Safety Study

San Diego Gas & Electric Company and
Southern California Gas Company
Pipeline Safety & Reliability Project

ENERCON
Excellence—Every project. Every day.

Prepared for:

San Diego Gas & Electric
8326 Century Park Court
San Diego, CA 92123

Prepared by:

Enercon Services, Inc.
1451 River Park Drive, Ste. 1000
Sacramento, CA 95815
(916) 480-0205

Prepared by:	Brian Norman Responsible Engineer	Date:	9/28/15
Reviewed by:	Chad Cramer Safety Analysis Supervisor	Date:	9/28/15
Reviewed by:	Marvin Morris Lead Responsible Engineer	Date:	9/28/15
Approved by:	Tom Trexler Project Manager	Date:	9/28/15

Table of Contents

List of Tables

List of Figures

List of Acronyms and Abbreviations

AC	alternating current
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
Btu	British thermal unit
CDE	*California Department of Education*
CFR	Code of Federal Regulations
cm	centimeter
CP	cathodic protection
CPUC	California Public Utilities Commission
D, d	diameter
DC	direct current
°F, F	Fahrenheit
FBE	fusion bonded epoxy
ft	foot
ft^2	square foot
GRI	Gas Research Institute
h, hr	hour
HCA	high consequence area
HLPSA	Hazardous Liquid Pipeline Safety Act of 1979 as amended
HVAC	heating ventilation and air conditioning
in	inch
IR	individual risk
ksi	kilopounds per square inch
kW	kilowatt
LFL	lower flammability limit
LNG	liquefied natural gas
LORS	laws, ordinances, regulations, and standards
m	meter
m^2	square meter
MAOP	maximum allowable operating pressure
MCAS	Marine Corps Air Station
mi	mile
MMcfd	million cubic feet per day
MMcfh	million cubic feet per hour
NGPSA	Natural Gas Pipeline Safety Act of 1968 as amended

List of Acronyms and Abbreviations (cont'd)

NTSB	National Transportation Safety Board
OPS	Office of Pipeline Safety
PEA	Proponent's Environmental Assessment
PG&E	Pacific Gas and Electric Company
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSEP	Pipeline Safety Enhancement Plan
psi(g)	pounds per square inch (gauge)
R, r	radius
REDOX	oxidation reduction reaction
s	second
SCADA	supervisory control and data acquisition
SCC	stress corrosion cracking
SDG&E	San Diego Gas & Electric Company
SMYS	specified minimum yield strength
SoCalGas	Southern California Gas Company
UFL	upper flammability limit
US	United States
USC	United States Code
USDOT	United States Department of Transportation
W	watt
yr	year

EXECUTIVE SUMMARY

San Diego Gas & Electric Company and Southern California Gas Company (Applicants) propose to construct, operate, and maintain a new proposed natural gas transmission pipeline (Proposed Project). This Safety Study analyzes the potential risks to individuals and the public associated with the construction and operation of the Proposed Project. The risks assessed and described in this report include those that could result from unintentional releases of natural gas and the possibility of subsequent fires and/or explosions. ***Individual and societal risks associated with the Proposed Project were found to be less than significant***.

Description of the Proposed Project: The primary component of the Proposed Project includes the construction of a 36-in-diameter transmission pipeline. The pipeline will be approximately 47 miles in length and will begin at the Rainbow Pressure-Limiting Station, proceed in a southerly direction through San Diego County, and terminate at the Marine Corps Air Station Miramar. The Applicants will also construct and maintain appurtenant facilities, including mainline valves, metering equipment, pressure-limiting equipment, in-line inspection equipment, cathodic protection systems, and an intrusion and leak monitoring system.

Study Methodology: The risk evaluation methodology presented in this Study uses generally accepted methods, models, and software to quantify the risk to individuals and the general public. The assessment uses conservative approaches and assumptions to ensure that all reasonable potential risk scenarios are evaluated. Proposed Project design features that would reduce the likelihood or consequences of an incident were not taken into account when evaluating risk.

Significance Criteria: Generally accepted domestic and international individual and societal risk significance criteria are used to evaluate the significance level of potential impacts of the Proposed Project: 1×10^{-6} fatalities/year (1 in a million years) is applied for individual risk; and a site casualty to societal risk criteria of less than 1.0 for societal risk. Risks at or below these levels are considered less than significant.

Conclusions: The risk assessment demonstrated that all risks were less than significant without taking into account Proposed Project design features that would reduce the likelihood or consequences of an incident. The individual risk level for the Proposed Project was determined to be 4.52×10^{-7} fatalities per year (i.e., 1 in 2,212,389 years); less than the generally accepted significance criteria of 1 in a million years. The societal risk level for the Proposed Project is also below the significance criteria—all events have a site casualties to societal risk criteria ratio of less than 1.0.

Proposed Project Design Features: The Proposed Project includes several design features, such as increased wall thickness and testing and inspection plans, intended to further reduce the risk of incidents involving third-party damage, external corrosion, material failure, and weld failure. These design features meet or exceed all applicable laws, ordinances, regulations, and standards to further reduce the frequency of releases. With these design features, risks associated with the Proposed Project will be reduced even further below their already less-than-significant levels.

1.0 INTRODUCTION

This Safety Study (Study) presents the potential risks to individuals and the public from the proposed facilities associated with San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) (jointly referred to as Applicants) proposed the Pipeline Safety & Reliability Project (Proposed Project). The risks assessed and described in this report include those that could result from unintentional releases of natural gas and the possibility of subsequent fires and/or explosions. Intentional releases of natural gas, such as blowdowns to clear out pipelines of natural gas for maintenance/repairs, are discussed in further detail in the Hazards and Hazardous Materials section of the Proponent's Environmental Assessment (SDG&E 2015).

The Study is divided into the following sections:

- Section 1 – Introduction
- Section 2 – Description of the Proposed Project
- Section 3 – Background
- Section 4 – Study Methodology
- Section 5 – Overview of Applicable Regulations, Plans, and Policies
- Section 6 – Calculation of Incident Rate
- Section 7 – Significance Criteria
- Section 8 – Risk Assessment
- Section 9 – Proposed Project Design Features
- Section 10 – Conclusion
- Section 11 – References

2.0 DESCRIPTION OF THE PROPOSED PROJECT

The Applicants are proposing to construct the Proposed Project to comply with the California Public Utilities Commission (CPUC) approved Pipeline Safety Enhancement Plan (PSEP) by replacing Line 1600 with a new gas transmission pipeline.

In addition, the Proposed Project will enable the Applicants to increase the capacity of the Applicants' natural gas transmission system by approximately 200 million cubic ft per day (MMcfd) by constructing a new 36-in-diameter pipeline from SDG&E's existing Rainbow Metering Station to a gas system tie-in point with existing pipeline on Marine Corps Air Station (MCAS) Miramar in San Diego County so that the Applicants have transmission capacity able to meet the predicted peak demand of core and non-core customers, including electric generation and clean transportation.

The primary components of the Proposed Project include the construction a 36-in-diameter transmission pipeline from the Rainbow Metering Station to the existing Line 2010 on the MCAS Miramar. The pipeline will be approximately 47 miles in length and will begin at a new Rainbow Pressure-Limiting Station and will proceed in a southerly direction through San Diego County terminating at the MCAS Miramar. In addition to the pipeline, the Applicants will construct and maintain appurtenant facilities, including mainline valves, metering equipment, pressure-limiting equipment, in-line inspection equipment, cathodic protection systems, and an intrusion and leak monitoring system. The pipeline will be primarily constructed within existing public and private rights-of-way.

3.0 BACKGROUND

Natural gas is comprised primarily of methane. Methane, in its natural state, is colorless, odorless, and tasteless. Methane is not toxic, but is classified as a simple asphyxiate, possessing a slight inhalation hazard. If methane is inhaled in high concentration, oxygen deficiency can result, leading to serious injury or fatality.

Methane has an ignition temperature of 1,000°F and is flammable at concentrations between 5 and 15% in air by volume. Unconfined mixtures of methane in air are not explosive. However, a flammable concentration within an enclosed space in the presence of an ignition source can explode. Methane is buoyant at atmospheric temperatures and disperses rapidly in air. The natural gas transported by the proposed pipeline will contain an odorant (e.g., methyl mercaptan) to aid in leak detection.

Unintentional releases of natural gas from the proposed pipeline and associated facilities (e.g., pressure limiting stations) could pose risks to human health and safety. For example, natural gas could be released from a leak or rupture in one of the pipe segments. If the natural gas release reaches a combustible mixture and an ignition source is present, a fire and/or explosion could occur, resulting in possible injuries and/or fatalities.

4.0 STUDY METHODOLOGY

This Study quantitatively calculates the potential risk to human health and safety as a result of unintended failures of the Proposed Project. In assessing these risks, ENERCON determined the applicability of federal, state and local regulations related to the Proposed Project.

Publicly available natural gas historical incident data from the Pipeline and Hazardous Materials Safety Administration (PHMSA), an agency of the United States Department of Transportation (USDOT), are used to calculate the pipeline baseline incident rates. An event that constitutes an "incident" is defined by the federal government using specific criteria (49 Code of Federal Regulations [CFR] Part 191.3) as described in Section 6.2. The cause of incidents was also evaluated from the PHMSA incident data.

Modeling software (CANARY Version 4.4) was used to determine consequences associated with all credible accident sequences. In conjunction with the historical incident data, results of the consequence models are used to determine individual and societal risk to the public. Individual risk and societal risk were assessed based on generally recognized criteria previously reviewed and accepted by the CPUC. These individual and societal risk assessments were then measured against generally accepted significance criteria to determine the level of project impact significance.

5.0 OVERVIEW OF APPLICABLE LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

5.1 Federal

The USDOT provides oversight for the nation's natural gas pipeline transportation system. Its responsibilities are promulgated under Title 49, United States Code (USC) Chapter 601. PHMSA, Office of Pipeline Safety (OPS), administers the national regulatory program to ensure the safe transportation of gas and other hazardous materials by pipeline.

5.1.1 Natural Gas Pipeline Safety Act of 1968

The Natural Gas Pipeline Safety Act of 1968 as amended (NGPSA) authorizes the USDOT to regulate pipeline transportation of natural (flammable, toxic, or corrosive) gas and other gases as well as the transportation and storage of liquefied natural gas (LNG). This act has been recodified as 49 USC Chapter 601.

The OPS shares portions of this responsibility with state agency partners and others at the federal, state, and local level. The State of California is certified under 49 USC Subtitle VIII, Chapter 601, §60105. The State has the authority to regulate intrastate natural and other gas pipeline facilities. The CPUC is the agency authorized to oversee intrastate gas pipeline facilities, including those proposed by the Applicants.

5.1.2 Code of Federal Regulations, Title 49, Part 192

Federal pipeline regulations are published in Title 49 of the CFR, Parts 190 through 199. 49 CFR 192 specifically addresses natural and other gas pipelines. Many of these pipeline regulations are written as performance standards. These regulations set the level of safety to be attained and allow the pipeline operator to use various technologies to achieve the desired result.

The proposed pipeline segments and ancillary facilities will all be designed, constructed, operated, and maintained in accordance with 49 CFR 192. Because these are intrastate facilities, the CPUC will have the responsibility for enforcing federal and state requirements. 49 CFR 192 is comprised of 15 subparts, which are summarized below:

- Subpart A, General: This subpart provides definitions, a description of the class locations used within the regulations, documents incorporated into the regulation by reference, conversion of service requirements, and other items of a general nature.
- Subpart B, Materials: This subpart provides the requirements for the selection and qualification of pipe and other pipeline components. Generally, it covers the manufacture, marking, and transportation of steel, plastic, and copper pipe used in gas pipelines and distribution systems.
- Subpart C, Pipe Design: This subpart covers the design (primarily minimum wall thickness determination) for steel, plastic, and copper pipe.

- Subpart D, Design of Pipeline Components: This subpart provides the minimum requirements for the design and qualification of various components (e.g. valves, flanges, fittings, passage of internal inspection devices, taps, fabricated components, branch connections, extruded outlets, supports and anchors, compressor stations, vaults, overpressure protection, pressure regulators and relief devices, instrumentation and controls, etc.
- Subpart E, Welding of Steel Pipelines: This subpart provides the minimum requirements for welding procedures, welder qualification, inspection, and repair/replacement of welds in steel pipeline systems.
- Subpart F, Joining of Materials Other Than by Welding: This subpart covers the requirements for joining, personnel and procedure qualification, and inspection of cast iron, ductile iron, copper, and plastic pipe joints.
- Subpart G, General Construction Requirements for Transmission Lines and Mains: This subpart provides the minimum construction requirements, including, but not limited to: inspection of materials, pipe repairs, bends and elbows, protection from hazards, installation in the ditch, installation in casings, underground clearances from other substructures, and minimum depth of cover.
- Subpart H, Customer Meters, Service Regulators and Service Lines: This subpart prescribes the minimum requirements for these components.
- Subpart I, Requirements for Corrosion Control: This subpart provides the minimum requirements for cathodic protection systems, required inspections and monitoring, remedial measures, and records maintenance.
- Subpart J, Testing Requirements: This subpart prescribes the minimum leak and strength test requirements.
- Subpart K, Uprating: This subpart provides the minimum requirements for increasing the maximum allowable operating pressure.
- Subpart L, Operations: This subpart prescribes the minimum requirements for pipeline operation, including: procedure manuals, change in class locations, damage prevention programs, emergency plans, public awareness programs, failure investigations, maximum allowable operating pressures, odorization, tapping, and purging.
- Subpart M, Maintenance: This subpart prescribes the minimum requirements for pipeline maintenance, including: line patrols, leakage surveys, line markers, record keeping, repair procedures and testing, compressor station pressure relief device inspection and testing, compressor station storage of combustible materials, compressor station gas detection, inspection and testing of pressure limiting and regulating devices, valve maintenance, prevention of ignition, etc.
- Subpart N, Qualification of Pipeline Personnel: This subpart prescribes the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility.
- Subpart O, Pipeline Integrity Management: This subpart was promulgated on December 15, 2003. It requires operators to implement pipeline integrity management programs on the gas pipeline systems.

In general, the requirements of the federal regulations become more stringent as the human population density increases. To this end, 49 CFR 192 defines area classifications, based on population density in the vicinity of a pipeline and specifies more rigorous safety requirements for more heavily populated areas. The class location is based on an area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. The four area classifications are defined as follows:

- Class 1: Location with 10 or fewer buildings intended for human occupancy.
- Class 2: Location with more than 10 but less than 46 buildings intended for human occupancy.
- Class 3: Location with 46 or more buildings intended for human occupancy or where the pipeline lies within 100 yards of a building, or a small well-defined outside area that is occupied by 20 or more people on at least 5 days a week for 10 weeks in any 12-month period.
- Class 4: Location where buildings with four or more stories above ground are prevalent.

Pipeline facilities located within class locations representing more populated areas are required to have a more conservative design. For example, pipelines constructed on land in Class 1 locations must be installed with a minimum depth of cover of 30 in in normal soil and 18 in in consolidated rock. Class 2, 3, and 4 locations, as well as drainage ditches of public roads and railroad crossings, require a minimum cover of 36 in in normal soil and 24 in in consolidated rock. All pipelines installed in navigable rivers, streams, and harbors must have a minimum cover of 48 in in soil or 24 in in consolidated rock.

Class locations also specify the maximum distance to a sectionalizing block valve (e.g., 10.0 miles in Class 1, 7.5 miles in Class 2, 4.0 miles in Class 3, and 2.5 miles in Class 4 locations). Pipe wall thickness, pipe design factors, pipeline design pressures, design factors, hydrostatic test pressures, maximum allowable operating pressure, inspection and testing of welds, and frequency of pipeline patrols and leak surveys must also conform to higher standards in more populated areas.

The proposed pipeline will be constructed within Class 1, 2, and 3 locations. The Applicants will be required to demonstrate compliance with the more stringent requirements, reduce the maximum allowable operating pressure (MAOP) or replace the segment with pipe of sufficient grade and wall thickness to comply with 49 CFR 192 for the new class location if the population density should increase enough to change the class location.

5.1.3 Pipeline Safety Improvement Act of 2002 (49 CFR Part 192, Subpart O)

Title 49 of the CFR 192 Subpart O, Pipeline Integrity Management, grew out of a series of pipeline incidents with severe consequences. This Subpart requires operators of gas pipeline systems in high consequence areas (HCAs) to significantly increase their minimum required maintenance and inspection efforts. For example, all lines located within HCAs must be analyzed by conducting a baseline risk assessment. In general, the integrity of the lines must also be evaluated using an internal inspection device or a direct assessment, as prescribed in the regulation.

