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APPENDIX D SYSTEM SAFETY AND RISK OF UPSET

This appendix presents the potential risks to the public from the proposed facilities. These risks would primarily result from unintentional releases of natural gas and the possibility of subsequent fires and/or explosions.

This appendix has been prepared by, and under the direction of, Brian L. Payne, P.E., a Principal of EDM Services, Inc., of Simi Valley, California. In 1993, Mr. Payne, on behalf of the California State Fire Marshal, published the landmark California Hazardous Liquid Pipeline Risk Assessment. This study utilized a completely audited ten year data set of California's regulated interstate and intrastate pipelines. It included a statistical analysis of the audited data set which provided insight into the causal factors of unintentional hazardous liquid pipeline releases. Since being published, the results have been used both nationally and internationally for conducting historical based and probabilistic pipeline risk assessments. Mr. Payne has also published numerous papers and articles on pipeline risk mitigation and risk assessment.

Mr. Payne has performed numerous pipeline risk assessments for major projects. Some of the more recent and relevant projects are listed below.

- Kinder Morgan, Concord to Sacramento, California, 71-mile, 20-inch Products Pipeline.
- Wickland Terminal Expansion Project, Contra Costa County, California (natural gas, crude oil, and refined petroleum products pipelines).
- Yellowstone Pipeline, Missoula, Montana to Thompson Falls, Idaho, 67-mile 12-inch Products Pipeline.
- Chevron KLM to Valero Crude Oil Connection, 1.6-mile, 12-inch Crude Oil Pipeline, Contra Costa County, California.
- Kirby Hills Natural Gas Storage Project, Solano County, California.
- Sacramento Natural Gas Storage Project, Sacramento, California.
- PG&E Line 108, 24-inch diameter, 11.0 mile long natural gas transmission pipeline and ancillary facilities, Sacramento County, California.
- PG&E Line 406/407 30-inch diameter, 42.3 mile natural gas transmission pipeline and ancillary facilities, Yolo, Sutter, Sacramento, and Placer Counties, California.
- Several Natural Gas and Hazardous Liquid Pipeline Risk Assessments to Support California Department of Education School Siting Evaluations

This work has been performed with oversight from the following local, state, and federal entities:

- Contra Costa, Solano, and Sacramento Counties
- California State Fire Marshal
- California State Lands Commission
- California Energy Commission
- California Public Utilities Commission
- California Department of Education
- California Department of Fish and Game
- United States Department of Transportation, Office of Pipeline Safety
- United States Department of Agriculture

1.0 ENVIRONMENTAL SETTING

1.1 Natural Gas Risks

Unintentional releases of natural gas from the proposed pipelines, compressor station and wells 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 was to reach a combustible mixture and an ignition source was present, a fire and/or explosion could occur, resulting in possible injuries and/or deaths.

1.2 Natural Gas Characteristics

Natural gas is comprised primarily of methane. It is colorless, odorless, and tasteless. Methane is not toxic, but is classified as a simple asphyxiate, possessing a slight inhalation hazard. If breathed in high concentration, oxygen deficiency can result in serious injury or death.

Methane has an ignition temperature of 1,000°F and is flammable at concentrations between 5 percent and 15 percent in air. 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.

2.0 APPLICABLE LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

2.1 Federal LORS

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

2.1.1 Regulatory Framework

Two statutes provide the framework for the Federal pipeline safety program. The Natural Gas Pipeline Safety Act of 1968 as amended (NGPSA) authorizes the DOT 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). Similarly, the Hazardous Liquid Pipeline Safety Act of 1979 as amended (HLPSA) authorizes the DOT to regulate pipeline transportation of hazardous liquids (crude oil, petroleum products, anhydrous ammonia, and carbon dioxide). Both of these Acts have 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 California Public Utilities Commission (CPUC) is the agency authorized to oversee intrastate gas pipeline facilities, including those proposed by the Applicant. (The California State Fire Marshal has jurisdiction for hazardous liquid pipelines.)

2.1.2 Pipeline Regulations

The Federal pipeline regulations are published in Title 49 of the Code of Federal Regulations (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 to some extent allow the pipeline operator to use various technologies to achieve the desired result.

The proposed pipeline segments and ancillary facilities would all be designed, constructed, operated, and maintained in accordance with 49 CFR 192. Since these are intrastate facilities, the CPUC would have the responsibility for enforcing the Federal and State requirements. 49 CFR 192 is comprised of 16 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, Gas Transmission Pipeline Integrity Management – This subpart was promulgated on December 15, 2003. It requires operators to implement pipeline integrity management programs on the gas transmission pipeline systems.

- Subpart P, Gas Distribution Pipeline Integrity Management - This subpart was published on December 4, 2009 in 74 FR 63934 and is effective February 2, 2010. It requires operators to implement pipeline integrity management programs on the gas distribution 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 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 small well-defined outside area pipeline any occupied by 20 or more people on at least 5 days a week for 10 weeks in any 12-month.

- Class 4 - Location where buildings with four or more stories aboveground 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 inches in normal soil and 18 inches 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 inches in normal soil and 24 inches in consolidated rock. All pipelines installed in navigable rivers, streams, and harbors must have a minimum cover of 48 inches in soil or 24 inches 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 and pipeline design pressures, 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 facilities would all be constructed within Class 1 locations (CVGS 2009). Although an increase in population density adjacent to the right-of-way is not anticipated (see Section 4.11, Land Use and Planning), the Applicant would 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.

2.1.3 Pipeline Integrity Management Regulations

49 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 (HCA's) to significantly increase their minimum required maintenance and inspection efforts. For example, all lines located within HCA's 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. Two incidents in particular, raised public concern regarding pipeline safety and necessitated these relatively new requirements.

Bellingham, Washington, June 10, 1999

According to the National Transportation Safety Board (NTSB) accident report, "about 3:28 p.m., Pacific daylight time, on June 10, 1999, a 16-inch diameter steel pipeline owned by Olympic Pipe Line Company ruptured and released about 237,000 gallons of gasoline into a creek that flowed through Whatcom Falls Park in Bellingham, Washington. About one and one half hours after the rupture, the gasoline ignited and burned approximately and one half miles along the creek. Two 10-year-old boys and an 18-year-old young man died as a result of the accident. Eight additional injuries were documented. A single-family residence and the City of Bellingham's water treatment plant were severely damaged. As of January 2002, Olympic estimated that total property damages were at least $45 million.

The major safety issues identified during this investigation are excavations performed by IMCO General Construction, Inc., in the vicinity of Olympic's pipeline during a major construction project and the adequacy of Olympic Pipe Line Company's inspections thereof; the adequacy of Olympic Pipe Line Company's interpretation of the results of in-line inspections of its pipeline and its evaluation of all pipeline data available to it to effectively manage system integrity; the adequacy of Olympic Pipe Line Company's management of the construction and commissioning of the Bayview products terminal; the performance and security of Olympic Pipe Line Company's supervisory control and data acquisition system; and the adequacy of Federal regulations regarding the testing of relief valves used in the protection of pipeline systems." (NTSB 2002)

Carlsbad, New Mexico, August 19, 2000

Per the NTSB accident report, "At 5:26 a.m., mountain daylight time, on Saturday, August 19, 2000, a 30-inch diameter natural gas transmission pipeline operated by El Paso Natural Gas Company ruptured adjacent to the Pecos River near Carlsbad, New Mexico. The released gas ignited and burned for 55 minutes. 12 persons who were camping under a concrete-decked steel bridge that supported the pipeline across the river were killed and their three vehicles destroyed. Two nearby steel suspension bridges for gas pipelines crossing the river were extensively damaged. According to El Paso Natural Gas Company, property and other damages or losses totaled $998,296.

The major safety issues identified in this investigation are the design and construction of the pipeline, the adequacy of El Paso Natural Gas Company's internal corrosion control program, the adequacy of Federal safety regulations for natural gas pipelines, and the adequacy of Federal oversight of the pipeline operator." (NTSB 2003)

Pipeline Integrity Management Regulations

As noted earlier, 49 CFR 192, Subpart O, Pipeline Integrity Management, is relatively new and was developed in response to the two major pipeline incidents discussed above. 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 was signed into law by the President in December 2002. As of December 17, 2004, gas transmission operators of pipelines in high consequence areas (HCA's) 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 DOT (68 Federal Register 69778, 69 Federal Register 18228, and 69 Federal Register 29903) defines HCA's 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 HCA's where a gas pipeline accident could do considerable harm to people 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.

The HCA's 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 feet (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. ($R = 0.69*(MAOP*d^2)^{0.5}$)

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

Once a pipeline operator has identified the HCA's along its pipeline(s), it must apply the elements of its integrity management program to those segments of the pipeline within the HCA's. The pipeline integrity management rule for HCA's requires inspection of the entire pipeline within HCA's every 7 years.

The proposed 14.7 mile 24-inch pipeline and dual 0.3 mile 16-inch pipeline facilities are located entirely within a Class 1 area. As a result, the lines would not be within an HCA. The impact radii are 544 and 413-feet for the 24 (1,070 psig maximum allowable operating pressure) and 16-inch (1,456 psig maximum allowable operating pressure) lines respectively. These impact radii are both less than the 660-foot impact radius which might create an HCA for a specific line segment. As a result, the Applicant will not be required to develop a Pipeline Integrity Management Plan. Should the population density increase, portions of the pipeline may become located within an HCA; should this occur, the Applicant would be required by Federal regulation to develop a Pipeline Integrity Management Plan and include the affected pipe segments into their Plan.

2.1.4 Compressor Building Regulations

Compressor building construction requirements and safeguards are regulated by Title 49, Code of Federal Regulations, Part 192 (49 CFR 192), the California Building Code (CBC), the California Fire Code, and other laws, ordinances, regulations and standards. The federal regulations require the following:

- The compressor building must be located to minimize the impact of fire on structures on adjacent property not under the control of the operator - 49 CFR Part 192.163(a).
- Space around the compressor building must be adequate to allow the free movement of firefighting equipment - 49 CFR Part 192.163(a).
- Compressor buildings must be constructed of noncombustible materials (where piping is greater than 2-inches in nominal diameter) - 49 CFR Part 192.163(b).
- Any main compressor building must have at least two unobstructed exits (per floor) with panic hardware on the doors that open outwardly - 49 CFR Part 192.163(c).
- All escape routes from the buildings must be unobstructed - 49 CFR Part 192.163(c).
- All fenced areas around compressor buildings must have two exits providing escape to a place of safety - 49 CFR Part 192.163(d).
- All fenced areas less than 200 feet from the compressor building must have gates that open outwardly, and when occupied, must be capable of being opened without a key - 49 CFR Part 192.163(d).
- All electrical equipment and wiring must conform to National Electric Code NFPA 70 - 49 CFR Part 192.163(e).
- The station must be equipped with an emergency shut down system that: isolates the station piping from the incoming and outgoing pipeline, shuts down any gas fired equipment, blows down the station piping to a safe location, and allows operation from at least two sites outside the gas area of the station near emergency egress gates and not more than 500 feet from the

limits of the compressor station. This ESD must not shut down emergency operating power for safety systems and emergency egress lighting - 49 CFR Part 192.167(a).

- The station piping must be protected by a pressure relief system or other suitable protective devices of sufficient capacity and sensitivity to ensure that the maximum operating pressure is not exceeded by more than 10%. Each vent line that exhausts gas from a pressure relief valve of a compressor station must extend to a location where the gas may be discharged without hazard - 49 CFR Part 192.169(a) and (b).

- Each compressor station must have adequate fire protection facilities. If fire pumps are part of these facilities, their operation must not be affected by the emergency shut-down system - 49 CFR Part 192.171(a).

- Each compressor station prime mover other than an electric motor, must have automatic shut-downs to protect against exceeding the maximum safe speed of the prime mover or compressor - 49 CFR Part 192.171(b).

- Each compressor unit within a compressor station must have a shut-down, or alarm device, that operates in the event of inadequate cooling or lubrication of the unit - 49 CFR Part 192.171(c).

- Each natural gas powered prime mover (engine) that operates with pressure injection must be equipped so that stoppage of the engine automatically shuts off the fuel and vents the engine distribution manifold. The muffler of a gas engine must have vent slots, or holes, in the baffles of each compartment to prevent gas from being trapped in the muffler - 49 CFR Part 192.171(d) and (e).

- Each compressor station building must be ventilated to ensure that employees are not endangered by the accumulation of gas in rooms, sumps, attics, pits, or other enclosed places - 49 CFR Part 192.173.

- Natural gas compressor station buildings must be equipped with fixed gas detection and alarm systems – 49 CFR Part 192.736.

2.2 State LORS

2.2.1 Pipeline Regulations

As noted earlier, these intrastate pipeline facilities would be under the jurisdiction of the CPUC, as a result of their certification by the OPS. (The State of California is certified under 49 USC Subtitle VIII, Chapter 601, §60105.) The State requirements for designing, constructing, testing, operating, and maintaining gas piping systems are stated in CPUC General Order Number 112. These rules incorporate the Federal regulations by reference, but for natural gas pipelines, they do not impose any additional requirements affecting public safety.

2.2.2 Compressor Building Regulations

The California Building Code (CBC) has additional, and in some cases overlapping requirements:

- The building must be constructed according to the setback guidelines established in the CBC and CFC for the appropriate occupancy classification.
- Local ordinances regarding fire equipment turning radii, dead end/turn around requirements also apply to the spacing requirements.
- The building structure must be constructed according to the requirements of the CBC for the building occupancy type (either F-1 or H-2) and acceptable noncombustible materials (building construction Types I or II) as defined by the CBC.
- The building must have two exits provided per CBC Chapter 10. The intent is that a person must be able to escape immediately from the building by proceeding in a direct path to a door that will swing open in the direction of egress (outward).
- The escape routes from the buildings must be designed and reviewed according to the requirements of CBC Chapter 10 - Means of Egress.
- The compressor station must be designed and built with fire suppression equipment that could reasonably be expected to extinguish a natural gas fire within the building due to equipment failure or other accidental release. The sizing of fire suppression systems must follow the guidelines of CBC Chapter 9, the California Fire Code, NFPA 13 Automatic Sprinkler Systems Handbook, NFPA 58 Liquefied Petroleum Gas Code, and NFPA 59 Utility LP – Gas Plant Code (NFPA 58 and 59 Required by 49 CFR Part 192.11).

Depending on the volume of gas within the closed system housed within the compressor building, the CBC and CFC provide additional building requirements. CBC Section 307 covers high hazard (Group H) structures and Section 306 covers factory structures (Group F). The building requirements are commensurate with the level of risk posed within the structure, with Group H structures being the more stringent.

Buildings with flammable gases volumes in excess of the exempt limits listed in CBC Table 307.1(1), Maximum Allowable Quantity Per Control Area of Hazardous Material Posing a Physical Hazard, are considered Group H-2. Table 307.1 identifies an exempt limit of 1,000 cubic feet of flammable gas, at normal temperatures and pressures (14.7 psig at ambient temperatures). This volume may be increased by 100% if automatic sprinkler systems are installed. Due to the high pressures of the piping system, the proposed compressor building is likely Group H-2.

2.2.3 Well Regulations

Natural gas storage and the retrieval through injection wells fall under the jurisdiction of the California Department of Conservation, Division of Oil, Gas and Geothermal Resources. The applicable California Code of Regulations is Title 14, Natural Resources, Division 2, Department of Conservation. These regulations cover drilling operations, blowout prevention, well casing, well completion, corrosion monitoring, testing, etc. The Department has published minimum standards for the casing string, cementing depth, annual cement fill requirements, blowout prevention, and other basic well standards for the Princeton Gas Field. (DOGR 2007)

3.0 IMPACT ANALYSIS AND MITIGATION

The proposed Project could pose additional risks to the public. Natural gas could be released from a leak or rupture. If the natural gas reached a combustible mixture and an ignition source was present, a fire and/or explosion could occur, resulting in possible injuries and/or deaths.

3.1 Fire Impacts

The physiological effect of fire to humans depends on the rate at which heat is transferred from the fire to the person, and the time the person is exposed to the fire. Skin that is in contact with flames can be seriously injured, even if the duration of the exposure is just a few seconds. Thus, a person wearing normal clothing is likely to receive serious burns to unprotected areas of the skin when directly exposed to the flames from a flash fire (vapor cloud fire).

Humans 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. So those close to the fire would receive thermal radiation at a higher rate than those farther away. The ability of a fire to cause skin burns due to radiant heating depends on the radiant heat flux to which the skin is exposed and the duration of the exposure. As a result, short-term exposure to high radiant heat flux levels can be injurious. But if an individual is far enough from the fire, the radiant heat flux would be lower, likely incapable of causing injury, regardless of the duration of the exposure.

An incident heat flux level of 1,600 btu/ft^2-hr is considered hazardous for people located outdoors and unprotected. Generally, humans located beyond this heat flux level would not be at risk to injury from thermal radiation resulting from a fire. The radiant heat flux effects to humans are summarized below. The first three endpoints have been used to evaluate the risk of public fatalities from the proposed project.:

- 12,000 btu/ft2-hr (37.7 kW/m2) – 100% mortality after 30 second exposure (CDE 2007).
- 8,000 btu/hr-ft^2 (25.1 kW/m^2) – 50% mortality after 30 second exposure (CDE 2007).
- 5,000 btu/ft2-hr (15.7 kW/m2) – 1% mortality after 30 second exposure (CDE 2007). In many instances, an able bodied person would increase the separation distance or seek cover during this 30 second period.
- 3,500 btu/hr-ft^2 (11.0 kW/m^2) - Second degree skin burns after ten seconds of exposure, 15% probability of fatality (Quest 2003). This assumes that an individual is unprotected or unable to find shelter soon enough to avoid excessive exposure.
- 1,600 btu/hr-ft^2 (5.0 kW/m^2) - Second degree skin burns after thirty seconds of exposure.

- 440 btu/hr-ft^2 (1.4 kW/m^2) - Prolonged skin exposure causes no detrimental effect (CDE 2007, Quest 2003).

3.2 Explosion Impacts

As noted earlier, natural gas does not explode unless it is in a confined space within a specific range of mixtures with air and is ignited. However, if an explosion does occur, the physiological effects of overpressures depend on the peak overpressure that reaches a person. Exposure to overpressure levels can be fatal. People located outside the flammable cloud when a combustible mixture ignites would be exposed to lower overpressure levels than those inside the flammable cloud. If a person is far enough from the source of overpressure, the explosion overpressure level would be incapable of causing injuries. The generally accepted hazard level for those inside buildings is an explosion overpressure is 1.0 psig. This level of overpressure can result in injuries to humans inside buildings, primarily from flying debris. The consequences of various levels of overpressure are outlined in the table below.

