APPENDIX B-1

System Safety and Risk of Upset

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APPENDIX B 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.

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 (USDOT) provides oversight for the nation's natural gas pipeline transportation system. Its responsibilities are promulgated under Title 49, United States Code (USC) Chapter 601. 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 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 15 subparts, which are summarized below:

- Subpart A, General – This subpart provides definitions, a description of the class locations used within the regulations, documents incorporated into the regulation by reference, conversion of service requirements, and other items of a general nature.

- Subpart B, Materials – This subpart provides the requirements for the selection and qualification of pipe and other pipeline components. Generally, it covers the manufacture, marking, and transportation of steel, plastic, and copper pipe used in gas pipelines and distribution systems.

- Subpart C, Pipe Design – This subpart covers the design (primarily minimum wall thickness determination) for steel, plastic, and copper pipe.

- Subpart D, Design of Pipeline Components – This subpart provides the minimum requirements for the design and qualification of various components (e.g. valves, flanges, fittings, passage of internal inspection devices, taps, fabricated components, branch connections, extruded outlets, supports and anchors, compressor stations, vaults, overpressure protection, pressure regulators and relief devices, instrumentation and controls, etc.

- Subpart E, Welding of Steel Pipelines – This subpart provides the minimum requirements for welding procedures, welder qualification, inspection and repair/replacement of welds in steel pipeline systems.

- Subpart F, Joining of Materials Other Than By Welding – This subpart covers the requirements for joining, personnel and procedure qualification, and inspection of cast iron, ductile iron, copper, and plastic pipe joints.

- Subpart G, General Construction Requirements for Transmission Lines and Mains – This subpart provides the minimum construction requirements, including, but not limited to: inspection of materials, pipe repairs, bends and elbows, protection from hazards, installation in the ditch, installation in casings, underground clearances from other substructures, and minimum depth of cover.

- Subpart H, Customer Meters, Service Regulators and Service Lines – This subpart prescribes the minimum requirements for these components.

- Subpart I, Requirements for Corrosion Control – This subpart provides the minimum requirements for cathodic protection systems, required inspections and monitoring, remedial measures, and records maintenance.

- Subpart J, Testing Requirements – This subpart prescribes the minimum leak and strength test requirements.

- Subpart K, Uprating – This subpart provides the minimum requirements for increasing the maximum allowable operating pressure.

- Subpart L, Operations – This subpart prescribes the minimum requirements for pipeline operation, including: procedure manuals, change in class locations, damage prevention programs, emergency plans, public awareness programs, failure investigations, maximum allowable operating pressures, odorization, tapping, and purging.

- Subpart M, Maintenance – This subpart prescribes the minimum requirements for pipeline maintenance, including: line patrols, leakage surveys, line markers, record keeping, repair procedures and testing, compressor station pressure relief device inspection and testing, compressor station storage of combustible materials, compressor station gas detection, inspection and testing of pressure limiting and regulating devices, valve maintenance, prevention of ignition, etc.

- Subpart N, Qualification of Pipeline Personnel – This subpart prescribes the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility.

- Subpart O, Pipeline Integrity Management – This subpart was promulgated on December 15, 2003. It requires operators to implement pipeline integrity management programs on the gas pipeline systems.

In general, the requirements of the Federal regulations become more stringent as the human population density increases. To this end, 49 CFR 192 defines area classifications, based on population density in the vicinity of a pipeline and specifies more rigorous safety requirements for more heavily populated areas. The class location is 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 be constructed within Class 1, 2, and 3 locations (SNGS 2008). 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. As noted later in this document, the Applicant is conservatively designing the project as though it were located within a class 4 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.

~~As noted earlier, t~~The proposed 16-inch pipeline facilities are located entirely within a Class ~~2 and~~ 3 area~~s~~. As a result, using the first HCA definition, the ~~portions of the~~ line ~~within Class 3 areas~~ would be within an HCA. The impact radii are 349-feet and~~,~~ 489-feet ~~and 261-feet~~ for the 16-inch line with a 1,000 psig MAOP and~~, 16-inch line with a~~ 1,965 psig MAOP ~~and 12-inch line with a 1,000 psig~~

~~MAOP~~ respectively. This is less than the 660-foot impact radius which might add additional portions within an HCA. As a result, certain portions of the Project will be required to be included in the Applicant's Pipeline Integrity Management Plan. Should the population density increase, additional portions of the pipeline may become located within an HCA; should this occur, the Applicant would be required by Federal regulation to include the affected pipe segments in their Pipeline Integrity Management 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.

~~Natural gas storage and the retrieval and 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~~.

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 and 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

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~~ (Quest 2003)~~. ~~Other data sources provide a 10% mortality at 5,500 Btu/hour-square foot and 15% mortality at 5,800 Btu/hour-square foot (CDE 2007).~~

- 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
2.30 psig	0% Mortality to Persons Inside Buildings or Persons Outdoors (CDE 2007)
3.10 psig	10% Mortality to Persons Inside Buildings (CDE 2007)
3.20 psig	<10% Mortality to Persons Outdoors (CDE 2007)
14.5 psig	1% Mortality to Those Outdoors (LEES)

Sources: LEES, CDE 2007, Quest 2003

For outdoor explosions, 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	1.0

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 ~~Natural~~ Gas Transmission and Gathering Lines (U.S. Department of Transportation [USDOT]) – 1970 through 2008~~7~~.
- 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. ~~Natural~~ 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. ~~Natural~~ Gas Transmission Lines - July 1984 through 2008~~7~~

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:

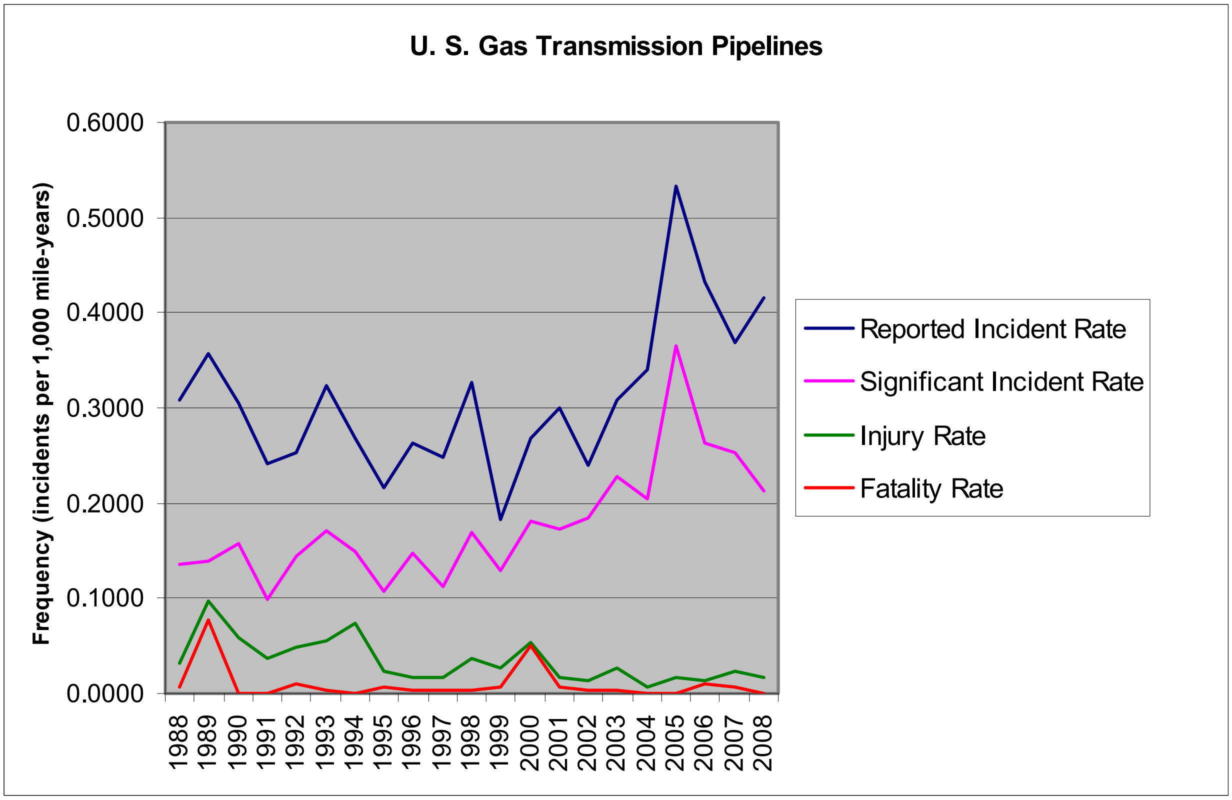
- Fatality or injury requiring in-patient hospitalization,
- $50,000 or more in total costs (measured in 1984 dollars),
- Highly volatile liquid releases of 5 barrels or more or other liquid releases of 50 barrels or more, or
- Liquid releases resulting in an unintentional fire or explosion.

These data are summarized below for the 22-year period from January 1, 1986 through December 31, 2008~~7.~~ 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~~six~~ year period, since the change in the USDOT reporting form (January 2002 through December 2008~~7~~), there were a total of 795~~761~~ 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~~was nearly $820,000~~ per incident. The average annual transmission pipeline mileage was 301,625~~301,373~~ miles for this seven~~six~~ year period. Using these data, the frequency of reportable incidents during this most recent seven~~five~~ year period was up slightly when compared to the 14~~22~~-year period presented above - 0.38~~42~~ incidents per 1,000 mile-years for 2002 through 2008~~7~~ versus 0.28~~27~~ incidents per 1,000 mile-years for 1986 through 2001~~2~~. 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~~019~~ and 0.0033~~004~~ 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. ~~Natural~~ 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~~summary statistics~~ 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~~report~~.

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~~7~~ 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:

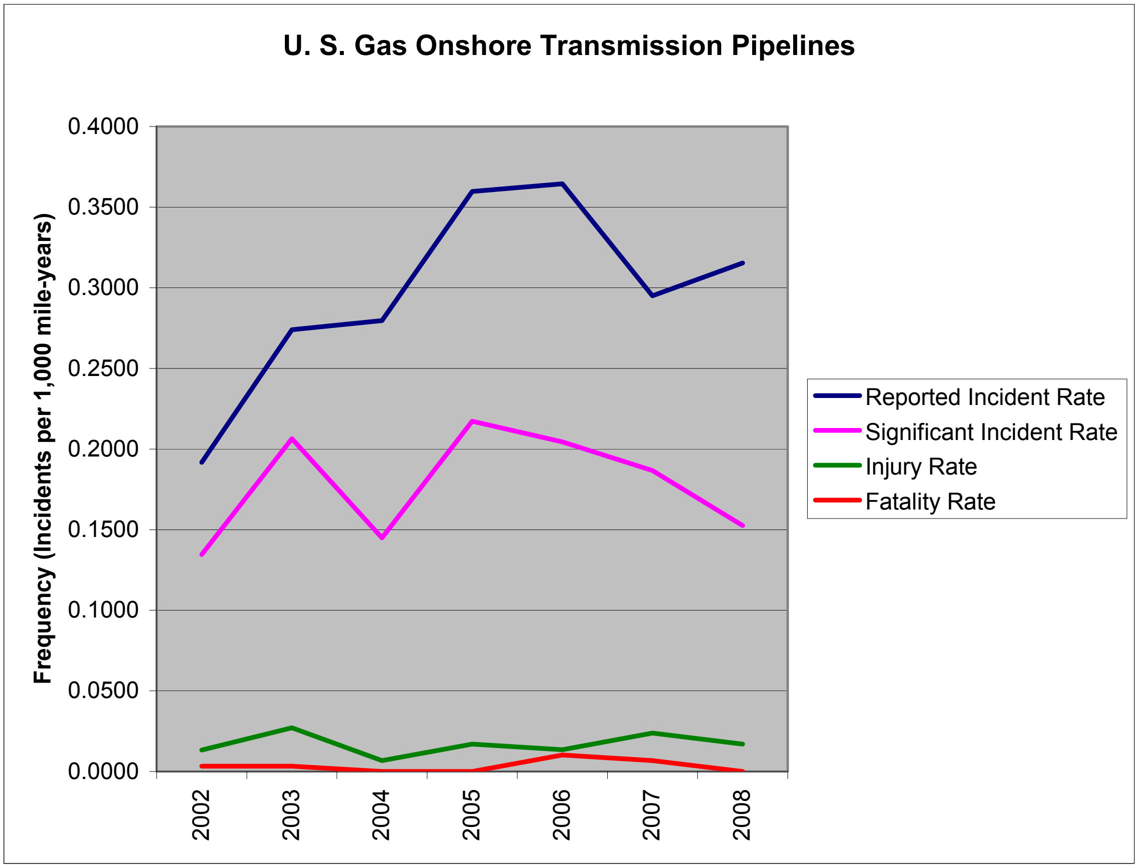
- Reportable Unintentional Releases – This figure would be reduced from 0.38~~42~~ to 0.29~~37~~ incidents per 1,000 mile-years

- 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 ~~be reduced from 0.019 to~~ 0.017 injuries per 1,000 mile-years
- Fatalities – This figure would increase slightly from ~~be unchanged at~~ 0.0033 to 0.0034 ~~0.004~~ fatalities per 1,000 mile-years

~~The database also includes incidents which occurred on offshore segments of pipeline. During the six year period between January 2002 and December 2007, there were 216 such incidents. 67 of these occurred on lines identified as "Gathering", while 149 occurred on segments identified as "Transmission". If these offshore releases are also removed from the database, and the mileage is adjusted to only include the onshore mileage, the following incident rates result~~:

- ~~Reportable Unintentional Releases – 0.29 incidents per 1,000 mile-years~~
- ~~Reportable Injuries - 0.017 injuries per 1,000 mile-years~~
- ~~Fatalities – 0.004 fatalities per 1,000 mile-years~~
- ~~Average Property Damage - $520,000~~

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



Source: USDOT

Figure 4.2-2 U.S. ~~Natural~~ 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. ~~Natural~~ Gas Transmission 1970 to June 1984	U.S. ~~Natural~~ Gas Transmission 1988 thru 2008 ~~July 1984 thru 2007~~ ~~(As Reported by USDOT)~~	U.S. ~~Natural~~ 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~~040~~	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~~004~~	0.015	0.042

4.6 Consequence Data Used In Analysis

The USDOT database of ~~natural~~ gas transmission pipeline releases from January 2002 through December 2008~~7~~ 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~~520~~ releases remaining from onshore transmission pipelines. Of there, the two major causes of releases were excavation damage and external corrosion. 131~~113~~ (21~~22~~%) of the releases were caused by excavation damage from a third party and the pipeline operator. 83~~71~~ (14%) of the releases were caused by external corrosion. The remaining 400~~336~~ (65~~64~~%) 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~~7~~%
- vehicles not related to excavation – 6%
- internal corrosion – 5%
- butt weld failure – 4~~5~~%
- rain and flooding – 4%
- body of pipe failure – 4%
- incorrect operation – 3%
- pipe weld seam failure – 3%
- ~~earth movement – 2%~~
- component failure – 3~~2~~%
- 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~~22~~% 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 mush 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)

The Applicant's proposed mitigation to increase the depth of cover to six-feet will provide increased protection from third party damage. A European Study found that increasing the pipe depth of cover beyond four feet decreased the risk of third party incidents by about 30% versus the depth of cover required by the 49 CFR 192. (HSE 2001)

The Applicant will also design each segment to the Class 4 (most conservative) area classification per 49 CFR 192, which will provide additional protection from third party damage, due to the somewhat thicker pipe wall thickness. This reduction is estimated to be about 25%. (HSE 2001)

Unfortunately, the European study did not present data regarding the combined use of increased depth of cover and increased wall thickness. It is doubtful that the results would be additive. For example, deeper burial depths decrease the likelihood of the line being hit by third parties excavating near the line, since the line would be placed below the depth of many excavations. However, due to the deeper burial, larger equipment would likely be used to excavate those excavations at depths that could impact the pipe. This larger equipment would be more prone to damage the line. A 33% reduction for the combined effectiveness of these two mitigation measures was assumed, in lieu of a third party incident rate 52.5% of the baseline value, which would reflect the addition of these two reductions [incident rate * (1-0.30) * (1-0.25)].

Using these 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 0.041~~043~~ incidents per 1.000 mile years (0.29 per 1,000 mile years baseline x 21~~22~~% caused by third party damage x 67% = 0.043 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

Incident Cause	Pre-1940	1940-49	1950-59	1960-69	1970-79	1980-89
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

Incident Cause	0-69°F	70-99°F	100-129°F	130-159°F	160°F+
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). In addition, pipe that will be installed using the horizontal directional drilling (HDD) technique, will have an outer coating of Powercrete®.
- Sacrificial Anode Cathodic Protection System - The proposed pipeline will be protected from external corrosion by a 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 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~~ve~~ 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 ~~third party damage~~ 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 externall~~y~~ corrosion caused incidents will likely approach zero. It should also be noted that the statistical impact of the new USDOT pipeline integrity regulations are unknown at this time. But they will likely reduce the frequency of releases from the proposed pipeline components located within an HCA which will be included in a Pipeline Integrity Management Plan.