In 2002, Congress passed an Act to strengthen the pipeline safety laws. The Pipeline Safety Improvement Act of 2002 (HR 3609) was passed by Congress on November 15, 2002, and signed into law by the president in December 2002. As of December 17, 2004, gas transmission operators of pipelines in HCAs were required to develop and follow a written integrity management program that contained all of the elements prescribed in 49 CFR 192.911 and addressed the risks on each covered transmission pipeline segment.

The USDOT (68 Federal Register 69778, 69 Federal Register 18228, and 69 Federal Register 29903) defines HCAs as they relate to the different class zones, potential impact circles, or areas containing an identified site as defined in 49 CFR 192.903. The OPS published a series of rules from August 6, 2002 to May 26, 2004 (69 Federal Register 69817 and 29904) that define HCAs where a gas pipeline accident could do considerable harm to individuals and their property. This definition satisfies, in part, the congressional mandate in 49 USC 60109 for the OPS to prescribe standards that establish criteria for identifying each gas pipeline facility in a high-density population area.

HCAs may be defined in one of two ways. Both methods are prescribed by 49 CFR 192.903. The first includes:

- Current Class 3 and 4 locations;
- Any area in Class 1 or 2 locations where the potential impact radius is greater than 660 ft (200 meters) and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or
- Any area in Class 1 or 2 locations where the potential impact circle includes an “identified site.”

In the second method, an HCA includes any area within a potential impact circle that contains:

- 20 or more buildings intended for human occupancy; or
- An “identified site.”

“Identified sites” include areas such as beaches, playgrounds, recreational facilities, camp grounds, outdoor theaters, stadiums, recreational areas, religious facilities, and other areas where high concentrations of the public may gather periodically as defined by 49 CFR 192.903.

The “potential impact radius” is calculated as the product of 0.69 and the square root of the maximum allowable operating pressure of the pipeline (in psig), multiplied by the pipeline diameter (in inches) squared as shown in the equation below.

$$R(ft) = 0.69\sqrt{MAOP(psig) \times d^2(in^2)}$$

The potential impact circle is a circle with a radius equal to the potential impact radius.

Once a pipeline operator has identified the HCAs along its pipeline(s), it must apply the elements of its integrity management program to those segments of the pipeline within the

HCAs. The pipeline integrity management rule for HCAs requires inspection of the entire pipeline within HCAs every 7 years.

The proposed 36-in (inner diameter of 34.75 in) natural gas transmission pipeline is located within Class 1, 2 and 3 areas. As a result, using the first HCA definition, the portions of the line within Class 3 areas will be within an HCA. The impact radii is 678 ft for the 36-in line with an 800 psig MAOP. This is greater than the 660 ft impact radius which might add additional portions within an HCA. As a result, certain portions of the Proposed Project will be required to be included in the Applicants' existing pipeline integrity management plan. Should the population density increase, additional portions of the pipeline may be located within an HCA; the Applicants will be required by federal regulation to include the affected pipe segments in their pipeline integrity management plan.

5.2 State

As noted earlier, these intrastate pipeline facilities will be under the jurisdiction of the CPUC, as a result of their certification by the OPS (the State is certified under 49 USC Subtitle VIII, Chapter 601, §60105).

5.2.1 California Public Utilities Commission General Order 112-F

The state requirements for designing, constructing, testing, operating, and maintaining gas piping systems are stated in CPUC General Order Number 112-F (which supersedes General Order 112-E). These rules incorporate the federal regulations by reference, but for natural gas pipelines, they do not impose any additional safety requirements beyond the federal requirements. State of California regulations provide specific safety requirements that are more stringent than the federal rules. Areas covered include: (a) exemptions, (b) hazardous pipeline safety technical standards, (c) intrastate pipeline operators, (d) leak detection and cathodic protection, (e) periodic hydrostatic testing, (f) hydrostatic test results, (g) maps, records procedures, inspections, (h) contingency plans, (i) notification of break, explosion or fire, (j) local enforcement, and (k) regulations for enforcement proceedings.

5.2.2 California Environmental Quality Act

The California Environmental Quality Act (CEQA) requires impacts resulting from construction, operation, and maintenance of a project be evaluated using significance criteria provided in Section VIII of the checklist in Appendix G of the California Environmental Handbook. Specific criteria relevant to the project can be found in the Hazards and Hazardous Materials category and address the question of whether the project would create a "significant hazard to the public or the environment through reasonably foreseeable upset and accident conditions involving the release of hazardous materials into the environment."

6.0 CALCULATION OF INCIDENT RATE

This section provides an overview of the primary risk to individuals that could result from an unintentional release; provides the data used to assess incident causality; and determines an incident rate associated with an unintentional release from the Proposed Project.

6.1 Risks Resulting from an Incident

Primary risks that could result from an unintentional release of natural gas include explosion and/or fire. If there were a rupture or leak in a pipeline, the released natural gas will combine with the ambient air and can form a vapor cloud. In an unconfined space, the positive buoyance of the methane result in rapid dispersal, preventing the formation of a persistent vapor cloud at ground level. In a confined space, a vapor cloud can result in an explosion if the natural gas reaches a combustible mixture with air (between 5 to 15 percent) in the presence of an ignition source. The most basic definition of an explosion is a sudden intense release of energy that often produces a loud noise, high temperatures and flying debris, and generates a pressure wave above normal atmospheric pressure (i.e., overpressure). The physiological effects of an explosion depends on the peak overpressure level that reaches an individual. Exposure to significant overpressure levels can be fatal. Individuals located outside the vapor cloud when a combustible mixture ignites would be exposed to lower overpressure levels than those inside the vapor cloud. If an individual is far enough from the explosion, the explosion overpressure level would be incapable of causing injuries.

An explosion overpressure of approximately 2.3 psi is estimated to result in an approximately 1% chance of mortality (a 1 in 100 chance of fatality) [Reference 11.4]. The risk analysis conservatively assumes that any individual exposed to an overpressure of 2.0 psi would not survive. For comparison, the effects of increasing blast overpressures on the human body (i.e., injuries that could occur) based on US Department of Defense data are summarized in Table 6-1.

Table 6-1: Blast Impacts on Human Body

Overpressure	Effect on Human Body
1 psi	Light injuries from fragments occur
2 psi	People injured by flying glass and debris
3 psi	Serious injuries are common, fatalities may occur
5 psi	Injuries are universal, fatalities are widespread

For events that do not result in explosions (i.e., blasts), the released natural gas could produce a fire. The physiological effect of fire on the human body depends on the rate at which heat is transferred from the fire to the individual and the time the individual is exposed to the fire. Individuals in the vicinity of a fire, but not in contact with the flames, would receive heat from the fire in the form of thermal radiation. Radiant heat flux decreases with increasing distance from a fire. Those close to the fire would receive thermal radiation at a higher rate than those farther away. The ability of a fire to cause injuries due to radiant heating depends on the radiant heat flux to which the individual is exposed and the duration of the exposure. As a result, even short-term exposure to high radiant heat flux levels can cause injuries. But if an individual is far enough from the fire, the radiant heat flux would be lower, and likely incapable of causing injury, regardless of the duration of the exposure.

A report prepared for the Gas Research Institute (GRI) [Reference 11.1] provides an approach to sizing the ground area potentially affected by the failure of a high-pressure natural gas pipeline. In determining HCAs, the report concluded that a heat flux of 5,000 Btu/hr•ft^2 corresponded to a 1% chance of mortality (i.e., 1 in 100 people directly exposed to this heat flux would not be expected to survive). The report also concluded that the heat fluxes associated with a 50% mortality rate and 100% mortality rate are 8,000 Btu/hr•ft^2, and 12,000 Btu/hr•ft^2, respectively. These incident heat flux mortality rates are based on a 30-second exposure time.

The heat fluxes listed above from the GRI report have been adopted by various agencies who provide guidance for conducting pipeline risk analyses, including the California Department of Education (CDE) in its Guidance Protocol for School Site Pipeline Risk Analysis [Reference 11.4]. For comparison with the heat fluxes that correspond to different mortality rates, some commonly used radiant flux endpoints are shown in Table 6-2 [Reference 11.5].

Table 6-2: Radiant Flux Endpoints

Radiant Flux Endpoint	Consequence
440 Btu/(hr•ft^2) [1.39 kW/m^2]	Skin can be exposed for a prolonged period of time with no serious detrimental effect.
1,600 Btu/(hr•ft^2) [5.05 kW/m^2]	Second-degree skin burns after 30 seconds of exposure.
3,500 Btu/(hr•ft^2) [11.0 kW/m^2]	Second-degree skin burns after 10 seconds of exposure.
6,700 Btu/(hr•ft^2) [21.1 kW/m^2]	Will not cause spontaneous wood ignition, regardless of exposure time.
7,000 Btu/(hr•ft^2) [22.1 kW/m^2]	Safe exposure limit for unprotected LPG bullet tanks.
10,000 Btu/(hr•ft^2) [31.5 kW/m^2]	Wooden structures ignite spontaneously after 15–20 minutes of exposure.

6.2 Pipeline and Appurtenant Component Baseline Incident Rate

The term "incident" has a specific meaning in terms of reporting criteria and does not necessarily result in an event that poses any danger to the public. As can be seen below, the release of natural gas that results in the injury or death of an individual is only one of several measures for meeting the reporting criteria for classification as an incident. For gas pipelines, 49 CFR Part 191.3 currently defines the incident criteria as:

1) An event that involves a release of gas from a pipeline, or of liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:
   i. A death, or personal injury necessitating in-patient hospitalization;

ii. Estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost;

iii. Unintentional estimated gas loss of three million cubic ft or more.

2) An event that results in an emergency shutdown of an LNG facility. Activation of an emergency shutdown system for reasons other than an actual emergency does not constitute an incident.

3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraphs (1) or (2) of this definition.

Many events that are reported as incidents do not pose a threat to the public, but were reported as incidents due to the unintentional loss of natural gas or the operated judged the event to be significant. A review of the historical incident data from the United States Department of Transportation (USDOT), as presented below, shows that a large percentage of incidents reported resulted in a release of natural gas that did not ignite, and therefore did not present a danger to the public since there was not a fire or explosion associated with the incident. Furthermore, a significant number of the reported incidents were due to small leaks as opposed to larger leaks or pipeline ruptures. Risk to the public associated with small leaks is much lower than a larger leak due to amount of natural gas released from the system. The baseline incident rate determined in this section does not differentiate between small leaks and large leaks, nor incidents that result in ignition of the natural gas and those that do not, and is therefore conservative in nature. The probability that an incident will result in a specific event, and the risk associated with that event is addressed in Section 8.1.

To determine a baseline incident rate of unintentional releases applicable to the Proposed Project, a detailed review of USDOT historical incident data was performed to eliminate incidents that would not be applicable to the Proposed Project. The pipeline to be installed as part of the Proposed Project is new construction, 36-in-diameter transmission pipeline with a specified minimum burial depth of 42 in. Incidents that are not applicable to this new pipeline are included for comparison as Attachment A of this study. This included incidents occurring on offshore pipelines, incidents involving gathering and distribution pipelines, releases of material other than natural gas, and incidents that occurred at compressor stations. There are no compressor stations associated with the Proposed Project and therefore, compressor station incidents are not included in the baseline incident rate. The analysis for baseline incident frequency does include incidents occurring at valve and metering stations as these facilities are included in the Proposed Project. The sections below detail the applicable USDOT historical incident data used to determine the baseline incident rate.

The results of this analysis determined an applicable baseline incident rate of 3.62×10^{-4} incidents per mile-year (or 0.362 incidents per 1,000 mile-years). This baseline incident rate will be applied in the risk assessment (Section 8.0). As stated above, this is the frequency of any incident that meets the reporting criteria as defined by 49 CFR Part 191.3, regardless of the consequences of the incident. Individual risk and societal risk associated with specific events that occur after a release (e.g., fires) are addressed in Section 8.0.

6.3 Historical Incident Data used for Determining Baseline Incident Rate

The USDOT started reporting data for incidents occurring on natural gas pipelines in 1970. These data include incidents occurring on a wide range of natural gas pipelines and associated facilities, including: interstate and intrastate pipelines; onshore and offshore pipelines; transmission, gathering and distribution pipelines; compressor stations; pressure limiting stations; etc. A subset of these data deemed relevant to the Proposed Project are included here as the basis for developing the previously discussed baseline incident rate used in this Study. In addition to reporting the occurrence of an incident, the recent historical data also provide information related to the cause of the incident. Causal data are valuable in determining the main contributors to incident rates so that risk reduction measures can be put in place to effectively prevent such future events.

Starting in 2002, the level of detail provided in incident reporting data significantly improved by including incident causes along with other consequence data such as fires and explosions. Therefore, the incident data from 2002 through 2014 are used to determine a distribution of the incident causes for releases from onshore natural gas transmission lines. Incident cause probabilities are presented in Table 6-3 below. The primary causes of incidents occurring on pipelines comparable to the Proposed Project in the 2002 to 2014 data set include malfunction of control/relief equipment (23.2%), material or weld failures (15.4%), and excavation damage (6.6%). Proposed Project design features intended to reduce or eliminate incidents can be found in Section 9.0.

Table 6-3: Incident Causes for Onshore Natural Gas Transmission Lines (2002–2014)

Cause	Incidents 2002–2009	Incidents 2010–2014	Total Incidents	Percentage of Total
Equipment Failure - Malfunction of Control/Relief Equipment	15	41	56	23.2%
Material or Weld Failure	25	12	37	15.4%
Other – Miscellaneous	15	5	20	8.3%
Excavation Damage	12	4	16	6.6%
Incorrect Operation	5	10	15	6.2%
Equipment Failure – Threaded Connection/Coupling	3	11	14	5.8%
Vehicle Not Related To Excavation	7	5	12	5.0%
Equipment Failure – Other	1	10	11	4.6%
Natural Forces – Lightning	5	6	11	4.6%

Table 6-3: Incident Causes for Onshore Natural Gas Transmission Lines (2002–2014)

Cause	Incidents 2002–2009	Incidents 2010–2014	Total Incidents	Percentage of Total
Natural Forces – Temperature	0	6	6	2.5%
Corrosion – External	5	1	6	2.5%
Natural Forces – Earth Movement	3	3	6	2.5%
Natural Forces – Heavy Rains/Flood	5	0	5	2.1%
Fire/Explosion As Primary Cause	4	1	5	2.1%
Natural Forces – High Winds	2	3	5	2.1%
Corrosion – Internal	3	1	4	1.7%
Other – Unknown	1	3	4	1.7%
Natural Forces – Other	0	4	4	1.7%
Electrical Arcing	0	2	2	0.8%
Other Outside Force Damage	0	1	1	0.4%
Vandalism/Intentional Damage	1	0	1	0.4%
		TOTALS	241	100.0%

7.0 SIGNIFICANCE CRITERIA

While there is not a universal acceptance criteria for determining risk, the generally accepted significance criterion used to evaluate fatality risk impacts on individuals is an annual likelihood of 1 x 10^{-6} fatalities/year (1 in a million years) [References 11.4 and 11.7]. A Survey of Worldwide Risk Criteria Applications was conducted by the American Institute of Chemical Engineers [Reference 11.17]. Risk criteria issued by governmental bodies at the country, regional, or local level and criteria issued by industry organizations are included in the survey. The predominant upper limit value for individual risk to the public is 1 x 10^{-6} fatalities/year, the value applied in this Study. The entities applying these criteria include US Department of Defense, The Netherlands, States of Australia, the Czech Republic, Singapore, Malaysia, and Santa Barbara County, California. Based on the results of this worldwide survey, application of an individual risk criteria of 1 x 10^{-6} fatalities/year is appropriate and has been applied in this Study.

Societal risk is the probability that a specified number of individuals will be affected by a given event. The accepted number of casualties is relatively high for lower probability events and much lower for more likely events. However, the accepted values for societal risk vary greatly by different agencies and jurisdictions. There are no prescribed societal risk guidelines for the United States or for the State of California. However, the CPUC has accepted safety/risk of upset studies[1] that use a site casualty and societal risk criteria ratio of less than one (1.0) as developed by the Netherlands Committee for the Prevention of Disasters uses the criteria as shown in Figure 7-1 [Reference 11.8]. Therefore, this Study evaluates societal risk in accordance with the same criteria. Risks at or below a site casualty to societal risk criteria ratio of less than 1.0 (as shown on Figure 7-1 below) for societal risk are considered less than significant.