Table 3.2-1
Explosion Over-Pressure Damage Thresholds

Side-On Over-Pressure	Damage Description
0.02 psig	Annoying Noise
0.03 psig	Occasional Breaking of Large Window Panes Under Strain
0.04 psig	Loud Noise; Sonic Boom Glass Failure
0.10 psig	Breakage of Small Windows Under Strain
0.20 psig	Glass Breakage - No Injury to Building Occupants
0.30 psig	Some Damage to House Ceilings, 10% Window Glass Broken
0.50 to 1.00 psig	Large and Small Windows Usually Shattered, Occasional Damage to Window Frames
0.70 psig	Minor Damage to House Structures, Injury, but Very Unlikely to Be Serious
1.00 psig	1% Probability of a Serious Injury or Fatality for Occupants in a Reinforced Concrete or Reinforced Masonry Building from Flying Glass and Debris 10% Probability of a Serious Injury or Fatality for Occupants in a Simple Frame, Unreinforced Building
2.40 psig	1% Mortality to Persons Inside Buildings or Persons Outdoors (CDE 2007)
3.10 psig	10% Mortality to Persons Inside Buildings (CDE 2007)
4.00 psig	10% Mortality to Persons Outdoors (CDE 2007)
5.70 psig	50% Mortality to Those Indoors (CDE 2007)
13 psig	50% Mortality to Those Outdoors (CDE 2007)
13 psig	99 % Mortality to Those Indoors (CDE 2007)
14.5 psig	1% Mortality to Those Outdoors (LEES)
72 psig	99% Mortality to Those Outdoors (CDE 2007)

Sources: LEES, CDE 2007, Quest 2003

The following endpoints have been used to evaluate potential explosion impacts to the public from the proposed project.

Table 3.2-2
Explosion Overpressure Levels

Mortality Rate	Outdoor Exposure (psig)	Indoor Exposure (psig)
99% Mortality	72	13
50% Mortality	13	5.7
1% Mortality	2.4	2.4

Source: CDE 2007

4.0 BASELINE DATA

In the following paragraphs, the anticipated frequency of unintentional releases and impacts to humans will be estimated using data from the following sources:

- United States Gas Transmission and Gathering Lines (U.S. Department of Transportation [USDOT]) – 1970 through 2008.
- United States Interstate Hazardous Liquid Pipelines (USDOT) - 1984 through 1998.
- California Regulated Interstate and Intrastate Hazardous Liquid Pipelines (Payne, 1993) - 1981 through 1990.

Each of these data sets provides pipeline incident data for reportable incidents. However, the criteria for reporting incidents differ for each source. This makes direct comparison of the individual results difficult. On the other hand, it provides a methodology for estimating incident rates for a variety of consequences.

4.1 U.S. Gas Transmission Lines - 1970 to June 1984

Since the USDOT natural gas pipeline reporting criteria changed in June 1984, the incident reports beginning in July 1984 have been summarized separately, in the next section of this document. The criteria for natural gas releases to be reported to the US DOT from 1970 through June 1984 were as follows:

- Resulted in a death or injury requiring hospitalization;
- Required the removal from service of any segment of a transmission pipeline;
- Resulted in gas ignition;
- Caused an estimated damage to the property owner, or of others, or both, of $5,000 or more;
- Involved a leak requiring immediate repair;
- Involved a test failure that occurred while testing either with gas or another test medium; or
- In the judgment of the operator, was significant even though it did not meet any of the above criteria.

The frequencies of the various consequences reported during this period are summarized below.

- Reportable Unintentional Releases - 1.3 incidents per 1,000 mile-years.

- Reportable Injuries - 0.096 injuries per 1,000 mile-years (0.007 public injuries per 1,000 mile-years).
- Fatalities - 0.016 fatalities per 1,000 mile-years (0.008 public fatalities per 1,000 mile-years).

It should be noted that during this 14½-year period, 36 (50%) of the total 72 fatalities and 161 (59%) of the total 274 of those injured were employees of the operating company.

4.2 U.S. Gas Transmission Lines - July 1984 through 2008

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 DOT. The criteria for natural gas releases to be reported to the DOT from July 1984 through the present were as follows:

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

Since the reporting threshold is now significantly greater than the prior $5,000 reporting criteria, a significant decrease in the resulting reportable incident rate resulted. However, the frequency of reportable injuries and fatalities also decreased, indicating improvements in pipeline safety.

The USDOT also filters the reported incidents and provides reports for “significant” pipeline incidents. These incidents include those which result in:

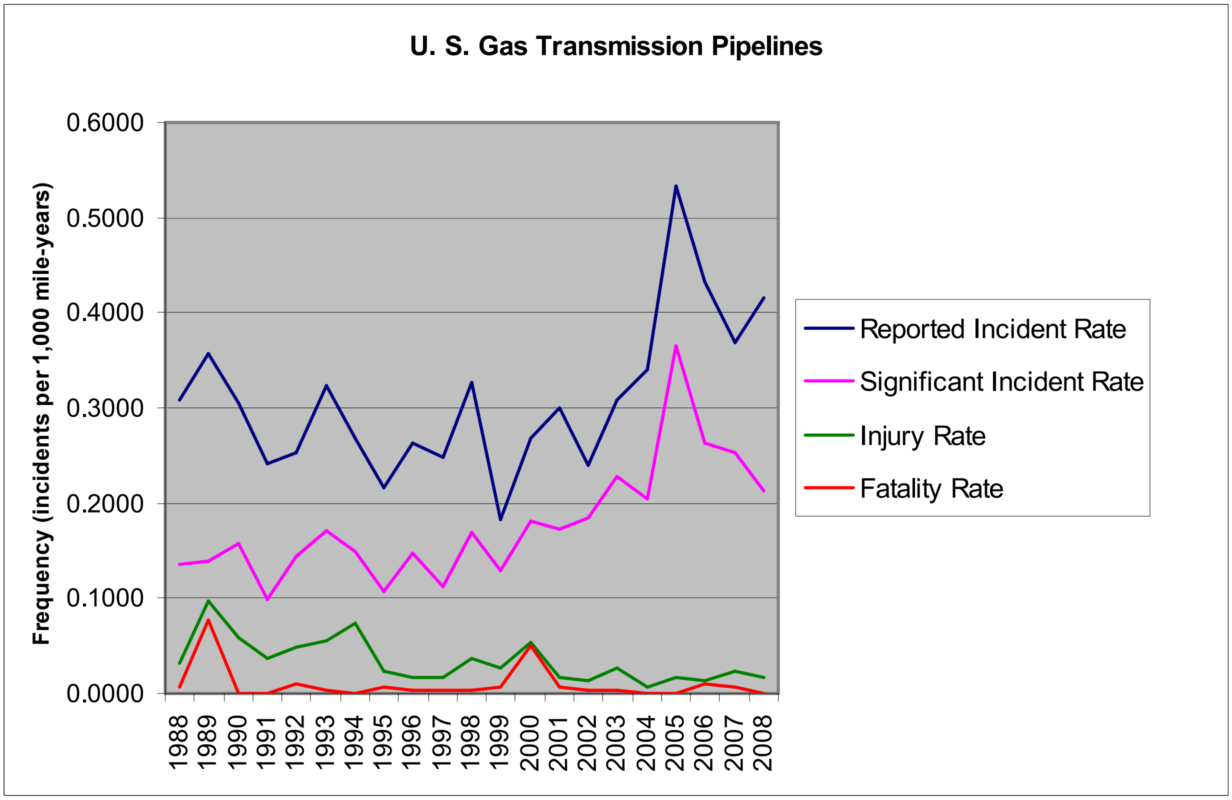
- Fatality or injury requiring in-patient hospitalization,
- $50,000 or more in total costs (measured in 1984 dollars),
- Highly volatile liquid releases of 5 barrels or more or other liquid releases of 50 barrels or more, or
- Liquid releases resulting in an unintentional fire or explosion.

These data are summarized below for the 22-year period from January 1, 1986 through December 31, 2008 for gas transmission pipelines (including both onshore and offshore segments, but excluding gathering lines).

- Reportable Unintentional Releases - 0.31 incidents per 1,000 mile-years
- Significant Incidents – 0.18 incidents per 1,000 mile-years
- Reportable Injuries - 0.040 injuries per 1,000 mile-years
- Fatalities - 0.010 fatalities per 1,000 mile-years

In 2002, the USDOT changed their reporting forms. At this time, operators were required to begin reporting additional data for each reportable release. These changes were significant. Some of the additional reporting fields included the reporting of fires and explosions, which were not required to be identified previously.

For the most recent seven year period, since the change in the USDOT reporting form (January 2002 through December 2008), there were a total of 795 reportable incidents from natural gas transmission pipelines, 516 "significant" incidents, including 35 reportable injuries, and 7 fatalities. The average property damage from the 516 "significant releases was over $1,200,000 per incident. The average annual transmission pipeline mileage was 301,625 miles for this seven year period. Using these data, the frequency of reportable incidents during this most recent seven year period was up slightly when compared to the 14-year period presented above - 0.38 incidents per 1,000 mile-years for 2002 through 2008 versus 0.28 incidents per 1,000 mile-years for 1986 through 2001. The frequency of "significant" incidents increased similarly, from 0.14 (1988 through 2001) to 0.24 (2002 through 2008). The injury and fatality rates for the most recent seven year period were 0.017 and 0.0033 incidents per 1,000 mile-years respectively, down significantly. These data are summarized in the following figure by year.



Source: USDOT, Incident Summary Statistics by Year and Natural Gas Transmission Pipeline Annual Mileage

Figure 4.2-1 U.S. Gas Transmission Pipeline Incident Rate History

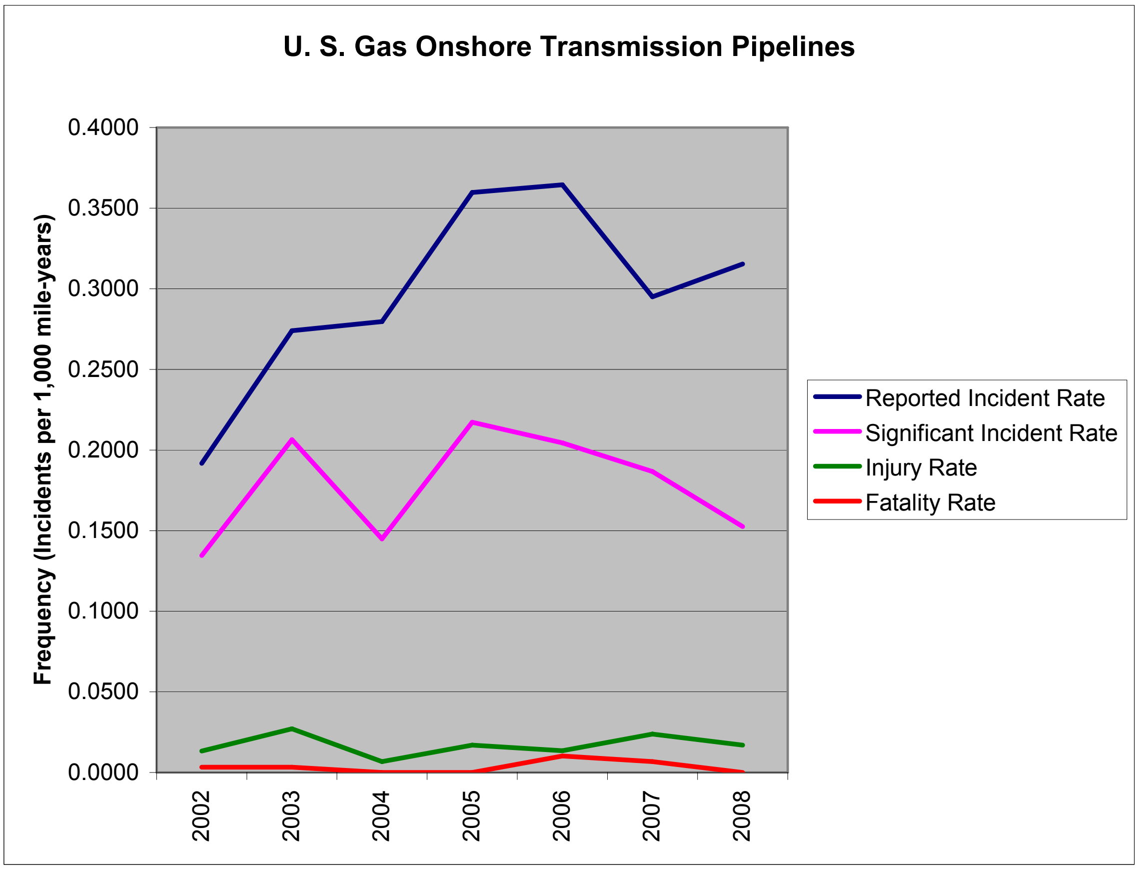
It should be noted that the above data, as included on the USDOT Incident Summary Statistics by Year includes 92 incidents which occurred on lines identified as “Gathering” in the USDOT gas transmission incident database (USDOT). An audit of the USDOT database is beyond the scope of this work. As a result, the reason that these data have been included in the USDOT incident database is unknown. There are several possible reasons. The operator may have indicated the classification of the line as “Gathering” in error. The USDOT may have inadvertently included the incident data in the wrong database.

The database also includes incidents which occurred on offshore line segments. However, making the maximum correction for these incidents does not significantly affect the results. The 2002 through 2008 data would be affected as follows, if the 92 incidents which occurred on lines identified as “Gathering” and those which occurred on “offshore” segments were deleted:

- Reportable Unintentional Releases – This figure would be reduced from 0.38 to 0.29 incidents per 1,000 mile-years

- Significant Incidents – This figure would be reduced from 0.24 to 0.18 incidents per 1,000 mile-years
- Reportable Injuries - This figure would remain unchanged at 0.017 injuries per 1,000 mile-years
- Fatalities – This figure would increase slightly from 0.0033 to 0.0034 fatalities per 1,000 mile-years

The data for onshore gas transmission pipelines only are presented in the following figure.



Source: USDOT

Figure 4.2-2 U.S. Gas Onshore Transmission Pipeline Incident Rate History

4.3 U.S. Hazardous Liquid Pipelines - 1984 through 1998

The criteria for hazardous liquid pipeline incidents to be reported to the DOT for inclusion in this data set were as follows:

- Explosion or fire not intentionally set by the operator;
- Loss of more than 50 barrels (2,100 gallons) of liquid or carbon dioxide;
- Escape to the atmosphere of more than five barrels per day of highly volatile liquid;
- Death of any person;
- 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
- 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.

The data for this period are summarized below:

- Reportable Unintentional Releases - 1.29 incidents per 1,000 mile-years
- Reportable Injuries - 0.076 injuries per 1,000 mile-years
- Fatalities - 0.015 fatalities per 1,000 mile-years

It should be noted that the 1994 Annual Report on Pipeline Safety excluded 1,851 individuals who were injured with minor burns and vapor inhalation from the failure and ignition of seven hazardous liquid pipelines during the San Jacinto River floods in mid-October, 1994, near Houston, Texas. These incidents were caused by severe flooding in the area. These injuries are not included in the injury rate shown above.

It is interesting to note that the incident rate for hazardous liquid pipeline releases (prior to 1994) was essentially the same as those for reportable U.S. natural gas transmission and gathering lines from 1970 through June 1984, which had a similar $5,000 property damage reporting requirement.

4.4 Regulated California Hazardous Liquid Pipelines - 1981 through 1990

This study, undertaken by the California State Fire Marshal, Pipeline Safety Division, included all regulated California interstate and intrastate hazardous liquid pipelines (Payne 1993). It included approximately 7,800 miles of pipeline data, over a ten year period (1981 through 1990). The systems included in this study had complete release records. The major difference for this study, as compared to ones discussed previously, is that all releases, regardless of size, cause, extent of property damage, or extent of injury were included in the study. Also, a complete audit of the pipeline inventory and release data was conducted. As a result, the incident rates resulting from this study were higher than presented in other studies, which only included reported releases fitting a relatively narrow set of criteria. A summary of these results is included below.

- Unintentional Releases - 7.08 incidents per 1,000 mile-years
- Injuries - 0.685 injuries per 1,000 mile-years
- Fatalities - 0.042 fatalities per 1,000 mile-years

4.5 Summary of Historical Pipeline Consequence Data

In the following table, the available pipeline release data have been summarized.

Table 4.5-1
Pipeline Release Consequences by Data Source

Consequence	U.S. Gas Transmission 1970 to June 1984	U.S. Gas Transmission 1988 thru 2008	U.S. Gas Onshore Transmission 2002 thru 2008	U.S. Hazardous Liquid - 1984 thru 1998	California Hazardous Liquid - 1981 thru 1990
	Incidents per 1,000 mile-years				
Reportable Incidents	1.30 ($5,000 criteria)	0.31 ($50,000 criteria)	0.29 ($50,000 criteria)	1.29 ($5,000 criteria)	7.08 (all incidents, regardless of size and value of property damage)
Significant Incidents	N/A	0.18	0.18	N/A	N/A
Injuries regardless of severity	N/A	N/A	N/A	N/A	0.685
Injury requiring hospitalization	0.096	0.034	0.017	N/A	N/A
Injuries requiring hospitalization, causing loss of consciousness, or preventing discharge of normal duties day following the incident	N/A	N/A	N/A	0.076	N/A
Fatalities	0.016	0.010	0.0034	0.015	0.042

4.6 Consequence Data Used In Analysis

The USDOT database of gas transmission pipeline releases from January 2002 through December 2008 has been analyzed. These data will be used to develop the baseline frequency of unintentional releases from the proposed facilities in subsequent sections of this document. After deleting all releases noted from "Gathering" lines and "Offshore" lines, there were 614 releases remaining from onshore transmission pipelines. Of there, the two major causes of releases were excavation damage and external corrosion. 131 (21%) of the releases were caused by excavation damage from a third party and the pipeline operator. 83 (14%) of the releases were caused by external corrosion. The remaining 400 (65%) of the releases were caused by a variety of factors, listed in descending order of frequency:

- miscellaneous or unknown – 12%
- malfunction of control or relief equipment – 8%
- vehicles not related to excavation – 6%
- internal corrosion – 5%
- butt weld failure – 4%
- rain and flooding – 4%
- body of pipe failure – 4%
- incorrect operation – 3%
- pipe weld seam failure – 3%
- component failure – 3%
- earth movement – 2%
- joint failure – 2%
- threaded fitting or coupling failure – 2%
- lightning – 1%
- fire and explosions – 1%
- fillet weld failure – 1%

- temperature - <1%
- wind - <1%
- rupture of previously damaged pipe - <1%
- vandalism - <1%

4.6.1 Third Party Damage Incident Rate

As noted above, third party damage caused 21% of the accidental pipeline releases. The Applicant will be required to implement the following mitigation measures to reduce the frequency of third party caused releases in accordance with applicable LORS:

- One-Call System – The Applicant will subscribe to the USA North underground service alert "one-call" system. A toll free number is available for contractors and others to use before they begin excavations. Once a contractor calls and identifies its proposed excavation location, the organization will notify the Applicant and other underground facility owners in the vicinity. The owners respond to these calls with personal communications with the excavator. If their facilities are nearby, they mark the location of their facilities on the ground, so third party intrusions can be avoided. Participation in a one-call system if required as part of an operator's damage prevention program, per 49 CFR 192.614.

- Line Marking – The Applicant is required by federal regulation (49 CFR 192.707) to install line marker posts such that the pipeline is readily identifiable. In addition, they are required to have warning signs installed at each side of road, railroad, and waterway crossings, and at fence lines across open or agricultural property, crossings of other lines (e.g., irrigation, oil, gas, telephone, utilities) where practical, and where the line is above ground in areas accessible to the public.

- Right-of-Way Patrolling - 49 CFR 192.705 requires each operator to have a patrol program to monitor for indications of leaks, nearby construction activity, and any other factors that could affect safety and operation. The frequency of these inspections is based on a number of factors. For the proposed line, these patrols must be conducted at least twice each calendar year for road crossings and once each calendar year in other locations.

- Leakage Surveys – A leakage survey must be conducted at least once each calendar year.