4.6.3 Miscellaneous Causes Incident Rate

As noted above, the remaining 64% 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 one-third reduction has been made to account for the remaining Applicant proposed mitigation measures and 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 0.126~~124~~ incidents per 1.000 mile years (0.29 per 1,000 mile-years baseline x 65~~64~~% x 2/3 = 0.124 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 0.194 incidents per 1.000 mile years (0.041~~043~~ from third party damage, 0.027 from external corrosion, and 0.126~~124~~ 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 4.9E-04 per year. (Weatherwax, et al 2008) Dividing this failure rate by the number of wells (5 plus one spare) yields a failure rate of 8.17E-05 per well per year; this results in a failure likelihood of 1 : 12,200 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 suggested by Weatherwax to determine the individual risk transects for releases from the well site.

- 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)

- 8.3-06 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:

- 1.5-mile long, 16-inch-diameter pipeline between the compressor station and the wellhead site, including the compressor station and associated facilities;
- 0.8-mile long, 16-inch-diameter pipeline between the compressor station and the SMUD interconnection just south of Fruitridge Road; and the
- ~~0.4-mile long, 12-inch-diameter pipeline between PG&E Line 172 and SMUD Line 700, including the meter station and associated facilities; and the~~
- Well site.

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 2.7-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	0.0069~~81~~	1 in 140~~20~~
USDOT Reportable Gas Releases - 1970 thru June 1984 criteria (>$5,000 damage)	1.30 per 1,000 mile-years	0.0030~~5~~	1 in 330~~280~~
USDOT Reportable Gas Releases - Current Criteria (>$50,000 damage)	0.194 per 1,000 mile-years	0.0004~~5~~	1 in 2,2~~1,9~~00
Well Site	$8.17x10^{-5}$ ~~0.49 per 1,000 years~~	0.004 (5 Wells) 0.005 (Six Wells) ~~0.0005~~	1 in 2,450 (5 Wells) 1 in 2,040 (6 Wells) ~~1 in 2,040~~

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 ~~three~~ 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	$1.6x10^{-3}$~~0.0019~~	1 : 620~~530~~
Injuries requiring hospitalization	0.017 incidents per 1,000 mile years	$3.9x10^{-5}$~~0.000046~~	1 : 26~~2~~,000
Fatalities (from pipeline components only, excludes well site)	0.004 fatalities per 1,000 mile years	$9.2x10^{-6}$~~0.000011~~	1 : 109~~93~~,000

As indicated in the table above, the annual aggregate probability of a fatality is $9.2x10^{-6}$ (1 : 109~~93~~,000), based on the qualitative risk assessment. This is the estimated 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. (Reference Table 6.5-1 for a summary of the differences between individual and aggregate risk.) ~~This is significantly higher than the generally accepted significance criterion is an annual likelihood of 1 in one million (1:1,000,000) (CDE 2007, CPUC 2006). As a result, this level of risk would generally be considered significant. (See also Section 7.0 of this Appendix.)~~

The anticipated frequencies of injuries and fatalities presented above are useful references. However, they do not facilitate 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 ~~liquefied petroleum gas (LPG)~~ pipeline transporting chlorine gas, which is much more likely to result in serious impacts due to toxicity~~fires and explosions~~. 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. For the rural portion of the proposed facilities, the values shown above overstate the risk to the public; while in the urban areas they likely understate the risk, due to the more likely public exposure resulting from the greater population density. 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.

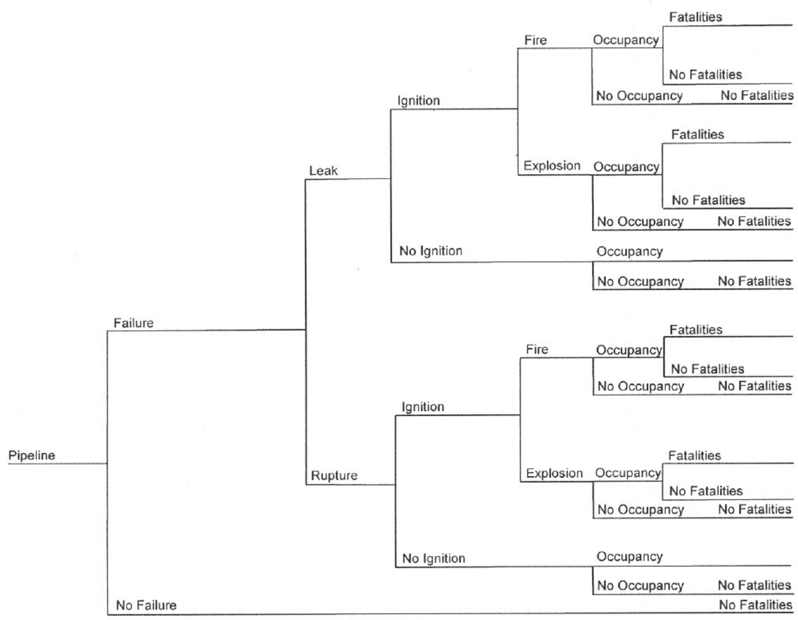


Figure 6-1 Consequence Event Tree

6.1 Baseline Frequency of Unintentional Releases

For this analysis, a baseline frequency of USDOT reportable unintentional releases of 0.194 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 8.17E-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 exploded.

In other words, 10.8% of the reported onshore natural gas transmission pipeline incidents resulted in fires while 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

Parameter	Conditional Consequence Probability	Value — Source
	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 were 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~~2~~ 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	650 psig normal operating pressure and 1,000 psig maximum allowable operating pressure for the 16-inch segment between compressor station and SMUD Line 7008. 1,450 psig normal operating pressure and 1,965 psig maximum allowable operating pressure for the 16-inch segment between the well site and compressor station. 1,450 psig normal operating pressure for reservoir. ~~1,000 psig for 12-inch segment between Line 700 to PG&E meter station~~ Note – The actual line pressures will vary depending on the operating scenarios~~, but will normally be less than these maximum values~~. The normal 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	100 Mcf per day (MMSCFD~~H~~) injection and 200 Mcf per day (MMSCFD~~H~~) withdrawal ~~for 16-inch segment between compressor station and SMUD Line 7008~~ ~~100 MMSCFH injection and 200 MMSCFH withdrawal for 16-inch segment between well site and compressor station~~ ~~70 MMSCFH maximum for 12-inch segment between Line 700 to PG&E meter station~~ An average flow rate of 150 MMSCFD was used for all pipeline release modeling. The facilities were assumed to be operational 50% of the time. 60 Mcf per day (MMSCFD) maximum free flow from each well
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 9.0 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 XX 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 Note – The applicant has indicated that the automatically actuated block valves are designed to go to the closed position within 20 seconds of a pipeline rupture. As a result, the duration of normal flow assumed is likely conservative.

Table 6.3-1 (Continued)

Parameter	Model Input
Pipe Length Upstream and Downstream of Break	0.40-mile for 16-inch segment between compressor station and SMUD Line 7008 - Low Pressure Segment 0.55~~75~~-mile for 16-inch segment between ~~well site and~~ compressor station and the automatically actuated valve (located between the compressor station and the well site) - High Pressure, Long Segment 0.20-mile for 16-inch line segment between the automatically actuated valve (located between the compressor station and the well site) and the well site - High Pressure Short Segment Note - All releases were assumed to occur at the mid-point of each line segment. Wells – 4,000 feet of 8-inch nominal diameter casing was assumed with all releases located at the well head. ~~0.2-mile for 12-inch segment between Line 700 to PG&E meter station~~
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 ~~Low~~ - 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.

Table 6.3-1 (Continued)

Parameter	Model Input
Obstacle Density	Low ~~Medium~~ for 16-inch Segments ~~Low for 12-inch Segments~~ 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. ~~For torch fires resulting from a full bore pipeline rupture, the mass flow rate after 1 second of the initial release was used.~~ This release flow rate is somewhat less than the initial flow rate and somewhat greater than the flow rate after this period.

~~The potential impacts from a well head failure have also been modeled. Similar to the pipeline release modeling, a 1-inch diameter and a complete rupture of a 20-inch casing (actual size unknown at this time) was assumed. The following parameters were used in the analysis.~~

- ~~Reservoir Volume – 2 Billion Standard Cubic Feet~~
- ~~Reservoir Pressure – 1,965 psig~~
- ~~Reservoir Withdrawal Rate – 200 MMSCFD~~
- ~~Duration Until Pipeline Shut-Down – 5 Minutes~~
- ~~Diameter of Casing – 20-inches (assumed)~~
- ~~Angle of Release~~

~~For a torch fire resulting from a full bore casing rupture, a stabilized mass flow rate of 2,700 pounds per second was assumed. This stabilized mass flow rate would be reached approximately 3 seconds after the release was initiated.~~

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 16-inch pipeline segments are surrounded by relatively open space, with nearby residential, heavy commercial, warehouse, and industrial~~, and open~~ space. ~~The 12-inch pipeline segment is surrounded by very open, rural land and the I-80 Freeway corridor. As a result, there is insufficient confinement to cause a significant vapor cloud explosion within the atmosphere along the 12-inch segment.~~ Along the 16-inch segment, 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 was only 0.38~~1.5~~ psig for the 16-inch segments, due to the relatively open industrial and commercial development (medium fuel reactivity and low obstacle density). This overpressure level is not high enough to pose potentially fatal risks to the public. ~~have a 1% probability of serious injury or fatality to occupants of reinforced concrete or reinforced masonry buildings due to flying glass and debris. There is a 10% probability of serious injuries to occupants of simple frame, unreinforced buildings. This over pressure level would generally not be great enough to cause injuries to those outdoors.~~

~~The peak overpressure was only 0.02 psig for the 12-inch line segment, due to the very open surroundings and lack of confinement. This level results in an annoying noise. However, beneath the I-80 causeway, the confinement could be considerable and explosion over-pressure levels would result in serious injuries and fatalities; but this area is not accessible to the public, except for the bike path along the top of the dike and at the Enterprise Boulevard underpass. In these areas, the peak side-on over-pressure would be more than 5 psig. This level can result in serious injuries to those outdoors and fatalities to those inside vehicles due to flying glass and debris.~~

The level of confinement within portions of the compressor building~~station~~ is sufficient to provide a 5.9~~5.5~~ psig peak over-pressure ~~in the vicinity of the compressors and other equipment~~(medium fuel reactivity, high obstacle density). This level can result in serious injuries to those in~~out~~doors. 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 short segment of 16-inch line between the compressor station and the well site, while operating at 1,450~~000~~ psig at a flow rate of 150 Mcf per

<u>day, with the release oriented at 45° above the horizon</u>. (The MAOP for this line segment is 1,965 psig.) The combustible portion of the vapor cloud is between the 5 and 15 mole percent contours.<u> 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.</u>

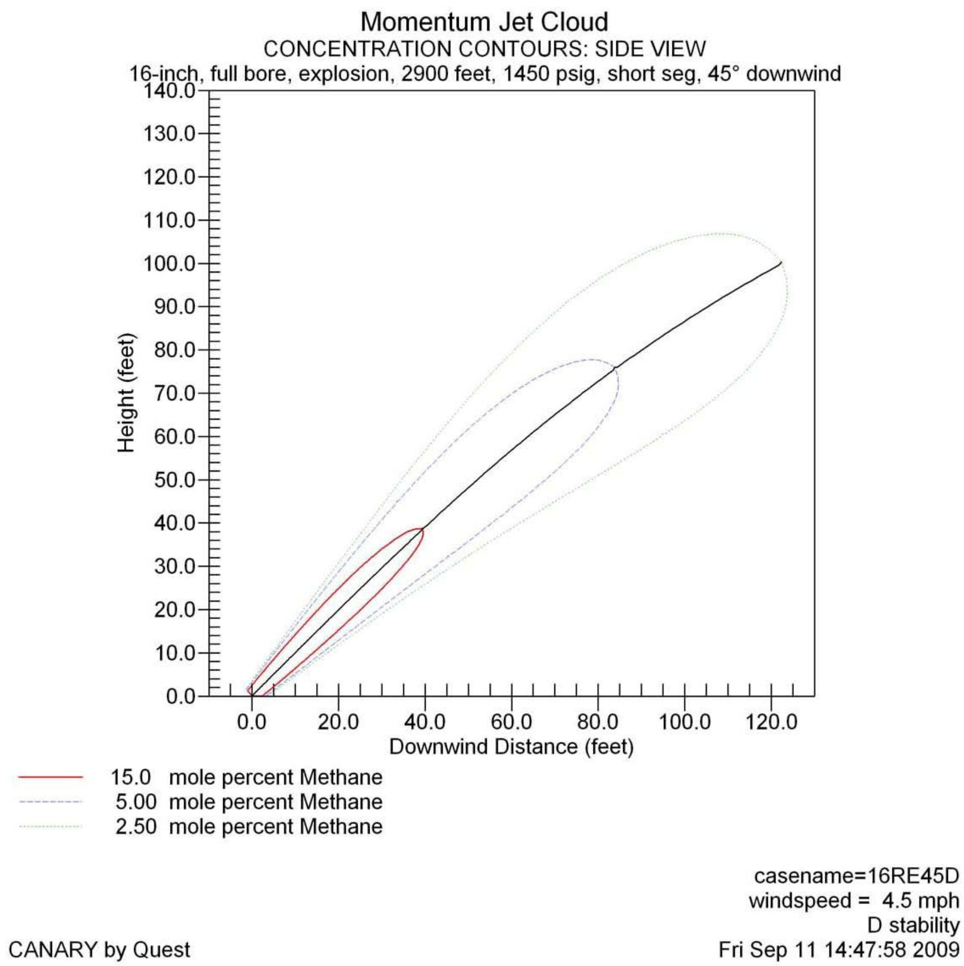


Figure 6.3.1-1 16-inch Compressor to Well Site Line Segment, Rupture Explosion, Elevation

~~The distances to various levels of peak side-on overpressures for each of the pipe segments are summarized in the table below. It is interesting to note that the results are essentially the same, whether the lines are operational, or are shut-in (no flow) and pressurized.~~

~~Table 6.3.1-1~~
~~Vapor Cloud Explosion Modeling Results~~

~~Release~~	~~Maximum Operating Pressure~~	~~Horizontal Distance from Unintentional Release (feet)~~		
		~~1.00 psig Overpressure~~	~~0.70 psig Overpressure~~	~~0.10 psig Overpressure~~
~~16-inch, 1.5 mile Pipeline Full Bore Release @ 45° above horizon~~	~~1,965 psig~~	~~203~~	~~290~~	~~2,030~~
~~16-inch, 1.5 Pipeline 1-inch Diameter Release @ 45° above horizon~~	~~1,965 psig~~	~~48~~	~~68~~	~~479~~
~~16-inch, 0.8 mile Pipeline Full Bore Release @ 45° above horizon~~	~~1,000 psig~~	~~122~~	~~175~~	~~1,223~~
	650 psig	104	148	1,036
~~16-inch, 0.8 Pipeline 1-inch Diameter Release @ 45° above horizon~~	~~1,000 psig~~	~~32~~	~~46~~	~~320~~
~~12-inch, 0.4 mile Pipeline Full Bore Release @ 45° above horizon~~	~~1,000 psig~~	~~N/A~~	~~N/A~~	~~N/A~~
~~12-inch, 0.4 Pipeline 1-inch Diameter Release @ 45° above horizon~~	~~1,000 psig~~	~~N/A~~	~~N/A~~	~~N/A~~
~~Well Site 1-inch Diameter Release Vertical~~	~~1,965 psig~~	~~401~~	~~573~~	~~4,010~~
~~Well Site Casing Full Bore Rupture Vertical~~	~~1,965 psig~~	~~48~~	~~68~~	~~476~~

The explosion modeling result~~s~~ for a vertical well casing rupture while operating at 1,450~~1,995~~ psig and a free flow rate of 60 Mcf per day is~~are~~ depicted in the figure~~s~~ below.