[1] Two recent projects evaluated by the CPUC included system safety and risk of upset studies: Sacramento Natural Gas Storage Project (2008) and the Central Valley Natural Gas Storage Project (2010).

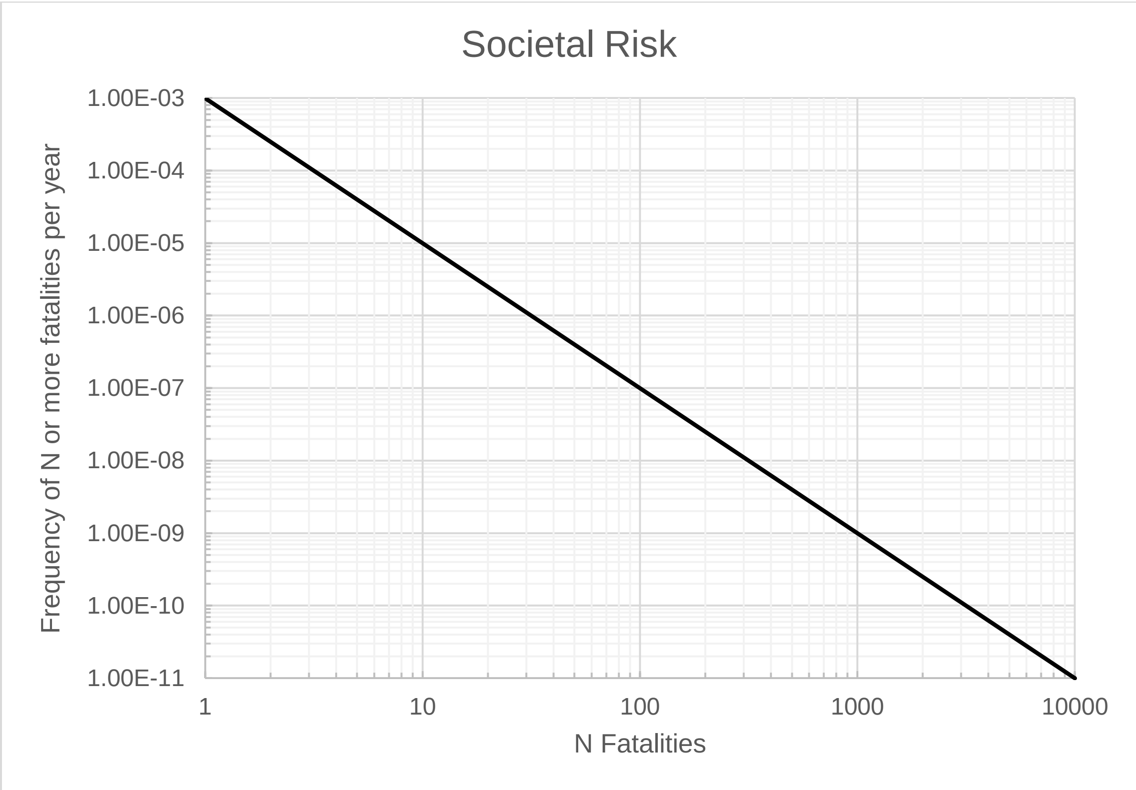


Figure 7-1: Societal Risk Criteria

8.0 RISK ASSESSMENT

To determine the risk associated with the Proposed Project, a detailed evaluation has been performed. This analysis considers the maximum population density along the proposed route, as well as the characteristics of the pipe contents in the event of an unintentional release.

The baseline incident rate used in this analysis is discussed in Section 6.0. This analysis was conducted using the consequence event tree shown in Figure 8-1, which presents each of the potential events that may result after an incident. As can be seen in the consequences column of this figure, the majority of possible outcomes of an incident do not result in fatalities. The likelihood that an incident will result in a specific event is called the “conditional probability” of that event. Conditional probabilities developed for each branch of this event tree are discussed in Section 8.1.

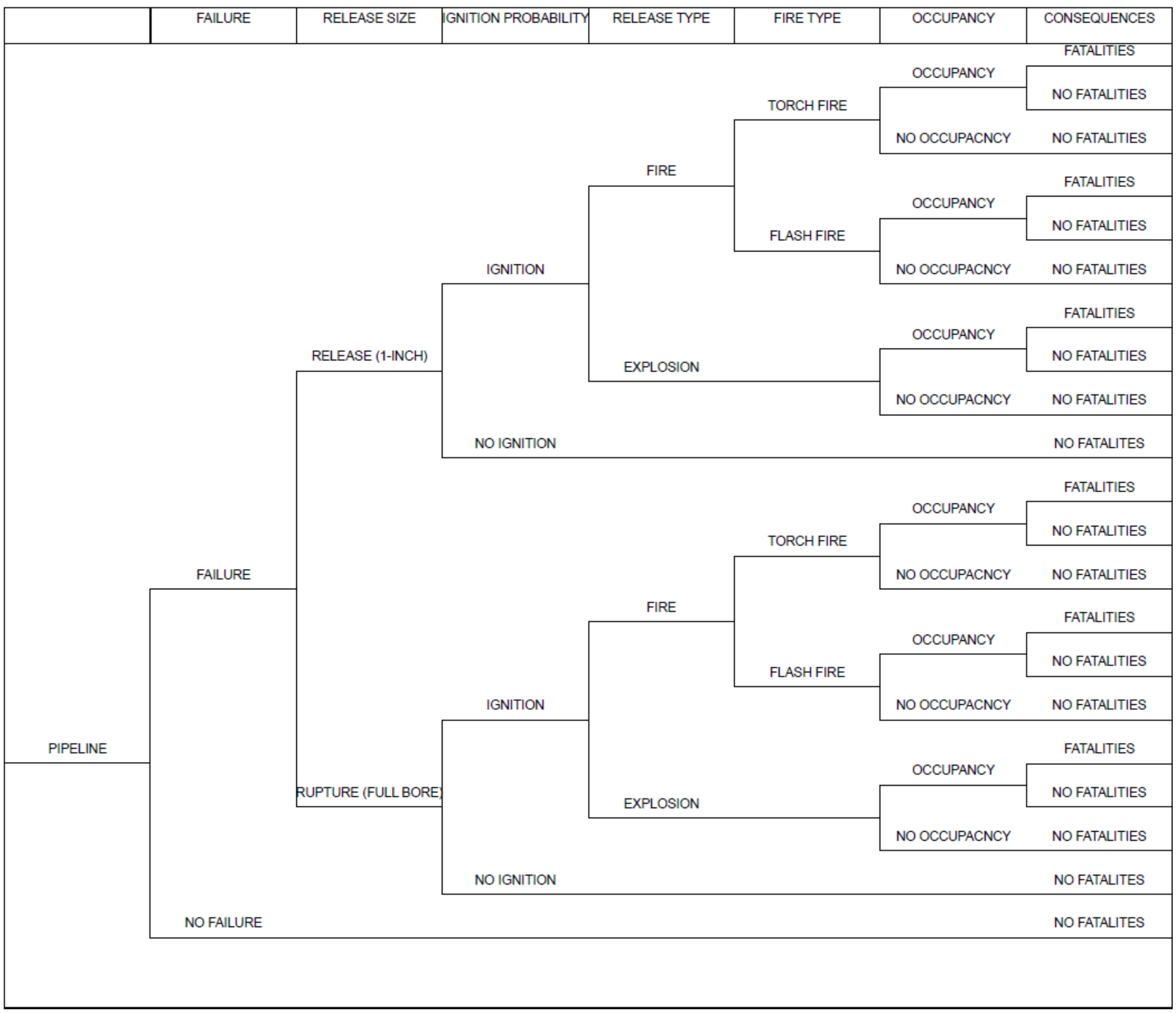


Figure 8-1: Pipeline Event Release Tree

8.1 Conditional Probability

To perform a probabilistic risk analysis, the conditional probabilities of each event tree branch in Figure 8-1 must be established. Unintentional natural gas pipeline release data from the USDOT [Reference 11.2] was evaluated to determine these conditional probabilities. Starting January 1, 2002, the incident reporting parameters for natural gas pipeline incidents were expanded to include fields for ignitions, explosions, leaks, ruptures, etc. Incident reporting prior to 2002 does not provide consistent data for these items of interest. Therefore, to determine the conditional probabilities for each event tree branch, historical incident data for onshore natural gas transmission pipelines from January 1, 2002, through December 31, 2014, were evaluated [Reference 11.2] (see Section 6.0). Over this time interval, there were a total of 241 transmission pipeline incidents reported to the USDOT that were deemed relevant to this analysis. The following data from these incidents are used to develop the conditional probabilities documented in Table 8-1 and Figure 8-3.

- 223 (92.5%) incidents were classified as leaks or cracks
- 18 (7.5%) incidents were classified as ruptures
- 37 (15.4%) incidents resulted in an ignition of natural gas

Table 8-1: Conditional Probabilities

Parameter	Conditional Probability	Value
Leak Size	Probability of Leak (the spectrum of leaks will be represented by a 1-in diameter hole in the analyses)	92.5%
	Probability of Rupture (complete, full diameter pipe severance)	7.5%
Ignition	Probability of No Ignition	84.6%
	Probability of Ignition	15.4%

Table 8-2: Combined Conditional Probabilities

Consequence	Conditional Release Consequence	Value
Fires or Explosion	Leak Resulting in a Fire/Explosion	0.925 x 0.154 = 14.2%
	Rupture Resulting in a Fire/Explosion	0.075 x 0.154 = 1.2%

USDOT data do not provide any differentiation regarding the type of fire (torch fire versus flash fire). If a vapor cloud were to migrate to a commercial or residential location, and remain above the lower flammable limit (LFL), subsequent ignition of the cloud would result in a flash fire. However, 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. The dominant hazard is, therefore, thermal radiation from a sustained torch fire [Reference 11.1]. To account for the dominant hazard following a postulated release from the pipeline, the analysis assumes that 90% of fires would result in torch fires and 10% of fires would result in flash fires.

Table 8-3: Combined Conditional Release Probability

Consequence	Conditional Release Consequence	Value
Torch Fires	Leak resulting in a torch fire	14.2% x 0.90 = 12.8%
	Rupture resulting in a torch fire	1.2% x 0.90 = 1.1%
Outdoor Flash Fires	Leak resulting in a flash fire	14.2% x 0.10 = 1.4%
	Rupture resulting in a flash fire	1.2% x 0.10 = 0.1%
Indoor Flash Fire	Leak resulting in an indoor flash fire	14.2% x 0.10 = 1.4%
	Rupture resulting in an indoor flash fire	1.2% x 0.10 = 0.1%

8.2 Release Modeling

To determine the consequences associated with the each of the postulated pipeline releases shown in Figure 8-1, a series of accidents were modeled using CANARY Version 4.4 software. For vapor cloud explosion modeling, this software uses the Baker-Strehlow model to determine peak side-on over-pressures as a function of distance from a release. The CANARY software also uses a torch fire model to determine heat radiation flux as a function of distance from a release.

Several evaluations were performed by varying critical parameters such as wind speed, stability class, temperature, etc., to determine the impact these parameters had on the results of the release modeling. The results of these sensitivity analyses were combined to determine the worst case consequences for each of the postulated accident scenarios.

Both the parameters and modeling inputs used in the CANARY program scenario modeling are given in Table 8-4, below.

Table 8-4: Release Modeling Inputs

Parameter	Model Input
Maximum Allowable Operating Pressure (MAOP)	800 psi for nominal 36-in diameter pipe (34.75-in inner diameter)
Typical Flow Rate	35 million cubic ft per hour (MMcfh)
Modeled Release	1-in diameter leak Full diameter rupture
Contents	94% Methane
Wind Speed	2 meters per second (4.5 mph)
Stability Class	D - Pasquill-Gifford atmospheric stability is classified by the letters A through F. Stability can be determined by three main factors: wind speed, solar insulation, and general cloudiness. In general, the most unstable (turbulent) atmosphere is characterized by stability class A. Stability A occurs during strong solar radiation and moderate winds. This combination allows for rapid fluctuations in the air and thus

Table 8-4: Release Modeling Inputs

Parameter	Model Input
	greater mixing of the released gas with time. Stability D is characterized by fully overcast or partial cloud cover during daytime or nighttime, and covers all wind speeds. The atmospheric turbulence is not as great during D conditions, so the gas will not mix as quickly with the surrounding atmosphere. Stability F generally occurs during the early morning hours before sunrise (no solar radiation) and under low winds. This combination allows for an atmosphere which appears calm or still and thus restricts the ability to actively mix with the released gas. A stability classification of "D" is generally considered to represent average conditions.
Relative Humidity	30%
Air and Surface Temperature	80°F
Continuous Release Duration	120 minutes
Duration of Normal Flow after Leak initiation	120 minutes (Conservative because this implies no reduction in flow due to pipeline isolation or pressure reduction).
Pipe Length Upstream and Downstream of Break	15,000 ft for individual risk (See Section 8.2.1 below). 105,600 ft (20 miles) for societal risk (See Section 8.2.1 below). Pipe length downstream of the break is conservatively assumed to be the remaining length of the pipeline.
Release Angle	0° (A horizontal release direction is conservatively assumed because it resulted in the highest consequences for torch fires and flash fires).
Torch Fire Flow Rate	Immediate Ignition: The analysis conservatively assumed immediate ignition of the released vapor for torch fire scenarios.
Fuel Reactivity	Medium: Most hydrocarbons (including natural gas at 94% methane) have medium reactivity, as defined by the Baker-Strehlow method. Low reactivity fluids include methane, natural gas (98+% methane), and carbon monoxide. High reactivity fluids include hydrogen, acetylene, ethylene oxide, and propylene oxide.
Obstacle Density (Explosion Only)	Low: This parameter describes the general level of obstruction to air movement in the area of the postulated leak. Low density occurs in open areas or in areas containing widely spaced obstacles. High density occurs in areas of many obstacles, such as tightly-packed process areas or multi-layered pipe racks.
Flame Expansion	3-D: This parameter defines the number of dimensions available for flame expansion. Open areas are 3-D, and produce the smallest levels of overpressure. 2.5-D expansions are used to describe areas that quickly transition from 2-D to 3-D. Examples include compressor sheds and the volume under elevated fan-type heat exchangers. 2-D expansions occur within areas bounded on top and bottom, such as pipe racks, offshore platforms, and some process units. 1-D expansion may occur within long confined volumes such as hallways or drainage pipes, and produce the highest overpressures.
Reflection Factor	2: This factor is used to include the effects of ground reflection when an explosion is located near grade. A value of 2 is recommended for ground level explosions.

8.2.1 Pipeline Release Locations

The release location modeled for individual risk is 15,000 ft from the source and the release location modeled for societal risk is 105,600 ft (20 miles) from the source. The bases for these release locations are discussed below.

The analyses for the full diameter rupture scenarios showed a sensitivity to the assumed incident location along the pipeline due to the contribution of gas in the upstream and downstream sections. The modeling parameters impacted by this are the pipe length upstream and downstream of the break. The analyses conservatively assumed the full inventory of the pipeline would be available for contribution to the accident (i.e., no credit is taken for isolation valves). For example, a rupture occurring one mile from the Rainbow Station, the pipe length downstream of the break was modeled as the remaining length of the pipeline. The sensitivity analyses determined that a rupture approximately 15,000 ft from the source would result in the longest torch fire and distance to the LFL. Moving the assumed rupture location closer to or farther away from the source would decrease the distances for the torch fire and LFL range. It must be noted that the area surrounding the pipeline 15,000 ft from the source is extremely remote with very few structures surrounding the proposed route. Therefore, selection of the rupture location at 15,000 ft from the source is conservative for determining individual risk.

The population density selected in determining societal risk associated with the Proposed Project was the highest population density identified along the alignment. This area was determined to be located approximately 20 pipeline miles south of the Rainbow Station. Therefore, this was the break location selected for modeling societal risk consequences.

8.2.2 Explosion Modeling Results

Natural gas is classified as a medium reactivity fuel (reactivity varies depending on gas quality) that generally does not explode unless the vapor cloud is confined in some manner. The proposed 36-in pipeline segments are surrounded by residential, commercial, warehouse, and open space areas. As a result, the obstacle density selected for vapor cloud explosions is low, which is defined as having a blockage ratio of less than 10%. Medium obstacle density is defined as having a blockage ratio between 10% and 40%. High obstacle density (greater than 40% blockage ratio) areas are generally identified as offshore oil platforms or other industrial facilities with equipment located in a configuration that prohibits the ability to walk through the area. Further, the buoyant nature of natural gas will cause it to rapidly disperse in air and prevent the collection of gas in confined areas near ground level. Due to the lack of confinement which is required for natural gas to explode, the analyses concluded that no postulated release scenarios resulted in an overpressure greater than 2.0 psi. As stated in Table 6-1, an overpressure of 2.0 psi could result in injuries from flying glass and debris but is less than the overpressure corresponding to a 1% mortality rate of 2.3 psi (see Section 6.2). Because no events result in an overpressure of greater than 2.0 psi, explosions are not considered as a contributor to the overall risk associated with operation of the Proposed Project. The explosion release modeling results are provided in Table 8-5, below.