- Public Education - 49 CFR 192.616 requires pipeline operators to develop and implement a written continuing public education program that follows the guidance provided in the

American Petroleum Institute's (API's) Recommended Practice 1162 Public Awareness Programs for Pipeline Operators as their public education procedure.

The California study found that the overall frequency of third party damage caused unintentional releases was 1.46 unintentional releases per 1,000 mile-years. For pipelines constructed in the 1950's, the frequency was only 0.88 unintentional releases per 1,000 mile-years; it was even lower for newer lines. These lower values were primarily due to the increased awareness of the threat from third party damage to pipeline facilities; newer lines have benefited from improved line marking, one-call dig alert systems, avoidance of high risk areas, improved documentation, increased depth of cover, and public awareness programs. (Payne 1993)

Using these historical data and the baseline frequency of 0.29 unintentional releases per 1,000 mile-years from the U. S. natural gas onshore transmission pipelines (2002 through 2007), the anticipated frequency of third party damage caused USDOT reportable releases is 0.061 incidents per 1.000 mile years (0.29 per 1,000 mile years baseline x 21% caused by third party damage = 0.061 incidents per 1,000 mile years).

4.6.2 External Corrosion Incident Rate

External corrosion of a buried pipe is an electro-chemical reaction, which can occur when bare (un-coated) steel is in contact with the earth. The moist soil surrounding a pipeline can serve as an electrolyte. When this occurs, the pipe can become an anode. The current then flows through the electrolyte, from the anode (pipe) to the cathode (soil). In this instance, the anode (pipe) loses material (corrodes) as this process occurs.

The intent of an effective external corrosion prevention program is twofold. First, the pipe is protected from corrosion by insulating it from contact with the electrolyte (moist soil) using an external coating. Second, in the event that the coating should fail, the pipe is prevented from becoming the anode by introducing some other material into the electrochemical chain that is more anodic than the pipe, or appears to be because of an impressed current. An impressed current or sacrificial anode cathodic protection system makes the current flow through the soil, toward the pipe, instead of away from it; thus, external corrosion is eliminated.

An impressed current system takes alternating current electrical power from a utility source or solar panels. A transformer is used to reduce the voltage. A rectifier then converts the alternating current to a direct current. The direct current flows to and through anodes (graphite, steel, or other material) and into the surrounding earth. At locations where there may be a break in the external pipe coating (holiday), the current will reach the pipeline. It will then flow along the line to the rectifier, completing the circuit, preventing external corrosion at the external pipe coating holiday.

External corrosion typically causes a relatively large percentage of unintentional releases. Often, these releases are relatively small in volume, with low release rates. However, they often can go unnoticed for long periods of time.

The California study found that the frequency of unintentional releases (of all volumes) caused by external corrosion varied significantly by decade of pipe construction and pipeline operating temperature.

The statistical analyses performed in the California study indicated that the decade of pipeline construction directly affected the incident rate. The reader should note that this figure included all spills, regardless of spill volume. The majority of these spills would not require USDOT reporting. As a result, the reader should not attempt to directly compare these values. They can only be compared after the spill volume distribution has been considered.

During the 1940s and 1950s, significant improvements were made in pipeline construction techniques and improvements in materials. Relative to external corrosion, the primary improvements included advances in external coatings and more widespread use of these coatings and cathodic protection systems. These items account for the significant reduction in external corrosion incident rates for modern pipelines, versus pipelines constructed prior to the 1940's. For newer pipelines, it is impossible to isolate the individual affects of pipe age and other improvements (e.g. technology, construction techniques, the more widespread use of high quality external coatings and cathodic protection systems). The table below presents the California data by decade of pipeline construction by incident cause.

Table 4.6.2-1
Incident Rates by Decade of Construction

Incident Cause	Pre-1940	1940-49	1950-59	1960-69	1970-79	1980-89
External Corrosion	14.12	4.24	2.47	1.47	1.24	0.00
Internal Corrosion	0.38	0.27	0.10	0.16	0.00	0.28
3rd Party - Construction	1.96	1.06	0.68	0.66	0.25	0.28
3rd Party - Farm Equipment	0.53	1.33	0.05	0.00	0.00	0.00
3rd Party - Train Derailment	0.00	0.00	0.00	0.05	0.25	0.00
3rd Party - External Corrosion	0.45	0.00	0.10	0.33	0.00	0.00
3rd Party - Other	0.30	0.13	0.05	0.05	0.00	0.00
Human Operating Error	0.30	0.13	0.00	0.11	0.25	0.00
Design Flaw	0.08	0.00	0.00	0.00	0.00	0.14
Equipment Malfunction	0.38	0.53	0.10	0.60	1.24	0.00
Maintenance	0.00	0.00	0.24	0.00	0.00	0.00
Weld Failure	0.38	0.27	0.15	0.44	0.25	0.00
Other	0.83	0.13	0.24	0.27	0.25	0.28
Total	19.71	8.09	4.18	4.14	3.73	0.98

Source: Payne 1993

The statistical analyses performed in the California study indicated that operating temperature directly affected the frequency of unintentional releases. Considering all pipelines, regardless of decade of construction, those that were operated near ambient temperatures had an external corrosion caused incident rate of 1.33 unintentional releases per 1,000 mile-years. The incident rate rose dramatically as the operating temperature was increased.

The proposed pipeline segment will be operated at ambient temperatures. The table below indicates that the external corrosion incident rates for the California lines operated at various temperatures ranged from 0.48 to 11.36 unintentional releases per 1,000 mile-years. However, the lines operated between 130°F and 159°F had a 1947 mean year of pipeline construction; as discussed earlier, pipe age also significantly affected the incident rate. This effect is also reflected in these data.

Table 4.6.2-2
Incident Rate by Operating Temperature

Incident Cause	0-69°F	70-99°F	100-129°F	130-159°F	160°F+
External Corrosion	0.48	1.33	7.11	11.36	11.31
Internal Corrosion	0.00	0.21	0.32	0.57	0.08
3rd Party - Construction	1.91	0.94	0.95	0.57	0.60
3rd Party - Farm Equipment	0.00	0.30	0.47	0.00	0.08
3rd Party - Train Derailment	0.00	0.04	0.00	0.00	0.00
3rd Party - External Corrosion	0.00	0.06	0.16	0.00	0.15
3rd Party - Other	0.00	0.24	0.16	0.00	0.15
Human Operating Error	0.00	0.11	0.00	0.00	0.23
Design Flaw	0.00	0.04	0.00	0.00	0.00
Equipment Malfunction	0.00	0.24	0.16	0.57	0.98
Maintenance	0.00	0.09	0.16	0.00	0.00
Weld Failure	0.00	0.19	0.32	0.00	0.60
Other	0.00	0.21	1.11	1.14	0.45
Total	2.39	4.00	10.92	14.21	14.63

Source: Payne 1993

To reduce the likelihood of releases caused by external corrosion, the following measures would be implemented by the Applicant in compliance with applicable LORS:

- Modern External Pipe Coating - The proposed pipeline segment will be externally coated with 16 mils of fusion bonded epoxy (FBE).

- Cathodic Protection System - The proposed pipeline will be protected from external corrosion using an impressed current or sacrificial anode current cathodic protection system.
- Monitoring - At least once each calendar year, at intervals not exceeding 15 months, the Applicant will be required to test their cathodic protection system in accordance with 49 CFR 192.465.
- Visual Inspections - Each time buried pipe is exposed for any reason, the Applicant will be required to examine the pipe for evidence of external corrosion in accordance with 49 CFR 192.459. If active corrosion is found, the operator is required to investigate and determine the extent. Pipeline operators are required to maintain records of these DOT required inspections. They are routinely reviewed by DOT staff during their inspections.

Using the historical data presented in Tables above, an opinion of the anticipated frequency of USDOT reportable unintentional releases due to external corrosion from the proposed pipe segments has been developed. These segments will normally be operated at ambient temperatures, using externally coated pipe, with a sacrificial anode cathodic protection system. The anticipated frequency of external corrosion caused USDOT reportable releases is 0.027 incidents per 1.000 mile years (0.29 per 1,000 mile-years baseline x 14% caused by third party damage x 2/3% = 0.027 incidents per 1,000 mile years). This frequency is intended to reflect the average value over a 40-year project life. During the early years of operation, the frequency of external corrosion caused incidents will likely approach zero.

4.6.3 Miscellaneous Causes Incident Rate

As noted above, the remaining 65% of the incidents not caused by third party damage or external corrosion are caused by a number of factors. Since each of these causes is a relatively small percentage of the total, adjustments were not made to them individually. A twenty percent reduction has been made to account for the fact that these facilities will be modern, new systems. A larger adjustment could have been made. However, the resulting frequency is intended to reflect the average value over a 40-year project life. The anticipated frequency of non-third party damage or external corrosion caused USDOT reportable releases is 0.151 incidents per 1.000 mile years (0.29 per 1,000 mile-years baseline x 65% x 80% = 0.151 incidents per 1,000 mile-years).

4.6.4 Overall Pipeline Facility Incident Rate

The anticipated frequency of USDOT reportable releases from the proposed pipeline facilities is 0.239 incidents per 1.000 mile years (0.061 from third party damage, 0.027 from external corrosion, and 0.151 from other causes). This baseline frequency of releases has been used in the risk assessment presented herein for releases from the pipeline components and compressor station.

4.6.5 Well Site Incident Rate

The anticipated annual failure rate for the well site is 4.90E-04 per year. (Weatherwax, et al 2008) Dividing this failure rate by ten wells (one vertical and eight directional) yields a failure rate of 4.90E-05 per well per year; this results in a failure likelihood of 1 : 20,400 per well per year. This baseline frequency of releases has been used in the risk assessment presented herein for releases from the wells.

This value is higher than that provided by other sources. However, other sources note that the higher frequency of failures in California is due to the complex geology, seismic activity, and the age of some wells used for gas storage. The following well release figures have been cited by other sources for natural gas storage facilities:

- 2.02E-05 per well per year (1 : 49,500 per well per year) - British Geological Survey, An Appraisal of Underground Gas Storage Technologies and Incidents, For the Development of Risk Assessment Methodology, 2007. (BGS 2007) It should be noted that this value has also been used in addition to the value discussed above to determine the individual risk transects for releases from the well site. This provides an anticipated range of well releases, between the upper and lower bounds.

- 1.2E-05 per well per year (1 : 83,300 per well per year) upper range for depleted oil and gas fields in Europe – Health and Safety Executive of the United Kingdom, Failure Rates for Underground Gas Storage, 2008. (HSE 2008)

- 8.3E-06 per well per year (1 : 120,500 per well per year) upper range for depleted oil and gas fields worldwide – Health and Safety Executive of the United Kingdom, Failure Rates for Underground Gas Storage, 2008. (HSE 2008)

5.0 QUALITATIVE RISK ASSESSMENT

In this section, the anticipated frequency of unintentional releases, injuries and fatalities will be developed using the historical baseline data presented above for the following project components:

- 14.7 mile long, 24-inch-diameter pipeline between the PG&E Line 400/401 and the compressor station, including the compressor station and associated facilities;
- Dual 0.3 mile, 16-inch-diameter pipelines between the compressor station and the remote well pad; and the
- Remote well pad, which includes up to 10 withdrawal wells.

5.1 Anticipated Frequency of Unintentional Releases

Using the baseline data compiled in the previous section, the anticipated frequencies of unintentional releases have been estimated. These data, for the proposed pipeline segments, totaling 15-miles in length, are shown in Table 5.1-1 below. These data also include anticipated releases from the meter and compressor stations and other appurtenances, which are also under USDOT jurisdiction and are subject to the pipeline incident reporting requirements. As a result, releases from these facilities have been included in the previously presented baseline data.

Table 5.1-1
Anticipated Frequency of Unintentional Releases

Incident Cause	Incident Rate	Anticipated Number of Incidents Per Year	Likelihood of Annual Occurrence
Total, All Releases, Regardless of Spill Volume	3.00 per 1,000 mile-years	0.0458	1 in 22
USDOT Reportable Gas Releases - 1970 thru June 1984 criteria (>$5,000 damage)	1.30 per 1,000 mile-years	0.0199	1 in 50
USDOT Reportable Gas Releases - Current Criteria (>$50,000 damage)	0.239 per 1,000 mile-years	0.0037	1 in 270
Well Site	4.90E-05 per well per year	0.0005 (10 Wells)	1 in 2,040 (10 Wells)

5.2 Anticipated Frequency of Injuries and Fatalities

Most unintentional natural gas releases are relatively small and do not cause personal injuries or death. In this section, the likelihood of human injuries and deaths will be estimated using historical baseline data. Later in this document, the human life impacts will be evaluated using a probabilistic approach.

As noted earlier, the primary natural gas component is methane, which is not toxic. Although methane presents a slight inhalation hazard, the primary risk to humans is posed by fire or explosion. A fire could result from a natural gas release with two conditions present. First, a volume of natural gas must be present within the combustible mixture range (5% to 15% methane in air). Second, a source of ignition must be present with sufficient heat to ignite the air/natural gas mixture (1,000°F). In order for an explosion to occur, a third condition must be present - the natural gas vapor cloud must be confined, at least to some degree. The higher the degree of confinement, the more potentially lethal the resulting explosion.

It is difficult to estimate the potential extent of human injury because there are so many variables affecting the size of a fire or explosion: rate of vapor cloud formation (controlled primarily by the release rate), size of the vapor cloud within the combustible range (controlled by weather, including wind and temperature, release rate, etc.), concentration of vapors (varying with wind and topographic conditions), degree of vapor cloud confinement, etc. (These actual conditions will be evaluated later, in Section 6.4 of this Appendix.)

Based on the historical data presented earlier, the following frequencies for human life consequences are anticipated from the pipeline components and associated metering, compressor station, and appurtenances:

Table 5.2-1
Human Life Impacts Based on Historical Data

Consequence	Frequency	Annual Number of Events	Annual Probability of Occurrence
Injuries regardless of severity	0.700 incidents per 1,000 mile years	1.07E-02	1 : 93
Injuries requiring hospitalization	0.017 incidents per 1,000 mile years	2.60E-04	1 : 3,800
Fatalities (from pipeline components only, excludes well site)	0.004 fatalities per 1,000 mile years	6.11E-05	1 : 15,000

As indicated in the table above, the annual aggregate probability of a fatality is 6.11E-05 (1 : 15,000), based on the qualitative risk assessment. This is the estimated annual likelihood of a fatality along the entire project, considering all of the project components. This aggregate risk should not be confused with individual risk, nor the individual risk thresholds presented herein. The individual risk of fatality is the probability of a fatality at a single specific location, whereas the aggregate risk is the probability of a fatality along the entire pipeline system. (Table 6.5-1 summarizes the differences between individual and aggregate risk.) The anticipated frequencies of injuries and fatalities presented above are useful references. However, they do not reflect an accurate evaluation of the specific parameters for the proposed pipeline facilities. For example, these summary data do not differentiate between the risks of a relatively benign natural gas pipeline and a pipeline transporting chlorine gas, which is much more likely to result in serious impacts due to toxicity. These historical data also do not differentiate between various population densities. For example, a release in an urban area is likely to cause more significant impacts to humans than a release in a rural, undeveloped area. In the following section, a probabilistic risk assessment will be presented. This analysis will consider the actual environment, pipe contents, pipe diameter, actual operating conditions and the proximity to the public.

6.0 QUANTITATIVE RISK ASSESSMENT

In this section, a probabilistic pipeline risk assessment will be presented. This analysis considers the actual site population density, as well as the characteristics of the pipe contents in the event of an unintentional release. This analysis was conducted using the following consequence event tree, with minor modifications to differentiate between flash and torch fires.

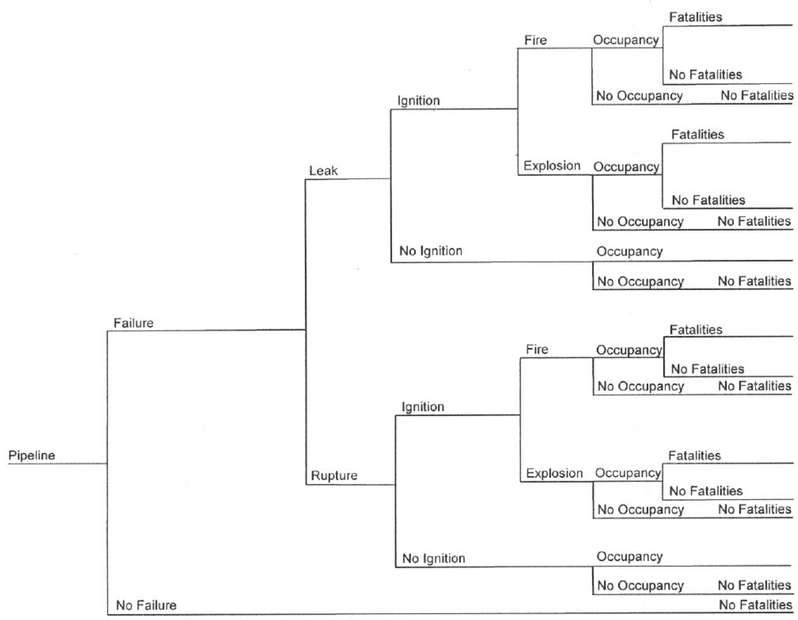


Figure 6-1 Consequence Event Tree

6.1 Baseline Frequency of Unintentional Releases

For this analysis, a baseline frequency of USDOT reportable unintentional releases of 0.239 incidents per 1,000 mile-years has been used for releases from the pipeline and compressor station. The analysis used an anticipated annual failure rate for each well of 4.90E-05. (These baseline frequencies were developed earlier in Section 4.6.4 and 4.6.5 of this Report.)

6.2 Conditional Consequence Probabilities

In order to conduct a probabilistic analysis, the conditional probabilities of each fault tree branch must be established. For example:

- What percentage of pipe failures are relatively small leaks versus full bore ruptures?
- What percentage of vapor clouds resulting from leaks and ruptures are ignited?

- What percentage of ignited vapor clouds burn versus explode?
- And in the event of a fire or explosion, do any serious injuries or fatalities result?

In order to evaluate these conditional probabilities, the actual unintentional release data reported to the Department of Transportation, Office of Pipeline Safety (USDOT) have been evaluated. Unfortunately, the USDOT incident reports prior to January 1, 2002 did not include fields for reporting fires or explosions; these fields were added in 2002. Between January 1, 2002 and December 31, 2007, there were 520 onshore transmission pipeline incidents reported to the USDOT. The following data are worth noting:

- 91 (17.5%) of the resulting vapor clouds ignited.
- 56 (61.5%) of the vapor clouds simply burned
- 35 (38.5%) of the vapor clouds were reported to have exploded.

In other words, 10.8% (61.5% of 17.5% = 10.8%) of the reported onshore natural gas transmission pipeline incidents resulted in fires while 6.7% (38.5% or 17.5% = 6.7%) resulted in explosions. 361 (69.4%) of the incidents were identified as being released directly from the pipeline, as apposed to other appurtenances (e.g., compressors, regulators, etc.). Of these, 109 (30%) of the pipeline releases were identified as ruptures. 26 (7%) of the pipeline release incidents resulted in fires and 20 (6%) resulted in explosions.

It is interesting to note that between January 1, 2002 and December 31, 2007, 55 (10.6%) of the reported 520 natural gas transmission pipeline incidents occurred in compressor stations; 14 (25%) of these incidents resulted in fires and 10 (18%) resulted in explosions. 50 (9.6%) of the reported incidents occurred at meter and/or regulator stations; 10 (20%) of these resulted in fires and 1 (2%) resulted in an explosion. The remaining 54 incidents were not identified as to which part or component of the pipeline system failed.

