition effects (most likely via free radical scavenging) in addition to diluent and thermal benefits, but this chemical inhibition effectiveness is both fuel dependent,[27] and dependent on the advancing flame front speed.[29]

Most of the suppression test data suggest that the various agents have comparable effectiveness for slow to moderate deflagrations, but that ammonium phosphate (and to a lesser extent potassium bicarbonate) becomes decidedly more effective for rapid deflagrations. However, Bartknecht concludes that none of these agents, as presently used in suppression systems, can suppress explosions in gases with K_G values exceeding 200 bar·m/s, or in dusts with K_{ST} values greater than 300 bar·m/s.

Recent tests at NIST[30] in a shock tube generating highly turbulent flames and quasidetonations demonstrate that these high-challenge explosions *can* be suppressed, provided (1) agent can be dispersed uniformly ahead of the shock wave, and (2) gaseous agent concentrations are around 10 vol percent, i.e., about twice as high as the Halon 1301 volumetric concentration used for more conventional, less challenging, explosion suppression applications.

The choice of agent must involve other considerations besides suppression effectiveness as determined by test data. Other relevant considerations include agent retention time to cope with repeated ignitions, agent compatibility with process materials, environmental impact regulations, and potential toxicity effects at the agent design concentration. U.S. regulations that define acceptable and unacceptable suppression agents, from environmental and toxicity considerations, are described in a significant new alternative policy for ozone-depleting chemicals.[31]

General guidelines for the design, installation, and maintenance of a reliable and effective explosion suppression system can be found in the literature[1,30,40] and in the manuals provided by system manufacturers. In addition, system manufacturers and approval organizations have a wealth of unpublished test and incident data that are often essential in developing system specifications and designs for specific applications.

VAPOR CLOUD EXPLOSIONS

Release of a large quantity of flammable gas or vapor into the atmosphere will result, at least temporarily, in the formation of a flammable vapor cloud. Ignition of the vapor cloud may, under certain vaguely defined conditions, result in sufficiently rapid flame propagation to generate destructive overpressures and blast waves. Qualitatively, the conditions required for a vapor cloud explosion are (1) a large quantity of detonation-prone gas/vapor; and (2) either a highly energetic ignition source or a highly obstructed environment supportive of turbulence-induced flame accelerations.

Historically,[31,32] all reported vapor cloud explosions have involved the release of at least 100 kg of flammable gas, with a quantity of 1000 to 10,000 kg being most common. The gases most often involved have been ethylene, propane, and butane. According to Wiekema's compilation of incident data,[32] all of the reported vapor cloud explosions have occurred in "semiconfined" environments such that buildings or other large structures were within the vapor cloud at the time of ignition. Wiekema's data suggest that the presence of a large building or structure within the cloud is a necessary, but not sufficient, condition for an explosion to occur, since at least 15 of 68 (22 percent) reported ignitions in semiconfined environments resulted in flash fires as opposed to explosions (37 other ignitions did result in explosions). Damage surveys indicate that many of the vapor cloud explosions were deflagrations rather than detonations. On the other hand, analyses of pressure waves generated from flame propagation through vapor clouds (e.g., Lee *et al*[33]) indicate that flame speeds of at least 100 m/s are necessary to generate potentially destructive overpressures greater than about 0.1 atm. Thus, the most likely scenario is that flame speeds on the order of a few hundred m/s (corresponding to so-called quasidetonations) were generated in the actual incidents as a result of flame acceleration around buildings and structures.