Table 8-5: Explosion Release Modeling Results

Release Type	Release Location[1]	Horizontal Distance from Release Point (Ft)		
		2.0 psi Overpressure	1.0 psi Overpressure	Distance to LFL
1-in Leak	15,000 ft upstream of source	N/A	N/A	52
Full Diameter Rupture	15,000 ft upstream of source	N/A	N/A	801
Full Diameter Rupture	105,600 ft (20 miles) upstream of source	N/A	N/A	698

1) See Section 8.2.1 for discussion of release locations.

8.2.3 Fire Modeling Results

8.2.3.1 Flash Fires

Flash fires can occur when a vapor cloud is formed, with some portion of the vapor cloud within the combustible range, and the ignition is delayed. Immediate ignition of the vapor is considered a torch fire and discussed below. If a vapor cloud were to migrate to a commercial or residential location, subsequent ignition of the cloud could result in an outdoor or indoor flash fire. Though the likelihood of a vapor cloud migrating into a building (through the HVAC system or other opening) and remaining above the LFL prior to ignition is considered unlikely, flash fires at both outdoor and indoor locations are considered in this analysis.

The maximum distance at which a vapor cloud could migrate and stay above the LFL for each release type is shown above in Table 8-5. This represents the maximum distance at which an indoor or outdoor flash fire could occur. Beyond this distance, the concentration would be below the LFL. For 1-in releases, the maximum distance at which a flash fire could occur is 52 ft from the pipeline. For a full diameter rupture, the maximum distance at which a flash fire could occur is 801 ft from the pipeline. This distance to LFL assumes that a full diameter pipe rupture occurs at an above ground appurtenance (pig facility, pressure limiting station, etc.). The distance to LFL for releases from the underground body of the pipeline was determined to be less than for the above ground release location. Therefore, using a distance of 801 ft is conservative. Figure 8-2 and Figure 8-3 show the maximum distance to the LFL (5% methane by volume or 4.73 mole percent) associated with a full diameter rupture and 1-in leak, respectively. Note that the terms ‘elevation’ and ‘Air/SS Temp’ in refer to the sensitivity analyses and does not imply a 15,000 ft elevation.

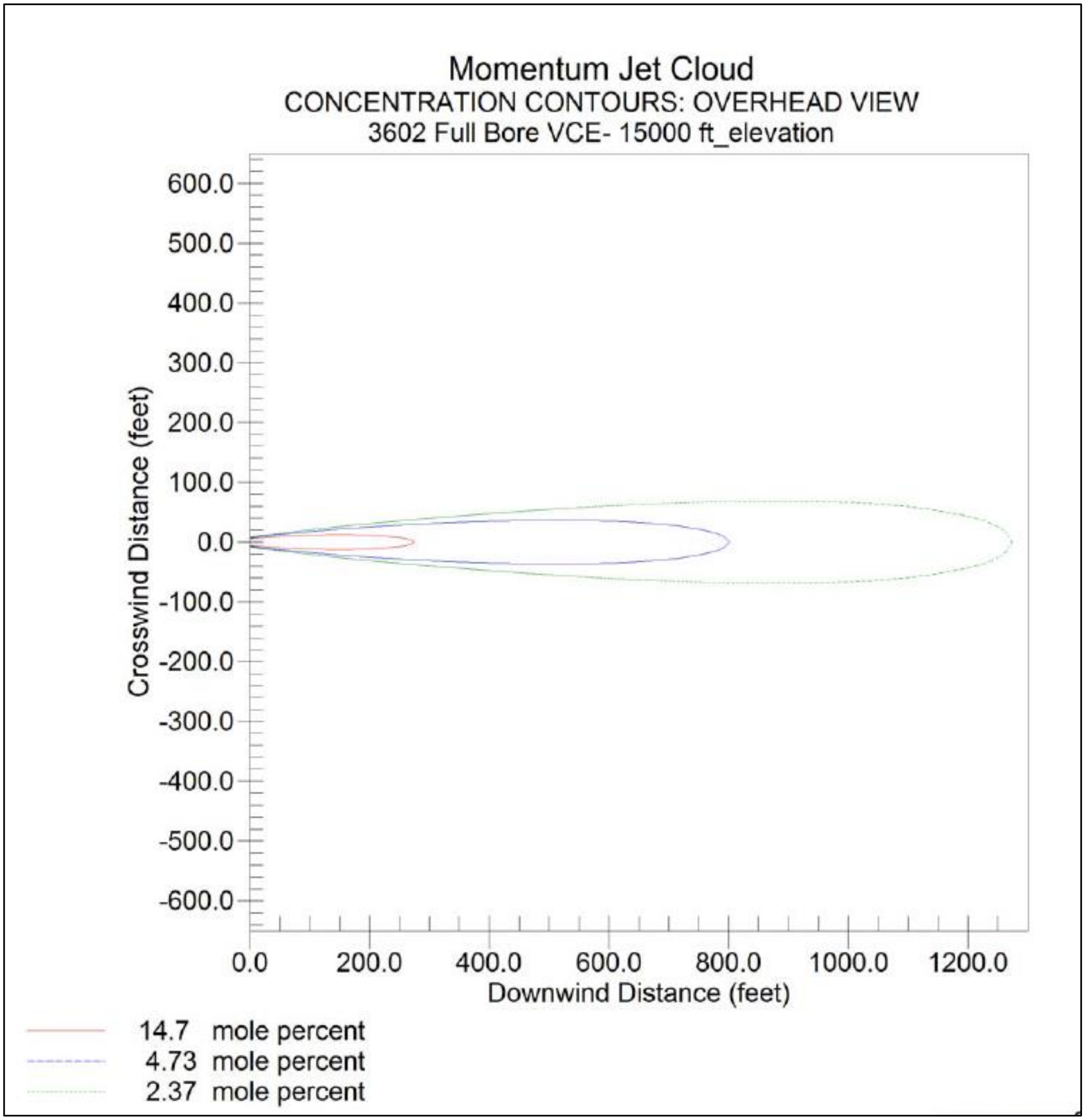


Figure 8-2: Vapor Cloud Dispersion, Full-Diameter Rupture

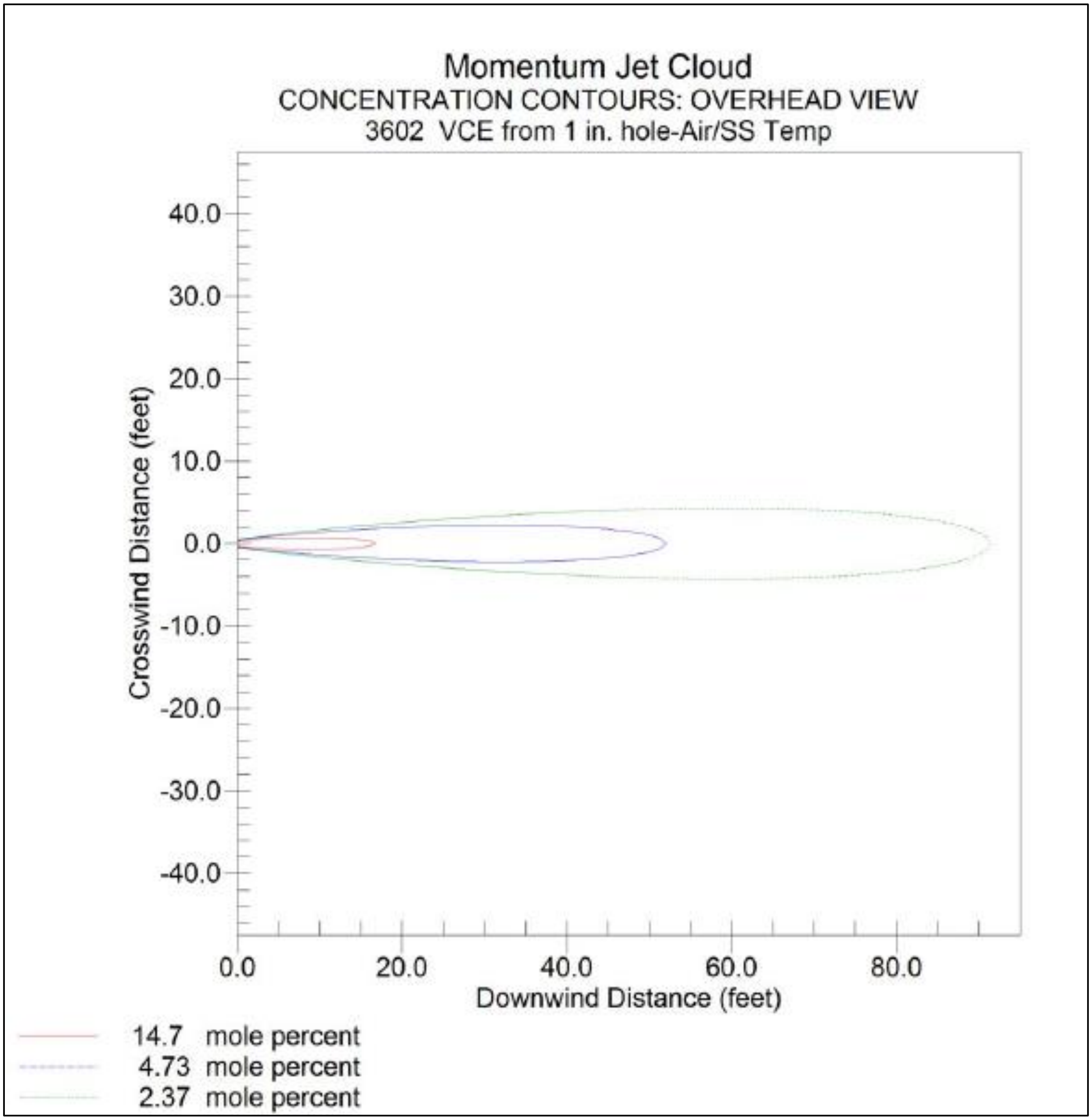


Figure 8-3: Vapor Cloud Dispersion, 1-inch Leak

8.2.3.2 Torch Fires

In determining the consequences due to torch fires initiating at the location of the release (i.e., on the pipeline), the analyses assumed immediate ignition would occur. As discussed in Section 6.0, impacts on the human body due to exposure to torch fires depends on the heat flux and exposure duration. This analysis conservatively assumes a 100% fatality for all receptors who are exposed to a heat flux of 5,000 Btu/hr•ft^2 or greater. This heat flux corresponds to a 1% mortality rate for exposure times of 30 seconds [Reference 11.1]. Conservatively, this analysis does not take into account the capability of receptors to flee from a torch fire. The results of the torch fire modeling are presented in Table 8-6 and show that the 5,000 Btu/hr•ft^2 isopleth extends 81 ft for the 1-in leak scenario and 972 ft for the full diameter rupture. As with the flash fires, the full diameter rupture torch fire conservatively assumes that the release occurs from an above ground appurtenance, which slightly increases the distance to the radiant heat flux endpoint.

The 3,500, 5,000, and 8,000 Btu/hr•ft^2 isopleths associated with each of the releases presented in Table 8-6 are shown in Figures 8-4 through 8-8.

Table 8-6: Torch Fire Modeling Results

Release Type	Release Location[1]	Release Angle	Flame Length (Ft)	Horizontal Distance (Ft) from Release Point to Heat Flux Density Thresholds		
				8,000 Btu/hr•ft^2	5,000 Btu/hr•ft^2	3,500 Btu/hr•ft^2
1-in Leak	15,000 ft downstream of source	0°	65.3	80.5	81	81.3
Full Diameter Rupture	15,000 ft downstream of source	0°	810	966	972	1018
Full Diameter Rupture	15,000 ft downstream of source	30°	809	747	896	1020
Full Diameter Rupture	15,000 ft downstream of source	45°	752	582	752	893
Full Diameter Rupture	105,600 ft (20 miles) downstream of source	0°	751	905	911	914

1) See Section 8.2.1 for discussion of release locations.