Table 6.2-1
Pipeline and Compressor Station Conditional Probabilities

Parameter	Conditional Consequence Probability	Value — Source
Leak Size	Probability of Release (1-inch diameter hole)	70% - USDOT
	Probability of Rupture (complete, full diameter pipe severance)	30% - USDOT
Ignition	Probability of No-Ignition	82.5% - USDOT
	Probability of Ignition	17.5% - USDOT
Fire/Explosion	Probability of Fire Upon Ignition	61.5% - USDOT
	Probability of Explosion Upon Ignition	38.5% - USDOT

Table 6.2-2
Pipeline and Compressor Station Combined Conditional Probabilities

Consequence	Conditional Release Consequence	Value
Fires	Release Resulting in a Fire	0.70 x 0.175 x 0.615 = 7.5%
	Rupture Resulting in a Fire	0.30 x 0.175 x 0.615 = 3.2%
Explosions	Release Resulting in an Explosion	0.70 x 0.175 x 0.385 = 4.7%
	Rupture Resulting in an Explosion	0.30 x 0.175 x 0.385 = 2.0%

The conditional probabilities for well releases were developed from two sources. Weatherwax reported that 80% of the failures would be conflagrations and 20% would be leaks, of which 50% would be ignited. The British Geological Survey found that for releases from wells associated with natural gas storage at depleted oil and gas fields, five of sixteen (31%) resulted in ignition and four of sixteen (25%) resulted in explosions. These data were combined to develop the following conditional probabilities, which were used in the well analysis. (Weatherwax et al 2008, BGS 2007)

Table 6.2-3
Injection/Withdrawal Well Conditional Probabilities

Parameter	Conditional Consequence Probability	Value — Source
Leak Size	Probability of Release (1-inch diameter hole)	20% - Weatherwax 2008
	Probability of Rupture (complete, full diameter pipe severance)	80% - Weatherwax 2008
Ignition	Probability of No-Ignition	50% - Weatherwax 2008 and BGS 2007
	Probability of Ignition	50% - Weatherwax 2008 and BGS 2007
Fire/Explosion	Probability of Fire Upon Ignition	61.5% - USDOT
	Probability of Explosion Upon Ignition	38.5% - USDOT

Table 6.2-4
Injection/Withdrawal Well Combined Conditional Probabilities

Consequence	Conditional Release Consequence	Value
Fires	Release Resulting in a Fire	0.20 x 0.50 x 0.615 = 6.15%
	Rupture Resulting in a Fire	0.80 x 0.50 x 0.615 = 24.6%
Explosions	Release Resulting in an Explosion	0.20 x 0.50 x 0.385 = 3.85%
	Rupture Resulting in an Explosion	0.80 x 0.50 x 0.385 = 15.4%

6.2.1 Flash Fires versus Torch Fires

The USDOT data does not provide any differentiation regarding the type of fire (torch fire versus flash fire). However, since there are a relatively large number of reported explosions in the USDOT database, it is likely that the number of flash fires is limited. There are also few historical flash fires on record (LEES). The analyses assumed that 10% of the fires would be flash fires and 90% would be torch fires.

6.2.2 Unignited Vapor Clouds, Flash Fires versus Indoor Explosions

Should the combustible portion of a vapor cloud migrate to nearby residences or commercial buildings before ignition, a flash fire would occur if the ignition was outdoors, or an explosion would occur indoors. Unfortunately, available references provide little data regarding the likelihood of these two occurrences. The analyses assumed that 90% of the fires would be flash fires and 10% would be explosions within the structures.

Table 6.2.2-1
Combined Conditional Probabilities

Consequence	Conditional Release Consequence	Value
Torch Fires	Release Resulting in a Torch Fire	7.5% x 0.90 = 6.8%
	Rupture Resulting in a Torch Fire	3.2% x 0.90 = 2.9%
Flash Fires (Vapor Cloud Ignition Outdoors)	Release Resulting in a Flash Fire	7.5% x 0.10 x 0.90 = 0.7%
	Rupture Resulting in a Flash Fire	3.2% x 0.10 x 0.90 = 0.3%
Indoor Explosion (Vapor Cloud Ignition Indoors)	Release Indoor Explosion	7.5% x 0.10 x 0.10 = 0.08%
	Rupture Indoor Explosion	3.2% x 0.10 x 0.10 = 0.03%

As indicated in the table above, flash fires and indoor explosions resulting from unignited vapor clouds are anticipated to be relatively unlikely events.

6.3 Release Modeling

In this section, various pipeline release scenarios are presented. The releases were modeled using CANARY, by Quest, version 4.3 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. Literally thousands of possible data combinations could be used to evaluate individual releases. However, in order to make a reasonable determination of likely releases, the following assumptions were used:

Table 6.3-1
Release Modeling Input

Parameter	Model Input
Normal and Maximum Allowable Operating Pressures	1,070 psig maximum allowable operating pressure for the 14.7 mile, 24-inch segment between PG&E Line 400/401 and the compressor station. 1,456 psig maximum allowable operating pressure for the dual 0.3 mile, 16-inch segments between the compressor station and the remote well pad. 1,400 psig maximum operating pressure for reservoir. Note – The actual line pressures will vary depending on actual operating conditions. The maximum allowable operating pressures were used in all release modeling included in this quantitative risk assessment.

Table 6.3-1 (Continued)

Parameter	Model Input
Typical Flow Rate	300 Mcf per day (MMSCFD) for the 14.7 mile, 24-inch line between PG&E Line 400/401 and the compressor station. 175 Mcf per day (MMSCFD) for the dual 0.3 mile, 16-inch lines between the compressor station and the remote well pad. 175 Mcf per day (MMSCFD) maximum free flow from each well. The facilities were assumed to be operational 50% of the time.
Modeled Releases	1-inch diameter release Full Bore release
Contents	Methane
Contents Temperature	70° F
Wind Speed	2 meters per second (4.5 mph) for vapor cloud explosion modeling 20 mph for torch fire modeling Note – See also Section 8.0 of this Report which provides an atmospheric condition sensitivity analysis.
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 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. Note – See also Section 8.0 of this Report which provides an atmospheric condition sensitivity analysis.
Relative Humidity	70%
Air and Surface Temperature	72° F
Continuous Release Duration	Two (2) hours
Duration of Normal Flow after Leak Initiation	Two (2) hours for release, five (5) minutes for rupture
Pipe Length Upstream and Downstream of Break	All releases were assumed to occur at the mid-point of each pipeline segment. Wells – 2.500 feet of 8-inch nominal diameter casing was assumed with all releases located at the well head.

Table 6.3-1 (Continued)

Parameter	Model Input
Release Angle	Aggregate and Societal Risk Assessment – Pipeline Releases 45° above horizontal (100% of releases) Individual Risk Assessment – Pipeline Releases 15° above horizontal, downwind (20% of releases) 45° above horizontal, downwind (20% of releases) Vertical (20% of releases) 45° above horizontal, upwind (20% of releases) 15° above horizontal, upwind (20% of releases) Aggregate and Societal Risk Assessment – Well Releases Vertical (100% of releases) Individual Risk Assessment – Well Releases 15° above horizontal, downwind (12.5% of releases) 45° above horizontal, downwind (12.5% of releases) Vertical (50% of releases) 45° above horizontal, upwind (12.5% of releases) 15° above horizontal, upwind (12.5% of releases)
Fuel Reactivity	Medium - Most hydrocarbons have medium reactivity, as defined by the Baker-Strehlow method. Low reactivity fluids include methane, natural gas (98+% methane), and carbon monoxide. The natural gas being transported is likely around 95% methane, which results in medium fuel reactivity. High reactivity fluids include hydrogen, acetylene, ethylene oxide, and propylene oxide.
Obstacle Density	Low for 24-inch and 16-inch segments and well site. This parameter describes the general level of obstruction in the area including and surrounding the confined (or semi-confined) volume. 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. Low obstacle density is appropriate due to the low building density and open space around the pipeline. The low obstacle density is also appropriate because the five release angles result in an unconfined, overhead vapor cloud, except for very near the release (low obstacle density). Where the vapor cloud is located at ground level, near the release, the surroundings are relatively open along the entire pipeline alignment (low obstacle density).
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.

The average mass flow rate for the first sixty seconds of the release was used to determine the mass flow rate for all torch fires. This release flow rate is somewhat less than the initial flow rate and somewhat greater than the flow rate after this period.

6.3.1 Explosion Modeling Results

As discussed previously, natural gas generally does not explode, unless the vapor cloud is confined in some manner. The proposed pipeline segments, remote well pad and compressor site are surrounded by relatively open space, with some residential, light commercial and industrial space. Should natural gas migrate into residences or other structures, the overpressures from an explosion within the confined space would be life threatening.

Outdoors, the peak overpressure would be only 0.38 psi, due to the relatively open environment (medium fuel reactivity and low obstacle density). This overpressure level is not high enough to pose potentially fatal risks to the public.

The level of confinement within the compressor building is sufficient to provide a 5 to 15 psig peak over-pressure. This level can result in serious injuries and fatalities to those indoors. However, since the site is not accessible to the public, these impacts should be limited to company and contract personnel.

The typical pipeline release modeled is depicted in the figure below. This figure shows an elevation view of a downwind release from a rupture of the 24-inch line between the PG&E Line 400/401 and the compressor station, while operating at 1,070 psig at a flow rate of 300 Mcf per day, with the release oriented at 45° above the horizon. The combustible portion of the vapor cloud is between the 5 and 15 mole percent contours. As depicted in this figure, the combustible portion of the vapor cloud is well overhead, where there would not be any confinement to cause an explosion.

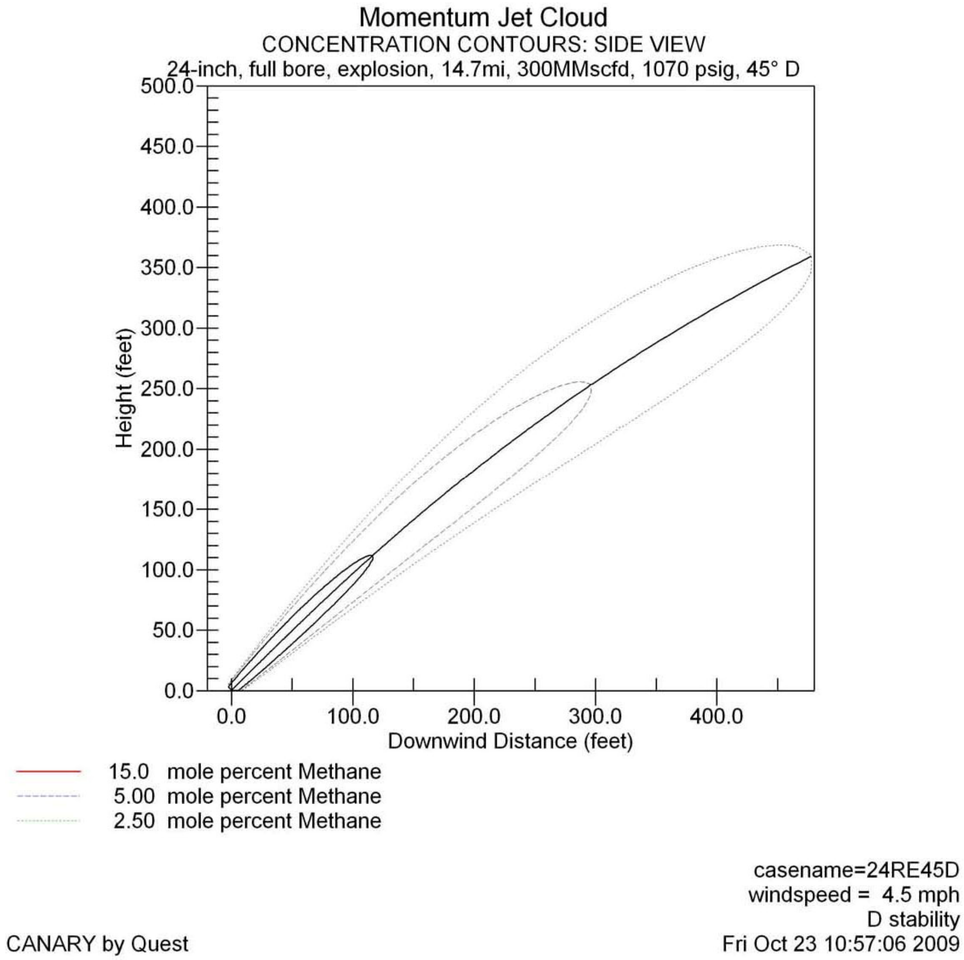


Figure 6.3.1-1 16-inch Compressor to Well Site Line Segment, Rupture Explosion, Elevation

The explosion modeling result for a vertical well casing rupture while operating at 1,400 psig and a free flow rate of 175 Mcf per day is depicted in the figure below.

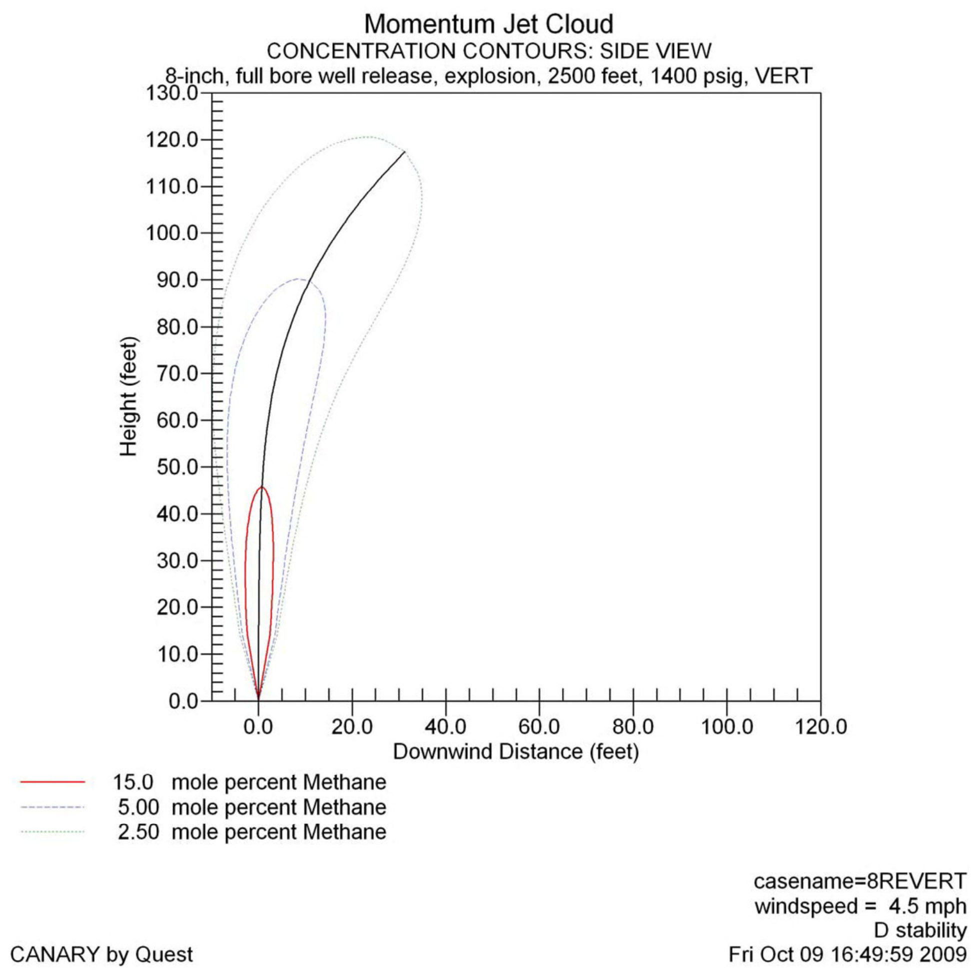


Figure 6.3.1-2 Well Head Casing Rupture Explosion, Elevation

As indicated above, the flammable portion of the vapor cloud (5 mole percent), would extend downwind less than 20-feet and rise less than 100-feet above the ground surface. The side-on over-pressure of the portion of the vapor cloud which is overhead is estimated at 0.38 psig; this low value is a result of the lack of confinement overhead. The results in plan view are provided in the following figure.

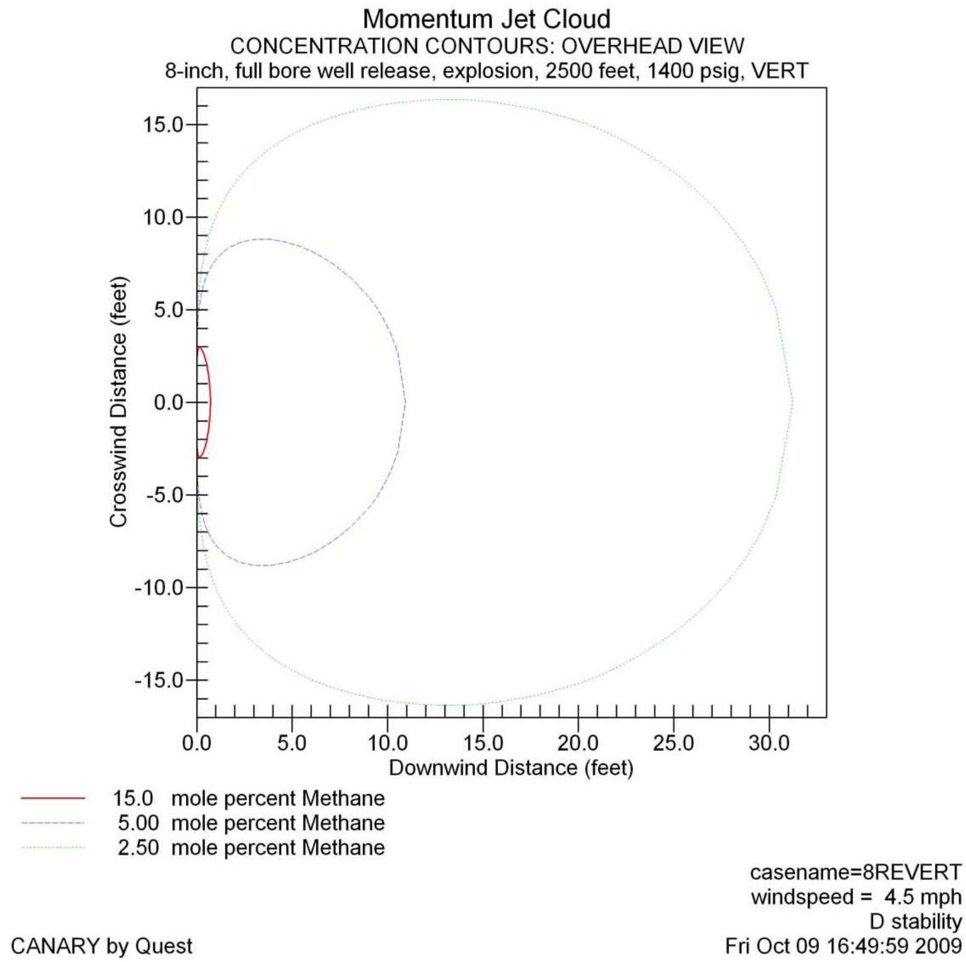


Figure 6.3.1-3 Well Head Casing Rupture Explosion, Plan

6.3.2 Torch Fire Modeling Results

The torch fire modeling results are presented in the following tables.