The most commonly used method* to assess blast wave effects from vapor cloud explosions is to employ ideal (point source) blast wave correlations based on the blast wave energy, i.e., the TNT equivalent energy. This energy is given by

$$E = \alpha \Delta H_c m_F \qquad (12)$$

where:

E = blast wave energy (kJ)
α = yield, i.e., the fraction of available combustion energy participating in blast wave generation
ΔH_c = theoretical net heat of combustion (kJ/kg)
m_F = mass of flammable vapor released (kg)

The corresponding TNT equivalent mass, kg, W_{TNT} is

$$W_{TNT} = E/4500 \text{ kg} \qquad (13)$$

Figure 3-16.14 is the ideal blast wave overpressure versus distance correlation used in conjunction with Equations 12 and 13. Distances in Figure 3-16.14 are scaled by the cube root of W_{TNT} in accordance with ideal blast wave theory.[34] The overpressures in Figure 3-16.14 are reflected shock wave overpressures associated with reflections of the incident shock wave off a solid surface perpendicular to the wave propagation direction. Nominal building damage and personnel injury thresholds are also indicated in Figure 3-16.14 and in Table 3-16.9. More accurate and comprehensive damage assessments should be based on actual structural dynamic loading calculations leading to impulse-overpressure damage thresholds as described, for example, by Fickett and Davis.[17]

Before Equations 12 and 13 can be used effectively, some guidance is needed on the selection of appropriate values of the yield, α. Data compiled by Gugan[35] and Davenport[31] on the effective yields from approximately 20 vapor cloud explosions showed a spread of four orders of magnitude, with the highest value in one particularly devastating incident being 25 to 50 percent. Wiekema's compilation[32] shows the effective yield to be about one percent for releases of 1,000 to 10,000 kg vapor, and to be in the range of 1 to 10 percent when more than 10,000 kg is released. The yield in the Flixborough explosion (one of the most destructive and the most thoroughly investigated and reported vapor cloud explosion to date) is 4 to 5 percent based on the 30 to 40 metric tons of cyclohexane released prior to ignition.[36] Thus, the specification of yields for blast damage predictions is an exercise in risk assessment, with

*Although the TNT equivalency method is most common in the United States, Europeans often use other methods.[32,39]

Attachment 9: TVA PSAR, Hartsville Nuclear Plants

TVA

HARTSVILLE NUCLEAR PLANTS

DOCKET NOS. STN-50-518,519,520,521

PSAR AMENDMENT 30

8002290381

2.2.3.4 Gas Pipeline Hazard

A gas pipeline installation belonging to the East Tennessee Natural Gas Company (ETNG) passes through the northern part of the Hartsville Site. As shown in Figure 2.2-9(T) the pipeline crosses the site boundary near the northwest corner, enters a compressor substation north-northeast of the plant, and leaves the site at the northeast site boundary. Approximately 1.67 miles of pipe lie within the site boundary with a closest approach of approximately 2,650 feet to the nearest critical plant structure.

An extensive investigation into the safety hazards posed by this pipeline has been conducted. The yearly probability of a hazard to the plant was determined in this investigation. Events which could cause a hazard to the plant were identified in the form of a hazard tree shown in Figure 2.2-10(T). The hazards from thermal radiation, blast overpressure, missile generation, and plant contamination by gas at an unacceptable concentration were analyzed to determine the probability of exceeding acceptable levels at the plant site. The yearly probability of exceeding the acceptability criteria (referred to as the hazard probability) was calculated using sophisticated analysis techniques. The analysis accounted for a broad range of parameters, such as leak location and size, time varying gas cloud size, shape, and orientation relative to the plant, meteorological conditions, and the time at which the gas cloud ignites.

It was determined that the yearly probability of a hazard due to thermal radiation, missile generation, and plant contamination

by gas at an unacceptable concentration is negligible. It was also determined that the best estimate of the yearly probability of a peak reflected overpressure of 2.4 psi at the plant due to a gas cloud detonation was 0.16 x 10 ·, assuming that unconfined natural gas can detonate. (There is some doubt that unconfined natural gas can detonate. See section 2.2.3.4.6.3.3(3) for further discussion. If unconfined natural gas cannot detonate, then the probability of a 2.4-psi peak reflected overpressure is zero.) 17 17 17

2.2.3.4.1 Gas Pipeline Description. A natural gas pipeline installation belonging to the East Tennessee Natural Gas (ETNG) Company passes through the northern part of the Hartsville site. The pipeline was constructed in the early 1950's and is part of a network consisting of approximately 1000 miles of major pipelines operated by ETNG. 17 17

The buried pipeline follows the terrain along its route. It crosses the northwest plant perimeter at an elevation of approximately 520 feet and rapidly rises to an elevation of 800 feet. It is nearly 200 feet in elevation above reactor building grade at its point of closest approach to a critical plant structure (diesel building for plant A, Unit 2).