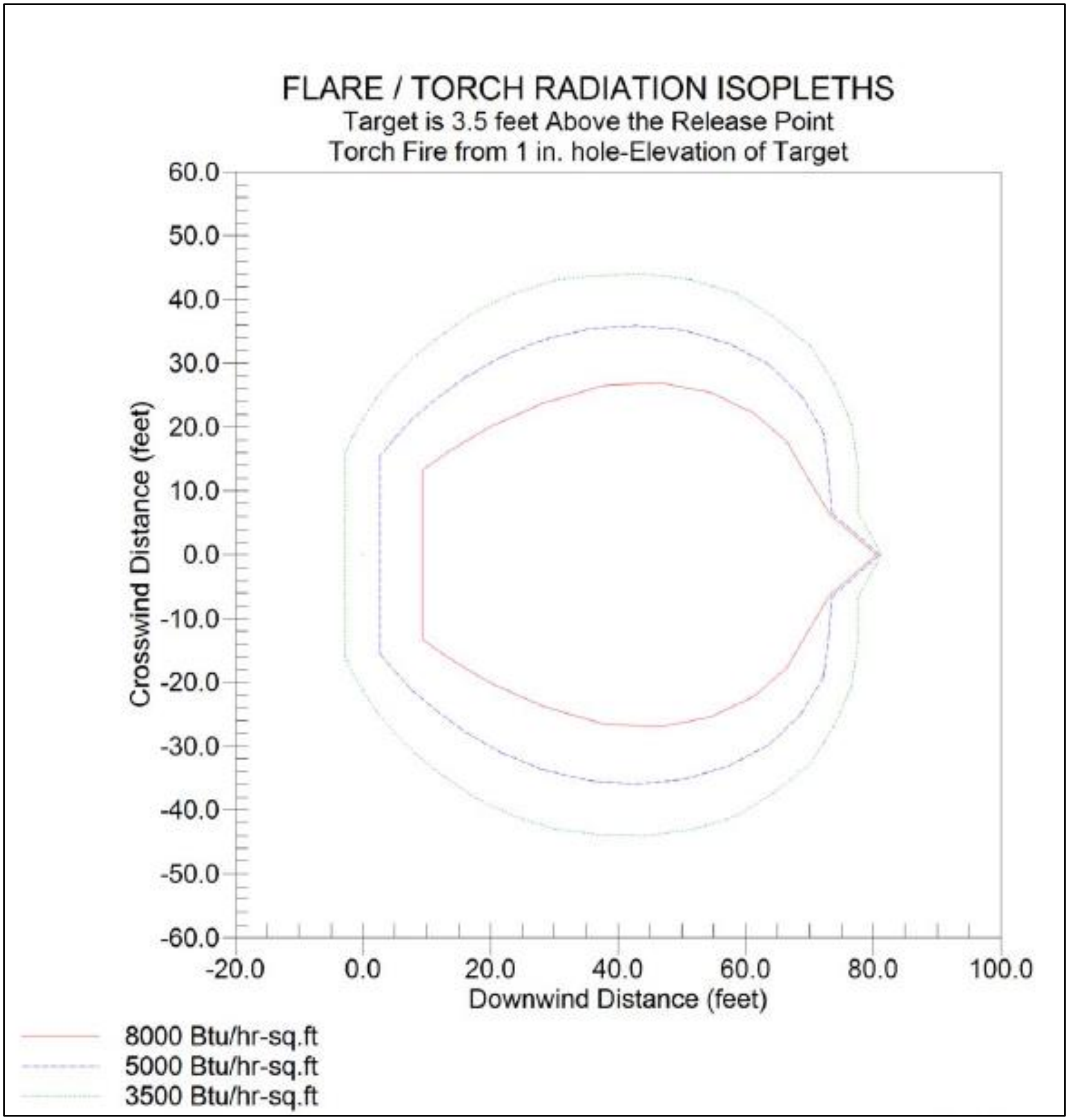


Figure 8-4: 1-inch Leak Torch Fire

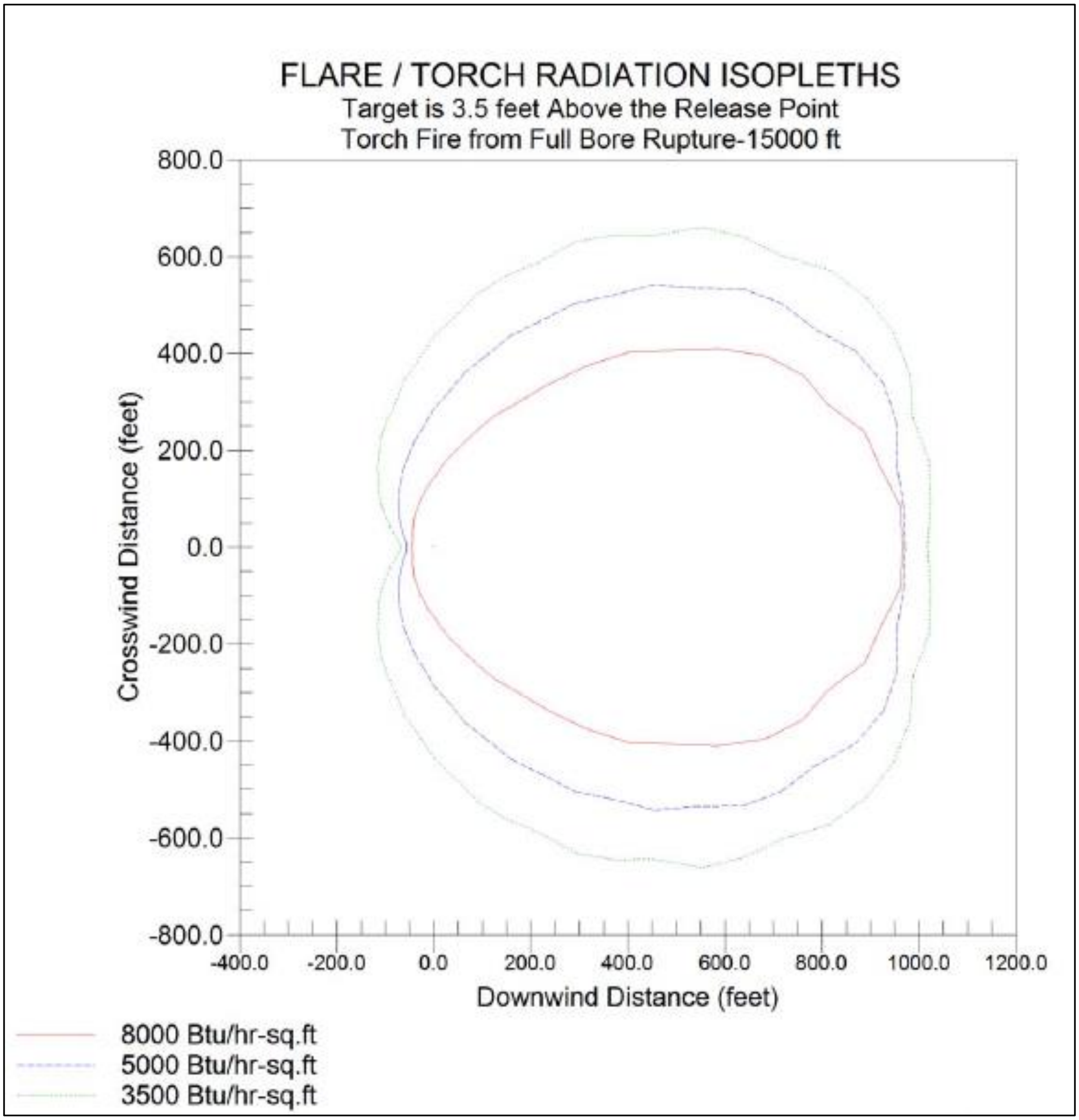


Figure 8-5: Full Diameter Rupture Torch Fire at 0° Release Angle

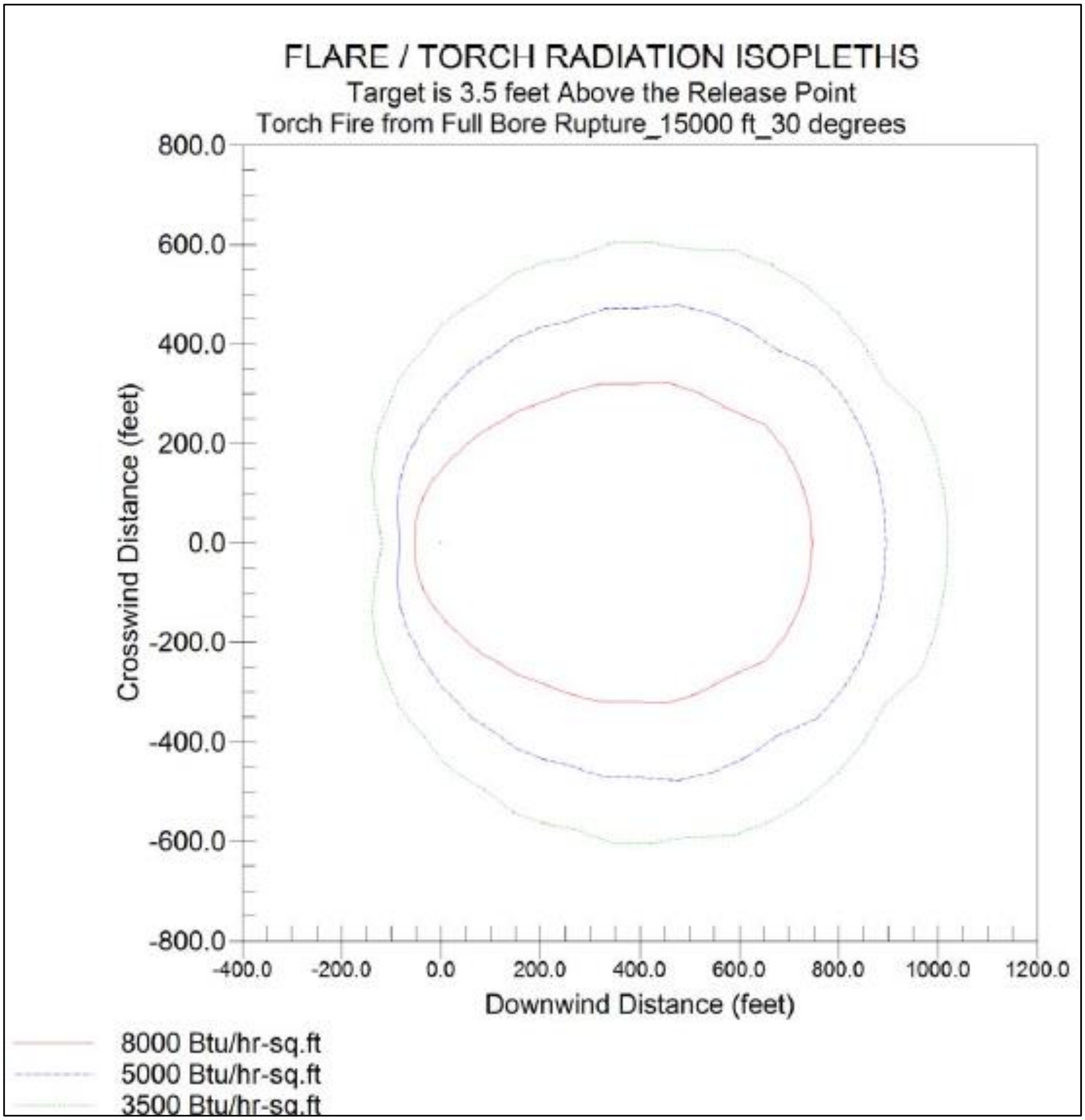


Figure 8-6: Full Diameter Rupture at 30° Release Angle

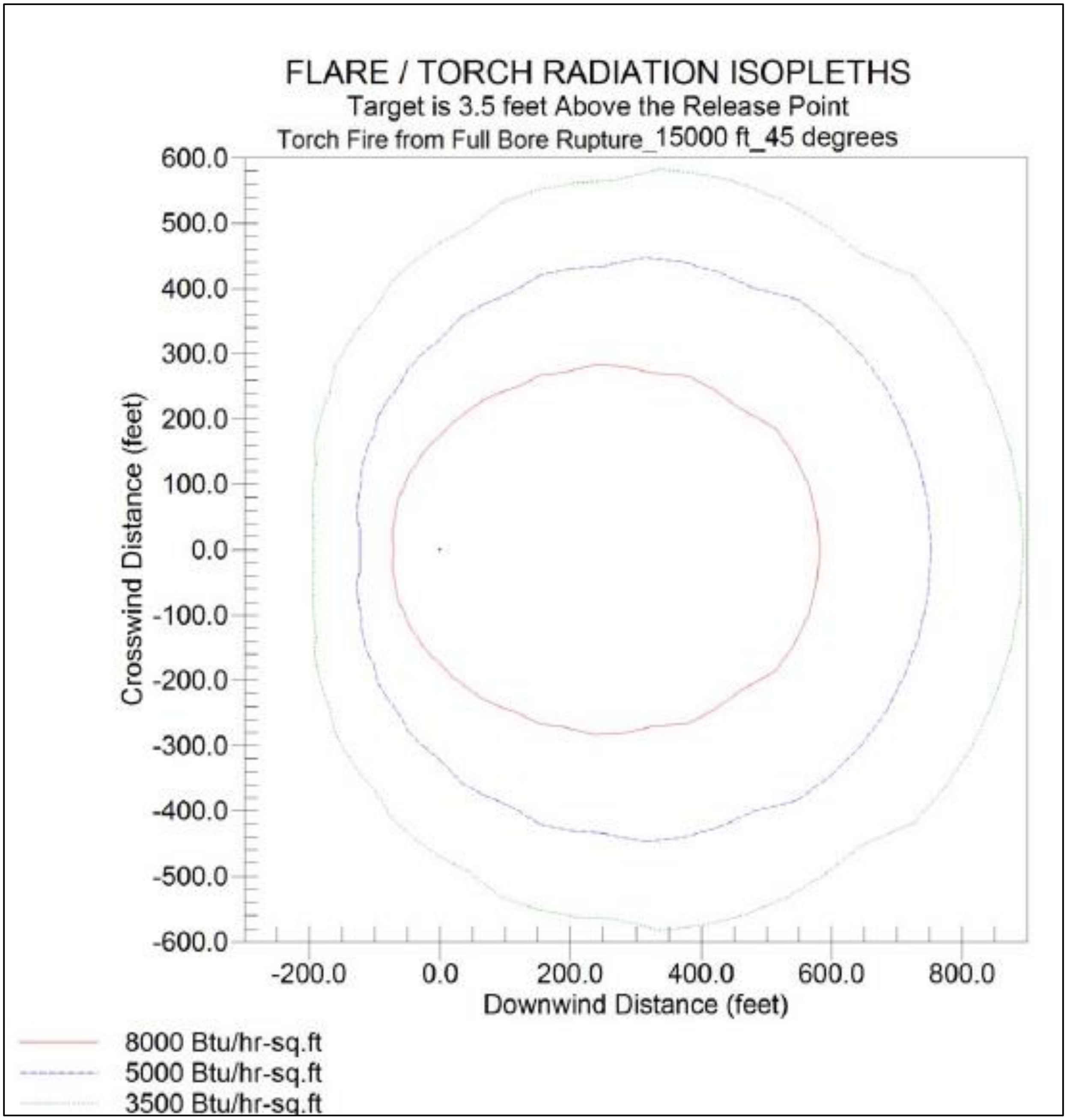


Figure 8-7: Full Diameter Rupture Torch Fire at 45° Release Angle

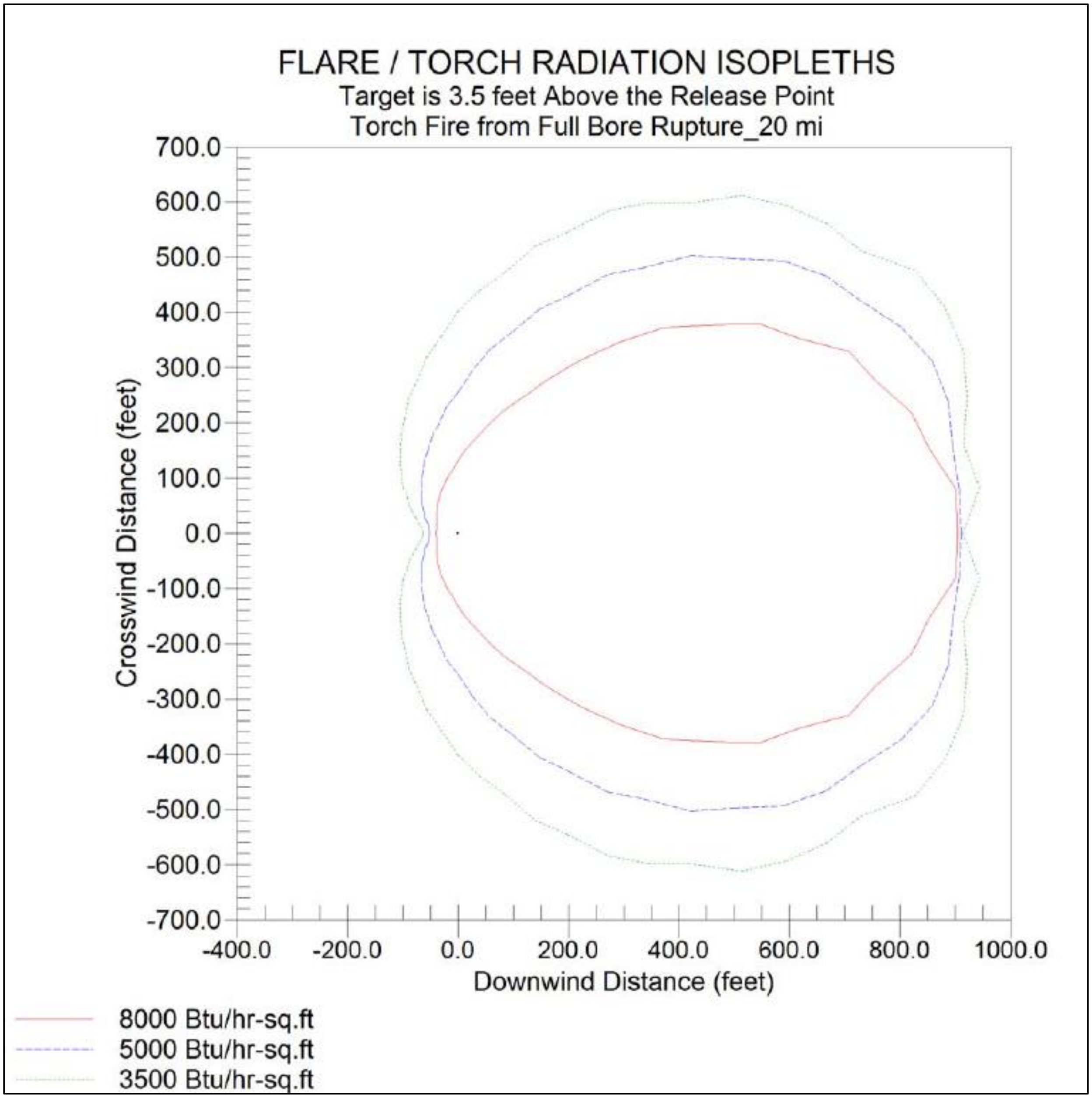


Figure 8-8: Full Diameter Rupture, 20 miles from the Source

8.3 Analysis Assumptions and Methodology

The analysis evaluates the postulated accident risk to receptors at three locations: residences, commercial buildings, and vehicle occupants. The risk to an individual at each location is dependent on the exposure time at a particular location. The number of hours per week the maximally exposed individual is assumed to be at each location are shown in Table 8-7.

8.3.1 Exposure Probability

Exposure probability is quantified based on a receptor's location and the length of time the receptor is assumed to spend in that location. To be conservative, the analysis assumed that residential and commercial receptors were located on both sides of the pipeline route and did not take into account locations along the Proposed Project route where residential or commercial receptors are located on only one side of the pipeline route.