Table 6.3.2-1
Torch Fire Modeling Results, 14.7 mile, 24-inch Pipeline Segment, Operational

Release Angle	Maximum Operating Pressure	Size of Release	Horizontal Distance from Unintentional Release to Endpoint Measured Perpendicular to Pipeline (feet) / Width of Exposure Measured Parallel to Pipeline (feet)		
			12,000 btu/hr-ft^2	8,000 btu/hr-ft^2	5,000 btu/hr-ft^2
15° Downwind	1,070 psig	Rupture	528	561	605
			424	554	720
45° Downwind	1,070 psig	Rupture	353	431	521
			330	480	676
Vertical	1,070 psig	Rupture	124	203	310
			210	340	558
45° Upwind	1,070 psig	Rupture	53	83	141
			200	340	540
15° Upwind	1,070 psig	Rupture	29	40	61
			156	270	490
15° Downwind	1,070 psig	1-inch	63	67	72
			44	62	80
45° Downwind	1,070 psig	1-inch	41	50	61
			38	54	74
Vertical	1,070 psig	1-inch	15	21	32
			26	40	62
45° Upwind	1,070 psig	1-inch	4	8	14
			20	36	58
15° Upwind	1,070 psig	1-inch	0	4	7
			0	22	30

Note – Radiant heat flux values shown are measured at 6-feet above ground surface.

Table 6.3.2-2
Torch Fire Modeling Results, 14.7 mile, 24-inch Pipeline Segment, Non-Operational

Release Angle	Maximum Operating Pressure	Size of Release	Horizontal Distance from Unintentional Release to Endpoint Measured Perpendicular to Pipeline (feet) / Width of Exposure Measured Parallel to Pipeline (feet)		
			12,000 btu/hr-ft²	8,000 btu/hr-ft²	5,000 btu/hr-ft²
15° Downwind	1,070 psig	Rupture	527	560	605
			414	540	716
45° Downwind	1,070 psig	Rupture	352	431	521
			322	480	670
Vertical	1,070 psig	Rupture	124	203	310
			216	340	550
45° Upwind	1,070 psig	Rupture	53	83	141
			208	336	546
15° Upwind	1,070 psig	Rupture	29	40	61
			150	270	460
15° Downwind	1,070 psig	1-inch	64	68	72
			48	60	80
45° Downwind	1,070 psig	1-inch	41	51	61
			36	52	74
Vertical	1,070 psig	1-inch	15	21	32
			26	40	62
45° Upwind	1,070 psig	1-inch	5	9	12
			22	36	58
15° Upwind	1,070 psig	1-inch	1	4	9
			4	20	44

Note – Radiant heat flux values shown are measured at 6-feet above ground surface.

Table 6.3.2-3
Torch Fire Modeling Results, Dual 0.3 mile, 16-inch Pipeline Segments, Operational

Release Angle	Maximum Operating Pressure[1]	Size of Release	Horizontal Distance from Unintentional Release to Endpoint Measured Perpendicular to Pipeline (feet) / Width of Exposure Measured Parallel to Pipeline (feet)		
			12,000 btu/hr-ft^2	8,000 btu/hr-ft^2	5,000 btu/hr-ft^2
15° Downwind	1,456 psig	Rupture	248	265	288
			204	262	344
45° Downwind	1,456 psig	Rupture	181	215	254
			166	240	326
Vertical	1,456 psig	Rupture	75	117	169
			110	178	272
45° Upwind	1,456 psig	Rupture	32	51	86
			100	164	262
15° Upwind	1,456 psig	Rupture	17	23	37
			78	132	226
15° Downwind	1,456 psig	1-inch	73	76	81
			56	72	94
45° Downwind	1,456 psig	1-inch	47	58	69
			54	70	92
Vertical	1,456 psig	1-inch	15	24	37
			30	48	72
45° Upwind	1,456 psig	1-inch	4	10	16
			22	40	68
15° Upwind	1,456 psig	1-inch	0	2	10
			0	16	52

Note – Radiant heat flux values shown are measured at 6-feet above ground surface.

[1] The torch fire modeling results shown in this table were developed using a maximum allowable operating pressure of 1,400 psig, which was originally proposed by the Applicant. The maximum allowable operating pressure for this line segment was subsequently changed to 1,456 psig. The torch fire impacts are essentially the same for both of these pressures. For example, for a full bore release at 45° above the horizon, the impact distances at 1,456 psig are 183, 217, and 257 feet for 100%, 50% and 1% mortality respectively. These values are within about one percent of those presented in the table. As a result, the torch fire release modeling has not been updated to reflect the minor increase in the maximum allowable operating pressure.

Table 6.3.2-4
Torch Fire Modeling Results, Dual 0.3 mile, 16-inch Pipeline Segments, Non-Operational

Release Angle	Maximum Operating Pressure[2]	Size of Release	Horizontal Distance from Unintentional Release to Endpoint Measured Perpendicular to Pipeline (feet) / Width of Exposure Measured Parallel to Pipeline (feet)		
			12,000 btu/hr-ft²	8,000 btu/hr-ft²	5,000 btu/hr-ft²
15° Downwind	1,456 psig	Rupture	202	219	234
			162	212	264
45° Downwind	1,456 psig	Rupture	155	182	213
			140	196	266
Vertical	1,456 psig	Rupture	75	110	156
			94	150	230
45° Upwind	1,456 psig	Rupture	33	53	87
			88	138	216
15° Upwind	1,456 psig	Rupture	17	25	41
			66	110	196
15° Downwind	1,456 psig	1-inch	71	74	79
			54	70	92
45° Downwind	1,456 psig	1-inch	46	56	68
			42	60	84
Vertical	1,456 psig	1-inch	15	23	36
			28	44	70
45° Upwind	1,456 psig	1-inch	4	11	16
			22	40	68
15° Upwind	1,456 psig	1-inch	0	3	10
			0	22	52

Note – Radiant heat flux values shown are measured at 6-feet above ground surface.

[2] The torch fire modeling results shown in this table were developed using a maximum allowable operating pressure of 1,400 psig, which was originally proposed by the Applicant. The maximum allowable operating pressure for this line segment was subsequently changed to 1,456 psig. The torch fire impacts are essentially the same for both of these pressures. As a result, the torch fire release modeling has not been updated to reflect the minor increase in the maximum allowable operating pressure.

Table 6.3.2-5
Torch Fire Modeling Results, Well Release

Release Angle	Maximum Operating Pressure	Size of Release	Horizontal Distance from Unintentional Release to Endpoint Measured Perpendicular to Pipeline (feet) / Width of Exposure Measured Parallel to Pipeline (feet)		
			12,000 btu/hr-ft^2	8,000 btu/hr-ft^2	5,000 btu/hr-ft^2
15° Downwind	1,400 psig	Rupture	189	203	217
			156	200	264
45° Downwind	1,400 psig	Rupture	131	158	188
			122	176	242
Vertical	1,400 psig	Rupture	47	75	115
			80	120	204
45° Upwind	1,400 psig	Rupture	20	31	51
			76	124	198
15° Upwind	1,400 psig	Rupture	11	16	23
			54	96	168
15° Downwind	1,400 psig	1-inch	71	75	79
			54	70	92
45° Downwind	1,400 psig	1-inch	46	56	67
			42	60	84
Vertical	1,400 psig	1-inch	15	23	36
			30	46	70
45° Upwind	1,400 psig	1-inch	2	9	16
			18	42	66
15° Upwind	1,400 psig	1-inch	0	3	8
			0	24	32

Note – Radiant heat flux values shown are measured at 6-feet above ground surface.

The torch fire isopleths for a vertical torch fire resulting from a full bore rupture of the 14.7 mile, 24-inch line segment between the PG&E Line 400/401 and the compressor station, while operating at 1,070 psig, are depicted are depicted graphically in the figure below.

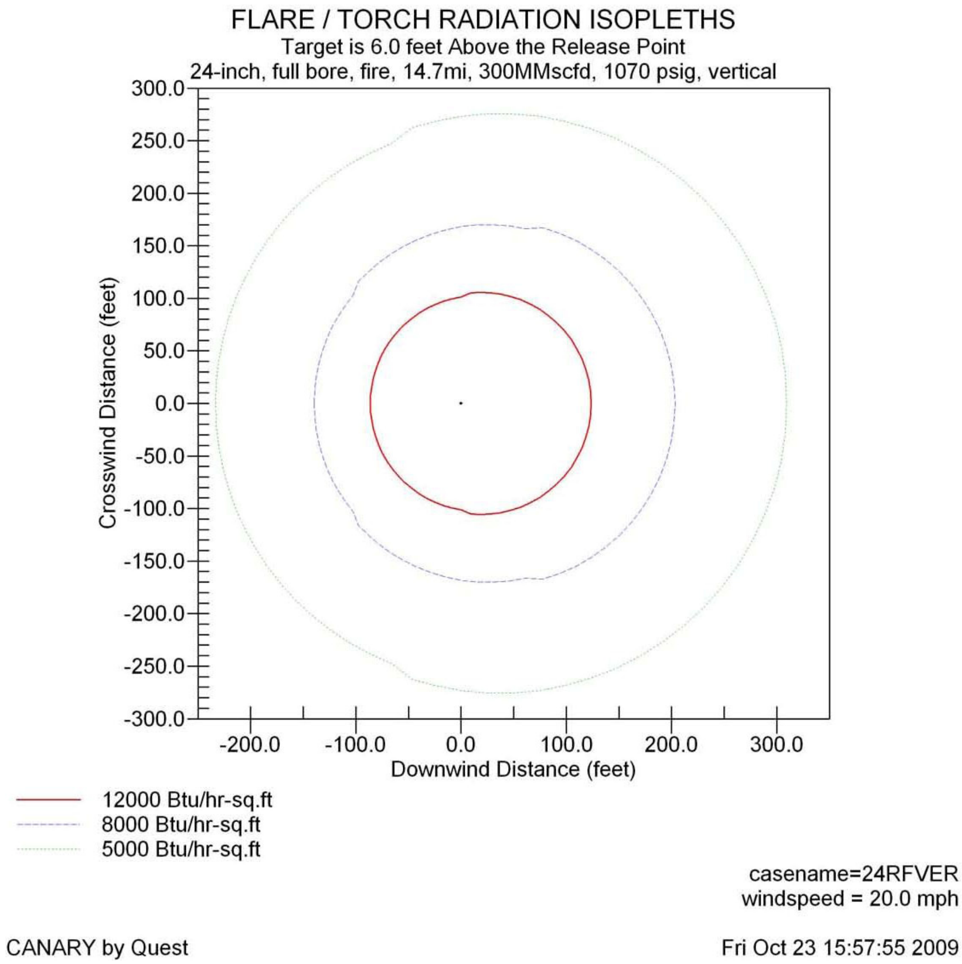


Figure 6.3.2-1 14.7 miles, 24-inch Line Segment Rupture, Vertical Torch Fire, Plan

The torch fire isopleths from a vertical casing rupture release are depicted in the figure below.

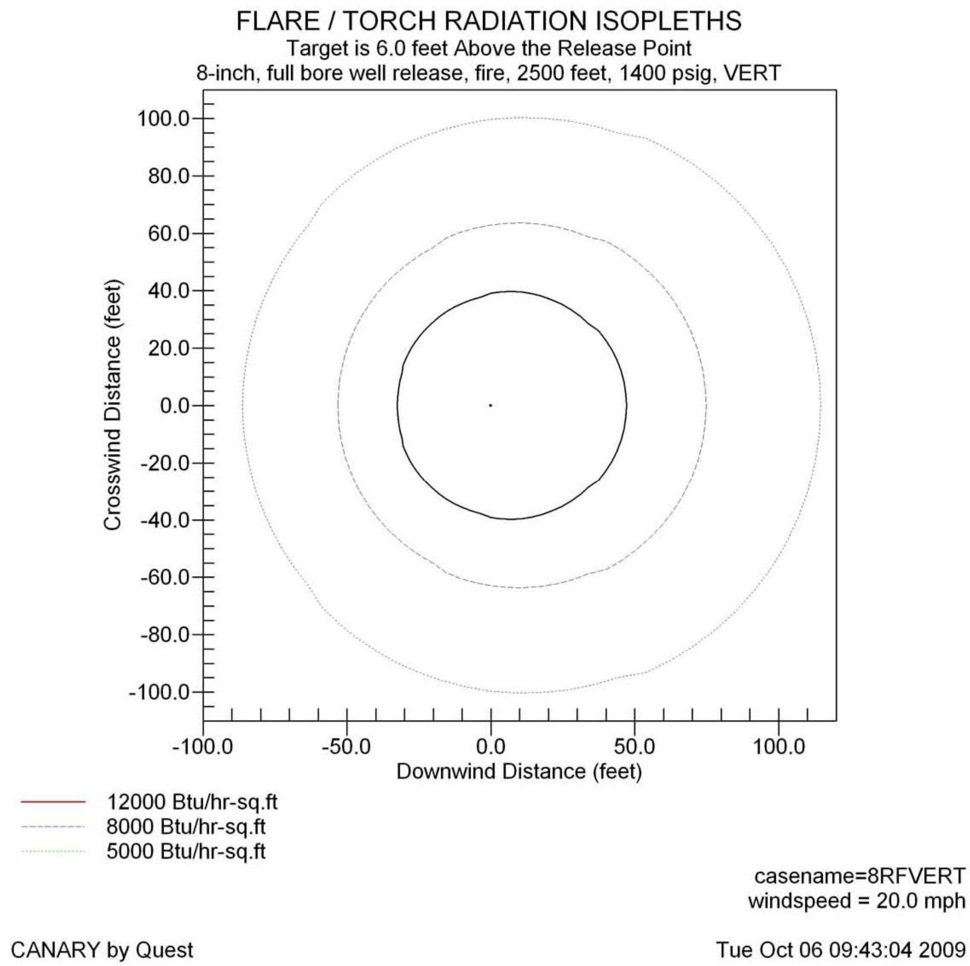


Figure 6.3.2-2 Well Head Casing Rupture, Vertical Torch Fire, Plan

6.3.3 Flash Fire Modeling Results

As discussed previously, 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. (If the ignition is immediate, a torch fire results.) In a flash fire, the portion of the vapor cloud within the combustible range burns quickly. It is assumed that those within the combustible portion of the vapor cloud would likely be fatally injured. Those outside the combustible portion of the vapor cloud would likely be uninjured. In other words, the public would generally be safe if they were too close to the release (over rich mixture, above the upper flammable limit) or beyond the portion of the vapor cloud with mixtures below the lower flammability limit. The results of the flash fire modeling are shown in the following tables.

Table 6.3.3-1
Flash Fire Modeling Results, 14.7 mile, 24-inch Pipeline Segment, Operational

Release Angle	Size of Release	Downwind Horizontal Distance from Unintentional Release to Lower Flammability Limit (feet) Measured Perpendicular to Pipeline	Width of Exposure (feet) Measured Parallel to Pipeline
15° Downwind	Rupture	443	48
45° Downwind	Rupture	296	47
Vertical	Rupture	109	47
45° Upwind	Rupture	0	0
15° Upwind	Rupture	0	0
15° Downwind	1-inch	52	5
45° Downwind	1-inch	34	5
Vertical	1-inch	2	5
45° Upwind	1-inch	0	0
15° Upwind	1-inch	0	0

Table 6.3.3-2
Flash Fire Modeling Results, 14.7 mile, 24-inch Pipeline Segment, Non-Operational

Release Angle	Size of Release	Downwind Horizontal Distance from Unintentional Release to Lower Flammability Limit (feet) Measured Perpendicular to Pipeline	Width of Exposure (feet) Measured Parallel to Pipeline
15° Downwind	Rupture	443	48
45° Downwind	Rupture	296	47
Vertical	Rupture	109	47
45° Upwind	Rupture	0	0
15° Upwind	Rupture	0	0
15° Downwind	1-inch	52	5
45° Downwind	1-inch	34	5
Vertical	1-inch	2	5
45° Upwind	1-inch	0	0
15° Upwind	1-inch	0	0

Table 6.3.3-3
Flash Fire Modeling Results, Dual 0.3 mile, 16-inch Pipeline Segments, Operational

Release Angle	Size of Release	Downwind Horizontal Distance from Unintentional Release to Lower Flammability Limit (feet) Measured Perpendicular to Pipeline[3]	Width of Exposure (feet) Measured Parallel to Pipeline
15° Downwind	Rupture	140	23
45° Downwind	Rupture	92	23
Vertical	Rupture	18	23
45° Upwind	Rupture	0	0
15° Upwind	Rupture	0	0
15° Downwind	1-inch	41	6
45° Downwind	1-inch	27	6
Vertical	1-inch	1	6
45° Upwind	1-inch	0	0
15° Upwind	1-inch	0	0

[3] The flash fire modeling results shown in this table were developed using a maximum allowable operating pressure of 1,400 psig, which was originally proposed by the Applicant. The maximum allowable operating pressure for this line segment was subsequently changed to 1,456 psig. The flash fire impacts are essentially the same for both of these pressures. For example, for a full bore release at 45° above the horizon, the impact distance (downwind distance to the lower flammability limit) is 93 feet at 1,456 psig. This value is within about one percent of that presented in the table. As a result, the flash fire release modeling has not been updated to reflect the minor increase in the maximum allowable operating pressure.

Table 6.3.3-4
Flash Fire Modeling Results, Dual 0.3 mile, 16-inch Pipeline Segments, Non-Operational

Release Angle	Size of Release	Downwind Horizontal Distance from Unintentional Release to Lower Flammability Limit (feet) Measured Perpendicular to Pipeline[4]	Width of Exposure (feet) Measured Parallel to Pipeline
15° Downwind	Rupture	175	29
45° Downwind	Rupture	115	29
Vertical	Rupture	26	29
45° Upwind	Rupture	0	0
15° Upwind	Rupture	0	0
15° Downwind	1-inch	40	6
45° Downwind	1-inch	26	6
Vertical	1-inch	1	6
45° Upwind	1-inch	0	0
15° Upwind	1-inch	0	0

[4] The flash fire modeling results shown in this table were developed using a maximum allowable operating pressure of 1,400 psig, which was originally proposed by the Applicant. The maximum allowable operating pressure for this line segment was subsequently changed to 1,456 psig. The flash fire impacts are essentially the same for both of these pressures. As a result, the flash fire release modeling has not been updated to reflect the minor increase in the maximum allowable operating pressure.

Table 6.3.3-5
Flash Fire Modeling Results, Well Release

Release Angle	Size of Release	Downwind Horizontal Distance from Unintentional Release to Lower Flammability Limit (feet) Measured Perpendicular to Pipeline	Width of Exposure (feet) Measured Parallel to Pipeline
15° Downwind	Rupture	109	17
45° Downwind	Rupture	71	17
Vertical	Rupture	11	18
45° Upwind	Rupture	0	0
15° Upwind	Rupture	0	0
15° Downwind	1-inch	40	6
45° Downwind	1-inch	26	6
Vertical	1-inch	1	6
45° Upwind	1-inch	0	0
15° Upwind	1-inch	0	0

6.4 Risk Analysis Exposure Assumptions and Methodology

In order to quantify the potential risks to humans, a number of assumptions must be made; otherwise, the effort required to perform the risk analysis can become unreasonably complex. The following paragraphs outline the assumptions made in estimating the frequency and severity of the potential hazards.