The pipe has an outside diameter of 22 inches and is operated at a maximum pressure of 720 psig at the compressor station. The average operating pressure at the point of closest approach is approximately 560 psig. The pipeline contains automatic isolation valves. The nearest ones to the plant are located

HNP-17

The minimum clearance for all conditions was found to be 275 feet. This occurs for break point 12, stability class G, and a wind speed of 7.5 miles per hour.

The minimum clearance for a given break point and stability class is relatively insensitive to wind speed. This is evident by comparision of the data within each column of Table 2.2-1(T). The time at which the minimum clearance condition occurs varies considerably with wind speed.

The results described above are based on the expected plume rise for each break point, stability class, wind speed, and time. An analysis was also performed to determine the impact of assuming worst-case estimates for plume rise equation variables, using the minimum clearance conditions (break point 12, stability class G, 7.5 mph, 750 seconds). A worst-case clearance of 60 feet was obtained in the analysis, which is described in the following paragraphs.

The results in Table 2.2-1(T) are calculated using the nominal plume rise coefficients given by Briggs (Reference 10). A maximum variation due to random factors of about 25 to 35 percent above or below the nominal rise can be expected. A worst-case coefficient of sixty-five percent of the nominal was therefore established as a lower bound on the plume rise due to random variations.

The gas temperature after expansion in the atmosphere may be less than the surrounding air, as discussed in Section 2.2.3.4.4.1. This temperature differential is expected to be not greater than 50° F. One hundred degrees Fahrenheit was established as a conservative bound on the temperature

differential for the worst-case. This differential reduces plume rise uniformly by approximately twelve percent.

The clearances in Table 2.2-1(T) are based on a vertical temperature gradient of 7 degrees Centigrade per 100 meters for Stability Class G. The worst-case temperature gradient expected at the site is 10 degrees Centigrade per 100 meters. Use of this value results in plume rises approximately 90 percent less than those on which Table 2.2-1(T) is based.

When all of the above factors were combined, a worst-case plume rise reduction of approximately 50 percent was obtained. The corresponding worst-case clearance to the air intakes is 60 feet.

This demonstrated that the probability of a hazard due to gas contamination is essentially zero, since gas at flammable concentrations did not approach the plant air intakes under worst-case conditions.

2.2.3.4.6.2 Heat Exposure Hazard

The probability of a hazard at the plant due to heat exposure was found to be negligible under worst-case conditions. A maximum heat flux of 200 BTU/ft^2 was obtained in the analysis. This may be compared with a flux of approximately 1,750 BTU/ft^2 required for spontaneous ignition of wood (Reference 18). Since all of the critical plant surfaces exposed to the heat radiated from a burning cloud are concrete, the maximum flux is well below that which would cause any damage.

The largest gas cloud flammable regions and lowest plume rises occur for low wind speeds under stable atmospheric (class G) conditions. These conditions also give rise to the highest heat fluxes. For a given break point and wind speed, the heat

flux increases with ignition time until the gas cloud recedes away from the plant. Analysis of the heat fluxes from various pipe segments revealed that the maximum flux resulted from a rupture in segment 14 (see Figure 2.2-16(T)), which has the lowest elevation. This condition occurred for a wind speed of 0.6 miles per hour and an ignition time of approximately 100 minutes after the start of gas release.

The maximum heat flux is based on the nominal plume rise for Stability Class G. If a worst-case reduction factor of 50 percent is applied to the nominal plume rise, as in the case of the gas contamination hazard (Section 2.2.3.4.6.1), the maximum heat flux is less than 800 Btu/ft². Thus, the worst-case heat flux is well below the flux which can cause damage to critical plant structures.