Table 8-7: Exposure Probabilities

Receptor Location	Hours per Week	Exposure Probability
Outside a Residence (e.g., yard)	8	4.8%
Inside a Residence	115	68.5%
Outside a Commercial Building (e.g., parking lot, street)	5	3.0%
Inside a Commercial Building	40	23.8%
Total for Maximally Exposed Individual	168	100%

8.3.2 Proximity to Residences and Commercial Buildings

The distance from the pipeline to a given receptor can be applied in the determination of risk. A receptor located far away from the pipeline will have an effective exposure length that is shorter than a receptor located nearer the line. When compared to hazard lengths given in Table 8-5 and Table 8-6, the distances to the nearest residences and commercial buildings are very short and would not result in a significant reduction in risk. Therefore, the analyses for releases from the pipeline do not take into account the distance between the receptors and the release location, essentially placing the maximally exposed individual's receptor location on top of the pipeline.

8.3.3 Exposure to Occupants of Residences and Commercial Buildings

8.3.3.1 Individual Risk

For torch fires, the impacted distance is the 5,000 Btu/hr•ft^2 isopleth, which corresponds to a 1% mortality rate [Reference 11.4]. The analysis conservatively assumes exposure for any duration of time to this heat flux would result in a fatality. The analysis also assumes that those protected inside a building would be able to safety evacuate should the structure catch fire. For flash fires, the analysis assumes that the migration of a vapor cloud above the LFL to a residential or commercial location would result in a flash fire if ignited. The analysis conservatively assumes a 100% mortality rate for those exposed to a flash fire for any duration of time. The impact distances assumed for the accident (i.e., torch fires and flash fires) are determined in

Section 8.2. The number of hours that the maximally exposed individual is assumed to be present at a given location are shown in Table 8-7 and discussed below.

Outdoor Residential Receptor

The analysis assumes residents spend an average of 8 hours outside per week but still on their property. This is a reasonable assumption as the National Human Activity Pattern Survey (NHAPS) sponsored by the U.S. Environmental Protection Agency (EPA) concluded that the average American spends 7.6% (or just under 13 hours per week) of their time outside [Reference 11.10]. In addition to the 5 hours per week assumed to be spent outside of a commercial building (discussed below), the exposure probabilities applied in this analysis are consistent with the NHAPS study. The study did not identify any statistical variation in time spent outdoors for residents of California versus other parts of the country.

Outdoor Commercial Receptor

The analysis for torch fires assumes occupants of commercial buildings spend an average of 5 hours per week outside (1 hour per day weekday). The risk analysis assumes a total outdoor exposure time of 13 hours per week (8 hours at residential locations and 5 hours at commercial locations). This is consistent with the NHAPS study results, which concluded that the average American spends 7.6% (just under 13 hours per week) of their time outdoors at either a residential or commercial location.

Indoor Residential Receptor

The NHAPS concluded that the average American spends 68.7% of their time inside a residence [Reference 11.10]. The risk analysis assumes the average individual spends 115 hours per week inside their residence (68.5%) and further assumes that 25% of the residential occupants would not evacuate due to the smell of odorized natural gas or would not be evacuated by emergency responders.

Indoor Commercial Receptor

The analysis assumes the average individual spends 40 hours per week inside commercial buildings (average workweek) and further assumes that 25% of the occupants of a commercial building would not evacuate due to the smell of natural gas or would not be evacuated by emergency responders.

8.3.3.2 Societal Risk

The societal risk analysis assumes the same exposure probabilities shown in Table 8-7 for the maximally exposed individual.

Torch Fires and Outdoor Flash Fires

The population exposed to a given event is the product of the population density within the area impacted. This area is assumed to be a circle with diameter of the torch fire or rectangle fully encompassing the area of a flammable vapor cloud. The analysis conservatively assumes that individuals exposed to the 5,000 Btu/hr•ft^2 heat flux for a torch fire (corresponding to a 1%

mortality rate per Reference 11.4) or located within the LFL isopleth for a flash fire will have a 100% mortality rate.

Indoor Flash Fires

As discussed above, societal risk is determined by the total number of individuals exposed to a given event. For indoor flash fires, an additional exposure factor of 0.25 (i.e., 75% of population not exposed to event) is applied to account for the small likelihood that a vapor cloud would migrate inside a building, remain above the LFL, and that occupants would fail to evacuate due to the smell of odorized natural gas or would not be evacuated by emergency responders. Further, since societal risk is dependent on the number of individuals exposed to the hazard, not applying this additional exposure factor would assume that the vapor cloud migrated (and stayed above the LFL) into all of the buildings within the impacted area which is very unlikely.

8.3.4 Exposures to Vehicle Occupants

The NHAPS study concluded that the average individual spends 5.5% of their time (approximately 9 hours per week) in their vehicle. The analysis assumes that occupants in passing vehicles would receive some level of protection from the radiant heat fires. Based on the amount of time spent inside a vehicle and the protection afforded by vehicles, the analysis for vehicular risk applies a 10% morality rate to vehicle occupants within the impact distance. The analysis also assumes that vehicles which cannot stop in time before reaching the torch fire or vapor cloud are also exposed.

Torch Fires

For torch fires, the impacted distance is the 8,000 Btu/hr•ft^2 isopleth, which corresponds to a 50% mortality rate [Reference 11.4]. In addition, due to the variation in the possible release angles (e.g., the flame may be directed away from the road), a 50% probability that the fire will be directed towards the road is applied to the likelihood of a torch fire.

Flash Fires

For flash fires, the impacted distance is the maximum distance that the vapor cloud remains above the LFL. In addition, due to the variation in the possible release angles (e.g., the plume may be directed away from the road), a 50% probability that the vapor cloud will be directed towards the road is applied to the likelihood of a flash fire.

8.3.5 Number of Vehicle Occupants

Traffic data from several roadways located near the proposed route were compiled to determine a maximum traffic density in determining the risk to vehicle occupants. The highways identified as high traffic areas near the proposed route were Interstate15 (I-15) and State Route 78. Peak hourly and annual average daily traffic for these highways at intersections along the proposed route are presented in Table 8-8 [Reference 11.13]. The values in this table correspond to peak traffic densities ranging from 1.83 vehicles per second to 4.83 vehicles per second. The analysis will conservatively assume five vehicles per second along highways for determining risk to vehicle occupants.

Table 8-8: Highway Traffic Data

Route	Post Mile	Description	Peak Hour (Vehicles/Hour)
I-15	30.627	Valley Parkway	17,400
I-15	31.517	Jct. Rte. 78	17,100
I-15	32.861	Escondido, El Norte Parkway	11,300
I-15	33.922	Centre City Parkway	8,900
I-15	36.636	Deer Springs Road	9,400
I-15	40.842	Gopher Canyon Road	10,900
I-15	43.279	Escondido Highway	9,100
I-15	46.491	Jct. Rte. 76	10,300
I-15	50.585	Mission Road	10,800
I-15	54.07	Rainbow Valley Boulevard	10,700
I-15	54.258	San Diego/Riverside County Line	10,800
State Route 78	16.539	Escondido, Jct. Rte. 15	12,500
State Route 78	17.268	Escondido, Centre City Parkway	6,600

Annual traffic data was reviewed to identify highly travelled surface streets along the proposed route. Peak hourly traffic data for several intersections with the highest peak hourly traffic data along the proposed route are presented in Table 8-9 [Reference 11.14]. The values in this table correspond to traffic densities ranging from 0.03 vehicles per second to 0.44 vehicles per second. The analysis will conservatively assume one vehicle per second along surface streets for determining risk to vehicle occupants.

Table 8-9: Surface Street Traffic Data

Primary Street	1st Cross Street	2nd Cross Street	Average Weekday Traffic Volumes (Vehicles/Day)
13th Ave	Quince St	Centre City Pkwy	2,700
13th Ave	Centre City Pkwy	Escondido Blvd	4,100
2nd Ave (E/B 1-Way)	Quince St	Centre City Pkwy	20,000
2ND Ave (E/B 1-Way)	Centre City Pkwy	Escondido Blvd	20,000
5th Ave	Quince St	Centre City Pkwy	5,000
5th Ave	Centre City Pkwy	Escondido Blvd	9,000
9th Ave	Quince St	Centre City Pkwy	17,500
9th Ave	Centre City Pkwy	Escondido Blvd	14,200

Table 8-9: Surface Street Traffic Data

Primary Street	1st Cross Street	2nd Cross Street	Average Weekday Traffic Volumes (Vehicles/Day)
Centre City Pkwy	9th Ave	13th Ave	30,600
Centre City Pkwy	Grand Ave	2nd Ave	34,200
Centre City Pkwy	2nd Ave	5th Ave	27,400
Centre City Pkwy	5th Ave	9th Ave	27,400
Centre City Pkwy	Interstate 15 Ramps	Country Club Ln	6,000
Centre City Pkwy	Iris Ln	Elorte Pkwy	20,700
Centre City Pkwy	13th Ave	Felicita Ave	31,800
Centre City Pkwy	Valley Pkwy	Grand Ave	32,900
Centre City Pkwy	Country Club Ln	Iris Ln	15,400
Centre City Pkwy	Route 78	Mission Ave	35,400
Centre City Pkwy	Elorte Pkwy	Route 78	35,400
Centre City Pkwy	Washington Ave	Valley Pkwy	29,600
Centre City Pkwy	Mission Ave	Washington Ave	29,400
Country Club Ln	Centre City Pkwy	Broadway	12,800
Country Club Ln	Nutmeg St	Centre City Pkwy	5,200
Elorte Pkwy	Iris Ln (S)	Centre City Pkwy	28,400
Elorte Pkwy	Centre City Pkwy	Escondido Blvd	26,000
Escondido Blvd	Felicita Ave	Centre City Pkwy Ramp	12,500
Felicita Ave	Escondido Blvd	Centre City Pkwy	26,300
Felicita Ave	Centre City Pkwy	Redwood St	10,900
Grand Ave	Quince St	Centre City Pkwy	2,500
Grand Ave	Centre City Pkwy	Escondido Blvd	10,300
Iris Ln (N)	Centre City Pkwy	Country Club Ln	5,500
Iris Ln (S)	Elorte Pkwy	Centre City Pkwy	5,400
Mission Ave	Quince St	Centre City Pkwy	28,400
Valley Pkwy (W/B 1-Way)	Escondido Blvd	Centre City Pkwy	20,400
Valley Pkwy 0/\J/B 1-Way)	Centre City Pkwy	Quince St	18,500
Washington Ave	Quince St	Centre City Pkwy	18,600
Washington Ave	Centre City Pkwy	Escondido Blvd	19,100
Pomerado Rd	Highland Valley Rd	Paseo del Verano Norte	27,900

Table 8-9: Surface Street Traffic Data

Primary Street	1st Cross Street	2nd Cross Street	Average Weekday Traffic Volumes (Vehicles/Day)
Pomerado Rd	Greens East Rd	Rancho Bernardo Rd	27,800
Pomerado Rd	Rancho Bernardo Rd	Bernardo Heights Pkwy	27,900
Pomerado Rd	Bernardo Heights Pkwy	Camino del Norte	28,800
Pomerado Rd	Camino del Norte	Ted Williams Pkwy	28,700
Pomerado Rd	Ted Williams Pkwy	Robinson Blvd	23,400
Pomerado Rd	Robinson Blvd	Poway Rd	25,300
Pomerado Rd	Poway Rd	Oak Knoll Rd	20,600
Pomerado Rd	Scripps Poway Pkwy	Creek Rd	22,000
Pomerado Rd	Creek Rd	Legacy Rd	23,300
Pomerado Rd	Legacy Rd	Spring Canyon Rd	23,300
Pomerado Rd	Avenida Magnifica	Scripps Ranch Blvd	22,100
Pomerado Rd	Scripps Ranch Blvd	Willow Creek Rd	23,700
Bear Valley Pkwy	Sunset Dr	San Pasqual Rd	37,800
Bear Valley Pkwy	San Pasqual Rd	Via Rancho Pkwy	37,600
Felecita Ave	Juniper St	Escondido Blvd	18,200
Felecita Ave	Escondido Blvd	Centre City Pkwy	26,300
Felecita Ave	Centre City Pkwy	Redwood St	15,000
Mission Rd	Old Hwy 395	Interstate 15	16,800

For highways, vehicles are assumed to be moving at 105 ft per second (ft/s), or approximately 70 miles per hour (mph). This is based on the maximum California highway speed limit [Reference 11.11]. For surface streets, vehicles are assumed to be moving at 60 ft/s, or approximately 40 mph. Each driver is assumed to have a reaction time of one second to hazards in the road, and the average braking deceleration for each vehicle is assumed to be 15 ft/s^2 [Reference 11.12]. For the determination of societal risk to vehicle occupants, each vehicle is assumed to contain two individuals (one driver, one passenger).

8.4 Individual Risks

The risk to the maximally exposed individual is determined in this section as a function of the baseline incident rate, the probability that an individual will be present at a given location, and the hazard segment length. The risk from the proposed pipeline to individuals located at each receptor location for the postulated accident types is presented in this section.

8.4.1 Exposures to Occupants of Residences and Commercial Buildings

As stated in Section 8.3.2, the accident consequence thresholds assumed for occupants of residences and commercial buildings is 5,000 Btu/hr•ft^2 for torch fires, or the maximum distance to the LFL for indoor and outdoor flash fires.

Torch Fire, Full Diameter Rupture: This event results in a torch fire where the 1% mortality rate heat flux of 5,000 Btu/hr•ft^2 extends approximately 972 ft from the release location.

Torch Fire, 1-in Leak: This event results in a torch fire where the 1% mortality rate heat flux of 5,000 Btu/hr•ft^2 extends approximately 81 ft from the release location.

Outdoor Flash Fire, Full Diameter Rupture: This event results in the dispersion of a vapor cloud that remains above the LFL for approximately 801 ft from the release location.

Outdoor Flash Fire, 1-in Leak: This event results in the dispersion of a vapor cloud that remains above the LFL for approximately 52 ft from the release location.

Indoor Flash Fire, Full Diameter Rupture: This event results in the dispersion of a vapor cloud that remains above the LFL for approximately 801 ft from the release location.

Indoor Flash Fire, 1-in Leak: This event results in the dispersion of a vapor cloud that remains above the LFL for approximately 52 ft from the release location.

8.4.2 Exposures to Vehicle Occupants

As stated in Section 8.3.4, the accident consequence threshold assumed for vehicle occupants is 8,000 Btu/hr•ft^2 for torch fires, or the maximum distance to LFL for flash fires.

Torch Fire, Full Diameter Rupture: This event results in a torch fire where the 50% mortality rate heat flux of 8,000 Btu/hr•ft^2 extends approximately 966 ft from the release location.

Torch Fire, 1-in Leak: This event results in a torch fire where the 50% mortality rate heat flux of 8,000 Btu/hr•ft^2 extends approximately 80.5 ft from the release location.

Outdoor Flash Fire, Full Diameter Rupture: This event results in the dispersion of a vapor cloud that remains above the LFL for approximately 698 ft from the release location.

Outdoor Flash Fire, 1-in Leak: This event results in the dispersion of a vapor cloud that remains above the LFL for approximately 52 ft from the release location.

8.4.3 Individual Risk Results

The individual risk associated with each postulated event is presented in Table 8-10. The risk to the maximally exposed individual is the cumulative risk of each of the postulated accident types for each receptor location, and is determined to be 4.52 x 10^{-7} fatalities per year (i.e., 1 in

2,212,389 years). This is less than the significance criteria of one fatality in one million years (1:1,000,000). The analysis for individual risk was conservatively determined without taking into account any Proposed Project design features, such as corrosion prevention, cathodic protection, increased wall thickness, early intrusion detection, etc. (see Section 9.0). Thus, the actual individual risk associated with the Proposed Project is even lower than what is calculated in this Study, 4.52×10^{-7}.

Table 8-10: Individual Risk Results

Rupture/ Leak	Torch Fire / Flash Fire	Receptor Location	Individual Risk (IR) (Fatalities/Year)
Rupture	Torch	Residential	6.60×10^{-8}
Rupture	Torch	Commercial	4.13×10^{-8}
Rupture	Outdoor Flash	Residential	6.27×10^{-9}
Rupture	Outdoor Flash	Commercial	3.92×10^{-9}
Rupture	Indoor Flash	Residential	2.25×10^{-8}
Rupture	Indoor Flash	Commercial	7.84×10^{-9}
Leak	Torch	Residential	6.78×10^{-8}
Leak	Torch	Commercial	4.24×10^{-8}
Leak	Outdoor Flash	Residential	4.82×10^{-9}
Leak	Outdoor Flash	Commercial	3.02×10^{-9}
Leak	Indoor Flash	Residential	1.73×10^{-8}
Leak	Indoor Flash	Commercial	6.03×10^{-9}
Rupture	Torch	Vehicle	6.89×10^{-8}
Rupture	Flash Fire	Vehicle	1.32×10^{-8}
Leak	Torch	Vehicle	7.08×10^{-8}
Leak	Flash Fire	Vehicle	1.01×10^{-8}

8.5 Societal Risks

Societal risk is calculated as the probability that a specific number of individuals will be impacted by a given event. To determine conservative results for the societal risk associated with the project, the maximum population density along the proposed route was used in the analysis. As discussed in Section 8.2.1, the release location used for the determination of societal risk was selected as the area along the line with the highest population density. The impacts and exposure areas for societal risk for each of the postulated accident types and receptor locations are presented below.