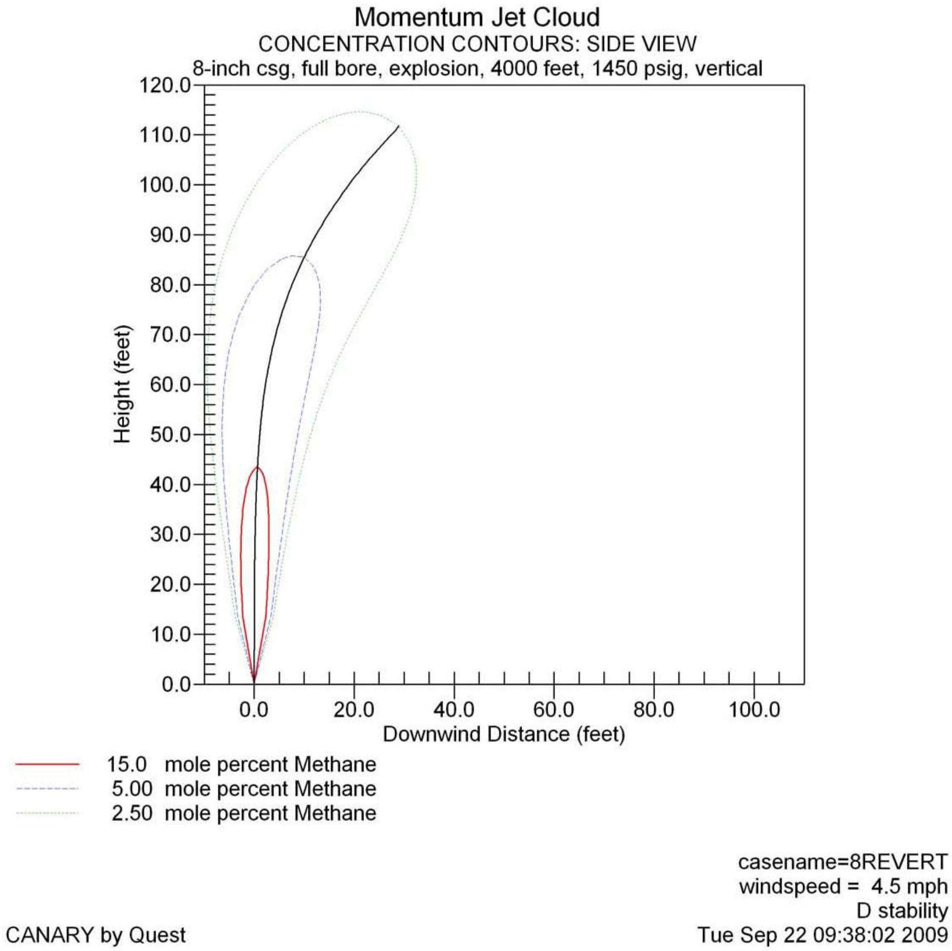


Figure 6.3.1-2 Well Head Casing Rupture Explosion, Elevation

As indicated above, the flammable portion of the vapor cloud (5 mole percent), would extend downwind less than 20~~about 100~~ feet and rise less than 100~~to about 320~~ 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. ~~is estimated at up to 1.5 psig, with 1.0 psig (sufficient to cause serious injuries and fatalities to 10% of those inside standard wood framed structures) up to 400 feet from the release.~~ The results in plan view are provided in the following figure.

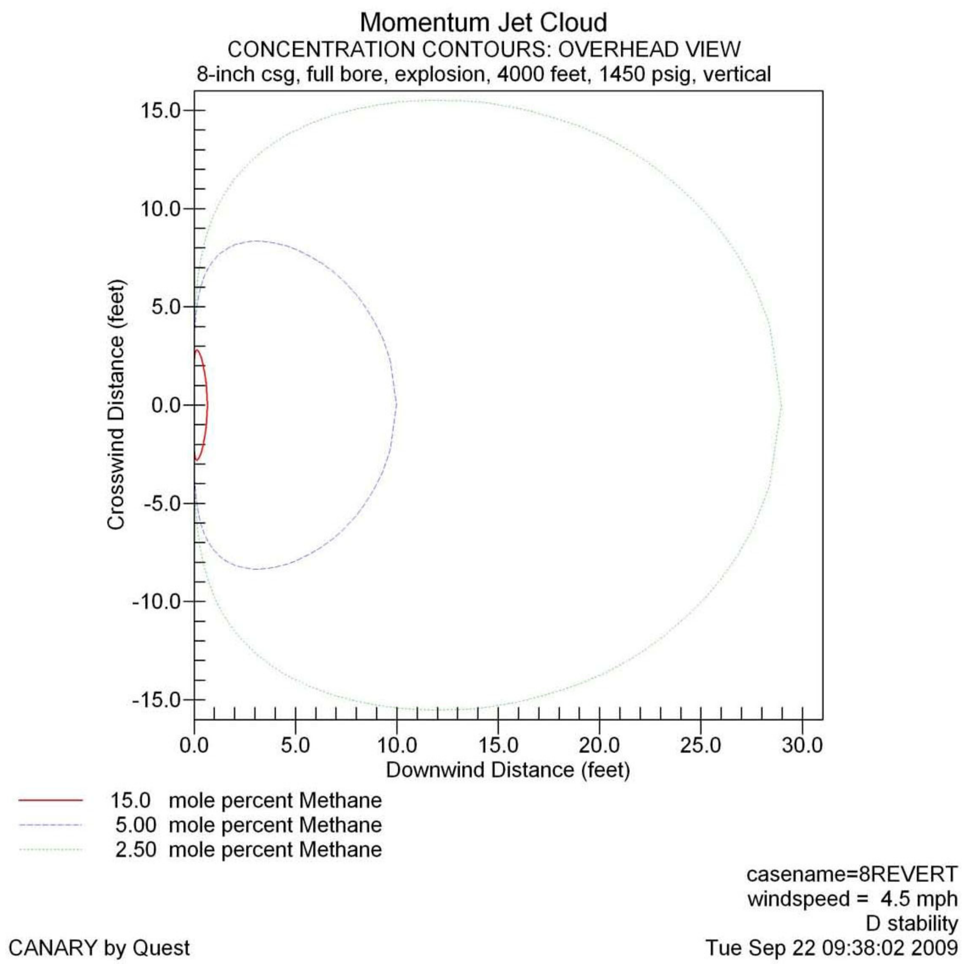


Figure 6.3.1-3 Well Head Casing Rupture Explosion, Plan

6.3.2 Torch Fire Modeling Results

~~**Torch Fires**~~

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

~~As indicated in the torch fire results table below, for a pipeline rupture, one would expect a radiant heat flux of 3,500 btu/hr-ft^2 (second degree skin burns after ten seconds of exposure, 15% probability of fatality if prolonged exposure) at up to roughly 800 feet from a release from the 16-inch line segments and 400-feet from the 12-inch line segment~~.

Table 6.3.2-1
Torch Fire Modeling Results, Low Pressure Pipeline Segment, Operational

Release Angle	Normal 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	650 psig	Rupture	207	226	240
			168	218	288
45° Downwind	650 psig	Rupture	156	184	217
			140	200	276
Vertical	650 psig	Rupture	68	105	149
			92	150	230
45° Upwind	650 psig	Rupture	29	47	77
			82	140	220
15° Upwind	650 psig	Rupture	13	22	34
			60	110	192
15° Downwind	650 psig	1-inch	51	54	58
			46	58	76
45° Downwind	650 psig	1-inch	51	54	59
			46	58	76
Vertical	650 psig	1-inch	50	54	60
			44	58	76
45° Upwind	650 psig	1-inch	49	54	59
			44	56	76
15° Upwind	650 psig	1-inch	50	54	59
			46	58	76

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

~~Release~~	~~Maximum Operating Pressure~~	~~Flame Length (feet)~~	~~Horizontal Distance from Unintentional Release (feet)~~		
	~~Normal Operating Pressure~~		~~8,000 btu/hr-ft^2~~	~~3,500 btu/hr-ft^2~~	~~1,600 btu/hr-ft^2~~
~~16-inch, 1.5 mile Pipeline Full Bore Release @ 45° above horizon~~	~~1,965 psig~~	~~595~~	~~576~~	~~823~~	~~1,067~~
~~16-inch, 1.5 Pipeline 1-inch Diameter Release @ 45° above horizon~~	~~1,965 psig~~	~~70~~	~~67~~	~~93~~	~~123~~
~~16-inch, 0.8 mile Pipeline Full Bore Release @ 45° above horizon~~	~~1,000 psig~~	~~423~~	~~419~~	~~588~~	~~770~~
~~16-inch, 0.8 Pipeline 1-inch Diameter Release @ 45° above horizon~~	~~1,000 psig~~	~~52~~	~~49~~	~~67~~	~~89~~
~~12-inch, 0.4 mile Pipeline Full Bore Release @ 45° above horizon~~	~~1,000 psig~~	~~297~~	~~291~~	~~406~~	~~545~~
~~12-inch, 0.4 Pipeline 1-inch Diameter Release @ 45° above horizon~~	~~1,000 psig~~	~~52~~	~~49~~	~~67~~	~~89~~
~~Well Site 1-inch Diameter Release Vertical~~	~~1,965 psig~~	~~70~~	~~28~~	~~57~~	~~95~~
~~Well Site Casing Rupture Vertical~~	~~1,965 psig~~	~~632~~	~~266~~	~~562~~	~~899~~

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

Table 6.3.2-2
Torch Fire Modeling Results, Low Pressure Pipeline Segment, Non-Operational

Release Angle	Normal 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	650 psig	Rupture	167	175	193
			130	170	226
45° Downwind	650 psig	Rupture	129	150	174
			116	160	218
Vertical	650 psig	Rupture	68	98	132
			80	126	190
45° Upwind	650 psig	Rupture	33	54	83
			70	110	178
15° Upwind	650 psig	Rupture	18	27	45
			56	96	160
15° Downwind	650 psig	1-inch	50	52	57
			46	58	76
45° Downwind	650 psig	1-inch	50	53	58
			44	56	74
Vertical	650 psig	1-inch	49	53	59
			44	56	74
45° Upwind	650 psig	1-inch	49	53	59
			44	56	74
15° Upwind	650 psig	1-inch	50	53	58
			44	58	76

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

Table 6.3.2-3
Torch Fire Modeling Results, High Pressure Long Pipeline Segment, Operational

Release Angle	Normal 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	1,450 psig	Rupture	316	328	367
			276	336	438
45° Downwind	1,450 psig	Rupture	217	262	313
			206	296	404
Vertical	1,450 psig	Rupture	80	128	193
			128	214	336
45° Upwind	1,450 psig	Rupture	33	52	88
			122	210	334
15° Upwind	1,450 psig	Rupture	13	26	39
			84	156	290
15° Downwind	1,450 psig	1-inch	74	80	87
			68	88	114
45° Downwind	1,450 psig	1-inch	73	80	88
			66	86	112
Vertical	1,450 psig	1-inch	69	77	87
			62	82	110
45° Upwind	1,450 psig	1-inch	66	75	86
			60	80	108
15° Upwind	1,450 psig	1-inch	69	77	86
			64	84	112

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

Table 6.3.2-4
Torch Fire Modeling Results, High Pressure Long Pipeline Segment, Non-Operational

Release Angle	Normal 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	1,450 psig	Rupture	294	307	341
			240	304	402
45° Downwind	1,450 psig	Rupture	204	246	293
			190	274	380
Vertical	1,450 psig	Rupture	77	123	184
			124	200	316
45° Upwind	1,450 psig	Rupture	32	51	85
			116	192	304
15° Upwind	1,450 psig	Rupture	19	24	37
			80	150	260
15° Downwind	1,450 psig	1-inch	74	79	86
			66	86	112
45° Downwind	1,450 psig	1-inch	73	79	87
			66	84	112
Vertical	1,450 psig	1-inch	68	76	86
			60	82	108
45° Upwind	1,450 psig	1-inch	66	75	85
			60	80	108
15° Upwind	1,450 psig	1-inch	68	76	85
			64	84	110

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

Table 6.3.2-5
Torch Fire Modeling Results, High Pressure Short Pipeline Segment, Operational

Release Angle	Normal 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	1,450 psig	Rupture	220	241	255
			180	240	310
45° Downwind	1,450 psig	Rupture	166	197	232
			154	216	296
Vertical	1,450 psig	Rupture	71	110	157
			100	160	250
45° Upwind	1,450 psig	Rupture	30	48	80
			96	154	240
15° Upwind	1,450 psig	Rupture	0	22	35
			72	120	208
15° Downwind	1,450 psig	1-inch	74	80	87
			68	88	114
45° Downwind	1,450 psig	1-inch	73	80	88
			66	84	112
Vertical	1,450 psig	1-inch	68	77	87
			62	82	110
45° Upwind	1,450 psig	1-inch	66	75	86
			60	82	110
15° Upwind	1,450 psig	1-inch	69	77	86
			64	84	112

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

Table 6.3.2-6
Torch Fire Modeling Results, High Pressure Short Pipeline Segment, Non-Operational

Release Angle	Normal 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	1,450 psig	Rupture	181	194	210
			146	192	250
45° Downwind	1,450 psig	Rupture	141	164	191
			124	178	240
Vertical	1,450 psig	Rupture	70	102	140
			88	138	208
45° Upwind	1,450 psig	Rupture	141	164	191
			78	124	192
15° Upwind	1,450 psig	Rupture	15	25	42
			64	106	176
15° Downwind	1,450 psig	1-inch	74	79	86
			66	86	112
45° Downwind	1,450 psig	1-inch	73	79	87
			66	84	112
Vertical	1,450 psig	1-inch	68	76	86
			60	82	108
45° Upwind	1,450 psig	1-inch	66	75	85
			60	80	108
15° Upwind	1,450 psig	1-inch	68	76	85
			64	84	110

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

Table 6.3.2-7
Torch Fire Modeling Results, Well Release

Release Angle	Normal 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	1,450 psig	Rupture	179	191	206
			150	190	248
45° Downwind	1,450 psig	Rupture	125	150	179
			116	170	230
Vertical	1,450 psig	Rupture	46	72	110
			76	120	192
45° Upwind	1,450 psig	Rupture	19	30	50
			74	116	188
15° Upwind	1,450 psig	Rupture	9	15	23
			54	92	162
15° Downwind	1,450 psig	1-inch	72	77	83
			62	78	104
45° Downwind	1,450 psig	1-inch	64	71	81
			56	76	100
Vertical	1,450 psig	1-inch	44	56	70
			44	66	92
45° Upwind	1,450 psig	1-inch	29	41	56
			40	60	86
15° Upwind	1,450 psig	1-inch	26	37	51
			40	60	86

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

The results for a vertical torch fire resulting from a full bore rupture of the long segment of the 16-inch line~~pipe~~ segment between the compressor station and the well sites, while operating at 1,450~~1,965~~ psig, are depicted are depicted graphically in the figure below. ~~As indicated, the 3.500 btu/hr-ft^2 isopleth extends over 800-feet from the release (downwind) and almost 600-feet to either side.~~

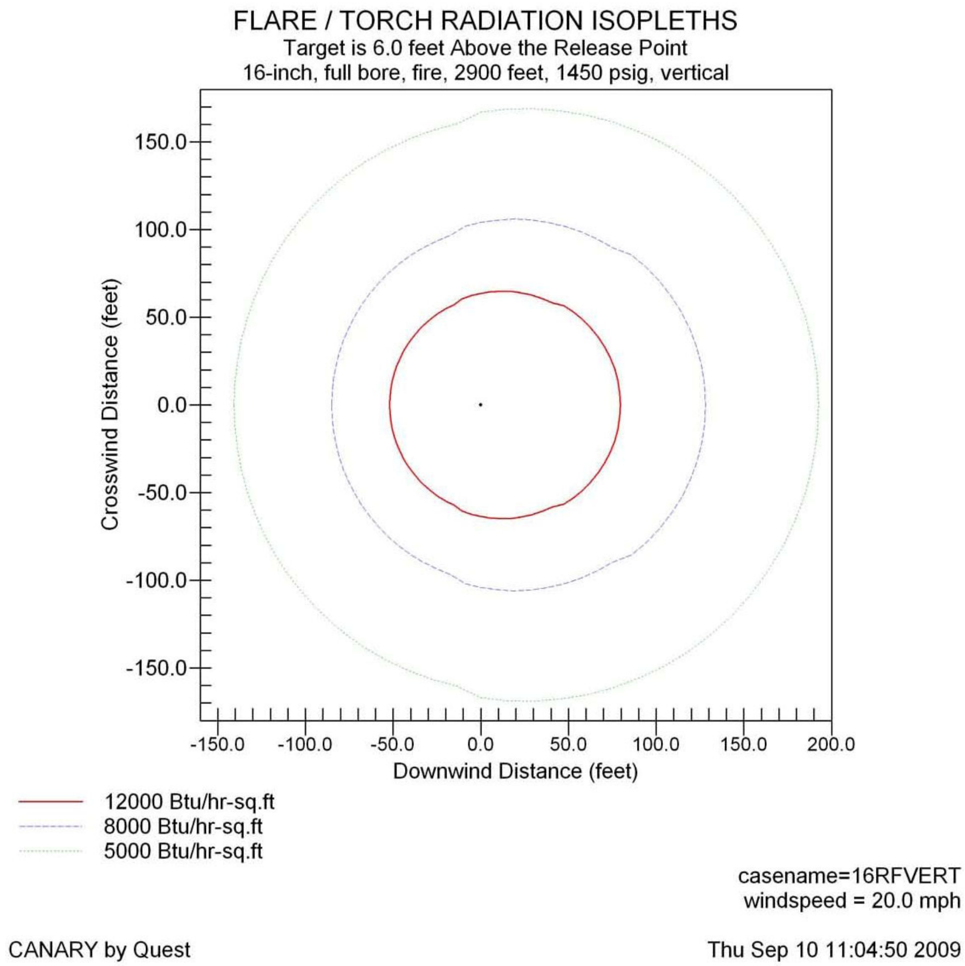


Figure 6.3.2-1 Long Segment of 16-inch Line, Compressor to Well Site ~~Line Segment~~, Rupture Torch Fire, Plan