2.2.3.4.6.3 Detonation Hazard. The detonation hazard was determined by calculating the yearly probability of exceeding the structural capabilities of the safety-related structures at the plant by air blasts or missile impacts. Plant structural capabilities given in the response to Question 130.22 were used in these analyses. These established that a conservative value for the most vulnerable safety-related structure was 2.4 psi peak reflected pressure. Combinations of various rupture locations (break points), meteorological conditions, and detonation times were evaluated in the estimation of hazard probability. 17

Attachment 10: ALOHA Benchmarking Test Case

1.0 OBJECTIVE

Verify that ALOHA 5.2.3 version is correctly predicting results on the installed computer, an IBM-compatible PC (ID#3W2BZ1) using Microsoft Windows XP® Professional, Version 2002, operating system with a Pentium(R) 4 processor.

2.0 TESTING METHOD AND ACCEPTANCE CRITERION

Select an example test case from the ALOHA User's Manual as a benchmark. Enter the test case input data on the installed computer and then compare the example and installed computer results. The values should be identical.

3.0 RESULTS

User's Manual Example 3: A Pipe Source was chosen as the benchmark test case to compare results because it is very similar to the postulated scenario being evaluated in this calculation. Example 3 input data, as shown on user's manual pages 143 through 149, was entered into the installed computer, with one exception: the internal computer clock was used instead of the example date and time to distinguish the two printed results.

Copies of both the "Footprint Plot" and "Text Summary" from the user's manual (page 40 in this calculation) and the installed computer output (pages 41 and 42 in this calculation) are attached. As shown, the plots are identical and the predicted numerical values on the text summaries are virtually identical. The only variations are in the "Total Amount Released," where the Example 3 value is 84,565 pounds vs. 84,564 pounds for the installed version and the user's manual text summary includes a default LOC (i.e., from library: 50000 ppm). These difference are considered insignificant.

4.0 CONCLUSION

The installed ALOHA 5.2.3 version is correctly predicting results as designed.

ALOHA®

AREAL LOCATIONS OF HAZARDOUS ATMOSPHERES

User's Manual

AUGUST 1999

EPCRA Reporting Center
703 816-4445, x 353, 398, 364, 292

U.S. ENVIRONMENTAL PROTECTION AGENCY

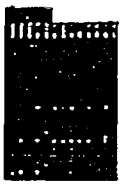
NATIONAL OCEANIC AND ATMOSPHERIC ADMINISTRATION

COMPUTER-AIDED MANAGEMENT OF EMERGENCY OPERATIONS
cameo®

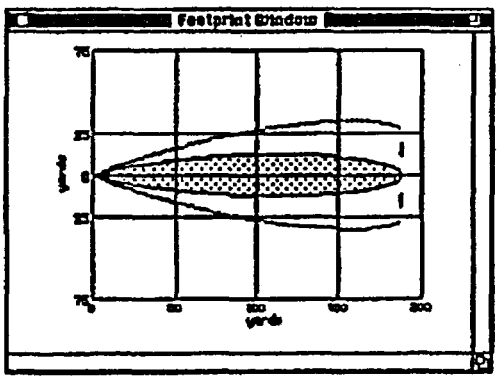
Chemical Emergency Preparedness and Prevention Office
Washington, D.C. 20460