6.4.1 Period of Operation

During periods of non-operation, when the pipelines are neither injecting nor withdrawing natural gas to/from the reservoir, they would be pressurized, but would be isolated from the PG&E Line 400/401 and the storage reservoir. The analyses assumed that the pipeline segments would be operational 50% of the time.

6.4.2 Exposure Probability

In cases where the exposure to impacts only occurred on one side of the pipeline, the probability was reduced by one-half. For example, where residential structures occurred on one side of the pipeline only, the probability of exposure was 50% of the value used where residential development occurred on both sides of the pipeline.

6.4.3 Exposure Proximity to Occupants of Residences and Commercial Buildings

In determining the distances from the pipe segments to existing residences and commercial buildings, the nearest distance from the pipeline to each structure was used. For individuals outside the structures, the analysis assumed that they would be located near the primary building. For releases from the well site, the distances were taken from the individual wells.

Flash Fires and Indoor Explosions

Residential Occupants: Should the combustible portion of a vapor cloud migrate to nearby residences before ignition, a flash fire would occur if the ignition were outdoors, or an explosion would occur indoors.

The analyses assumed a 100% probability of fatality to those exposed to a flash fire. However, those housed within their residences were assumed to be sufficiently protected from an outdoor flash fire to prevent serious injury or fatality. The analyses assumed that those protected inside a residence would be able to evacuate safely should the structure catch fire, after the flash fire subsided. The analyses assumed that occupants of these residences would be outside their homes, exposed to outdoor flash fire effects, an average of 10% of the time (roughly 17 hours per week).

In the event that natural gas were to migrate inside the structure, the analysis assumed a 100% probability of fatality. The analyses assumed a 75% probability that occupants would be evacuated by emergency responders, or evacuate the structure on their own once they identified the gas odorant, before the gas reached a combustible mixture and ignited. The analysis assumed that occupants of these residences would be inside their homes, exposed to potential indoor explosions, an average of 70% of the time (16.8 hours per day). This results in a 17.5% probability of exposure (25% not evacuated x 70% = 17.5%).

Commercial Building Occupants: This analysis is similar to that described above for residential structures, except for the exposure duration. For a 1-inch diameter release, where the exposure width is relatively small, the analyses assumed that occupants of the commercial buildings would be outside the buildings, exposed to flash fire effects, an average of 6% of the time (roughly 10 hours per week, 2 hours per work day). For a flash fire resulting from a rupture, the width of the impact area is much larger and the likelihood of an individual being exposed is much higher. For these cases, the individual risk assessment analyses assumed an outdoor exposure of 50 hours per week (30% of the time); the societal risk assessment assumed an exposure of 6%, as this type of analysis considers the likelihood of fatal impacts to the total number of people exposed to the hazard.

In the event that natural gas were to migrate inside the structure, the analyses assumed a 100% probability of fatality to building occupants. The analyses assumed that occupants would be within the building 50 hours per week (30% of the time), with a 75% probability that occupants would be evacuated by emergency responders, or evacuate the structure on their own once they identified the gas odorant, before the gas reached a combustible mixture. This results in a 7.5% probability of exposure (25% not evacuated x 30% = 7.5%).

Torch Fires

Residential Occupants: The aggregate, individual and societal risk analyses assumed that 100% of the residents exposed to 12,000 btu/hr-ft^2 heat flux would be fatally injured; 50% of those exposed to 8,000 btu/hr-ft^2 would be fatally injured, and 1% of those exposed to 5,000 btu/hr-ft^2 would be fatally injured while they are outside their homes (30 second exposure assumed). As depicted in Figure 9.10-1, presented later in this report, 100% ,mortality was assumed inside the 12,000 btu/hr-ft^2 isopleth, 75% mortality was assumed between the 12,000 btu/hr-ft^2 and 8,000 btu/hr-ft^2 heat flux isopleth (average of 100% and 50% mortality); and 25% mortality was assumed between the 8,000 btu/hr-ft^2. and 5,000 btu/hr-ft^2 heat flux contour (average of 50% and 1% mortality).

The analyses also assumed that those protected inside their residence would be able to evacuate safely should the structure catch fire. For 1-inch diameter releases, where the exposure width is relatively small, the analyses assumed that occupants of these residences would be outside their homes, exposed to torch fire effects, an average of 10% of the time (roughly 17 hours per week). For a torch fire resulting from a rupture, the width of the impact area is much larger and the likelihood of an individual being exposed is much higher. For these cases, the individual risk assessment analyses assumed an outdoor exposure of 50 hours per week (30% of the time); the societal risk assessment assumed an exposure of 6%, as this type of analysis includes the estimated number of people exposed to the hazard; in other words, it is less likely that the maximum number of exposed individuals versus a single person would be present at a given location in the event of a rupture.

Commercial Building Occupants: This analysis is similar to that discussed above for residences. However, the analysis assumed that occupants of commercial buildings would be outside, exposed to torch fire effects from a 1-inch diameter release, an average of 10 hours per week (6% of the time). The individual risk analyses assumed an exposure of 30% for torch fires resulting from full bore ruptures, due to the much larger width of exposure. For the societal risk assessment, an exposure of 6% was used for both 1-inch diameter and full bore releases.

Explosions

The analysis assumed a 10% probability of fatality to building occupants exposed to an over-pressure level of 1.00 psig due to flying glass and debris. As described above, residential buildings were assumed to be occupied 70% of the time (16.8 hours per day) and commercial buildings were assumed to be occupied 30% of the time (50 hours per week). However, as noted earlier, the peak overpressure levels from this project are anticipated to be only 0.38 psig, due to the lack of confinement. As a result, fatalities resulting from explosions are not anticipated from the proposed project. The overpressure levels are expected to be well below the threshold required to cause serious injuries or fatalities to those outdoors.

6.4.4 Exposures to Vehicle Occupants

Flash Fires

There is little actual or experimental data available for natural gas flash fires. Based on a full bore release at 45° above the horizon from the 24-inch diameter line segments at the modeled conditions, the flammable concentration of the vapor cloud would be roughly 50-feet wide (measured parallel to the pipeline, perpendicular to the release). A vehicle traveling at 40 miles per hour perpendicular to the release would only be within the flammable portion of the vapor cloud for about one second, unless the vehicle were stopped (e.g., red light, etc.).

Considering the variety of possible release angles, the likely short duration of exposure, and the protection afforded by the vehicle, these analyses assumed that 10% of the occupants of vehicles exposed to the modeled maximum horizontal projection of a flash fire resulting from pipeline releases would be fatally injured.

It should be noted that 100% casualties are assumed for similar analyses used in the United Kingdom. However, there is evidence that those exposed to flash fires can survive. Although natural gas flash fires are rare, an event occurred on October 1982 which is noteworthy. This event is noted in the Report on a Study of International Pipeline Accidents (HSE 2000). In this case an end cap blew off the end of a natural gas pipeline in Pine Bluff, Arkansas. The ignition of the resulting gas cloud was delayed, until the flammable portion of the cloud reached a nearby welding machine. As stated in the report, "All seven persons at the accident site were engulfed in the flash-fire. The two welder-helpers, who were wearing goggles but not welding helmets, and the two company employees standing atop the ditch at the east and south end were placed in intensive care at a local hospital. Another worker on top the ditch was admitted to the hospital in a serious but stable condition. The two welders, who were under the pipe when the fire erupted and were more sheltered from the fire, were treated and released from the hospital… While none of the workmen were killed, they were not representative of the population as a whole; they were relatively young, fit and wearing working clothes. Children or the elderly (perhaps 50% of the population), or those wearing less protective clothing in a similar fire would probably not have survived."

The flash fire impacts resulting from a well casing failure are negligible. As shown earlier (Table 6.3.3-5) , the vapor cloud resulting from a vertical release at the well site would not be expected to extend far enough from the site to be a potential threat.

Torch Fires

Because the exposure time to passing vehicles would be limited, the analyses assumed that occupants in passing vehicles would be somewhat protected from the radiant heat due to torch fires. The analyses assumed that fatalities would only occur to those exposed directly to the flame or those within the 8,000 btu/hr-ft^2 isopleth. (See Tables 6.3.2-1 through 6.3.2-4 for actual data.) It should be noted that the flame lengths and distances to the 8,000 btu/hr-ft^2 are essentially the same. Due to the variation in the possible release angles (e.g., the flame may be vertical, or pass above the vehicle) and the possibility for vehicle occupants to pass through the hazard area relatively quickly, the aggregate and societal risk analyses assumed a 10% probability of fatality.

Explosions

The peak overpressures resulting from atmospheric explosions are not anticipated to be sufficient to cause public fatalities.

6.4.5 Number of Vehicle Occupants Exposed to Release

The analysis estimated the number of individuals exposed as follows:

- The major exposures to vehicle occupants would occur at the Interstate 5 and Old Highway 99 crossings. The traffic counts for I-5 were obtained from the CALTRANS web site (hhht://traffic-counts.dot.ca.gov) on January 7, 2010. In Colusa County, the I-5 traffic volume was estimated at 25,000 trips per day. The Old Highway 99 traffic volume was estimated at 12,000 trips per day. All other roadways were estimated at 100 trips per day.

- An average traffic speed of 40 miles per hour was used, except for I-5 and Old Highway 99, where a traffic speed of 65 miles per hour was used.

- The length of hazard, measured along the roadway, was determined individually for each type of release by modeling. These data are summarized in Table 6.5.2-1. For flash fires and vapor cloud explosions, a minimum exposure of 1 vehicle was used, since a passing vehicle is a likely source of ignition for an unignited vapor cloud.

- The normal stopping distance was determined using a one second reaction time and 15 feet per second rate of deceleration.
- An average vehicle occupancy of 1 was assumed for aggregate risk and 2 for societal risk.

6.5 Aggregate Risk

In this section, the probable loss of life (PLL) or aggregate risks will be presented. These PLL or aggregate risk values should not be confused with the individual risk (IR) transects presented in the following Section 6.6. The individual risk is the likelihood of an individual fatality per year, at a specific location, assuming a continuous exposure. PLL or aggregate risk on the other hand, is the numeric combination of the frequency of anticipated fatalities from each possible exposure, for all of the project components, over the entire project length, over a given time duration.

For PLL or aggregate risk , the probabilities of exposure are based on the type of occupancy. For example, the aggregate risk assessment assumes that residential occupants would be outdoors, potentially exposed to torch fire impacts 50 hours per week (30% of the time), versus 100% of the time for individual risk.

In other words, the PLL or aggregate risk is a type of risk integral; it is the summation of risk, as expressed by the product of the anticipated consequences and their respective likelihood for each hazard scenario, for all of the project components, over the entire project length, using the anticipated probability of exposure for each hazard scenario. The risks are then summed for all of the potential events that might occur, from each of the project components, throughout the entire project length. The PLL or aggregate risk results are then presented as the anticipated frequency of a fatality per year.

The differences between individual and aggregate (PLL) risk are summarized in the following table.

Table 6.5-1
Individual Risk (IR) versus Aggregate (PLL) Risk

Item	Individual Risk (IR)	Aggregate or PLL Risk
Exposure Location	Single Specific Location	Cumulative, Along the Length of the Entire Project
Probability of Exposure	100% 24 hours per day, 365 days per year	Actual Value, Normally Less Than 100% Based on Realistic Probability of Exposure to Specific Hazard
Significance Threshold	1 : 1,000,000 Some Jurisdictions Only No Established Threshold in U.S. or California	No Known Established Threshold

The aggregate risk results are summarized in the following table.

Table 6.5-2
Aggregate Risk Results, Pipe Segments

Release Description	Residential Exposure (lineal feet)	Commercial or Public Exposure (lineal feet)	PLL or Aggregate Risk Annual Likelihood of Fatality
14.7 mile, 24-inch Pipe Segment			
Indoor Explosion Full Bore Rupture	690	2,115	2.04E-09
Indoor Explosion 1-inch Release	0	0	0
Torch Fire Full Bore Rupture[5]	1,055	3,330	9.01E-07
Torch Fire 1-inch Release	0	0	0

[5] The exposure distances shown in these tables for torch fires are for 50% mortality (8,000 btu/hr-ft^2 isopleth). The exposure length is less for 100% mortality (12,000 btu/hr-ft^2 isopleth) and greater for 1% mortality (5,000 btu/hr-ft^2 isopleth).

Release Description	Residential Exposure (lineal feet)	Commercial or Public Exposure (lineal feet)	PLL or Aggregate Risk Annual Likelihood of Fatality
Flash Fire Full Bore Rupture	690	2,115	4.63E-08
Flash Fire 1-inch Release	0	0	0
Total	N/A	N/A	9.49E-07 1 : 1,050,000
Dual 0.3 Mile, 16-inch Pipe Segments			
Indoor Explosion Full Bore Rupture	0	0	0
Indoor Explosion 1-inch Release	0	0	0
Torch Fire Full Bore Rupture	0	2,310	4.46E-07
Torch Fire 1-inch Release	0	0	0
Flash Fire Full Bore Rupture	0	0	0
Flash Fire 1-inch Release	0	0	0
Total	N/A	N/A	4.46E-07 1 : 2,240,000

Table 6.5-3
Aggregate Risk Results, Well Site[6]

Release Description	Residential Exposure (number of Wells)	Commercial or Public Exposure (Number of Wells)	PLL or Aggregate Risk Annual Likelihood of Fatality
Indoor Explosion Full Bore Rupture	0	0	0
Indoor Explosion 1-inch Release	0	0	0
Torch Fire Full Bore Rupture	0	0	0
Torch Fire 1-inch Release	0	0	0
Flash Fire Full Bore Rupture	0	0	0
Flash Fire 1-inch Release	0	0	0
Total	N/A	N/A	0

Table 6.5-4
Aggregate Risk Results, Roadways

Release Description	Interstate 5 (lineal feet)	Old Highway 99 (lineal feet)	All Other Roadways (lineal feet)	PLL or Aggregate Risk Annual Likelihood of Fatality
Torch Fire Full Bore Rupture	1,110	992	30,176	2.15E-06
Torch Fire 1-inch Release	258	140	6,483	3.34E-07
Flash Fire Full Bore Rupture	246	128	20,242	1.57E-07

[6] The potentially significant impacts from the wells do not extend beyond the applicant proposed buffer fence. As a result, releases from the well heads do not pose potentially fatal impacts to the public.

Release Description	Interstate 5 (lineal feet)	Old Highway 99 (lineal feet)	All Other Roadways (lineal feet)	PLL or Aggregate Risk Annual Likelihood of Fatality
Flash Fire 1-inch Release	160	42	339	1.71E-08
Total	8.68E-07	3.10E-07	1.48E-06	2.65E-06 1 : 380,000

The total aggregate risk of annual fatality is 4.05E-06 (1 : 250,000).

6.6 Individual Risk

Individual risk (IR) is most commonly defined as the frequency that an individual may be expected to sustain a given level of harm from the realization of specific hazards, at a specific location, within a specified time interval. Individual risk is typically measured as the probability of a fatality per year. The risk level is typically determined for the maximally exposed individual; in other words, it assumes that a person is present continuously – 24 hours per day, 365 days per year. The likelihood is most often expressed numerically, using one of the values shown in Table 6.6-1 below.

Table 6.6-1
Individual Risk Numerical Values

Annual Likelihood of Fatality	Numerical Value	Scientific Notation	Shorthand
1 in 100	1.00×10^{-2}	1.00E-02	10^{-2}
1 in 1,000	1.00×10^{-3}	1.00E-03	10^{-3}
1 in 10,000	1.00×10^{-4}	1.00E-04	10^{-4}
1 in 100,000	1.00×10^{-5}	1.00E-05	10^{-5}
1 in 1,000,000	1.00×10^{-6}	1.00E-06	10^{-6}
1 in 10,000,000	1.00×10^{-7}	1.00E-07	10^{-7}
1 in 100,000,000	1.00×10^{-8}	1.00E-08	10^{-8}
1 in 1,000,000,000	1.00×10^{-9}	1.00E-09	10^{-9}

The individual risks posed by the various project components are shown in the following figures. These figures present risk transects which show the annual risk of fatality resulting from a pipeline release as a function of the downwind distance from the pipeline, measured perpendicular to the pipeline. (The upwind distances would be much less for downwind releases and greater for upwind releases.) The results are shown for the pipe segments both before and after mitigation. It should be noted that these data are based on the continuous presence of a person at a specific location (24 hours per day, 365 days per year). It should also be noted that the highest risks are posed directly over the pipelines. These maximum annual individual risks of fatality are summarized in the paragraphs which follow.

6.6.1 14.7 Mile, 24-inch Line Segment

The maximum annual probability of fatality for this component is 4.39E-07 (1 : 2,280,000). The results are presented graphically in the following figure.

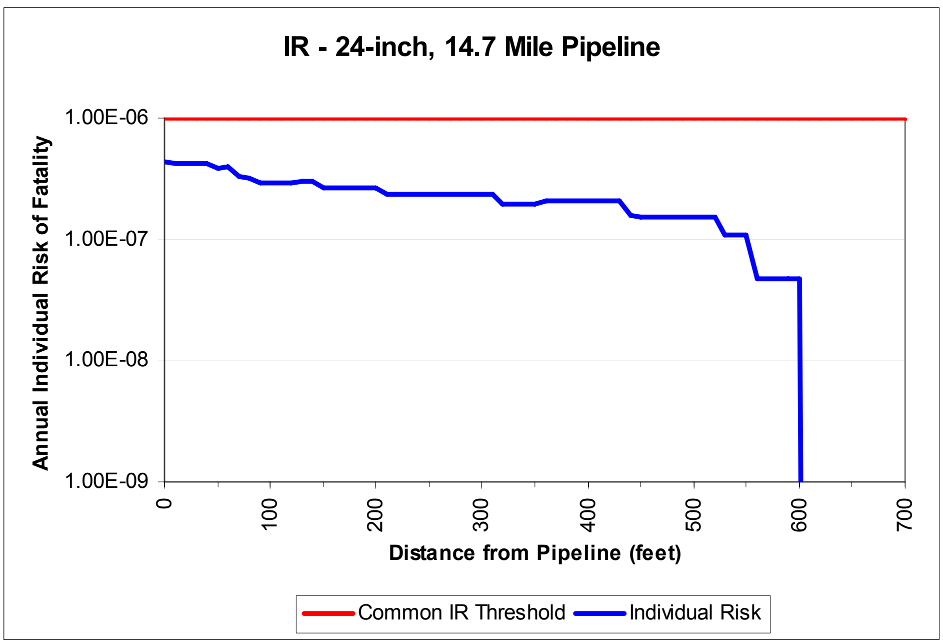


Figure 6.6.1-1 Individual Risk Transect, 14.7 mile, 24-inch Line Segment

The individual risk of annual fatality posed by this component is less than the common individual risk threshold one in one million.

6.6.2 Dual 0.3 Mile, 16-inch Line Segments

The maximum annual probability of fatality for these components is 5.38E-07 (1 : 1,860,000). The results are presented graphically in the following figure.