The results for a torch fire resulting from a casing rupture are depicted in the figure below. ~~As indicated, the 3.500 btu/hr-ft² isopleths extend roughly 600-feet from the release (downwind) and aver 400-feet to either side.~~

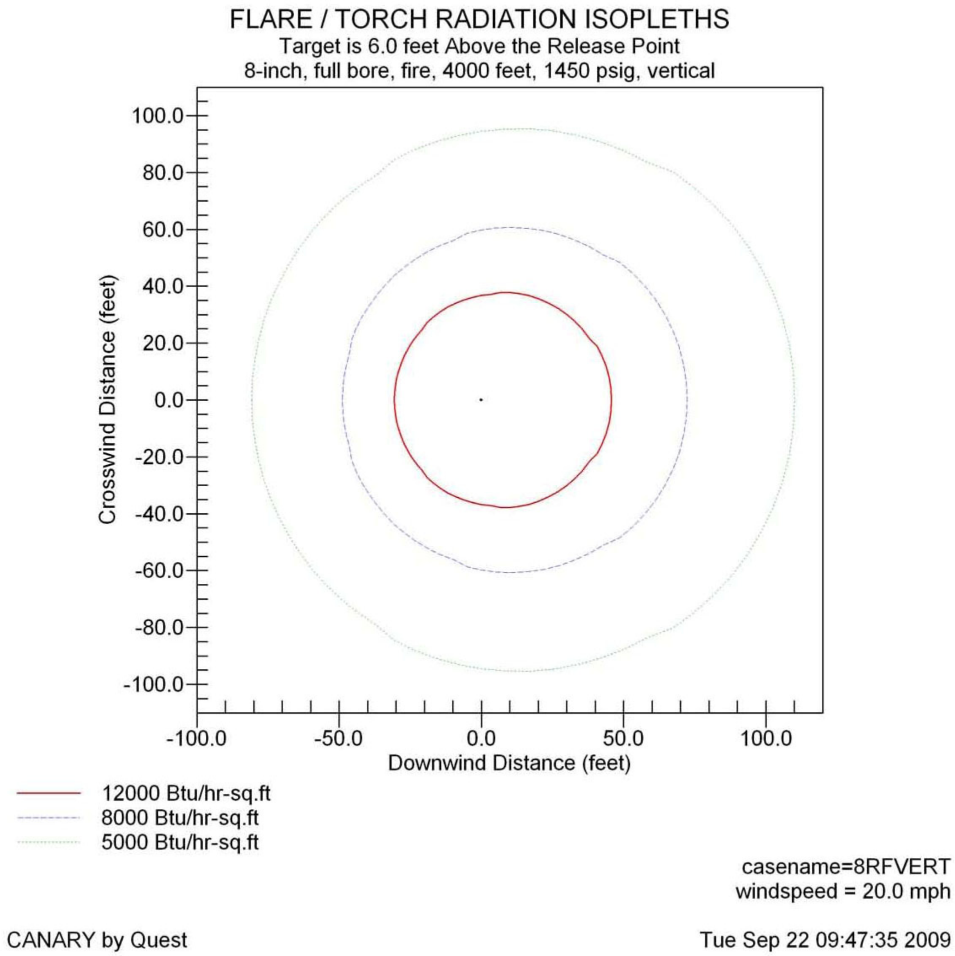


Figure 6.3.2-2 Well Head Casing Rupture Torch Fire, Plan

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~~seriously injured or killed~~. 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~~concentrations~~ below the lower flammability limit. The results of the flash fire modeling are shown in the following tables.~~below:~~

Table 6.3.3-1~~2-2~~
Flash Fire Modeling Results, Low Pressure 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	117	18
45° Downwind	Rupture	76	18
Vertical	Rupture	11	18
45° Upwind	Rupture	0	0
15° Upwind	Rupture	0	0
15° Downwind	1-inch	27	4
45° Downwind	1-inch	18	4
Vertical	1-inch	1	4
45° Upwind	1-inch	0	0
15° Upwind	1-inch	0	0

~~Release~~	~~Maximum Operating Pressure~~	~~Distance from Unintentional Release (feet)~~	
		~~Upper Flammability Limit (LFL)~~	~~Lower Flammability Limit (UFL)~~
~~16-inch, 1.5 mile Pipeline Full Bore Release @ 45° above horizon~~	~~1,965 psig~~	~~67~~	~~140~~
~~16-inch, 1.5 Pipeline 1-inch Diameter Release @ 45° above horizon~~	~~1,965 psig~~	~~15~~	~~32~~
~~16-inch, 0.8 mile Pipeline Full Bore Release @ 45° above horizon~~	~~1,000 psig~~	~~39~~	~~85~~
~~16-inch, 0.8 Pipeline 1-inch Diameter Release @ 45° above horizon~~	~~1,000 psig~~	~~10~~	~~22~~
~~12-inch, 0.4 mile Pipeline Full Bore Release @ 45° above horizon~~	~~1,000 psig~~	~~33~~	~~84~~
~~12-inch, 0.4 Pipeline 1-inch Diameter Release @ 45° above horizon~~	~~1,000 psig~~	~~12~~	~~33~~
~~Well Site 1-inch Diameter Release Vertical~~	~~1,965 psig~~	~~0~~	~~2~~
~~Well Site Casing Rupture Vertical~~	~~1,965 psig~~	~~19~~	~~106~~

Table 6.3.3-2
Flash Fire Modeling Results, Low Pressure 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	119	18
45° Downwind	Rupture	77	18
Vertical	Rupture	12	19
45° Upwind	Rupture	0	0
15° Upwind	Rupture	0	0
15° Downwind	1-inch	27	4
45° Downwind	1-inch	18	4
Vertical	1-inch	1	4
45° Upwind	1-inch	0	0
15° Upwind	1-inch	0	0

Table 6.3.3-3
Flash Fire Modeling Results, High Pressure Long 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	117	30
45° Downwind	Rupture	116	30
Vertical	Rupture	27	30
45° Upwind	Rupture	0	0
15° Upwind	Rupture	0	0
15° Downwind	1-inch	42	6
45° Downwind	1-inch	27	6
Vertical	1-inch	2	6
45° Upwind	1-inch	0	0
15° Upwind	1-inch	0	0

Table 6.3.3-4
Flash Fire Modeling Results, High Pressure Long 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	165	27
45° Downwind	Rupture	108	27
Vertical	Rupture	24	28
45° Upwind	Rupture	0	0
15° Upwind	Rupture	0	0
15° Downwind	1-inch	42	6
45° Downwind	1-inch	27	6
Vertical	1-inch	2	6
45° Upwind	1-inch	0	0
15° Upwind	1-inch	0	0

Table 6.3.3-5
Flash Fire Modeling Results, High Pressure Short 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	128	21
45° Downwind	Rupture	84	21
Vertical	Rupture	15	21
45° Upwind	Rupture	0	0
15° Upwind	Rupture	0	0
15° Downwind	1-inch	42	6
45° Downwind	1-inch	27	6
Vertical	1-inch	2	6
45° Upwind	1-inch	0	0
15° Upwind	1-inch	0	0

Table 6.3.3-6
Flash Fire Modeling Results, High Pressure Short 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	185	31
45° Downwind	Rupture	122	31
Vertical	Rupture	29	31
45° Upwind	Rupture	0	0
15° Upwind	Rupture	0	0
15° Downwind	1-inch	42	6
45° Downwind	1-inch	27	6
Vertical	1-inch	2	6
45° Upwind	1-inch	0	0
15° Upwind	1-inch	0	0

Table 6.3.3-7
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	103	16
45° Downwind	Rupture	67	16
Vertical	Rupture	10	17
45° Upwind	Rupture	0	0
15° Upwind	Rupture	0	0
15° Downwind	1-inch	42	6
45° Downwind	1-inch	27	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 SMUD line and the storage reservoir. The analyses assumed that the pipeline segments would be operational 50% of the time.

6.4.2~~1~~ 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. Where one side had commercial development and the other side had residential development, the exposures were evaluated separately.

6.4.3~~2~~ 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~~middle of the site~~.

~~Exposures to Occupants of Residences and Commercial Buildings~~

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 ~~serious injury or~~ 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 ~~serious injury or~~ 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 estimated 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 ~~serious injury or~~ 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 analyses assumed that residents within the 8,000 btu/hr-ft^2 heat flux contour would be exposed to a 0.50 probability of fatality while they are outside their homes. The analyses assumed that individuals would be sheltered from injurious radiant heat impacts while inside their home.~~ 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 XX, presented later in this report, 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); 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 presents 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 these 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 ~~a serious injury or~~ 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~~3~~ 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 high pressure 16-inch diameter line segments at the modeled conditions, the flammable concentration of the vapor cloud would be roughly~~less than~~ 100-feet wide (measured parallel to the pipeline, perpendicular to the release)~~ for releases from both the 16-inch and 12-inch line segments~~. 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 two seconds, 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 ~~a~~ pipeline releases would be fatally injured~~seriously injured or killed~~.

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, the vapor cloud resulting from a vertical release at the well site would not be expected to migrate 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 ~~serious injuries and~~ fatalities would only occur to those exposed directly to the flame or those within the 8,000 btu/hr-ft^2 isopleth~~, which would extend up to about 600-feet from the 16-inch line segments and 300-feet for the 12-inch line segments~~. (See Tables 6.3.2-1 through 6.3.2-7 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 ~~serious injury or~~ fatality ~~was assumed~~.

~~For vertical torch fire releases from the well casing, the flame would not be expected to interfere with the motoring public. For these situations, the at grade impact of the 8,000 btu/hr-ft^2 isopleth was used. This impact extends up to 266-feet from a full bore casing rupture at 6-feet above grade. For a 1-inch diameter release, the 8,000 btu/hr-ft^2 isopleth is not expected to extend beyond the well site. A 10% probability of serious injury or fatality was assumed for motor vehicle occupants within the 8,000 btu/hr-ft^2 isopleth. For reference, a 50% mortality is normally used for this level of exposure to unprotected individuals.~~

Explosions

The peak overpressures resulting from atmospheric explosions are not anticipated to be sufficient to cause serious injuries for the 16-inch line segments and well casing full bore ruptures. ~~A 10% fatality rate has been assumed for those exposed to these incidents inside buildings due to broken glass and flying debris.~~

6.4.~~5~~4 Number of Vehicle Occupants Exposed to Release

The analysis estimated the number of individuals exposed as follows:

- The traffic counts were obtained from Section D of this document.
- An average traffic speed of 40 miles per hour was used~~, except for I-80 which used 80 miles per hour and the West Capitol onramp which used 60 miles per hour~~.
- The length of hazard, measured along the roadway, was determined individually for each type of release by modeling. These data are summarized in T~~t~~able 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 individual risk and 2 for societal risk.

For the individual risk analysis, if the above calculation yielded a number greater than unity, the number exposed was reduced to one individual.

6.5 Aggregate~~Individual~~ Risk~~s~~

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
Low Pressure Pipe Segment			
Indoor Explosion Full Bore Rupture	0	156	$6.94x10^{-11}$
Indoor Explosion 1-inch Release	0	0	0
Torch Fire Full Bore Rupture	0	500	$6.82x10^{-8}$
Torch Fire 1-inch Release	0	130	$9.43x10^{-9}$
Flash Fire Full Bore Rupture	0	156	$2.50x10^{-9}$

Release Description	Residential Exposure (lineal feet)	Commercial or Public Exposure (lineal feet)	PLL or Aggregate Risk Annual Likelihood of Fatality
Flash Fire 1-inch Release	0	0	0
Total	N/A	N/A	8.01×10^{-8} 1 : 12,500,000
High Pressure Long Pipe Segment			
Indoor Explosion Full Bore Rupture	0	504	2.24×10^{-10}
Indoor Explosion 1-inch Release	0	0	0
Torch Fire Full Bore Rupture	0	2,854	2.96×10^{-7}
Torch Fire 1-inch Release	0	350	1.51×10^{-8}
Flash Fire Full Bore Rupture	0	504	8.07×10^{-9}
Flash Fire 1-inch Release	0	0	0
Total Pre-Mitigation	N/A	N/A	3.19×10^{-7} 1 : 3,130,000
High Pressure Short Pipe Segment			
Indoor Explosion Full Bore Rupture	0	458	2.04×10^{-10}
Indoor Explosion 1-inch Release	0	0	0
Torch Fire Full Bore Rupture	1,910	742	4.08×10^{-7}
Torch Fire 1-inch Release	0	480	3.39×10^{-8}
Flash Fire Full Bore Rupture	0	458	7.34×10^{-9}
Flash Fire 1-inch Release	0	0	0
Total Pre-Mitigation	N/A	N/A	4.50×10^{-7} 1 : 2,220,000

Table 6.5-3
Aggregate Risk Results, Well Site

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	4	6.42×10^{-6}
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 Pre-Mitigation	N/A	N/A	5.42×10^{-6} 1 : 185,000

Table 6.5-4
Aggregate Risk Results, Roadways

Release Description	Elder Creek (lineal feet)	Power Inn Road (lineal feet)	Fruitridge (lineal feet)	PLL or Aggregate Risk Annual Likelihood of Fatality
Torch Fire Full Bore Rupture	262	1,736	136	3.05×10^{-7}
Torch Fire 1-inch Release	80	1,710	25	4.27×10^{-7}
Flash Fire Full Bore Rupture	116	1,710	46	1.65×10^{-8}
Flash Fire 1-inch Release	27	0	1	7.61×10^{-10}
Total Pre-Mitigation	N/A	N/A	N/A	7.49×10^{-7} 1 : 1,340,000

The total aggregate risk of annual fatality is 7.02x10-6 (1 : 142,000).