8.5.1 Exposure to Occupants of Residences and Commercial Buildings

Torch Fire, Full Diameter Rupture: This event results in a torch fire where the 1% mortality rate heat flux of 5,000 Btu/hr•ft^2 extends approximately 911 ft from the release location. To determine the societal risk for this event, the population density is multiplied by the area impacted by this event, which is conservatively assumed to be a circle with a diameter equal to the maximum distance of the 5,000 Btu/hr•ft^2 heat flux isopleth (911 ft).

Torch Fire, 1-in Leak: This event results in a torch fire where the 1% mortality rate heat flux of 5,000 Btu/hr•ft^2 extends approximately 81 ft from the release location. To determine the societal risk for this event, the population density is multiplied by the area impacted by this event, which is conservatively assumed to be a circle with a diameter equal to the maximum distance of the 5,000 Btu/hr•ft^2 heat flux isopleth (81 ft).

Outdoor Flash Fire, Full Diameter Rupture: This event results in the dispersion of a vapor cloud that remains above the LFL for approximately 698 ft from the release location. To determine the societal risk for this event, the population density is multiplied by the area impacted by this event, which is conservatively assumed to be a rectangle that fully encompasses the flammable vapor cloud, with a maximum length of 698 ft.

Outdoor Flash Fire, 1-in Leak: This event results in the dispersion of a vapor cloud that remains above the LFL for approximately 52 ft from the release location. To determine the societal risk for this event, the population density is multiplied by the area impacted by this event, which is conservatively assumed to be a rectangle that fully encompasses the flammable vapor cloud, with a maximum length of 52 ft.

Indoor Flash Fire, Full Diameter Rupture: This event results in the dispersion of a vapor cloud that remains above the LFL for approximately 698 ft from the release location. To determine the societal risk for this event, the population density is multiplied by the area impacted by this event, which is conservatively assumed to be a rectangle that fully encompasses the flammable vapor cloud, with a maximum length of 698 ft.

Indoor Flash Fire, 1-in Leak: This event results in the dispersion of a vapor cloud that remains above the LFL for approximately 52 ft from the release location. To determine the societal risk for this event, the population density is multiplied by the area impacted by this event, which is conservatively assumed to be a rectangle that fully encompasses the flammable vapor cloud, with a maximum length of 52 ft.

8.5.2 Exposures to Vehicle Occupants

Societal risk to vehicle occupants is calculated in a similar fashion to individual risk for vehicle occupants, but assumes that each vehicle exposed to the incident is occupied by two individuals (one driver and one passenger). However, unlike societal risk for occupants of residences and commercial buildings, societal risk for vehicle occupants conservatively assumes the worst case release location as discussed in Section 8.2. This is because the societal risk for occupants of residences and commercial buildings is dependent upon the highest population density along the proposed route, whereas societal risk for vehicle occupants is dependent upon the assumed traffic density. Even though the worst case release location is not adjacent to a major highway or surface street, assuming this release location allows for a conservative analysis. The accident consequence thresholds assumed for vehicle occupants is 8,000 Btu/hr•ft^2 for torch fires, or the maximum distance to the LFL for flash fires. The maximum distance to each of the consequences thresholds is presented in Section 8.4.2 and is therefore not repeated here.

8.5.3 Societal Risk Results

The societal risk for each postulated event is first determined individually as the product of the area impacted by a given event and the population density. Societal risk is then presented on an F-N curve; where F is the cumulative frequency of N or more fatalities, and N is the number of fatalities. The societal risk results are presented on Figure 8-9 which shows that the cumulative frequency of N or more fatalities is below the acceptance criteria and all events have a site casualties (SC) to societal risk criteria (SRC) ratio of less than 1.0. See Section 7.0, Significance Criteria, for discussion of the acceptance criteria for societal risk.

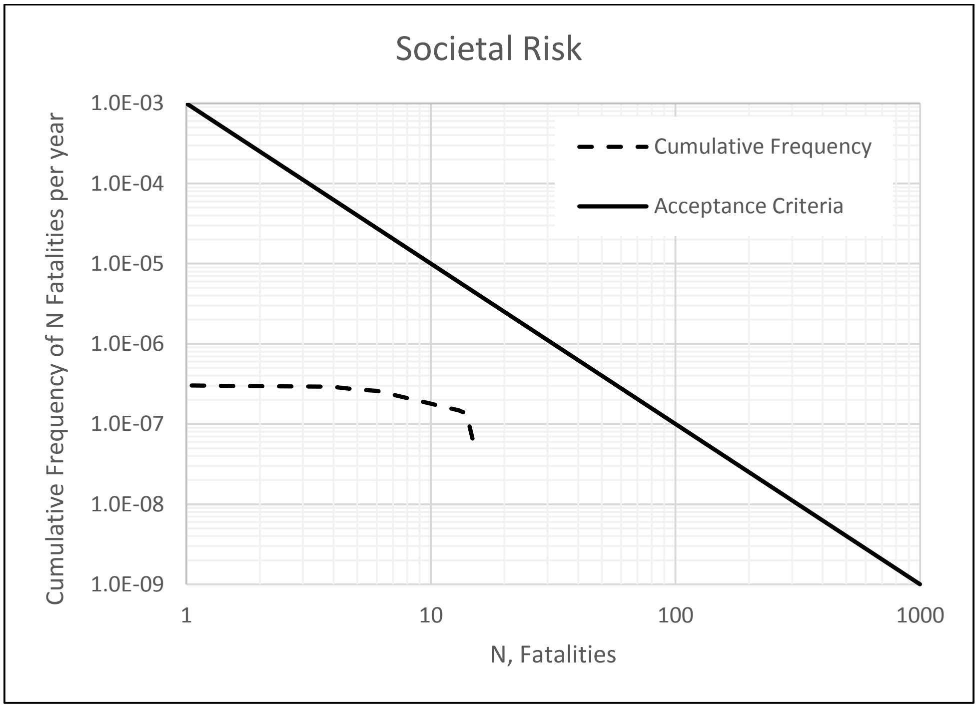


Figure 8-9: F-N Curve for Societal Risk

The analysis for societal risk was determined without taking into account any Proposed Project design features, such as corrosion prevention, cathodic protection, increased wall thickness, etc. (see Section 9.0). Thus, the societal risk associated with the Proposed Project is even lower than estimated in this analysis.

9.0 PROPOSED PROJECT DESIGN FEATURES

The Proposed Project includes design features that use the best available design, technology, and practices to reduce the frequency of inadvertent releases and associated risks. These design features, presented below, meet or exceed applicable laws, ordinances, regulations, and standards to reduce the frequency of inadvertent releases. The pipeline will be designed, constructed, operated, and maintained in accordance with USDOT regulations CFR Title 49, Part 192, and CPUC standards embodied under G.O. 112-E. The Proposed Project also has been developed in accordance with The Applicants' Pipeline Safety Enhancement Plan (PSEP), pursuant to CPUC Decision D.11-06-017.

To provide a conservative assessment, the risk assessment presented in this study does not take into account these Proposed Project design features, or other government-required measures, in its determination of individual and societal risk for the Proposed Project (see Section 8.0, Risk Assessment). However, implementation of these design features will reduce risks associated with the Proposed Project further below their less than significant levels as discussed in Section 8.0, Risk Assessment, and defined in Section 7.0, Significance Criteria.

Note that natural forces (including earth movement) are included as incident causes in determination of the baseline incident rate and therefore contribute to the individual and societal risk calculated in this Study (see Table 6-3). Proposed Project design features included in this section do not include those related to ground disturbance activities, such as earthquakes. Risks and measures associated with ground movement are included in the Hazards and Hazardous Materials section of the Proponent's Environmental Assessment.

Proposed Project design features include:

- **Wall Thickness and Strength**: Pipe will have minimum pipe wall thickness of 0.625 in steel[2] meeting American Petroleum Institute standard API 5LX-65, ensuring the pipe has a minimum yield strength of 65 kilopounds per square in (ksi), tensile strength of 77 ksi, maximum tensile ratio of 0.93, and minimum elongation of 18 percent.
- **Burial Depth**: Pipeline will be buried approximately 42 in below ground surface.[3]
- **Intrusion Detection Monitoring System**: An advanced intrusion detection monitoring system will be used to provide early warning when digging, drilling, boring, cutting,

[2] A study performed in the United Kingdom [Reference 11.9] evaluated the effectiveness of various forms of third-party damage mitigation. The study evaluated increased wall thickness for multiple pipe diameters. For smaller lines (e.g., 24 inches), the study found that an increased wall thickness reduced the likelihood of a failure as much as 80%. The study failed to analyze a 36-in pipeline wall thickness greater than 11.9 mm (~0.5 inch). However, based on trends documented for other lines, it would be reasonable to reduce the likelihood of an unintentional release due to third-party damage based on the 0.625-inch piping wall thickness being proposed; however this feature was not taken into account when assessing risk in this Study.

[3] The United Kingdom study [Reference 11.9] determined that a reduction factor of 0.66 can be applied to pipelines buried at a depth greater than 80 cm (~32 inches). The depth of cover for the proposed pipeline is 42 inches Therefore, it would be reasonable to reduce the likelihood of third-party damage to account for the actual depth of cover; however this feature was not taken into account when assessing risk in this Study.

compacting, or unplanned vehicle operations pose a threat to pipeline integrity (third-party damage risks). The system will continuously monitor for ground movement and temperature gradients associated with an unplanned release of gas and may consist of fiber optic cable buried above and/or adjacent to pipeline, which would be wired to a system monitoring station collocated with supervisory control and data acquisition (SCADA) equipment (monitoring stations will have secured power source). Warning mesh/tape (48-in wide) will be installed at least one foot below grade on top of the pipeline along the length of the pipeline trench as a visual barrier and early warning device.[4]

- **Mainline Valves**: Mainline valves will be installed at a minimum of every five miles along the entire pipeline route to shut down the flow of gas during operation and maintenance activities or emergency situations. Valve spacing will meet Class 4 location criteria. Valves will allow Applicants to meet or exceed criteria for isolation and depressurization of designated sections of the pipeline in less than 30 minutes in the event of pipeline failure[5]. Valves will be designed for automatic shut-off without operator intervention and will be installed underground; valve controls will be installed aboveground. The design will include a 10-in-diameter or 12-in-diameter blowoff valve and stack situated approximately three ft above the ground. All aboveground piping and equipment will be enclosed with six-foot-high, concrete, earth-toned block wall for security purposes.
- **Leak Detection Monitoring System**: Gas detection sensors will be employed at key locations along the pipeline to support early detection and management of unplanned gas releases. The system will provide a near "real time" alarm if gas concentration levels indicate a potential release. The system might include fiber optic equipment along and above the pipeline and in high consequence areas (e.g., schools or hospitals) and methane detectors.
- **Cathodic Protection System**: The cathodic protection system consists of cathodic protection rectifiers, buried anodes, and test stations that will be situated along the pipeline. Approximately three rectifiers and three deep-well anode beds will be installed at approximately three of the proposed valves. Each rectifier will require a utility pole to provide power and an electric meter. The rectifier and electric meter will be mounted on the power pole. The anode bed will be installed vertically below grade near the aboveground power pole at a depth between 150 ft and 500 ft. Each anode will have a coated wire lead that will be connected to the rectifier. The anode bed will be located in close proximity to the proposed pipeline and rectifier. The rectifier will be connected to the pipeline to establish protection. Cathodic protection test stations will be installed at approximately 2,000-foot intervals along the pipeline. Wires will be connected to the pipeline and brought to the

[4] The United Kingdom study [Reference 11.9] determined that pipelines protected with an additional warning/protection device (e.g., warning tape) resulted in a reduction in third-party caused events. These reduction factors ranged from 0.6 to 0.03. Therefore, it would be reasonable to apply a reduction factor for third-party damage due to the preventive measures being implemented such as the fiber optic cable, warning tape, etc.; however this feature was not taken into account when assessing risk in this Study.

[5] While the mainline valves will limit the inventory of natural gas unintentionally released, the accident analysis modeling was performed without consideration of this feature and conservatively assumed that the entire inventory of the pipeline would be released.

surface to an approximately three-foot-high above-grade polyvinyl chloride cylinder. In urban areas a street surface access road cover will be used.[6]

- **Pipe Welding, Coating, and Bending**: Pipe will be welded double-jointed into approximately 80-foot lengths prior to transport to the project site. Pipe will be welded into longer sections where topographical and/or existing conditions allow open trenches for prolonged periods. Sidebooms will be used to pick up each joint of pipe, align it with the adjacent joint, and make first part (i.e., pass) of the weld. All onsite welding ("field welding") will be performed by qualified welders in accordance with the American Petroleum Institute Standard 1104 (Welding Pipe Lines and Related Facilities) and CFR Title 49, Part 192. All new pipeline welds will be inspected both visually and radiographically (i.e., via X-ray) by certified weld inspectors.[7] Pipe, including field joints, will be coated with an epoxy coating, such as Fusion Bonded Epoxy (FBE) or Protal 7200[8]. New pipeline segments will be inspected to locate and repair faults or voids in the pipeline coating prior to being lowered into the trench. Most of pipe will be bent in the field with track-mounted pipe-bending equipment; however, some pipe bends will be fabricated offsite. Once the trench is excavated, any bends that are required—to avoid substructures or changes in the alignment—will be determined, measured, and completed for installation.
- **Pipe Lowering, Backfill, and Compaction**: Welded pipe segments or individual pipe lengths will be lifted and lowered into the trench by sideboom tractors. Cradles with rubber rollers or padded slings will be used to avoid damaging the pipe's protective coating. The trench bottom will be padded with a layer of imported rock-free sand if rocks are present in the trench. Native material excavated from the pipeline trench will be used to backfill the trench. In general, backfill will not be compacted. In urban areas, concrete trucks will backfill the trench with an engineered sand/slurry mixture. The backfill process in urban areas will be in accordance with standard engineering practices and permit requirements.

---

[6] The baseline incident rate used for the risk assessment for this Study includes many incidents which occurred on older pipelines. Cathodic protection systems used on older pipelines are less effective than those to be used for the Proposed Project. Implementation of this improved design feature would ensure a further reduction in risk to the public below what is determined in this Study.

[7] From 2002–2014 material or weld failure accounted for 15.4% of all incidents for onshore natural gas transmission lines comparable to the Proposed Project (see Table 6-3). Many weld failures occurred on older pipelines that were installed when standards for conducting and inspecting welds were not as robust. Applicants' policies to ensure the integrity of welding performed on the Proposed Project were developed in accordance with American Petroleum Institute (API) 1104 and American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section IX. All welds in fittings fabricated by welding shall be radiographed in accordance with Section V of ASME code. Longitudinal welds shall meet the acceptable limits of ASME Section VIII, and girth welds shall meet the acceptable limits of API 1104, Section 6. This Study does not take into account implementation of specific Proposed Project design features in the determination of individual and societal risk; therefore, implementation of these welding standards will result in a further reduction in risk to the public below what is determined in this Study.

[8] Many older pipelines employed pipe coatings, such as coal tar, that are much less effective than modern external pipe coatings, such as FBE. A 2007 report by the Canadian Energy Pipeline Association stated that FBE has been used by the industry for 30 years with no reported incidents of stress corrosion cracking, even in locations known to exhibit cracking on parallel asphalt or tape coated pipelines (Reference 11.15). The baseline incident rate used in the risk assessment for this Study is derived partially from incidents stemming from older pipelines that used non-FBE coatings. Implementation of this improved design feature would ensure a further reduction in risk to the public below what is determined in this Study.

- **Inspection and Testing**: The pipeline will undergo various inspections and testing during construction and as part of maintenance activities. These tasks are detailed in Table 9-1.