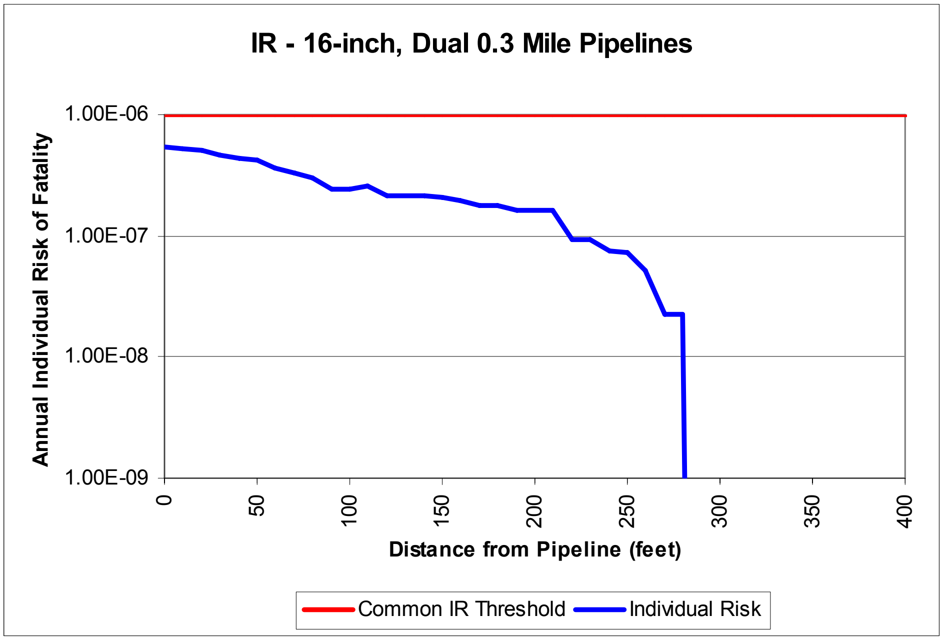


Figure 6.6.2-1 Individual Risk Transect, Dual 0.3 Mile, 16-inch Line Segments

The individual risk of annual fatality posed by this component is less than the common individual risk threshold one in one million.

Although the potentially significant impact distances for the 16-inch line segments are generally less than those for the 24-inch line segment, the individual risk posed by the dual parallel 16-inch lines is somewhat higher than for the 24-inch line segment. This is because for a given length of exposure, the two parallel 16-inch line segments are twice as likely to experience a release. In other words, for the 16-inch line segments, the consequences of a release are lower than for the 24-inch line; but a release from the two parallel lines is two times more likely to occur within a given length.

6.6.3 Remote Well Pad

The maximum annual probability of fatality for this component is 2.99E-05 (1 : 33,500). The results are presented graphically in the following figure.

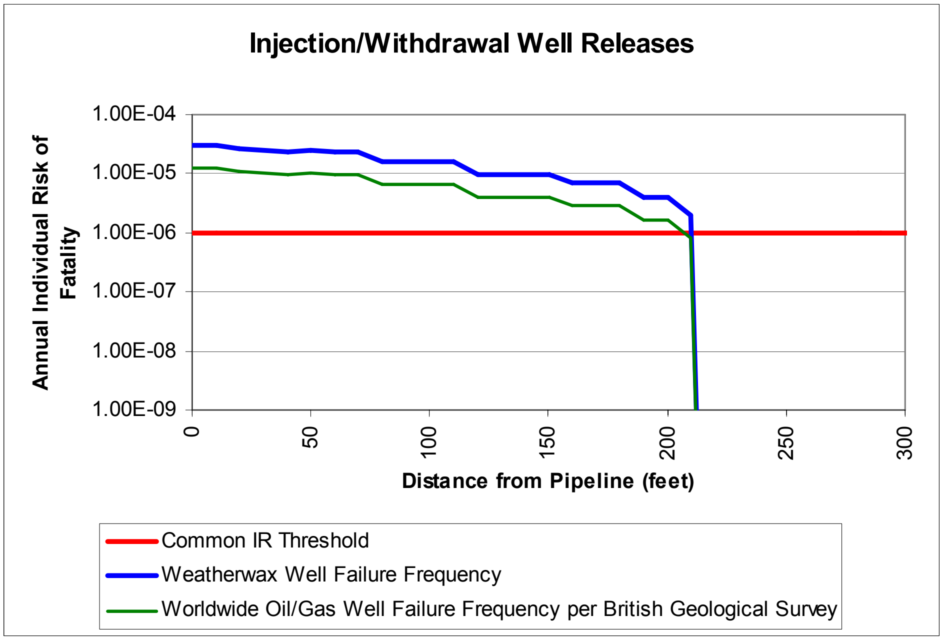


Figure 6.6.3-1 Individual Risk Transect, Remote Well Pad

The annual individual risk of fatality at the well site exceeds the generally accepted risk threshold of one in one million for a distance of 210 feet from the wells. However, the applicant has proposed the installation of a buffer fence at a minimum distance of 220 feet from each well head. This will keep the public at least 220 feet from the wells. As a result, the individual risk of fatality to the public is less than significant.

6.7 Societal Risk

Societal risk is the probability that a specified number of people would be affected by a given event. The generally accepted number of casualties is relatively high for lower probability events and much lower for more probable events, as discussed later in Section 7.1 of this document.

6.7.1 Exposures to Occupants of Residences and Commercial Buildings

The following societal risk scenarios have been considered:

- Flash Fire or Indoor Explosion, 1-inch Diameter Pipeline Release – These impacts could be significant within about 34-feet of the 14.7 mile, 24-inch line and 27 feet of the dual 0.3 mile, 16-inch line segments. (Reference Tables 6.3.3-1 through 6.6.3-4.)

- Flash Fire or Indoor Explosion, Full Bore Pipeline Release – These impacts are localized and could be significant within about 296-feet of the 14.7 mile, 24-inch line and 92 feet of the dual 0.3 mile, 16-inch line segments. (Reference Tables 6.3.3-1 through 6.6.3-4.) The analyses assumed that one commercial building could be impacted, with an exposure of up to ten persons outdoors; up to fifty could be exposed inside a commercial/industrial building.

- Torch Fire, 1-inch Diameter Pipeline Release – These impacts could be significant within about 74-feet of the 14.7 mile, 24-inch line and 92 feet of the dual 0.3 mile, 16-inch line segments. (Reference Tables 6.3.2-1 through 6.6.2-4.) The analyses assumed that one commercial building could be impacted, with an exposure of up to ten persons outdoors.

- Torch Fire, Full Bore Release – These impacts could be significant within about 676-feet of the 14.7 mile, 24-inch line and 326 feet of the dual 0.3 mile, 16-inch line segments. (Reference Tables 6.3.2-1 through 6.6.2-4.) The analysis assumed that up to two residences and one commercial structure could be affected by a release. A population of up to four per residence and up to ten individuals per commercial building was used (outdoors).

- Explosion, 1-inch Diameter Pipeline Release - The overpressure level is less than 1.00 psig. As a result, explosion impacts are not expected to result in public fatalities.

- Explosion, Full Bore Pipeline Release - The overpressure level is less than 1.00 psig. As a result, explosion impacts are not expected to result in public fatalities.

- Torch Fire, Full Bore Well Casing Release (Vertical) – The impacts resulting from flash fires and explosions are not anticipated to extend beyond the buffer fence proposed by the Applicant. (Reference Tables 6.3.2-5 and 6.3.3-5.)

The lengths of the pipeline segments posing these exposures to the public at residential and commercial buildings are summarized in Table 6.5-2. The number of wells posing these exposures to the public is summarized in Table 6.5-3.

6.7.2 Exposures to Vehicle Occupants

The societal risk analysis to vehicle occupants used the same methodology as outlined earlier for the aggregate risk. However, an average occupancy of two occupants per vehicle was used. The lengths of the pipeline segments posing exposures to the motoring public are summarized in Table 6.5-4.

6.7.3 Societal Risk Results

The societal risk results are summarized in Figure 6.7.3-1 below. Situations which do not pose any potential risk to the public have not been shown. As indicated, the societal risks posed by the proposed project are less than the often used significance threshold, adopted in the Netherlands. Criteria other than that used in the Netherlands, are shown for reference. It is worth noting that the California Department of Education (CDE) and the County of Santa Barbara (SBCO) have an upper and lower bound for acceptable and unacceptable societal risks. Between these two bounds is a "grey area", similar to that discussed for individual risks in Section 7.1.2 of this document. Other international jurisdictions have similar "grey areas" or ALARP (as low as reasonably practical) principals for moderate risk levels. The societal risks posed by this project fall below the negligible thresholds set by these agencies, except for one scenario which falls slightly above the negligible threshold.

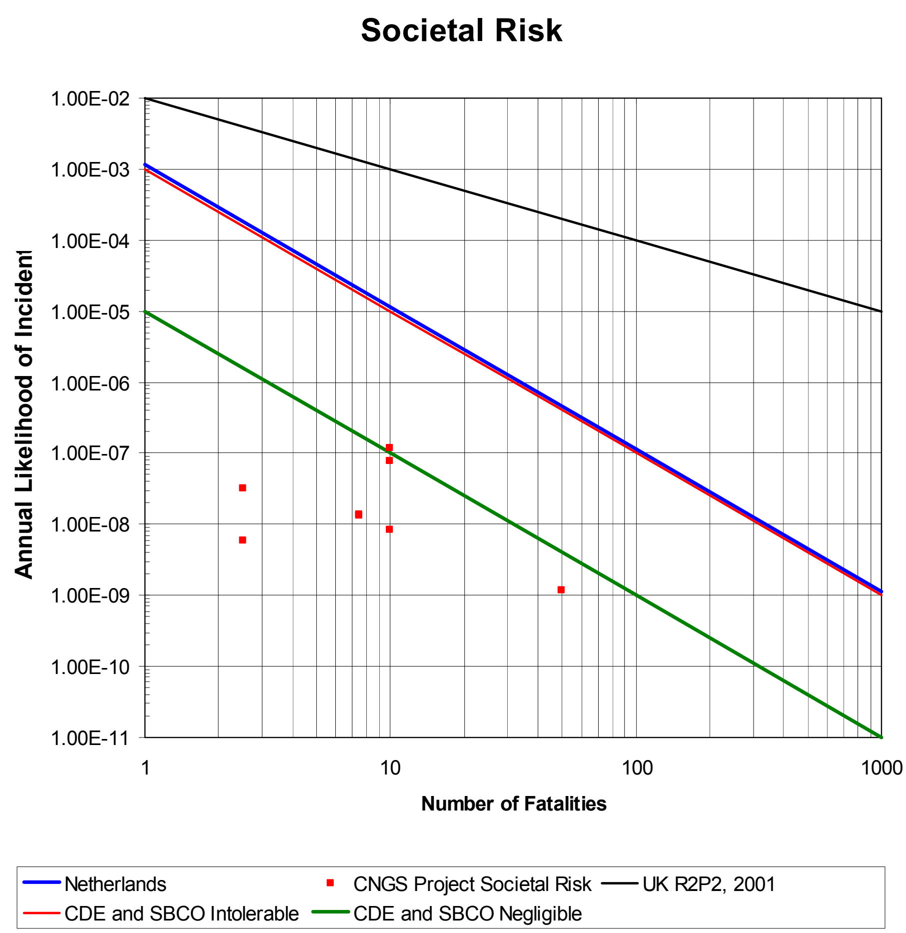


Figure 6.7.3-1 Societal Risk Results

7.0 ENVIRONMENTAL IMPACTS AND MITIGATION

7.1 Definition and Use of Significance Criteria

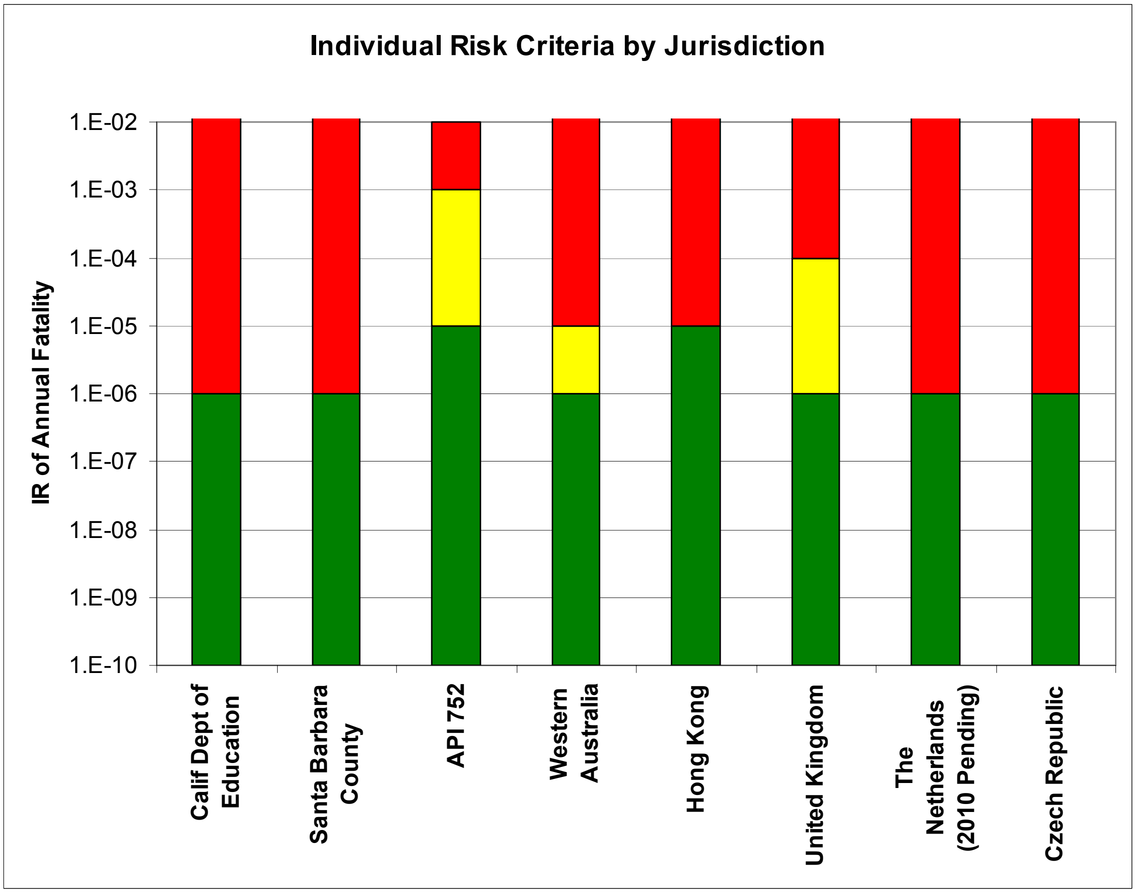
7.1.1 Aggregate Risk

As discussed previously, aggregate risk, or probable loss of life (PLL), is one risk measure used to evaluate projects. Aggregate risk is the total anticipated frequency of a particular consequence, normally fatalities, that could be anticipated over a given time period, for all project components (e.g., the entire pipeline system, including compressor facilities and the well site). Aggregate risk is a type of risk integral; it is the summation of risk, as expressed by the product of the anticipated consequences and their respective likelihood. The integral is summed over all of the potential events that might occur for all of the project components, over the entire project length. There are no known codified bright line thresholds for acceptable levels of PLL or aggregate risk.

7.1.2 Individual Risk

As discussed previously, individual risk (IR) is most commonly defined as the frequency that an individual may be expected to sustain a given level of harm from the realization of specific hazards, at a specific location, within a specified time interval. Individual risk is typically measured as the probability of a fatality per year. The risk level is typically determined for the maximally exposed individual; in other words, it assumes that a person is present continuously – 24 hours per day, 365 days per year.

The California Department of Education defines individual risk as the probability of fatality for an individual exposed to the physical impact of a hazard, at a specific location, within a specified period of time. (CDE 2007) The individual risk threshold most commonly used, where one has been established, is an annual likelihood of fatality of one in one million (1:1,000,000, 1×10^{-6}, or 1.0E-06 fatalities per year); this individual risk threshold has been used in this document. However, the United States federal and California state governments have not adopted individual risk thresholds; the acceptable level of risk is left to local decision makers and project proponents. The figure below presents the individual risk thresholds for a number of jurisdictions, where such thresholds have been adopted.



Sources: (CDE 2007, SBCO 2008, API 1995, Marszal 2001

Figure 7.1.2-1 Individual Risk Thresholds by Jurisdiction

The upper end of the green areas represent the de minimus[7] risk values for each jurisdiction; IR risk levels within the green range are considered broadly acceptable. Risks within this green region are considered so low that no further consideration is warranted. In addition, risks within the green band are generally considered so low that it is unlikely that any risk reduction would be cost effective, since extraordinary measures would normally be required to further reduce the risk. As a result, a benefit – cost analysis of risk reduction is typically not undertaken.

[7] Latin term for "of minimum importance" or "trifling." Essentially it refers to something or a difference that is so little, small, minuscule, or tiny that the law does not refer to it and will not consider it. In a million dollar deal, a $10 mistake is de minimus.

The lower end of the red areas represent the de manifestus[8] risk values; IR risk levels within the red range are considered unacceptable and the risks are not normally justified on any grounds.

Some jurisdictions have adopted a "grey area', where the risk levels may be negotiated or otherwise considered. The United Kingdom developed the ALARP (as low as reasonably practicable) approach. This approach is depicted by the yellow areas in Figure 3.1-1. Generally, risks within the yellow area may be tolerable only if risk reduction is impractical or if its cost is grossly disproportionate to the risk improvement gained. The underlying concept is to maximize the expected utility of an investment, but not expose anyone to an excessive increase in risk.

The United States government has opposed setting tolerable risk guidelines. The 1997 final report of the Presidential/Congressional Commission on Risk Assessment and Risk Management (Commission), entitled Framework for Environmental Health Risk Management, included the following finding, "There is much controversy about bright lines, "cut points," or decision criteria used in setting and evaluating compliance with standards, tolerances, cleanup levels, or other regulatory actions. Risk managers sometimes rely on clearly demarcated bright lines, defining boundaries between unacceptable and negligible upper limits on cancer risk, to guide their decisions. Congress has occasionally sought to include specified bright lines in legislation. A strict "bright line" approach to decision making is vulnerable to misapplications since it cannot explicitly reflect uncertainty about risks, population within, variation in susceptibility, community preferences and values, or economic considerations – all of which are legitimate components of any credible risk management process." The report states further, "Furthermore, use of risk estimates with bright lines, such as one-in-a-million, and single point estimates in general, provide a misleading implication of knowledge and certainty. As a result, reliance on command-and-control regulatory programs and use of strict bright lines in risk estimates to distinguish between safe and unsafe are inconsistent with the Commission's Risk Management Framework and with the inclusion of cost, stakeholder values, and other considerations in decision-making." (Commission 1997)

The United States is not alone in its opposition to establishing fixed risk thresholds. The vast majority of nations do not have government established risk tolerance criteria. In these cases, risk tolerance is left to individual owners and other decision makers.

Despite the fact that the United States does not have a bright line individual risk threshold, the country has an exemplary safety record. Many believe that this is due to two factors. First, the free market allows the application of capital where it will produce the most risk reduction benefits. And

[8] ALARP (as low as reasonably practical) principle states that there is a level of risk that is intolerable, sometimes called the de manifestus risk level. Above this level risks cannot be justified.

secondly, the tort system provides a mechanism to determine third party liability costs in the event of an injury or fatality. These factors generally result in sound risk reduction decisions which are normally based on a cost-benefit analysis. (Marszal 2001)

7.1.3 Societal Risk

Societal risk is the probability that a specified number of people will be affected by a given event. The accepted number of casualties is relatively high for lower probability events and much lower for more probable events. However, the acceptable values for societal risk vary greatly by different agencies and jurisdictions. Unfortunately, there are no prescribed societal risk guidelines for the United States, nor the State of California. The United Kingdom, considers those events which result in 100 fatalities, with an annual probability of 1.0 x 10-5 (1:100,000) or less. The Committee for the Prevention of Disasters, uses the criteria as shown in Figure 7.1.3-1 below. This data is the same as the criteria used in the Netherlands. These criteria have been used to evaluate societal risk in this document.