~~In the following paragraphs, the impacts (e.g. serious injuries and fatalities) to individuals exposed to a fire or explosion will be presented. The lengths of pipeline and well site facilities that could impact the public are summarized, for each of the identified conditions.~~

~~6.5.1 Exposures to Occupants of Residences and Commercial Buildings~~

~~Flash Fire or Indoor Explosion, 1-inch Diameter Pipeline Release – These impacts could be significant within about 25 feet of the 16-inch line segments (22-feet @ 1,000 psig and 32-feet @ 1,965 psig) and 33-feet of the 12-inch line. None of proposed facilities would be located within this proximity of existing residences or commercial buildings.~~

~~Flash Fire or Indoor Explosion, Full Bore Pipeline Release – These impacts could be significant within about 110 feet of the 16-inch line segments (85-feet @ 1,000 psig and 140-feet @ 1,965 psig) and 84-feet of the 12-inch line. 950 lineal feet of the line are located within 110-feet of existing commercial buildings along the 16-inch line segment, with an exposure on one side of the line.~~

~~Torch Fire, 1-inch Diameter Pipeline Release – These impacts could be significant within about 80 feet of the 16-inch line segments (67-feet @ 1,000 psig and 93-feet @ 1,965 psig to 3,500 btu/hr-ft² isopleth) and 67-feet of the 12-inch line. None of the 16-inch line is within this proximity to existing~~

~~residences or commercial buildings. For the 12-inch line, none of the proposed facilities would be located within this proximity of existing residences or commercial buildings.~~

~~Torch Fire, Full Bore Pipeline Release – These impacts could be significant within about 600 feet of the 16-inch line segments (588-feet @ 1,000 psig and 823-feet @ 1,965 psig to 3,500 btu/hr-ft^2 isopleth and 419-feet @ 1,000 psig and 576-feet @ 1,965 psig to 8,000 btu/hr-ft^2 isopleth) and 300-feet of the 12-inch line. Approximately 2,320 lineal feet of the 16-inch line is within this proximity to existing residences while about 10,315 lineal-feet is within this proximity of existing commercial buildings. For the 12-inch line, about 100-feet of the proposed facilities would be located within this proximity of the existing commercial buildings. (A 24-hour occupancy has been assumed for this building.)~~

~~Explosion, 1-inch Diameter Pipeline Release - These impacts could be significant within 50 feet of the 16-inch line segments; the 12-inch line does not present a potentially injurious over-pressure level. None of the 16-inch line is within this proximity to existing residences or commercial buildings.~~

~~Explosion, Full Bore Pipeline Release - These impacts could be significant within 200 feet of the 16-inch line segments; the 12-inch line does not present a potentially injurious over-pressure level. Approximately 1,760 lineal feet of the 16-inch line is within this proximity to existing residences while about 1,410 lineal-feet is within this proximity of existing commercial buildings.~~

~~The lengths of the proposed pipeline segments that could pose potentially serious impacts are summarized in the following table:~~

~~Table 6.5.1-1~~
~~Length of Line Posing Potentially Serious Impacts to Building Occupants~~

~~Event~~	~~Length of 16-inch Line Posing Potentially Serious Impact~~	
	~~Residential Buildings~~	~~Commercial Buildings~~
~~1-inch Diameter Flash Fire 25-foot Impact Distance~~	~~0~~	~~0~~
~~1-inch Diameter 16-inch Lines Torch Fire 80-foot Impact Distance~~	~~0~~	~~0~~
~~Rupture Flash Fire 110-foot Impact Distance~~	~~0~~	~~950~~
~~Rupture Torch Fire 600-foot Impact Distance~~	~~2,320~~	~~10,315~~
~~1-inch Diameter Explosion 50-foot Impact Distance~~	~~0~~	~~0~~

~~Rupture~~ ~~Explosion~~ ~~200-foot Impact Distance~~	~~1,760~~	~~1,410~~
~~Length of 12-inch Line Posing Potentially Serious Impact~~		
~~Rupture~~ ~~Torch Fire~~ ~~300-foot Impact Distance~~	~~0~~	~~100~~

~~Torch Fire, Full Bore Well Casing Release (Vertical) – The 8,000 btu/hr-ft^2 isopleth is anticipated to extend 266 feet from the well site. This is sufficient to pose risks to the nearby commercial properties.~~

~~Explosion, Full Bore Well Casing Release (Vertical) – The 1.0 psig overpressure level is anticipated to extend 401-feet from a release. This will pose risks to both nearby residences and commercial properties.~~

~~6.5.2 Exposures to Vehicle Occupants~~

~~For the 12-inch and 16-inch line segments, the lengths of line which could pose potentially serious injuries or fatalities to vehicle occupants are shown in the table below.~~

~~Table 6.5.2-1~~
~~Length of 16-inch Line Posing Potentially Serious Impacts to Vehicle Occupants~~

~~Event~~	~~Width of Exposure (feet)~~	~~Length of 16-inch Line Posing Potentially Serious Impact~~		
		~~Power Inn Road Exposure Probability = 50% (one side)~~	~~Fruitridge Road Exposure Probability = 50% (one side)~~	~~Elder Creek Exposure Probability = 100% (both sides)~~
~~1-inch Diameter Flash Fire~~ ~~25-feet Impact Distance~~	~~15-feet Vapor Cloud Minimum 1 Vehicle Exposed~~	~~1,335~~	~~25~~	~~120~~
~~1-inch Diameter~~ ~~Torch Fire~~ ~~60-feet Impact (Flame) Distance~~ ~~(52-feet @ 1,000 psig and 70-feet @ 1,965 psig)~~	~~80-feet~~ ~~(8,000 btu/hr-ft^2)~~	~~1,405~~	~~60~~	~~190~~
~~Rupture~~ ~~Flash Fire~~ ~~110-feet Impact Distance~~	~~70-feet Vapor Cloud Minimum 1 Vehicle Exposed~~	~~1,890~~	~~100~~	~~270~~
~~Rupture~~ ~~Torch Fire~~ ~~500-feet Impact (Flame) Distance~~ ~~(423-feet @ 1,000 psig and 595-feet @ 1,965~~	~~600-feet~~ ~~(8,000 btu/hr-ft^2)~~	~~2.320~~	~~520~~	~~1,070~~

~~psig)~~				
~~1-inch Diameter Explosion 40-feet Impact Distance (32-feet @ 1,000 psig and 48-feet @ 1,965 psig)~~	~~80-feet @ 1 psig Overpressure Minimum 1 Vehicle Exposed~~	~~1,790~~	~~45~~	~~150~~
~~Rupture Explosion 200-feet Impact Distance (122-feet @ 1,000 psig and 203-feet @ 1,965 psig)~~	~~300-feet @ 1 psig Overpressure Minimum 1 Vehicle Exposed~~	~~1,970~~	~~150~~	~~370~~

~~The potential impacts from the proposed 12-inch line segments have been analyzed using the same methodology as outlined above. The data are presented in Table 6.5.2-2 below.~~

~~Table 6.5.2-2~~
~~Length of 12-inch Line Posing Potentially Serious Impacts to Vehicle Occupants~~

~~Event~~	~~Width of Exposure (feet)~~	~~Length of 12-inch Line Posing Potentially Serious Impact~~	
		~~I-80 Exposure Probability = 50% (one side)~~	~~West Capitol Onramp Exposure Probability = 100% (both sides)~~
~~Rupture Flash Fire 84-feet Impact Distance~~	~~70-feet Vapor Cloud Minimum 1 Vehicle Exposed~~	~~0~~	~~40~~
~~Rupture Torch Fire 297-feet Impact (Flame) Distance~~	~~600-feet (8,000 btu/hr-ft2)~~	~~1,800~~	~~700~~

~~Torch Fire, Full Bore Well Casing Release (Vertical) – The 8,000 btu/hr-ft^2 isopleth extends 266 feet from the release. This is sufficient to pose risks to passing vehicle occupants.~~

~~Explosion, Full Bore Well Casing Release (Vertical) – The 1.0 psig overpressure level is anticipated to extend 401-feet from a release. This is sufficient to pose risks to passing vehicle occupants.~~

~~6.5.3 Individual Risk Results~~

~~The individual risk of serious injury or fatality is approximately 6.9 x 10^{-6}. This represents a 1:145,000 likelihood of a serious injury or fatality annually. This value is roughly seven times the generally accepted significance criteria of one in one-million per year (1:1,000,000). As a result, the individual risk from the proposed project is considered significant.~~

~~It should be noted that this analysis was done based on the existing level of land development and traffic volumes. Should population density or traffic volumes increase over the life of the project, the resulting likelihood of serious injuries and fatalities will increase accordingly.~~

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	1.0×10^{-2}	1.0E-2	10^{-2}
1 in 1,000	1.0×10^{-3}	1.0E-3	10^{-3}
1 in 10,000	1.0×10^{-4}	1.0E-4	10^{-4}
1 in 100,000	1.0×10^{-5}	1.0E-5	10^{-5}
1 in 1,000,000	1.0×10^{-6}	1.0E-6	10^{-6}
1 in 10,000,000	1.0×10^{-7}	1.0E-7	10^{-7}
1 in 100,000,000	1.0×10^{-8}	1.0E-8	10^{-8}
1 in 1,000,000,000	1.0×10^{-9}	1.0E-9	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 Low Pressure Line Segment

The pre-mitigation maximum annual probability of fatality for this component is 2.24×10^{-7} (1 : 4,410,000). The results are presented graphically in the following figure.

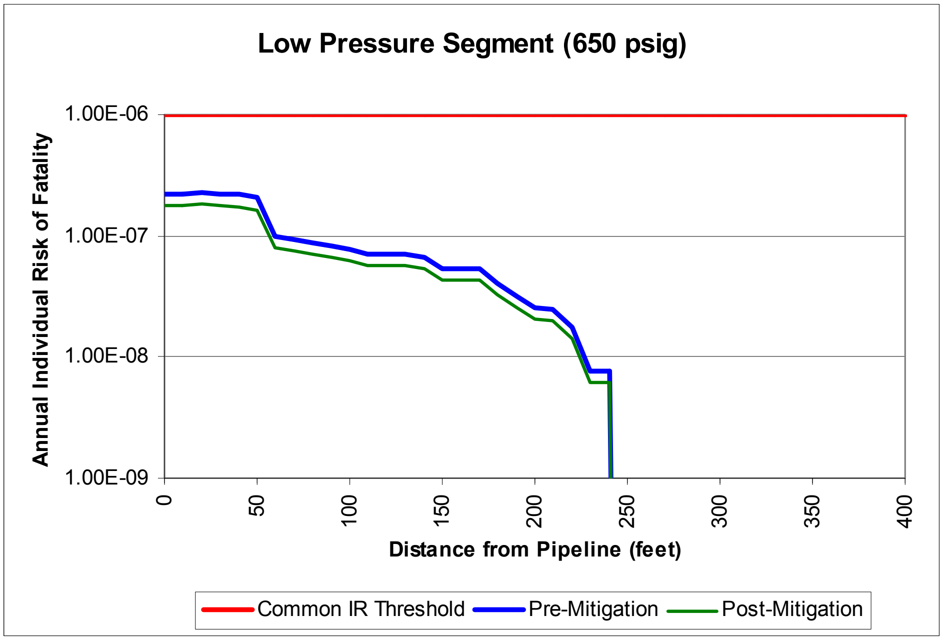


Figure 6.6.1-1 Individual Risk Transect, Low Pressure Line Segment

6.6.2 High Pressure Long Line Segment

The pre-mitigation maximum annual probability of fatality for this component is 3.33×10^{-7} (1 : 3,000,000). The results are presented graphically in the following figure.

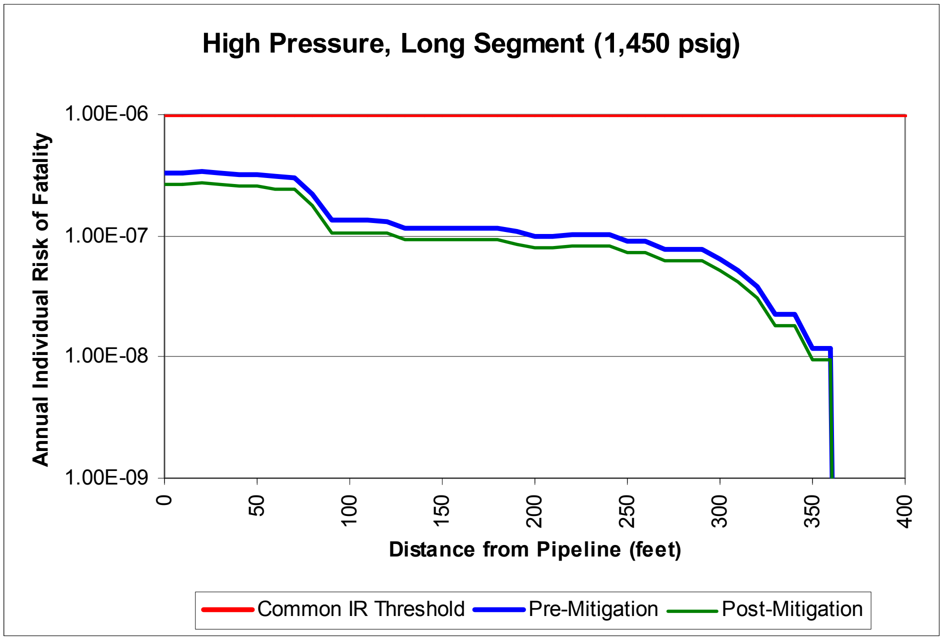


Figure 6.6.2-1 Individual Risk Transect, High Pressure Long Line Segment

6.6.3 High Pressure Short Segment

The pre-mitigation maximum annual probability of fatality for this component is 2.83×10^{-7} (1 : 3,500,000). The results are presented graphically in the following figure.

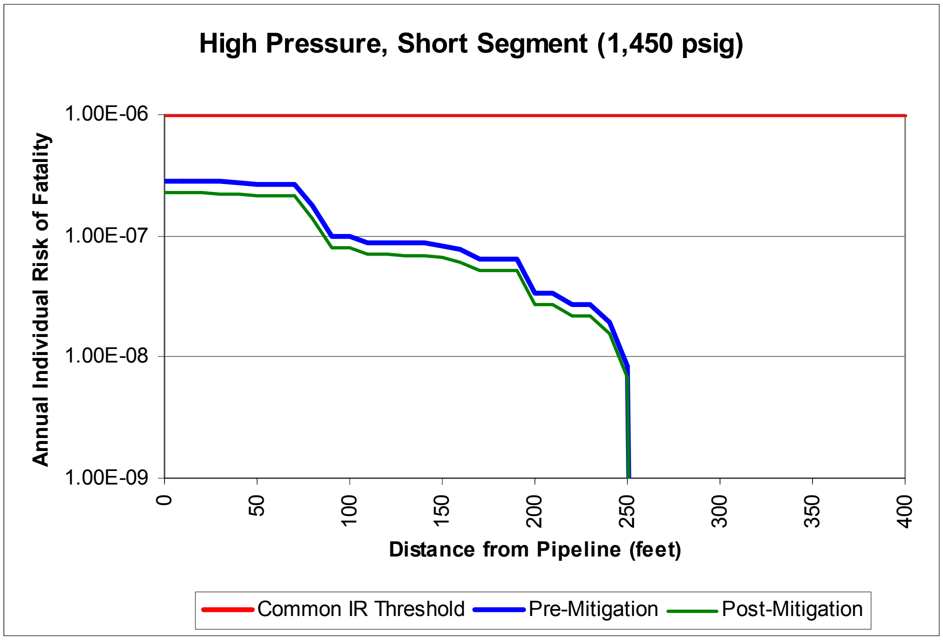


Figure 6.6.3-1 Individual Risk Transect, High Pressure Short Line Segment

6.6.4 Well Site

The pre-mitigation maximum annual probability of fatality for this component is 5.05×10^{-5} (1 : 19,800). The results are presented graphically in the following figure.

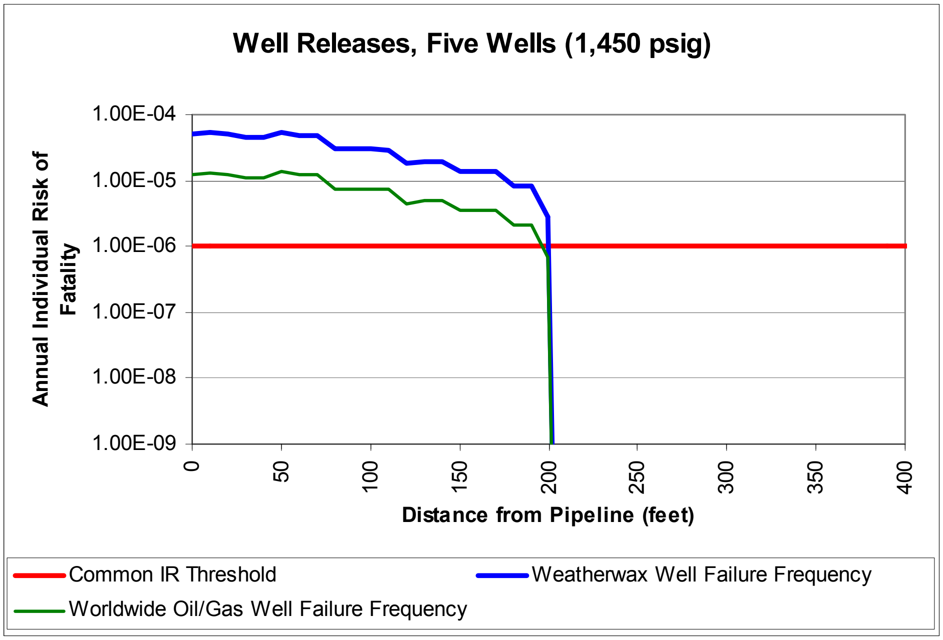


Figure 6.6.4-1 Individual Risk Transect, Well Site

6.7~~6~~ Societal Risks

Societal risk is the probability that a specified number of people would~~ill~~ 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~~6~~.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 27~~25~~-feet of the 16-inch line ~~and 33-feet of the 12-inch line~~ segments. (Reference Tables 6.3.3-1 through 6.6.3-6.) None of proposed facilities would be located within this proximity of existing residences or commercial buildings to pose a public risk.