Hazardous Materials Response Division
Seattle, Washington 98115

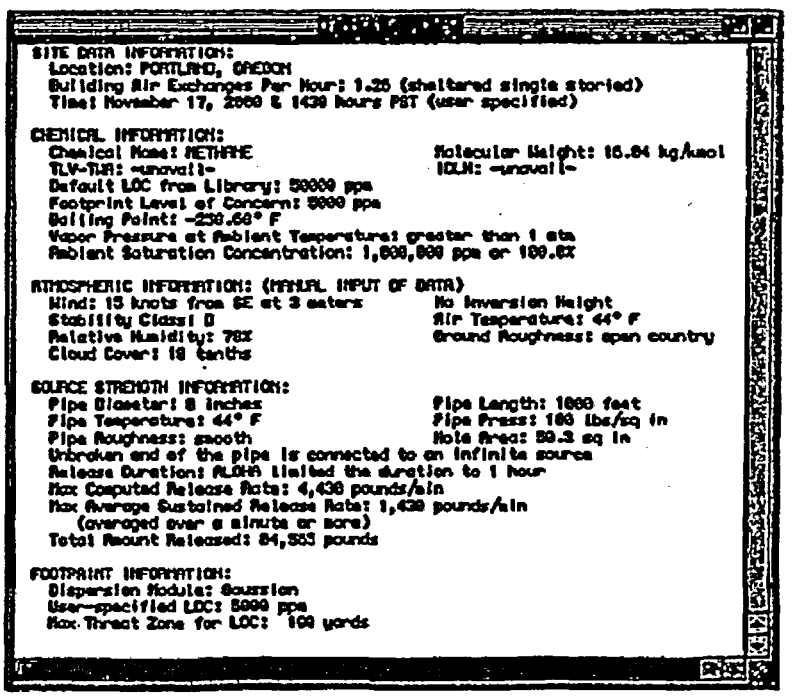
5 Choose Footprint from the Display menu.



ALOHA predicts that the concentration of methane may exceed 5,000 ppm for up to about 190 yards downwind of the leaking pipe.



Your Text Summary should now look like the one below.



```
SITE DATA INFORMATION:
  Location: PORTLAND, OREGON
  Building Air Exchanges Per Hour: 1.25 (sheltered single storied)
  Time: November 17, 2000 @ 1430 hours PST (user specified)

CHEMICAL INFORMATION:
  Chemical Name: METHANE                    Molecular Weight: 16.04 kg/kmol
  TLV-TWA: -unavail-                        IDLH: -unavail-
  Default LOC from Library: 50000 ppm
  Footprint Level of Concern: 5000 ppm
  Boiling Point: -258.68° F
  Vapor Pressure at Ambient Temperature: greater than 1 atm
  Ambient Saturation Concentration: 1,000,000 ppm or 100.0%

ATMOSPHERIC INFORMATION: (MANUAL INPUT OF DATA)
  Wind: 15 knots from SE at 3 meters        No Inversion Height
  Stability Class: D                        Air Temperature: 44° F
  Relative Humidity: 78%                    Ground Roughness: open country
  Cloud Cover: 10 tenths

SOURCE STRENGTH INFORMATION:
  Pipe Diameter: 8 inches                   Pipe Length: 1000 feet
  Pipe Temperature: 44° F                   Pipe Press: 100 lbs/sq in
  Pipe Roughness: smooth                    Hole Area: 50.3 sq in
  Unbroken end of the pipe is connected to an infinite source
  Release Duration: ALOHA limited the duration to 1 hour
  Max Computed Release Rate: 4,430 pounds/min
  Max Average Sustained Release Rate: 1,430 pounds/min
     (averaged over a minute or more)
  Total Amount Released: 84,555 pounds

FOOTPRINT INFORMATION:
  Dispersion Module: Gaussian
  User-specified LOC: 5000 ppm
  Max Threat Zone for LOC:  190 yards
```