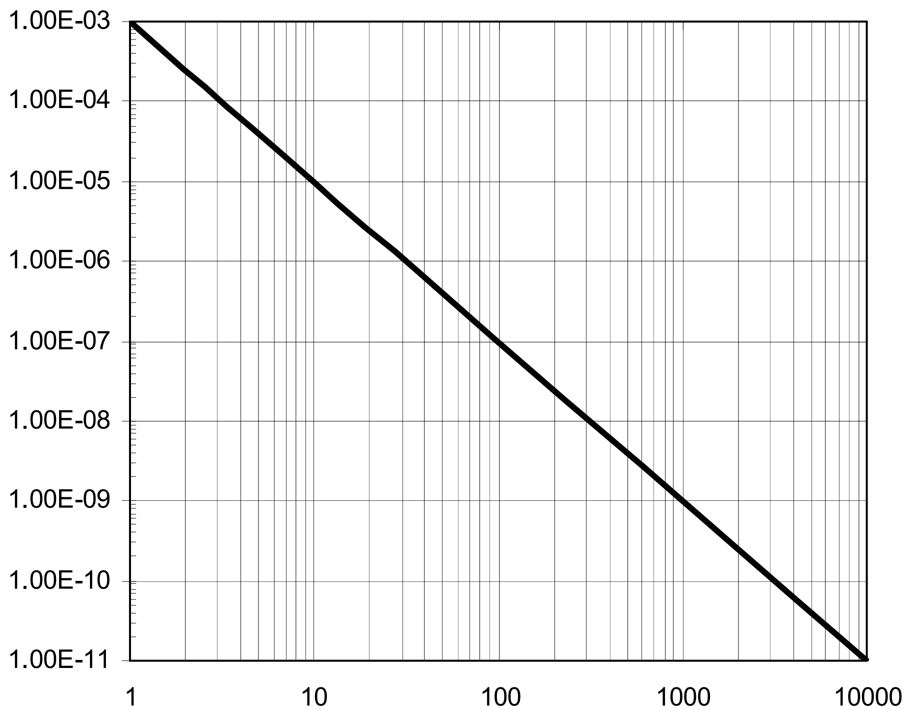


Figure 7.1.3-1 Societal Risk Criteria[9]

[9] Source: Committee for the Prevention of Disasters, The Hague

7.2 Applicant Proposed Measures

The Applicant has not proposed any mitigation measures to enhance pipeline safety above the minimum regulatory requirements outlined in Section 2.0 of this document.

The Applicant has proposed the installation of a buffer fence at the remote well pad. This buffer fence will keep the public beyond the potentially significant individual risk isopleths.

7.3 System Safety Impact Discussion

7.3.1 Impact SS-1

Environmental Impacts and Mitigation Measures

b. Would the project 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?

Less Than Significant

An unintentional release from the proposed project could result in serious injuries and/or deaths. These impacts are less than significant (Class III). The results are summarized in the following table.

Table 7.3.1-1
Aggregate and Individual Risk Result Summary

Risk Analysis	Annual Risk of Fatality	Annual Probability of Occurrence	Significance Threshold
Qualitative Aggregate Risk	6.11E-05	1 : 15,000	No Known Codified Risk Threshold
Quantitative Aggregate Risk	4.05E-06	1 : 250,000	No Known Codified Risk Threshold
Individual Risk 14.7 mile, 24-inch Line	4.39E-07	1 : 2,280,000	1 : 1,000,000 Less Than Significant
Individual Risk Dual 0.3 Mile, 16-inch Lines	5.38E-07	1 : 1,860,000	1 : 1,000,000 Less Than Significant

Risk Analysis	Annual Risk of Fatality	Annual Probability of Occurrence	Significance Threshold
Individual Risk Remote Well Site	2.99E-05	1 : 33,500	1 : 1,000,000 Less Than Significant[10]
Societal Risk	See Figure 6.7.3-1	See Figure 6.7.3-1	See Figure 6.7.3-1 Less Than Significant

As noted above, all of the risks fall below significance thresholds except for the well site individual risk. As depicted in Figure 6.6.4-1, the risks posed at the well site extend approximately 210-feet from each well head. The wells are located about 220 feet from the buffer fence. As a result, the significant impacts do not extend beyond the fence boundary and the public would not be exposed to potentially significant risk levels.

These analyses are not absolutely precise. However, they do provide a reasonable estimate of the public risks posed. It should also be noted that should traffic volumes and/or population density increase over the project life, the risks posed will increase beyond the levels stated herein.

[10] The applicant has proposed a buffer fence at a minimum of 220 feet from the well heads. This will keep the public beyond the potentially fatal impacts. At this distance from the well heads, the individual risk of fatality is below the significance threshold.

8.0 ATMOSPHERIC CONDITION SENSITIVITY ANALYSIS

The release modeling presented herein assumed a single combination of wind and atmospheric stability for flash fires and vapor cloud explosions and a single wind speed for evaluating torch fire impacts. The intent was to select the parameters which depict a conservative average release. While some releases may result in impacts at greater distances, the probability of these events would be relatively small. In most instances, the distances to impacts would be less than those incorporated into the analysis. The following paragraphs present the modeling results for a variety of atmospheric conditions and compare them to those used in the analysis.

8.1 Flash Fires

The downwind distances to the lower flammability limit (LFL), which would be the maximum downwind distances to the flash fire boundaries are shown in Table 8.1-1 and 8.1-2 below. It should be noted that these are the maximum downwind distances only; they do not take into account the fact that the vapor cloud may be located overhead. For example, for the releases at 45° above grade, the vast majority of the vapor cloud is located well above grade. As a result, one would not be exposed to flash fire impacts at this location; the flash fire would be located overhead. The analysis conservatively used the horizontal projection of the overhead vapor cloud in establishing flash impact distances. However, for the pipe segments associated with this project, the risk posed by flash fires is only about one percent (1%) of the total. As a result, although this approach is conservative, it does not appreciably affect the results.

Table 8.1-1
14.7 Mile, 24-inch Line Segment, Flash Fire Impact Distances (feet), Rupture, Release 45° Above Horizon, Downwind

Atmospheric Stability[11]	Wind Speed					
	0 mps 0 mph	2 mps 4.5 mph	4 mps 8.9 mph	6 mps 13.4 mph	8 mps 17.9 mph	10 mps 22.4 mph
A	489	146	105	85	73	66
B	489	191	142	118	104	94
C	489	237	184	158	141	129
D	489	**296**	245	217	199	186
E	489	331	286	N/A	N/A	N/A
F	489	366	N/A	N/A	N/A	N/A

Notes:
1. The above horizontal downwind distances are to the lower flammability limit, in feet.
2. mps = meters per second.
3. mph = miles per hour.
4. Shaded cell reflects impact distance used in the analysis.
5. N/A indicates wind and stability combinations that do not normally occur.

[11] 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 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.

Table 8.1-2
14.7 mile, 24-inch Line Segment, Flash Fire Impact Distances (feet), 1-inch Diameter, Release 45° Above Horizon, Downwind

Atmospheric Stability[4]	Wind Speed					
	0 mps 0 mph	2 mps 4.5 mph	4 mps 8.9 mph	6 mps 13.4 mph	8 mps 17.9 mph	10 mps 22.4 mph
A	51	18	13	10	8	7
B	51	23	17	14	12	11
C	51	28	22	18	16	15
D	51	**34**	28	25	22	21
E	51	38	33	N/A	N/A	N/A
F	51	42	N/A	N/A	N/A	N/A

Notes:
1. The above horizontal downwind distances are to the lower flammability limit, in feet.
2. mps = meters per second.
3. mph = miles per hour.
4. Shaded cell reflects impact distance used in the analysis.
5. N/A indicates wind and stability combinations that do not normally occur.

8.2 Torch Fires

In the event that an individual were exposed to radiant heat flux as a result of a continuous fire (e.g., torch fire), the natural reaction would be to increase the distance from the exposure to prevent harmful impacts. In other words, an able bodied individual would be expected to move away from and/or find protection to avoid injury. The analyses presented herein assumed a thirty (30) second exposure time in evaluating torch fire impacts; it assumed that those exposed to torch fire impacts would be exposed for thirty (30) seconds and that they would not seek shelter or move further from the hazard. Fatalities could occur from a shorter exposure; but the required radiant heat flux levels would be much higher and the impact distances would be shorter. The method used herein is consistent with that used by the California Department of Education and others. (CDE 2007)

The analyses presented herein conservatively assumed that ignition occurred immediately after the initiation of a release. This results in the longest torch fire impact distances for pipeline ruptures. As shown in Figure 8.2-1 below, the mass flow rate from a given pipeline release decays rapidly after a pipeline rupture, as the pipeline depressurizes. As the mass flow rate decays, the resulting torch flame length becomes shorter and smaller, resulting in shorter distances to a given radiant heat flux level. As a result, when the ignition is delayed, the distances to significant levels of radiant heat flux are reduced. The torch fire impact distances for 1-inch releases are not normally affected by the time between release and ignition, since the mass flow rate is essentially constant, due to the relatively large volume of gas stored within the pipeline.

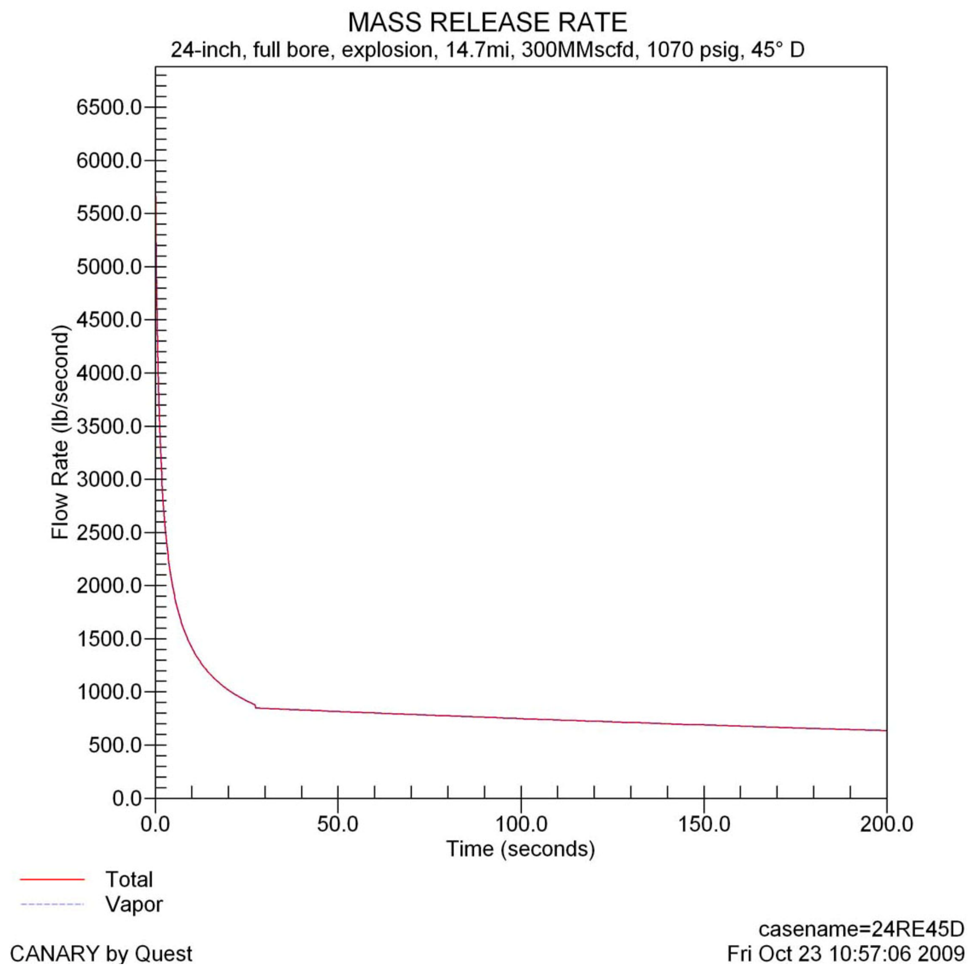


Figure 8.2-1 14.7 mile, 24-inch Line Segment, Mass Release Flow Rate

The downwind torch fire impact distances for pipeline ruptures and 1-inch diameter release are presented in the tables which follow.

Table 8.2-1
14.7 mile, 24-inch Line Segment, Torch Fire Impact Distances (feet), Rupture, Release 45° Above Horizon, Downwind

Radiant Heat Flux Endpoint 30 Second Exposure	Wind Speed								
	0 mps 0.0 mph	2 mps 4.5 mph	4 mps 8.9 mph	6 mps 13.4 mph	8 mps 17.9 mph	10 mps 22.4 mph	12 mps 26.9 mph	14 mps 31.4 mph	16 mps 35.8 mph
100% Mortality 12,000 btu/hr-ft^2	202	255	312	339	349	356	362	368	373
50% Mortality 8,000 btu/hr-ft^2	350	380	415	423	429	434	438	442	445
1% Mortality 5,000 btu/hr-ft^2	497	512	516	518	520	523	526	528	530

Notes:
1. The above horizontal distances are in feet.
2. mps = meters per second.
3. mph = miles per hour.
4. The analyses presented herein used a wind speed of 20 mph.

Table 8.2-2
14.7 mile, 24-inch Line Segment, Torch Fire Impact Distances (feet), 1-inch Diameter, Release 45° Above Horizon, Downwind

Radiant Heat Flux Endpoint 30 Second Exposure	Wind Speed								
	0 mps 0.0 mph	2 mps 4.5 mph	4 mps 8.9 mph	6 mps 13.4 mph	8 mps 17.9 mph	10 mps 22.4 mph	12 mps 26.9 mph	14 mps 31.4 mph	16 mps 35.8 mph
100% Mortality 12,000 btu/hr-ft^2	29	34	39	41	41	41	41	42	42
50% Mortality 8,000 btu/hr-ft^2	45	48	50	50	50	50	50	51	51
1% Mortality 5,000 btu/hr-ft^2	61	61	61	61	61	61	61	61	61

Notes:
1. The above horizontal distances are to the lower flammability limit, in feet.
2. mps = meters per second.
3. mph = miles per hour.
4. The analyses presented herein used a wind speed of 20 mph.

9.0 MODELING ASSUMPTIONS

A number of assumptions have been made in order to conduct the risk analyses presented herein. For the most part, these assumptions are conservative and tend to result in an overstatement of risk. The major assumptions and methodology which affect the results presented herein are summarized below:

- Wind Direction – For all releases, the wind was assumed to blow perpendicular to the pipeline. This results in the greatest distance to the various impact levels for downwind situations.

- Torch Fire Immediate Ignition – The torch fire analyses assumed that the ignition occurred immediately after the initiation of a release; in other words, all releases where an ignition source was present that resulted in a torch fire were assumed to result from immediate ignition. This approach results in the longest torch fire impact distances for pipeline ruptures. As shown in Figure 6.0-1 previously, the mass flow rate from a given pipeline release decays rapidly after a pipeline rupture, as the pipeline depressurizes. As the mass flow rate decays, the resulting torch fire flame length becomes shorter and smaller, resulting in shorter distances to a given radiant heat flux level. As a result, when the ignition is delayed, the distances to significant levels of radiant heat flux are reduced. The average mass flow rate for the first sixty seconds of the release was used to determine the mass flow rate for all torch fires. The torch fire impact distances for 1-inch diameter releases are not affected by the time between release and ignition, since the mass flow rate is essentially constant, due to the relatively large volume of gas stored within the pipeline.

- Flash Fires – For flash fire impacts which were located overhead, the horizontal extent of the hazard was projected to grade level. This results in some overstatement of the impact since an overhead flash fire would not normally impact those on the ground. For example, for the releases at 45° above grade, the vast majority of the vapor cloud is located well above grade. The analyses conservatively used the horizontal projection of the overhead vapor cloud in establishing flash fire impact distances. However, for these pipe segments, the risk posed by flash fires is only a small portion of the total. As a result, although this approach is conservative, it does not appreciably affect the results.

- Quantification of Results – Most of the impact isopleths from a release are in the general shape of an ellipse. For example, the figure below presents the torch fire isopleths for various mortality levels for a vertical release. These isopleths are elliptical. However, in performing the analyses, the areas of mortality were assumed to be rectangular, as shown in the figure. This results in some conservatism, since the area outside the ellipse but inside the rectangle is subject to less risk than assumed in the analyses.

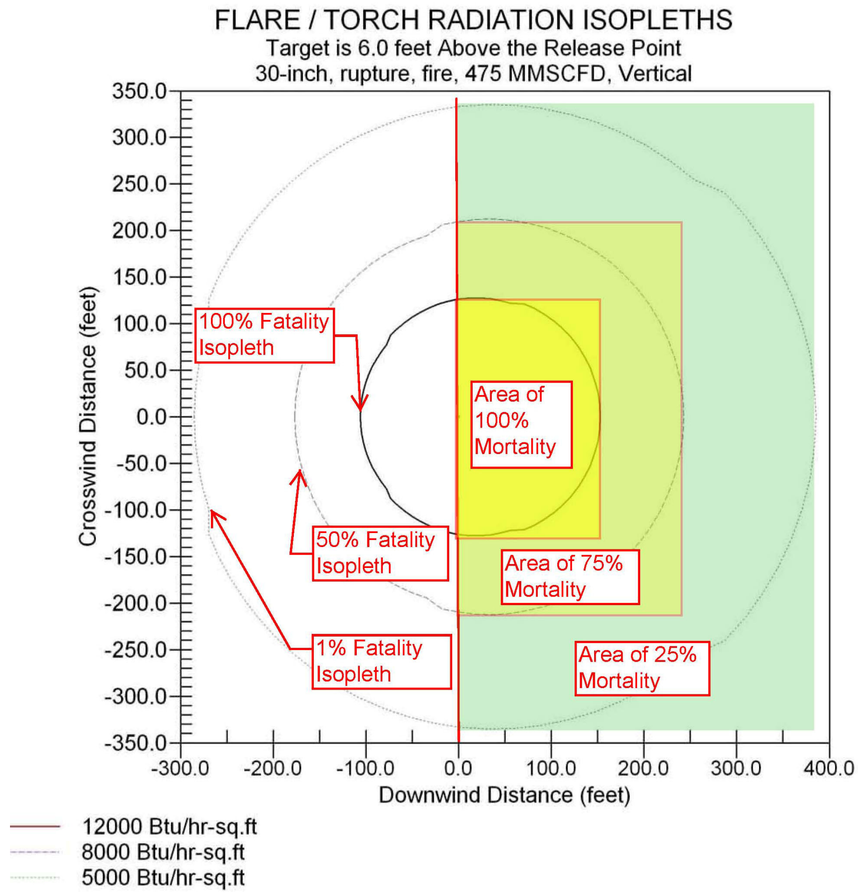


Figure 9.0-1 Typical Pipeline Rupture Mass Release Flow Rate

- Torch Fire Exposure - A thirty (30) second exposure was assumed for all individuals exposed to radiant heat flux levels resulting from torch fires. This conservatively assumes that able bodied persons would not take efforts to find shelter or distance themselves from the hazard for the entire duration of the exposure; if they did, the risk would be reduced.

10.0 REFERENCES

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