- Flash Fire or Indoor Explosion, Full Bore Pipeline Release – These impacts are localized and could be significant within about 116~~110~~ feet of the 16-inch line segments~~ and 84-feet of the 12-inch line~~. (Reference Tables 6.3.3-1 through 6.6.3-6.) 1,118~~950~~ lineal feet of the 16-inch line would be~~are~~ located within the flash fire impact distance~~110-feet of existing commercial buildings~~. The width of the exposures are presented in Tables 6.3.3-1 through 6.6.3-6. ~~extends approximately 80-feet (8,000 btu/hr-ft² isopleth) and about 120-feet (3,500 btu/hr-ft² isopleth).~~ 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 88~~80~~ feet of the 16-inch line segments~~ and 67-feet of the 12-inch line~~. (Reference Tables 6.3.2-1 through 6.6.2-6.) About 960 lineal feet ~~None~~ of proposed facilities would be located within this proximity of existing ~~residences or~~ commercial buildings to pose a public risk. 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 232~~600~~ feet of the 16-inch line segments~~ and 300-feet of the 12-inch line~~. (Reference Tables 6.3.2-1 through 6.6.2-6.) Approximately 1,910~~2,320~~ lineal feet of the 16-inch line is within this proximity to existing residences, with an exposure on one side of the line. About 4,096 ~~while about 10,315~~ lineal-feet is within this proximity of existing commercial buildings. ~~For the 12-inch line, about 100-feet of the proposed facilities would be located within this proximity to the existing commercial building.~~ The 8,000~~3,500~~ btu/hr-ft^2 isopleth extends up to about 100~~823~~ feet ~~and 406 feet~~ on either side of the release, measured perpendicular to the release, for the 16-inch ~~and 12-inch~~ line segments. ~~respectively. The 8,000 btu/hr-ft² isopleth extends about 576 feet and 291 feet on either side of the release, for the 16-inch and 12-inch line segments respectively.~~ Using a roughly 200~~600~~-foot-long potentially significant exposure for the 16-inch line, the analysis assumed that up to two~~six~~ residences and one~~up to two~~ commercial structure~~s~~ 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). ~~For the 12-inch line, a population of up to ten individuals 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. ~~These impacts could be significant within 50 feet of the 16-inch line segments; the 12-inch line does not present a potentially injurious over-pressure level. None of the pipeline components are anticipated to present a hazard to residences or commercial buildings.~~

- 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. ~~These impacts could be significant within 200 feet of the 16-inch line segments; the 12-inch line does not present a potentially injurious over-pressure level. Approximately 1,760 lineal-feet of the 16-inch line is within this proximity to existing residences while about 1,410 lineal-feet is within this proximity of existing commercial buildings. A width of exposure to a 1 psig pressure level of 400 feet was assumed, resulting in up to 4 residences, housing 4 individuals per residence and up to two commercial buildings, with 50 occupants each (conservative assumption).~~

- Torch Fire, Full Bore Well Casing Release (Vertical) – The impacts resulting from flash fires and explosions are not anticipated to extend beyond the property line. Only the~~The~~ 5,000~~8,000~~ btu/hr-ft^2 isopleth would extend beyond the fence line. The 5,000 btu/hr-ft^2 isopleth extends 110 feet ~~266 feet~~ from a well release, with a width of 192 feet~~the release~~. (Reference Tables 6.3.2-7 and 6.3.3-7.) The analysis assumed that one~~three~~ commercial building could be impacted by a release, with up to 10 persons outdoors ~~per establishment~~.

~~Explosion, Full Bore Well Casing Release (Vertical) – The 1.0 psig overpressure level is anticipated to extend 401-feet from a release. The analyses assumed that this could impact up to four residences (four residents each) and four commercial buildings (50 occupants each).~~

6.7~~6~~.2 Exposures to Vehicle Occupants

The societal risk analysis to vehicle occupants used the same methodology as outlined earlier for the aggregate ~~individual~~ risk. However, an average occupancy of two occupants per vehicle was used.

6.7~~6~~.3 Societal Risk Results

Selected~~The~~ results of the societal risk analyses are summarized below. Situations which do not pose any potential risk to the public have not been shown. As indicated, the ratio of site casualties to the societal risk criteria is less than 1.0 for each situation. In other words, the number of anticipated casualties is less than that generally considered acceptable for the given exposure probability. As a result, the societal risks for these potential hazards are not considered significant, using the stated societal risk criteria; the number of anticipated site casualties is less than the societal risk criteria corresponding to the exposure probability. (Reference Section 7.1 of this document regarding acceptable risk thresholds.)

Table 6.7~~6~~.3-1
Societal Risk Summary for Residential and Commercial Buildings

Release	Exposure Probability	Probability of ~~Serious Injury or~~ Fatality to Exposed Individuals	Population Exposed	Number of Site Casualties (SC)	Societal Risk Criteria (SRC)	SC/SRC
Low Pressure 16-inch Line Segment~~s~~ Exposure to Occupants of Residences and Commercial Buildings						
Rupture Flash Fire Commercial Outdoors	5.00E-10 ~~3.04e-09~~	1.00	10	10	1,415 ~~600~~	0.0071 ~~0.017~~
~~Rupture Torch Fire Residential~~	~~1.24e-07~~	~~0.50~~	~~24~~	~~12~~	~~50~~	~~0.240~~
Rupture Torch Fire Commercial	1.03E-08 ~~6.61e-07~~	1.00 ~~0.50~~	10 ~~20~~	10	311 ~~20~~	0.0322 ~~0.500~~
~~Rupture Explosion Residences~~	~~4.57e-07~~	~~0.10~~	~~16~~	~~1.6~~	~~40~~	~~0.040~~
~~Rupture Explosion Commercial~~	~~1.57e-07~~	~~0.10~~	~~100~~	~~10~~	~~90~~	~~0.111~~
High Pressure 16-inch Long Line Segment Exposure to Occupants of Residences and Commercial Buildings						
Rupture Flash Fire Commercial Outdoors	1.61E-09	1.00	10	10	787	0.0127
Rupture Torch Fire Commercial	4.39E-08	1.00	10	10	151	0.0663
High Pressure 16-inch Short Line Segment Exposure to Occupants of Residences and Commercial Buildings						
Rupture Flash Fire Commercial Outdoors	1.47E-09	1.00	10	10	826	0.0121
Rupture Flash Fire Commercial Indoors	2.04E-10	1.00	50	50	2,215	0.0226
Rupture Torch Fire Residential	5.80E-08	1.00	8	8	131	0.0609

Table 6.6.3-1 (Continued)

Release	Exposure Probability	Probability of ~~Serious Injury or~~ Fatality to Exposed Individuals	Population Exposed	Number of Site Casualties (SC)	Societal Risk Criteria (SRC)	SC/SRC
Rupture Torch Fire Commercial	2.05E-08	1.00	10	10	221	0.0453
~~*12-inch Line Segment*~~						
~~Rupture Torch Fire Commercial~~	~~5.34e-08~~	~~0.50~~	~~10~~	~~5~~	~~150~~	~~0.033~~
Well Site						
Rupture Torch Fire Commercial	8.22E-10 ~~8.09e-11~~	0.25 ~~0.50~~	10 ~~30~~	2.5 ~~15~~	1,103 ~~1,500~~	0.0023 ~~0.010~~
~~Rupture Explosion Residences~~	~~6.57e-10~~	~~0.10~~	~~16~~	~~1.6~~	~~1,200~~	~~0.0013~~
~~Rupture Explosion Commercial~~	~~2.81e-10~~	~~0.10~~	~~200~~	~~20~~	~~1,500~~	~~0.0133~~

The societal impacts for risks to the motoring public are summarized in the following table.

Table 6.7~~6~~.3-2~~1~~
Societal Risk Summary for Vehicle Occupants

Release	Exposure Probability	Probability of ~~Serious Injury or~~ Fatality to Exposed Individuals	Population Exposed	Number of Site Casualties (SC)	Societal Risk Criteria (SRC)	SC/SRC
16-inch High Pressure Short Segment - Power Inn Road						
~~1-inch Flash Fire~~	~~1.85e-07~~	~~0.10~~	~~2.96~~	~~0.3~~	~~70~~	~~0.004~~
1-inch Torch Fire	4.05E-06 ~~1.75e-06~~	0.10	3.79 ~~3.74~~	0.4	16 ~~20~~	0.0241 ~~0.019~~
Rupture Flash Fire	1.48E-07 ~~1.12e-07~~	0.10	2.92 ~~3.62~~	0.3 ~~0.4~~	82 ~~100~~	0.0036 ~~0.004~~
Rupture Torch Fire	2.49E-06 ~~1.24e-06~~	0.10	5.38 ~~9.99~~	0.5 ~~1.0~~	20 ~~30~~	0.0269 ~~0.033~~
~~1-inch Explosion~~	~~1.55e-06~~	~~0.10~~	~~3.74~~	~~0.4~~	~~20~~	~~0.013~~
~~Rupture Explosion~~	~~7.32e-07~~	~~0.10~~	~~6.39~~	~~0.6~~	40	~~0.016~~

Table 6.6.3-2 (Continued)

Release	Exposure Probability	Probability of ~~Serious Injury or~~ Fatality to Exposed Individuals	Population Exposed	Number of Site Casualties (SC)	Societal Risk Criteria (SRC)	SC/SRC
16-Inch Low Pressure Segment - Fruitridge						
1-inch Flash Fire	1.38E-10 ~~3.46e-09~~	0.10	1.95 ~~2.00~~	0.2	2,688 ~~400~~	0.0001 ~~0.001~~
1-inch Torch Fire	3.74E-08 ~~7.47e-08~~	0.10	2.40 ~~2.58~~	0.2 ~~0.3~~	164 ~~120~~	0.0015 ~~0.002~~
Rupture Flash Fire	2.81E-09 ~~5.93-09~~	0.10	2.07 ~~2.50~~	0.2 ~~0.3~~	597 ~~350~~	0.0003 ~~0.001~~
Rupture Torch Fire	1.30E-07 ~~2.78e-07~~	0.10	3.57 ~~6.88~~	0.4 ~~0.7~~	88 ~~70~~	0.0041 ~~0.012~~
~~1-inch Explosion~~	~~3.90-08~~	~~0.10~~	~~2.58~~	~~0.3~~	~~150~~	~~0.002~~
~~Rupture Explosion~~	~~5.57e-08~~	~~0.10~~	~~4.40~~	~~0.4~~	~~100~~	~~0.003~~
16-inch High Pressure Long Segment - Elder Creek						
1-inch Flash Fire	7.47E-09 ~~3.32e-08~~	0.10	1.58 ~~1.51~~	0.2	366 ~~200~~	0.0004 ~~0.001~~
1-inch Torch Fire	1.89E-07 ~~4.50-07~~	0.10	1.91	0.2	73 ~~40~~	0.0026 ~~0.005~~
Rupture Flash Fire	1.46E-08 ~~3.20e-08~~	0.10	2.13 ~~1.85~~	0.2	262 ~~200~~	0.0008 ~~0.001~~
Rupture Torch Fire	4.22E-07 ~~1. 14e-06~~	0.10	3.02 ~~5.09~~	0.3 ~~0.5~~	49 ~~30~~	0.0062 ~~0.017~~
~~1-inch Explosion~~	~~2.60e-07~~	~~0.10~~	~~1.91~~	~~0.2~~	~~50~~	~~0.004~~
~~Rupture Explosion~~	~~2.75e-07~~	~~0.10~~	~~3.25~~	~~0.3~~	~~60~~	~~0.005~~
~~Well Site – Power Inn Road~~						
Rupture Torch Fire	0.00~~2.70e~~-09	~~0.10~~	~~8.79~~	~~0.9~~	~~600~~	~~0.002~~
Rupture Flash Fire	0.00~~1.88e~~-09	~~0.10~~	~~12.39~~	~~1.2~~	~~800~~	~~0.002~~
~~12-inch - West Capital Onramp~~						
~~Rupture Torch Fire~~	~~2.02e-07~~	~~0.10~~	~~6.38~~	~~0.6~~	~~70~~	~~0.001~~
~~Rupture Flash Fire~~	~~5.69e-10~~	~~0.10~~	~~2.32~~	~~0.2~~	~~1,500~~	~~0.000~~
~~12-inch – I-80~~						
~~Rupture Torch Fire~~	~~9.61e-07~~	~~0.10~~	~~38.86~~	~~3.9~~	~~30~~	~~0.130~~

These results are presented graphically in the following figure. As indicated, the actual societal risk posed by the proposed project is less than the significance thresholds. (Reference Section 7.3 of this document for a complete discussion of societal risk thresholds.) Criteria other than that used in the Netherlands, which has been used as the societal risk threshold herein, are shown for reference. It is worth noting that the California Department of Education and Santa Barbara County 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. Other international jurisdictions have similar "grey areas" or ALARP principals for moderate risk levels. However, the societal risks posed by this project fall below the negligible threshold set by these agencies.

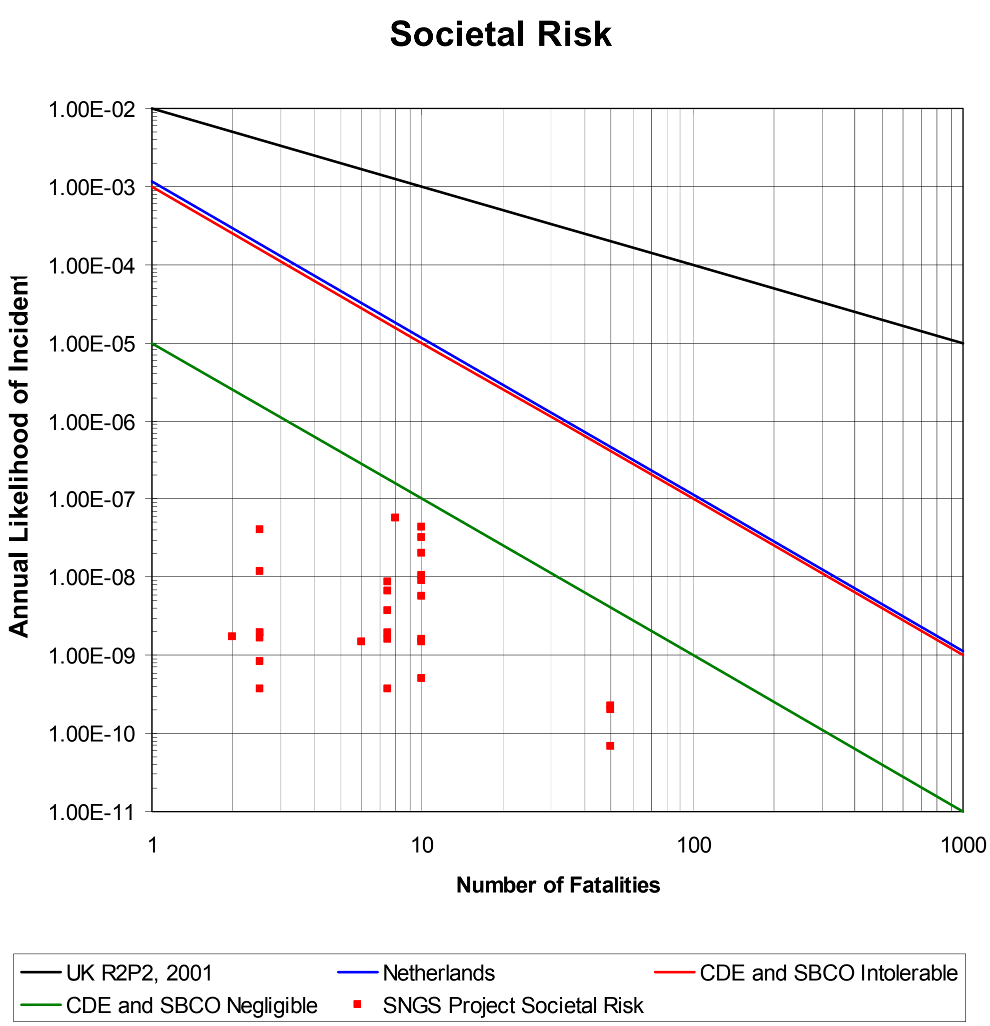


Figure 6.7.3-1 Societal Risk Results

There are a few release scenarios that could impact both building occupants and vehicle passengers. For example, an explosion along Power Inn Road could impact commercial buildings, the residential neighborhood, and vehicle occupants.

The data has been combined for torch fires resulting from a rupture of the 16-inch line segment along Power Inn Road. ~~An estimated 2,000 lineal foot segment of this line could impact commercial, residential, and vehicular traffic. The annual probability of an incident along this line segment is approximately 3e-07. The resulting societal risk criteria is roughly 50 casualties. The estimated number of casualties from this event is 23 (12 residential, 10 commercial, and 1 vehicle occupant).~~ The resulting ratio of site casualties to societal risk criteria is an explosion resulting from a rupture torch fire at this location is less than one~~0.5~~. Since this value is less than one, these impacts are not generally considered significant.