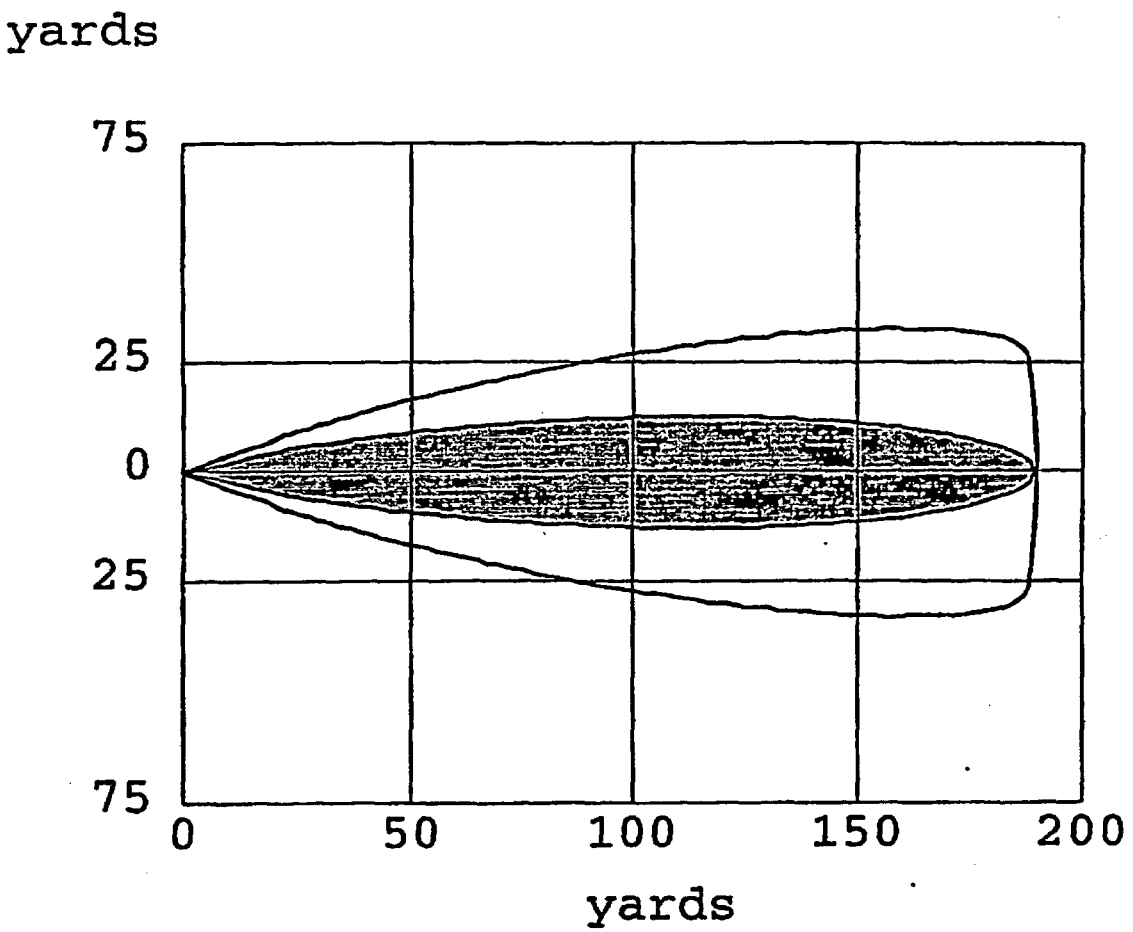
Footprint Window ALOHA® 5.2.3

Time: December 5, 2003 0822 hours PST (using computer's clock)

Chemical Name: METHANE

Wind: 15 knots from SE at 3 meters

FOOTPRINT INFORMATION:
Dispersion Module: Gaussian
User-specified LOC: 5000 ppm
Max Threat Zone for LOC: 190 yards



Text Summary ALOHA® 5.2.3

```
SITE DATA INFORMATION:
  Location: PORTLAND, OREGON
  Building Air Exchanges Per Hour: 1.26 (sheltered single storied)
  Time: December 5, 2003  0822 hours PST (using computer's clock)

CHEMICAL INFORMATION:
  Chemical Name: METHANE          Molecular Weight: 16.04 kg/kmol
  TLV-TWA: -unavail-              IDLH: -unavail-
  Footprint Level of Concern: 5000 ppm
  Boiling Point: -258.68° F
  Vapor Pressure at Ambient Temperature: greater than 1 atm
  Ambient Saturation Concentration: 1,000,000 ppm or 100.0%

ATMOSPHERIC INFORMATION: (MANUAL INPUT OF DATA)
  Wind: 15 knots from SE at 3 meters
  No Inversion Height
  Stability Class: D              Air Temperature: 44° F
  Relative Humidity: 78%          Ground Roughness: open country
  Cloud Cover: 10 tenths

SOURCE STRENGTH INFORMATION:
  Pipe Diameter: 8 inches         Pipe Length: 1000 feet
  Pipe Temperature: 44° F         Pipe Press: 100 lbs/sq in
  Pipe Roughness: smooth          Hole Area: 50.3 sq in
  Unbroken end of the pipe is connected to an infinite source
  Release Duration: ALOHA limited the duration to 1 hour
  Max Computed Release Rate: 4,430 pounds/min
  Max Average Sustained Release Rate: 1,430 pounds/min
     (averaged over a minute or more)
  Total Amount Released: 84,564 pounds

FOOTPRINT INFORMATION:
  Dispersion Module: Gaussian
  User-specified LOC: 5000 ppm
  Max Threat Zone for LOC:  190 yards
```