Table 9-1: Pipeline Inspection and Testing Schedule

Description	Minimum Frequency
Inspection of all valves	Annually
Inspection of pressure-limiting equipment	Annually
Inspections of pneumatic and electronic autoclosure equipment associated with the valves	Twice per year
Inspections of electronic equipment not associated with the valves	Annually
Pipeline patrol and leak surveys of the entire line	Twice per year
Patrols of the highway and railroad crossings	Four times per year
Patrol for the class location survey	Annually
Cathodic protection surveys	Annually
Readings taken from rectifiers providing cathodic protection	Six times per year
Inspections of above-ground facilities for atmospheric corrosion	Once every three years
Pigging or inline inspection	Once every seven years
Exposing various portions of the pipeline to verify pigging results	Once every seven years
Providing locate-and-mark services (i.e., DigAlert or 8-1-1)	Varies based on requests by third parties
Providing surveillance of entities excavating over the pipeline	Varies (12 times per year)

10.0 CONCLUSION

This Study analyzes the potential individual and societal risks associated with construction and operation of the Proposed Project, which involves the potential for there to be a leak or rupture thereby releasing natural gas that may be subsequently ignited. This Study uses historical data to identify the potential events that could occur, determine the probability of each of those events occurring, and uses standard modeling software to calculate the consequences of those events should they transpire along the alignment for the Proposed Project. This Study concludes that all risks associated with the Proposed Project are less than significant. The individual risk level is conservatively determined to be 4.52×10^{-7} fatalities per year (i.e., 1 in 2,212,389 years); less than the generally accepted significance criteria. The societal risk level for all potential events associated with the Proposed Project is a ratio of less than 1.0, also below the significance criteria. These calculations do not take into account the effect of implementing Applicants proposed risk reduction measures and compliance with government required risk reduction measures. Based on studies of the effectiveness of such measures, it is reasonable to assume that implementation of these measures will further reduce the potential for any incident which can impact public safety to occur as a result of construction and operation of the Proposed Project.

11.0 REFERENCES

11.1 Stephens, M.J. 2000. *A Model for Sizing High Consequence Areas Associated With Natural Gas Pipelines*. Gas Research Institute.

11.2 U.S. Department of Transportation (USDOT) Pipeline and Hazardous Safety Administration Distribution (PHMSA). 2015. Transmission & Gathering, LNG, and Liquid Accident and Incident Data. Available at phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=fdd2dfa122a1d110VgnVCM1000009ed07898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print. Accessed on March 27, 2015.

11.3 Title 49 of the Code of Federal Regulations Part 191.3, 49 CFR 191.3.

11.4 California Department of Education (CDE). 2007. *Guidance Protocol School Site Pipeline Risk*, Volume 1, Section 4, 2007.

11.5 Quest Consultants, Inc. 2009. CANARY by Quest User's Manual Version 4.4.

11.6 California State Fire Marshal. 1993. Hazardous Liquid Pipeline Assessment.

11.7 California Public Utilities Commission (CPUC). 2006. *Mitigated Negative Declaration for the Kerby Hills Natural Gas Storage Facility*.

11.8 Committee for the Prevention of Disasters. 1999. *Guidelines for Quantitative Risk Assessment*, Committee for the Prevention of Disasters (CPR 18E). The Hague.

11.9 WS Atkins Consultants Ltd. 2001. *An Assessment of Measures in use for Gas Pipelines to Mitigate Against Damage Caused by Third Party Activity*.

11.10 Klepeis N.E., Nelson W.C., Ott W.R., et al. 2001. The National Human Activity Pattern Survey (NHAPS), *A Resource for Assessing Exposure to Environmental Pollutants*. Lawrence Berkley National Lab. Available at energy.lbl.gov/ie/viaq/pubs/LBNL-47713.pdf. Accessed on May 7, 2015.

11.11 California Department of Motor Vehicles. 2015. *California Driver Handbook*.

11.12 University of Pennsylvania. Vehicle Stopping Distance and Time. Available at nacto.org/docs/usdg/vehicle_stopping_distance_and_time_upenn.pdf. Accessed on May 18, 2015.

11.13 California Department of Transportation. 2013. *Traffic Volumes on the California State Highway System*.

11.14 San Diego Association of Governments. City of Escondido Traffic Study 2006 to 2010. Available at www.sandag.org/resources/demographics_and_other_data/transportation/adtv/index.asp Accessed on September 3, 2015.

11.15 Canadian Energy Pipeline Association. 2007. Stress Corrosion Cracking, Recommended Practices, 2nd Edition.

11.16 Code of Federal Regulations, Title 49, Part 192 (49 CFR 192).

11.17 American Institute of Chemical Engineers. 2009. Guidelines for Developing Quantitative Safety Risk Criteria, Appendix B.

Attachment A

Additional Historical Incident Data

Safety Study
San Diego Gas & Electric Company and
Southern California Gas Company
Pipeline Safety & Reliability Project

ENERCON

ATTACHMENT A: ADDITIONAL HISTORICAL INCIDENT DATA

The historical incident data in this section was not used in the calculation of the baseline incident rate used in the Study but is presented here for comparative review. For comparison with the anticipated frequency of unintentional releases used in this analysis, incident data from the following sources has been compiled:

- United States Natural Gas Transmission and Gathering Lines (U.S. Department of Transportation [USDOT]), 1970 through 2014.
- United States Interstate Hazardous Liquid Pipelines (USDOT), 1984 through 1998.
- California Regulated Interstate and Intrastate Hazardous Liquid Pipelines (Payne 1993), 1981 through 1990.
- Canadian Natural Gas Pipeline Incident Rate (Transportation Safety Board of Canada), 2004 through 2013.

Each of these data sets detailed below provides varying information about releases that meet specific criteria to be classified as a reportable incident. Even though each data set has differing criteria for reportable incidents, the information from each set provides a valuable source of historical information that was deemed significant enough to be reportable.

U.S. Natural Gas Transmission Lines: 1970 to June 1984

Historical incident data are supplied by the U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA) from 1970 through 2014. In 1984, the USDOT increased the minimum property damage dollar value reporting requirement from $5,000 to $50,000 (Title 49 of the Code of Federal Regulations [CFR] Part 191.3). Because of this change, incident rates before and after 1984 are based on slightly different criteria for onshore natural gas transmission lines.

For natural gas transmission lines, reportable incidents prior to June 1984 are defined as follows (49 CFR 191.3).

1) An event that involves a release of gas from a pipeline that results in one or more of the following consequences:
    i. A fatality, or personal injury necessitating in-patient hospitalization;
    ii. Estimated property damage of $5,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost;
    iii. Unintentional estimated gas loss of three million cubic feet or more;
2) An event that results in an emergency shutdown of an LNG facility. Activation of an emergency shutdown system for reasons other than an actual emergency does not constitute an incident.
3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraphs (1) or (2) of this definition.

All reportable incidents occurring between 1970 and June 1984 were evaluated. Based on the USDOT data, the following frequencies for various consequences were calculated for this time period.

- Total number of reportable incidents: $1.7 \times 10^{-3} \frac{Incidents}{mi-yr}$ (1.7 incidents per 1,000 mile-years)
- Total number of reportable injuries: $9.7 \times 10^{-5} \frac{Injuries}{mi-yr}$ (0.097 injuries per 1,000 mile-years)
- Total number of fatalities: $1.6 \times 10^{-5} \frac{Fatalities}{mi-yr}$ (0.016 fatalities per 1,000 mile-years)

U.S. Natural Gas Transmission Lines: July 1984 through 2014

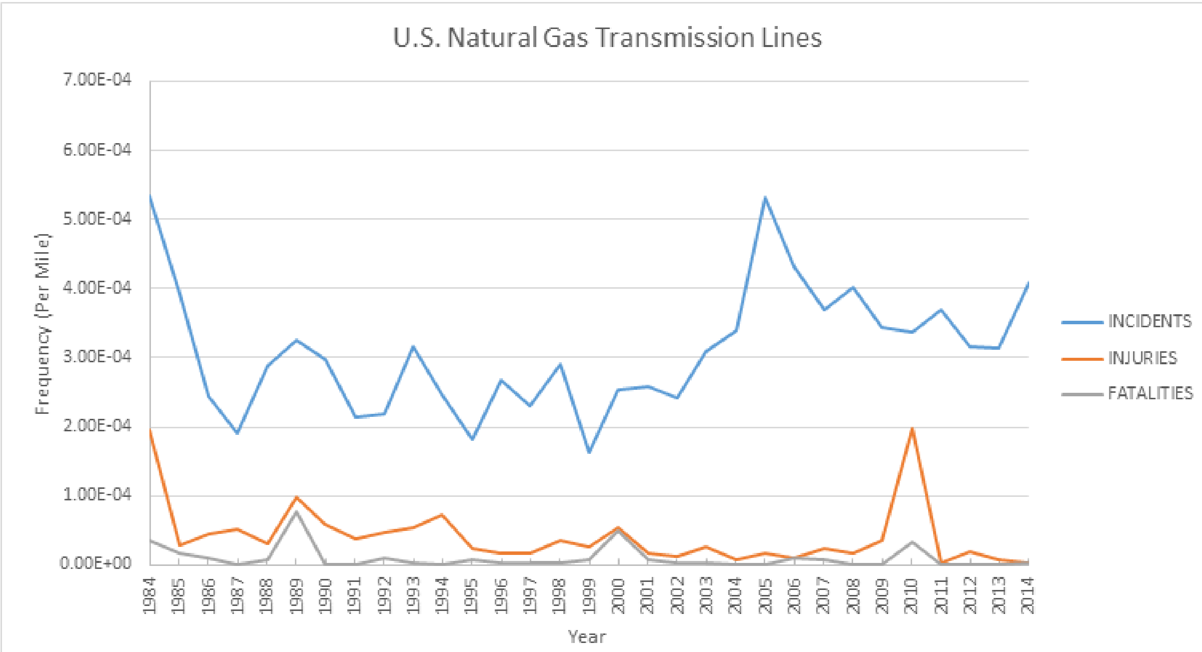
In June 1984, the USDOT changed the criteria for reporting natural gas releases. The most significant change was that in general, leaks causing less than $50,000 property damage no longer required reporting to the USDOT. The criteria for natural gas releases to be reported to the USDOT from July 1984 through the present were as follows:

1) Events which involved a release of gas from a pipeline, or of liquefied natural gas (LNG) or gas from an LNG facility, which caused:
   i. A fatality, or personal injury necessitating inpatient hospitalization; or
   ii. Estimated property damage, including costs of gas lost by the operator, or others, or both, of $50,000 or more.
2) An event which resulted in an emergency shut-down of an LNG facility; or
3) An event that was significant, in the judgment of the operator, even though it did not meet the criteria above.

Because the reporting threshold increased significantly above the prior $5,000 reporting criteria, a decrease in reported incidents is expected. Further, the frequency of reportable injuries and fatalities also decreased, indicating improvements in pipeline safety, which could also contribute to a reduced number of reported incidents. Based on the USDOT data, the following frequencies for various consequences were calculated for reportable incidents for onshore natural gas transmission lines occurring after June 1984 through the year 2014.

- Total number of reportable incidents: $3.0 \times 10^{-4} \frac{Incidents}{mi-yr}$ (0.3 incidents per 1,000 mile-years)
- Total number of reportable injuries: $3.8 \times 10^{-5} \frac{Injuries}{mi-yr}$ (0.038 injuries per 1,000 mile-years)
- Total number of fatalities: $9.0 \times 10^{-6} \frac{Fatalities}{mi-yr}$ (0.009 fatalities per 1,000 mile-years)

The average annual rate for each of the consequences above is shown in the figure below for the time period from 1984 through 2014. Note that the spike in injuries and fatalities in 2010 is due to the San Bruno accident that occurred in September of 2010.



Annual Natural Gas Transmission Line Incident Rates

Starting in 2002, the level of detail included in incident reporting data significantly improved by including incident causes along with other data such as the occurrence of a fire or explosion. As a result as discussed in the Study, the 2002 through 2014 data will be evaluated separately.

U.S. Natural Gas Onshore Transmission Lines: 2002 through 2014

As stated above, the level of detail in incident report significantly improved starting in 2002. This extra detail allows for better determination of the cause and consequences of each incident. The criteria for classification of an incident for this time period is the same as discussed in the Study. Based on the USDOT data, the following frequencies for various consequences were calculated for reportable incidents for onshore natural gas transmission lines occurring from 2002 through the year 2014. All reported incidents are used in this assessment, including those occurring at onshore appurtenances and compressor stations.

- Total number of reportable incidents: $3.0 \times 10^{-4} \frac{Incidents}{mi-yr}$ (0.3 incidents per 1,000 mile-years)
- Total number of reportable injuries: $3.0 \times 10^{-5} \frac{Injuries}{mi-yr}$ (0.038 injuries per 1,000 mile-years)
- Total number of fatalities: $4.7 \times 10^{-6} \frac{Fatalities}{mi-yr}$ (0.009 fatalities per 1,000 mile-years)

U.S. Hazardous Liquid Pipelines: 1984 through 1998

The criteria for hazardous liquid pipeline incidents reported to the USDOT for the years 1984 through 1988 are as follows:

1) Explosion or fire not intentionally set by the operator;
2) Loss of more than 50 barrels (2,100 gallons) of liquid or carbon dioxide;
3) Escape to the atmosphere of more than five barrels per day of highly volatile liquid;
4) Death of any person;
5) Bodily harm to any person resulting in loss of consciousness, necessity to carry the person from the scene, or disability which prevents the discharge of normal duties or the pursuit of normal activities beyond the day of the accident; and/or
6) Estimated property damage to the property of the operator, or others, or both, exceeding \$5,000, prior to June 1994. After June 1994, this criteria was changed to \$50,000, including the cost of clean-up, recovery, and the value of any lost product.

   Based on these criteria, the following frequencies for various consequences were calculated for reportable incidents for hazardous liquid pipeline incidents occurring from 1984 through 1998.

- Total number of reportable incidents: $1.3 \times 10^{-3} \frac{Incidents}{mi-yr}$ (1.3 incidents per 1,000 mile-years)
- Total number of debilitating injuries reported: $1.1 \times 10^{-4} \frac{Injuries}{mi-yr}$ (0.11 debilitating injuries per 1,000 mile-years)
- Total number of fatalities: $1.5 \times 10^{-5} \frac{Fatalities}{mi-yr}$ (0.015 fatalities per 1,000 mile-years)

Regulated California Hazardous Liquid Pipelines: 1981 through 1990

Reportable incidents for hazardous liquid pipelines in California from 1981 through 1990 are given below. The mileage used is the sum of California hazardous liquid pipeline mileage reported annually from 1981 through 1990.

- Total number of reportable incidents: $1.4 \times 10^{-3} \frac{Incidents}{mi-yr}$ (1.4 incidents per 1,000 mile-years)
- Total number of injuries regardless of severity: $4.6 \times 10^{-4} \frac{Injuries}{mi-yr}$ (0.46 injuries per 1,000 mile-years)
- Total number of fatalities: $4.2 \times 10^{-5} \frac{Fatalities}{mi-yr}$ (0.042 fatalities per 1,000 mile-years)

Canadian Natural Gas Pipeline Incident Rate: 2004 through 2013

Reportable incidents on natural gas transmission lines were evaluated based on data provided by the Transportation Safety Board of Canada. The incident data evaluated was from 2004 through 2013, which is the oldest data readily available. Note that only reportable incidents are used.

- Total number of reportable incidents: 3.4 x $10^{-4}\ \frac{Incidents}{mi-yr}$ (0.34 incidents per 1,000 mile-years)

Summary of Historical Pipeline Consequence Data

The below table provides a summary of the historical incident release data from each of the data sources and date ranges discussed above.

Summary of Historical Pipeline Incident Rates

Consequence	U.S. Natural Gas Transmission 1970–June 1984	U.S. Natural Gas Transmission July 1984–2014	U.S. Natural Gas Onshore Transmission 2002–2014	U.S. Hazardous Liquid 1984–1998	California Hazardous Liquid 1981–1990	Canadian Natural Gas Transmission 2004–2013
	Incident Rate (per mile-year)					
Reportable incidents	1.7 x 10^{-3}	3.0 x 10^{-4}	3.0 x 10^{-4}	1.3 x 10^{-3}	1.4 x 10^{-3}	3.40 x 10^{-4}
Injuries regardless of severity	N/A	N/A	N/A	N/A	4.6 x 10^{-4}	N/A
Injuries requiring hospitalization	9.7 x 10^{-5}	3.8 x 10^{-5}	3.0 x 10^{-5}	N/A	N/A	N/A
Injuries: debilitating	N/A	N/A	N/A	1.1 x 10^{-4}	N/A	N/A
Fatalities	1.6 x 10^{-5}	9.0 x 10^{-6}	4.7 x 10^{-6}	1.5 x 10^{-5}	4.2 x 10^{-5}	N/A