~~The societal risk results presented herein are somewhat higher than those presented in the Applicant's probabilistic risk assessment (Weathermax 2008). However, the conclusions are the same; the project poses societal risks below the generally accepted significance level.~~

7.0 ENVIRONMENTAL IMPACTS AND MITIGATION

7.1 Definition and Use of Significance Criteria

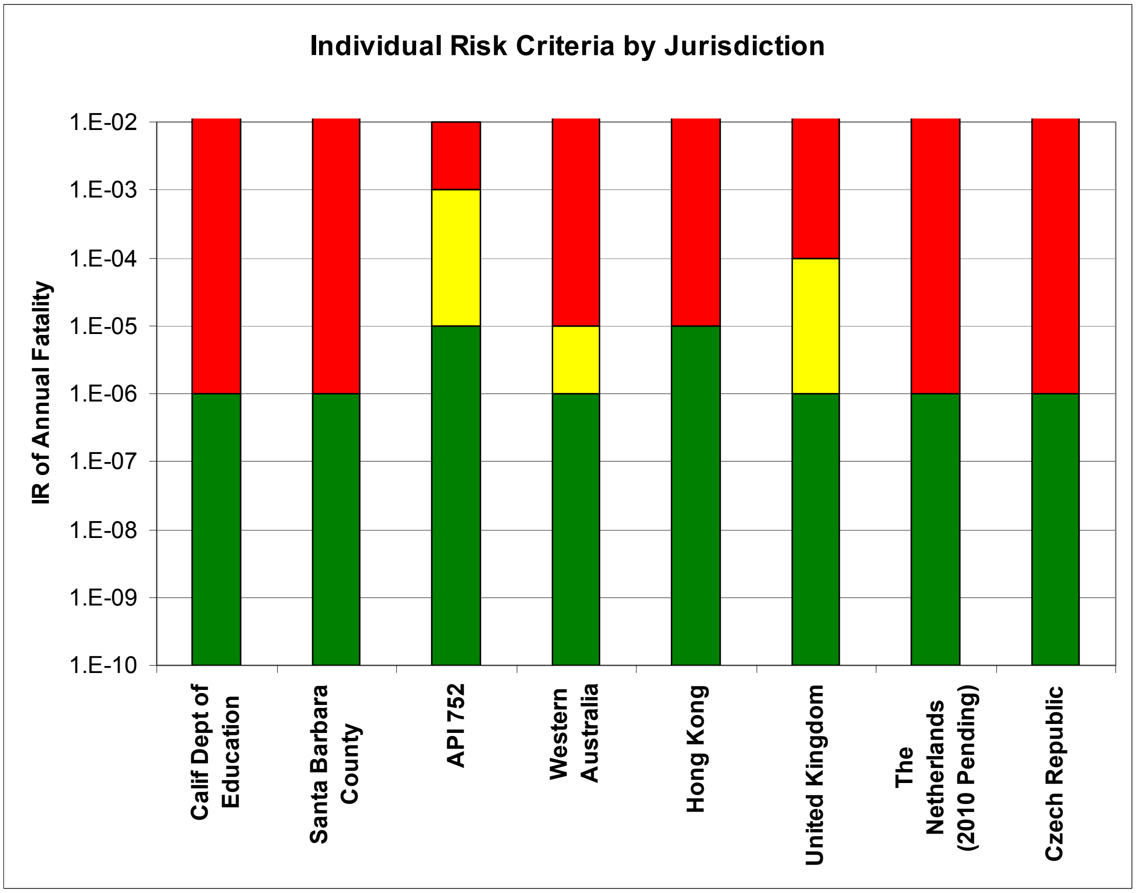
7.1.1 Aggregate Risk

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~~1~~ 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 x 10-6, or 1.0E-06 fatalities per year). 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[1] 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.

[1] 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[2] 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

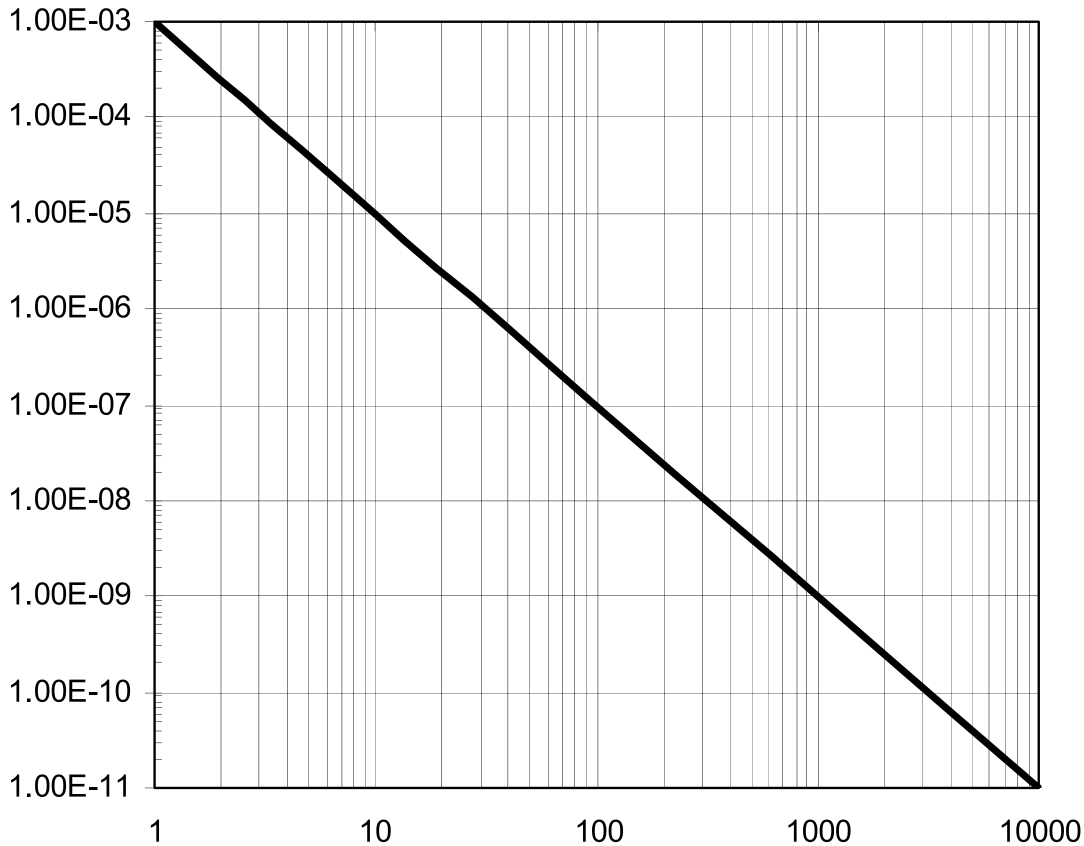
[2] ALARP (as low as reasonably practical) principle states that there is a level of risk that is intolerable, sometimes called the de manifestus risk level. Above this level risks cannot be justified.

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)

~~For individual fatality risks, the generally accepted significance criterion is an annual likelihood of 1 in one million per year (1:1,000,000) (CDE 2007, CPUC 2006).~~

7.1.3~~2~~ 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~~2~~-1 below. This data is the same as the criteria used in the Netherlands~~ and is the most conservative of the published data for Western Europe~~. These criteria have been used to evaluate societal risk in this document.



Source: Committee for the Prevention of Disasters, The Hague

Figure 7.1.3~~2~~-1 Societal Risk Criteria

7.2 Applicant Proposed Measures

This section outlines the mitigation measures that will be incorporated into the project by the Applicant. (Weatherwax~~,~~ et al 2008; SNGS, LLC 2007):

Pipeline Segments

The following Applicant proposed mitigation has been ~~will be~~ incorporated into the pipeline portion of the project.

- The minimum depth of cover for each of the pipeline segments will be at least 6-feet.
- 100% of the circumferential welds will be inspected using radiographic techniques in accordance with API 1104.
- A sectionalizing valve will be provided on the pipe segment between the well field and the compressor station.

- A control system and associated equipment will be provided to facilitate rapid closure of important safety valves, including those in the well field and on the pipe segment between the well field and the compressor station.

- During periods when there is no flowing gas, the block valves at each end of each pipe segment will be closed to "shut-in" the facilities. During non-operational periods, the pipe segments will be pressurized, but will be isolated from natural gas sources. During these periods, the pressure within each line segment will be monitored~~it will be possible to monitor the line pressure~~; a pressure drop would be indicative of an otherwise undetected leak in the system.

- All pipe segments will be designed to Class 4 (most conservative) area classification per 49 CFR 192.

- Remotely operated emergency shut-down (ESD) valves will be provided at both ends of each pipe segment that will automatically close and isolate the pipelines in the event of a potentially dangerous condition such as over-pressure, leak, or fire.

- The natural gas will be odorized.

- Software based leak detection will be used to alert the operator of potential leaks on the 16-inch diameter pipe segments.

- In addition to 16 mils of fusion bonded external coating, pipe that will be installed using the horizontal directional drilling (HDD) method will have an outer Powercrete® coating.

- An automatically actuated intermediate block valve will be installed between the compressor station and the well site. This valve will reduce the impacts from torch fires resulting from a pipeline rupture. This valve is designed to close within 20 seconds of a rupture.

Compressor Station

The following Applicant proposed mitigation has been ~~will be~~ incorporated into the compressor station site:

- The compressor station will be secured by two levels of security. The perimeter of the 382 acre industrial park is secured with a security fence and gate, with a 24-hour site security staff. The compressor station site itself will be surrounded by an 8-foot high steel security fence with barbed wire, with gates maintained in a closed and locked default status, actuated with key cards.

- The Station Control Center, which is located at the compressor station site, will be manned 24 hours per day.

- Emergency backup power will be provided by a 75 kilowatt diesel generator.

- Motion detectors will be installed on posts along the perimeter security fence. Motion detected within the facility will result in an alarm and trigger the activation of security lighting during periods of darkness.

- A security lighting system will be provided within the compressor station site. The system will be manually operated, but will have automatic activation in the event of an emergency alarm for fire, smoke, or intrusion.

- All buildings on the site will be equipped with fire and smoke detectors. In addition, the compressor building will be equipped with heat and flash detectors. All sensors will be integrated into the control system with audible and visual alarms.

Well Site

The following Applicant proposed mitigation has been ~~will be~~ incorporated into the well site portion of the project.

- The well site will be surrounded by a 10-foot high masonry wall, with a security gate actuated by key card entry.

- The wells will be provided with fire and gas detectors and will be under continual audio/video surveillance from the continually manned compressor station. They will also be provided with three ESD valves: a subsurface down hole ESD, an ESD Located at the well head, and an ESD located at the pipeline interface. In the event of either a high or low pressure alarm, a fire alarm at the wellhead, or potentially dangerous level of natural gas is detected, these ESD valves will automatically close in order to limit the supply of natural gas to the fire or leak.

- A third party peer review will be conducted by a well control specialist, under the supervision of the Sacramento City Fire Department.

- A back-up power system will be installed to provide electrical power in an emergency or power outage.

- A security lighting system will be provided. The system will be manually operated, but will have automatic activation in the event of an intrusion.

- Motion detectors will be installed along the top, inside perimeter of the masonry wall. Motion detected within the facility will result in an alarm and trigger the activation of security lighting during periods of darkness.
- Security cameras will be installed along the inside top of the masonry wall. Visual signals will be relayed to the Control Center 24 hours per day.
- All alarms at the well site will be monitored 24 hours per day at the Control Center.

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?

Significant and Unavoidable

An unintentional release from the proposed project could result in serious injuries and/or deaths. These impacts are significant and unavoidable (Class I). 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	9.2×10^{-6}	1 : 109,000	No Known Codified Risk Threshold
Quantitative Aggregate Risk	7.02×10^{-6}	1 : 142,000	No Known Codified Risk Threshold
Individual Risk Low Pressure Segment	2.24×10^{-7}	1 : 4,410,000	1 : 1,000,000 Less Than Significant
Individual Risk High Pressure Long Segment	3.33×10^{-7}	1 : 3,000,000	1 : 1,000,000 Less Than Significant
Individual Risk High Pressure Short Segment	2.83×10^{-7}	1 : 3,500,000	1 : 1,000,000 Less Than Significant

Risk Analysis	Annual Risk of Fatality	Annual Probability of Occurrence	Significance Threshold
Individual Risk Well Site	5.05×10^{-5}	1 : 4,410,000	1 : 1,000,000 Significant
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 200-feet from each well. The wells are located about 75 feet from the eastern fence at the well site. As a result, the significant impacts extend about 125-feet beyond the fence boundary. (Reference Figure B-6 of the EIR, which shows the relationship of the wells to the perimeter fence.)

~~The qualitative risk analysis determined that the annual probability of fatalities resulting from the proposed project was 1:93,000. The individual quantitative risk analysis resulted in an annual fatality probability of 1:140,000, less than that from the qualitative risk assessment due to the Applicant proposed mitigation. These levels exceed the generally accepted significance criteria. It should be noted however that the stated assumptions have a significant impact on the results.~~

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.

7.3.2 Mitigation Measure SS-1

SS-1a: The CPUC shall conduct, or cause to be conducted, an independent, third party design review of the Applicant's construction drawings, supporting calculations, and specifications and shall monitor and observe construction to ensure compliance with all applicable LORS, imposed mitigation, and Applicant proposed mitigation. This review shall also include a review of the pipeline control and leak detection system to insure that the system performance is consistent with the assumptions stated herein. The Applicant shall make payments to the CPUC for these design reviews, plan checks, and construction inspection services. These design review and construction observation services shall not in any way relieve the Applicant of its responsibility and liability for the design, construction, operation, maintenance and emergency response for these facilities.

SS-1b: A 6-inch wide polyethylene marker tape shall be installed approximately 18-inches below the ground surface, above the center of each pipeline segment. The marking tape shall be brightly colored and shall be marked with an appropriate warning (e.g., Warning – High Pressure Natural Gas Pipeline).

SS-1c: The Applicant shall submit to the CPUC an Operation and Maintenance (O&M) manual, prepared in accordance with 49 CFR 192.605. The O&M manual shall address internal and external maintenance inspections of the completed facility, including but not limited to details of integrity testing methods to be applied, corrosion monitoring and testing of the cathodic protection system, and leak monitoring. In addition, the O&M manual shall also include a preventative mitigation measure analysis for the use of automatic shutdown valves per Federal DOT Part 192.935(c) requirements. The O&M manual shall also incorporate all of the Applicant's proposed mitigation.

SS-1d: The Applicant shall conduct an in-line inspection of the pipeline if the Maximum Allowable Operating Pressure (MAOP) creates a circumferential stress greater than 40% of the Specified Minimum Yield Strength (SMYS). The in-line inspection tool shall be capable of identifying pipe anomalies caused by internal and external corrosion and other causes of metal loss. The inspections shall be performed at regular intervals, in accordance with the Applicant's Integrity Management Program.

SS-1e: An Integrity Management Program for High Consequence Area (HCA) portions of the pipeline shall also be prepared in accordance with 49 CFR 192, Subpart O. The Integrity Management Program shall be submitted to the CPUC.

SS-1f: Line pipe shall be manufactured in the year 2000 or later.

7.3.3 Rational for Mitigation

The risks posed by the pipeline segments are ~~significance of these risks is~~ primarily due to possible torch fires ~~and explosions~~ resulting from pipeline releases and ruptures, primarily along Power Inn Road, where roughly 0.4-miles of the line are within the hazard footprint. The exposures along the other roadways and developed areas are similar, however the exposures are less due to the shorter exposure lengths, lower population densities, and lower traffic volumes. If the anticipated frequency of pipeline releases and ruptures within the hazard footprint were reduced, then the resulting individual risks posed by the Proposed Project would be reduced proportionally. The proposed mitigation measures are intended to minimize the likelihood and consequences of pipeline ruptures. The natural gas pipeline incidents, which were identified as "ruptures" in the USDOT database from 2002 through 2006 have been reviewed. The following points are worth noting:

- 46% of the ruptures were considered longitudinal tears or cracks. Of the components where the manufacturing date was provided, the average date of manufacture was 1955 – roughly 50 years old at the time of failure. Roughly three-quarters of these incidents were caused by third party damage and external corrosion, with the remainder being caused by a variety of factors.

- 50% or the ruptures were considered circumferential separation. For these cases, there was not a predominant cause(s).
- 4% or the ruptures were considered "other".

The primary risks posed by well releases are from torch fires. As shown in Table 6.3.2-7, these impacts can be significant to 206 feet from the well (15° downwind release); the width of the torch fire impact is 248 feet. These impacts extend beyond the facility fence line. As shown in Table 6.3.3-7, the maximum downwind horizontal distance to flash fire impacts is 103 feet, with a width of 16 feet. These impacts only extend about 25 feet beyond the facility fence line.

Third Party Damage Mitigation Effectiveness

In ~~western~~Western Europe, the effectiveness of various forms of third party damage mitigation has been studied (HSE 2001). The findings are summarized below:

- Increased Wall Thickness – For 24-inch diameter pipe, a wall thickness of 0.375-inches or greater was found to reduce the frequency of third party caused unintentional releases. The Applicant proposed mitigation of designing the pipe for Class 4 area classification insures that the pipe wall will be greater than that required by regulation. The proposed pipe wall thicknesses are ~~0.330-inches for the 12-inch segment,~~ 0.375-inches for the segments between the compressor station and the pipeline connection at Fruitridge Road, and 0.656-inches for the segment between the well site and the compressor station.
- Increased Depth of Cover – Pipelines with a depth of cover of 48-inches or greater experienced a reduction in third party caused incidents. The Applicant proposed mitigation provides a minimum of 6-feet of cover.
- Supplemental Third Party Protection – Pipelines protected with some form of third party warning device (e.g., marker tape, concrete cap, steel plates, etc.) experienced a reduction in third party caused incidents.