Attachment 11: Design Verification Checklist

RAMATOME ANP

DESIGN VERIFICATION CHECKLIST

Document Identifier 32-2400572-02

Title Natural Gas Pipeline Hazard Risk Determination

1.	Were the inputs correctly selected and incorporated into design or analysis?	☒ Y	☐ N	☐ N/A
2.	Are assumptions necessary to perform the design or analysis activity adequately described and reasonable? Where necessary, are the assumptions identified for subsequent re-verifications when the detailed design activities are completed?	☒ Y	☐ N	☐ N/A
3.	Are the appropriate quality and quality assurance requirements specified? Or, for documents prepared per FANP procedures, have the procedural requirements been met?	☒ Y	☐ N	☐ N/A
4.	If the design or analysis cites or is required to cite requirements or criteria based upon applicable codes, standards, specific regulatory requirements, including issue and addenda, are these properly identified, and are the requirements/criteria for design or analysis met?	☒ Y	☐ N	☐ N/A
5.	Have applicable construction and operating experience been considered?	☐ Y	☐ N	☒ N/A
6.	Have the design interface requirements been satisfied?	☐ Y	☐ N	☒ N/A
7.	Was an appropriate design or analytical method used?	☒ Y	☐ N	☐ N/A
8.	Is the output reasonable compared to inputs?	☒ Y	☐ N	☐ N/A
9.	Are the specified parts, equipment and processes suitable for the required application?	☐ Y	☐ N	☒ N/A
10.	Are the specified materials compatible with each other and the design environmental conditions to which the material will be exposed?	☐ Y	☐ N	☒ N/A
11.	Have adequate maintenance features and requirements been specified?	☐ Y	☐ N	☒ N/A
12.	Are accessibility and other design provisions adequate for performance of needed maintenance and repair?	☐ Y	☐ N	☒ N/A
13.	Has adequate accessibility been provided to perform the in-service inspection expected to be required during the plant life?	☐ Y	☐ N	☒ N/A
14.	Has the design properly considered radiation exposure to the public and plant personnel?	☐ Y	☐ N	☒ N/A
15.	Are the acceptance criteria incorporated in the design documents sufficient to allow verification that design requirements have been satisfactorily accomplished?	☐ Y	☐ N	☒ N/A
16.	Have adequate pre-operational and subsequent periodic test requirements been appropriately specified?	☐ Y	☐ N	☒ N/A
17.	Are adequate handling, storage, cleaning and shipping requirements specified?	☐ Y	☐ N	☒ N/A
18.	Are adequate identification requirements specified?	☐ Y	☐ N	☒ N/A
19.	Is the document prepared and being released under the FANP Quality Assurance Program? If not, are requirements for record preparation review, approval, retention, etc., adequately specified?	☒ Y	☐ N	☐ N/A

FRAMATOME ANP

DESIGN VERIFICATION CHECKLIST

Comments:

1. Although Reg. Guide 1.91 (Ref. 3) does not address effects of airblasts associated w/pipelines, equation 1 of Reg. Guide 1.91 ($R \geq kW^{1/3}$), used in the determination of the exposure distance (Section 6.1.3 on p. 7 and Attachment 4), is based on the concept of TNT equivalence and applicable to hydrocarbons under pressure.

2. The benchmarking test case for the ALOHA program (Attachment 10) meets the requirements of FANP procedure 402-01, Section VII.C.

Note: Comments 1 and 2 are from the Design Verification Checklist attached to Revision 1 of this calculation.

Verified By:	J.H. Snooks	J.H. Snooks	1/19/2004
First, MI, Last)	Printed / Typed Name	Signature	Date