The quantitative risk analyses considered the effects of increased wall thickness and depth of cover, since these mitigations were proposed by the Applicant. By implementing the marker tape, the frequency of third party caused incidents may be reduced by an additional 10% or so.

External Corrosion Mitigation Effectiveness

Although data is not available to quantify the effectiveness of the external corrosion mitigation measures, the qualitative impacts can be summarized as follows:

- Increased Wall Thickness – Although increased pipe wall thickness does not prevent external corrosion, it allows more time to pass before a leak may result. This increased time period increases the likelihood that the anomaly will be identified by the operator before a release occurs.
- In-Line Internal Inspection – Internal inspections of pipelines using modern techniques can identify external corrosion and other pipe wall anomalies, reducing the likelihood of a release.

Circumferential Separation Mitigation Effectiveness

Inspecting 100% of the circumferential welds in accordance with API 1104, per the Applicant's proposed mitigation, will decrease the likelihood of weld defects, which caused a portion of the circumferential separation ruptures noted in the USDOT database.

7.3.4 Residual Impacts

With the proposed mitigation, the pipeline ~~individual~~ risk will be reduced approximately twenty percent (20%)~~somewhat~~. ~~However, t~~The effect of the Applicant's proposed mitigation has already been considered in the analysis. The residual individual risk at the well site will exceed the individual risk significance threshold. However, it should be noted that these impacts only extend about 125-feet beyond the facility fence.

It should be noted that there are a significant number of natural gas pipeline facilities located in similar, and even more heavily urbanized areas. Many of these pipeline facilities pose a greater risk to the public than the proposed line segments. The risks posed by these facilities have been generally accepted as a cost of modern living in other locations.

8.0 PROJECT ALTERNATIVES

8.1 Gas Field Alternatives

8.1.1 Freeport Gas Field

Environmental Setting

The Freeport Gas Field is located approximately 5 miles southwest of the Florin Gas Field on agricultural land located on the suburban fringe of Elk Grove. Much of the Freeport Gas Field is located beneath an operating wastewater treatment plant.

Environmental Impacts and Mitigation Measures

Similar to the Proposed Project, this alternative would involve constructing facilities including injection/withdrawal wells, compressor station, and connecting pipelines.

Comparison to the Proposed Project

The storage site is located primarily outside of developed residential and commercial areas. However, it does extend beneath residential development at the southern end of the field. As a result, potential safety impacts to the public would likely be somewhat less than for the proposed project. However, this project would require a 5-mile, 16-inch diameter pipeline. The aggregate and societal risks posed by the pipeline, compressor station, and well site would depend on the actual pipeline alignment and the facilities' proximity to the public (e.g. roadways, residential and commercial developed areas, etc.). If the pipeline followed heavily traveled roadways, or came near developed areas, the resulting impacts would likely be similar to those presented for the Proposed Project. The aggregate and societal risks would likely be reduced because of the lower population density. The individual risk would remain essentially the same as that presented for the Proposed Project, since the individual risk is the likelihood of fatality at a specific point along the pipeline; it does not take into account the length of the line segment or the population density. ~~significant; otherwise, the risks would likely be less than significant.~~ Potential development over the project life would also be factor that could increase public risk over time.

8.1.2 Snodgrass Slough Gas Field

Environmental Setting

The Snodgrass Slough Gas Field is located approximately 20 miles southwest of the Florin Gas Field on agricultural land adjacent to Reclamation District 551 Borrow Canal, 3 miles east of the Sacramento River and California State Highway 160, and 4 miles north of the nearest population center, Walnut Grove. The alternative would be located in a largely agricultural area

Environmental Impacts and Mitigation Measures

Similar to the Proposed Project, this alternative would involve constructing facilities including injection/withdrawal wells, compressor station, and connecting pipelines.

Comparison to the Proposed Project

The storage site is located in an entirely rural, undeveloped area. As a result, potential safety impacts to the public would be less than for the proposed project. However, this project would require a 10-mile, 16-inch diameter pipeline. As with the other project alternatives, the aggregate and societal risks posed by the pipeline and related facilities would depend on their proximity to the public (e.g. roadways, residential and commercial developed areas, etc.). If the pipeline followed heavily traveled roadways, or came near developed areas, the resulting impacts would likely be similar to those presented for the Proposed Project. The aggregate and societal risks would likely be reduced because of the lower population density. The individual risk would remain essentially the same as that presented for the Proposed Project, since the individual risk is the likelihood of fatality at a specific point along the pipeline; it does not take into account the length of the line segment or the population density. ~~significant; otherwise, the risks would likely be less than significant.~~ Potential development over the project life would also be factor that could increase public risk over time.

8.1.3 Thornton Gas Field

Environmental Setting

The Thornton Gas Field is located approximately 20 miles south of the Florin Gas Field on agricultural land south of the Cosumnes River Preserve, 1.5 miles east of Interstate 5 and 1 mile north of the town of Thornton.

Environmental Impacts and Mitigation Measures

Similar to the Proposed Project, this alternative would involve constructing facilities including injection/withdrawal wells, compressor station, and connecting pipeline(s). This alternative would construct nearly 7 miles of pipeline traveling through a largely rural area in order to reach tie-ins.

Comparison to the Proposed Project

The storage site is located in an entirely rural, undeveloped area. As a result, potential safety impacts to the public would be less than for the proposed project. However, this project would require a 7-mile, 16-inch diameter pipeline. As with the other project alternatives, the aggregate and societal risks posed would depend on the actual pipeline alignment and the facilities' proximity to the public (e.g. roadways, residential and commercial developed areas, etc.). If the pipeline followed heavily traveled roadways, or came near developed areas, the resulting impacts would likely be similar to those presented for the Proposed Project. The aggregate and societal risks would likely be reduced because of the lower population density. The individual risk would remain essentially the same as that presented for the Proposed Project, since the individual risk is the likelihood of fatality at a specific point along the pipeline; it does not take into account the length of the line segment or the population density. ~~significant; otherwise, the risks would likely be less than significant.~~ Potential development over the project life would also be factor that could increase public risk over time.

8.2 Project Design Alternatives

8.2.1 Alternative Pipeline Route 1

Environmental Setting

This alternative would utilize the same construction locations for the wellhead site, compressor station, and Sacramento Municipal Utilities District (SMUD) Line 700 tie-in. Only the pipeline route would differ from the Proposed Project. From the northwest corner of the wellhead site, this alternative would head due east to the Union Pacific Railroad (UPRR) tracks. This alternative would parallel Junipero Street and cross an active industrial use yard. It would then parallel the UPRR tracks north to Elder Creek Road. This route would be approximately 7,800 feet long. This alternative would be approximately 450 feet longer than the Proposed Project.

Environmental Impacts and Mitigation Measures

The potential impacts for this alternative are similar to those posed by the proposed project. However, the lengths of line posing potentially serious impacts to building and vehicle occupants are different. The primary change is minimizing the impacts to vehicle occupants and residential development along Power Inn Road. ~~These data are summarized in the following tables.~~

~~Table 8.2.1-1~~
~~Length of 16-inch Line Posing Potentially Serious Impacts to Building Occupants~~

~~Event~~	~~Length of 16-inch Line Posing Potentially Serious Impact~~	
	~~Residential Buildings~~	~~Commercial Buildings~~
~~1-inch Diameter Flash Fire 25-foot Impact Distance~~	~~0~~	~~0~~
~~1-inch Diameter Torch Fire 80-foot Impact Distance~~	~~0~~	~~1,500~~
~~Rupture Flash Fire 110-foot Impact Distance~~	~~0~~	~~1,500~~
~~Rupture Torch Fire 600-foot Impact Distance~~	~~500~~	~~10,500~~
~~1-inch Diameter Explosion 50-foot Impact Distance~~	~~0~~	~~0~~
~~Rupture Explosion 200-foot Impact Distance~~	~~100~~	~~2,000~~

~~**Table 8.2.1-2**~~

~~**Length of 16-inch Line Posing Potentially Serious Impacts to Vehicle Occupants**~~

~~Event~~	~~Width of Exposure (feet)~~	~~Length of 16-inch Line Posing Potentially Serious Impact~~		
		~~Power Inn Road Exposure Probability = 50% (one side)~~	~~Fruitridge Road Exposure Probability = 50% (one side)~~	~~Elder Creek Exposure Probability = 100% (both sides)~~
~~1-inch Diameter Flash Fire 25-feet Impact Distance~~	~~15-feet Vapor Cloud Minimum 1 Vehicle Exposed~~	~~0~~	~~25~~	~~120~~
~~1-inch Diameter Torch Fire 60-feet Impact (Flame) Distance~~	~~800-feet (8,000 btu/hr-ft²)~~	~~0~~	~~60~~	~~190~~
~~Rupture Flash Fire 110-feet Impact Distance~~	~~70-feet Vapor Cloud Minimum 1 Vehicle Exposed~~	~~0~~	~~100~~	~~270~~
~~Rupture Torch Fire 500-feet Impact (Flame) Distance~~	~~600-feet (8,000 btu/hr-ft²)~~	~~400~~	~~520~~	~~1070~~
~~1-inch Diameter Explosion 40-feet Impact Distance~~	~~80-feet @ 1 psig Overpressure Minimum 1 Vehicle Exposed~~	~~0~~	~~45~~	~~150~~
~~Rupture Explosion 200-feet Impact Distance~~	~~300-feet @ 1 psig Overpressure Minimum 1 Vehicle Exposed~~	~~100~~	~~150~~	~~370~~

Comparison to the Proposed Project

The individual risk would not be affected by this alternative, since the pipeline segment lengths would be essentially the same as those for the Proposed Project. (The individual risk is the likelihood of fatality at a specific point along the pipeline; it does not take into account the length of the line segment, nor the population density.)

The aggregate risk of annual fatality for the pipeline segments would be 9.35×10^{-7}, about 40% less than the Proposed Project. The aggregate risk for the well site would remain unchanged. The total aggregate risk of annual fatality for this alternative would be 6.36×10^{-6}, about 9% less than the Proposed Project.

The societal risk posed by this alternative is presented in the following figure. As indicated, the risks are below the significant threshold.

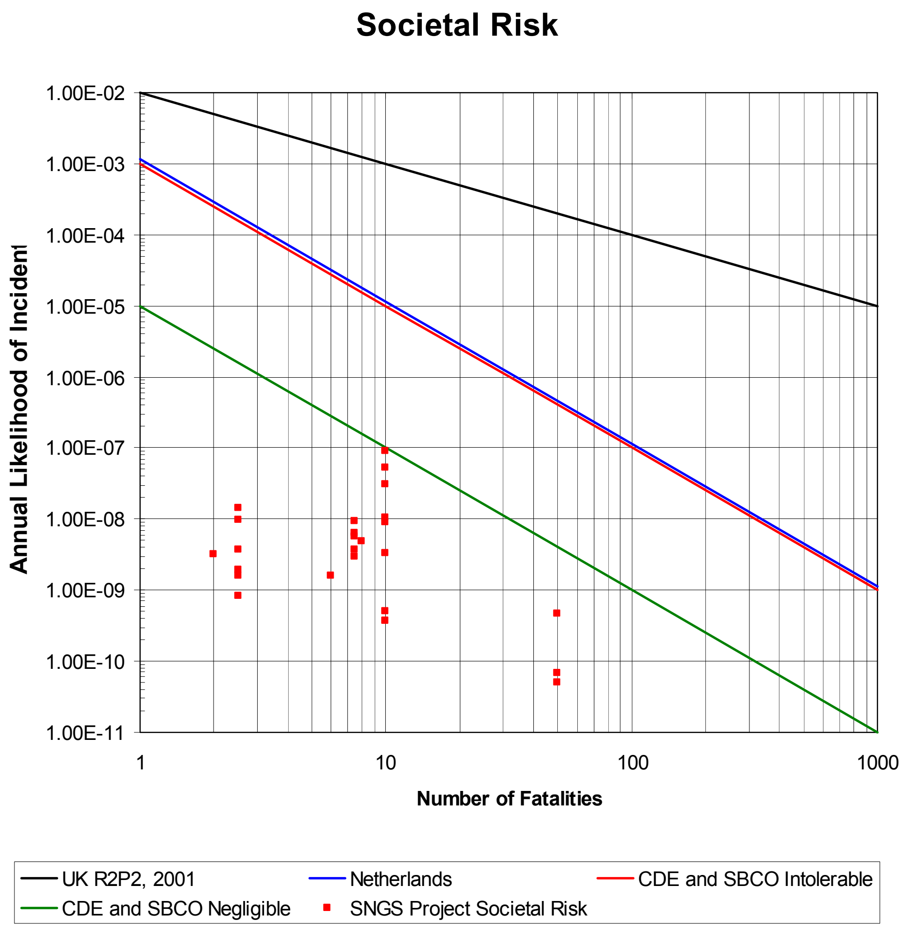


Figure 8.2.1-1 Societal Risk Results, Alternative 1

~~This project alternative reduces the individual impacts posed by the 16-inch line segments by 24%. The total individual risk of serious injury or fatality for this alternative, including the 16-inch and 12-inch pipeline segments, the compressor station, the well site, and the meter station is approximately 6.2×10^{-6}, roughly 10% less than the proposed project. This represents a 1:160,000 likelihood of a serious injury or fatality annually. This value is roughly six times the generally accepted significance criteria of one in one-million per year (1:1,000,000). As a result, the individual risk from this alternative is considered significant.~~

8.2.2 Alternative Pipeline Route 2

Environmental Setting

This alternative would utilize the same construction locations for the wellhead site, compressor station, and SMUD Line 700 tie-in. Only the pipeline route would differ from the Proposed Project. From the northwest corner of the wellhead site, this alignment would run approximately 600 feet north within the utility alignment to Berry Avenue, and then parallel the UPRR tracks north to Elder Creek Road. This alignment would be approximately 7,700 feet long. This alternative would be approximately 350 feet longer than the Proposed Project.

Environmental Impacts and Mitigation Measures

The potential impacts for this alternative are similar to those posed by the proposed project. However, the lengths of line posing potentially serious impacts to building and vehicle occupants are different. ~~These data are summarized in the following tables.~~

~~Table 8.2.2-1~~
~~Length of 16-inch Line Posing Potentially Serious Impacts to Building Occupants~~

~~Event~~	~~Length of 16-inch Line Posing Potentially Serious Impact~~	
	~~Residential Buildings~~	~~Commercial Buildings~~
~~1-inch Diameter Flash Fire 25-foot Impact Distance~~	~~0~~	~~0~~
~~1-inch Diameter Torch Fire 80-foot Impact Distance~~	~~0~~	~~2,100~~
~~Rupture Flash Fire 110-foot Impact Distance~~	~~0~~	~~2,100~~
~~Rupture Torch Fire 600-foot Impact Distance~~	~~1,000~~	~~10,300~~
~~1-inch Diameter Explosion 50-foot Impact Distance~~	~~0~~	~~0~~
~~Rupture Explosion 200-foot Impact Distance~~	~~750~~	~~2,200~~

~~Table 8.2.2-2~~
~~Length of 16-inch Line Posing Potentially Serious Impacts to Vehicle Occupants~~

~~Event~~	~~Width of Exposure (feet)~~	~~Length of 16-inch Line Posing Potentially Serious Impact~~		
		~~Power Inn Road Exposure Probability = 50% (one side)~~	~~Fruitridge Road Exposure Probability = 50% (one side)~~	~~Elder Creek Exposure Probability = 100% (both sides)~~
~~1-inch Diameter Flash Fire 25-feet Impact Distance~~	~~15-feet Vapor Cloud Minimum 1 Vehicle Exposed~~	~~700~~	~~25~~	~~120~~
~~1-inch Diameter Torch Fire 60-feet Impact (Flame) Distance~~	~~800-feet (8,000 btu/hr-ft²)~~	~~750~~	~~60~~	~~170~~
~~Rupture Flash Fire 110-feet Impact Distance~~	~~70-feet Vapor Cloud Minimum 1 Vehicle Exposed~~	~~800~~	~~100~~	~~270~~
~~Rupture Torch Fire 500-feet Impact (Flame) Distance~~	~~600-feet (8,000 btu/hr-ft²)~~	~~1,100~~	~~520~~	~~930~~
~~1-inch Diameter Explosion 40-feet Impact Distance~~	~~80-feet @ 1 psig Overpressure Minimum 1 Vehicle Exposed~~	~~700~~	~~45~~	~~150~~
~~Rupture Explosion 200-feet Impact Distance~~	~~300-feet @ 1 psig Overpressure Minimum 1 Vehicle Exposed~~	~~850~~	~~150~~	~~470~~

Comparison to the Proposed Project

The individual risk would not be affected by this alternative, since the pipeline segment lengths would be essentially the same as those for the Proposed Project. (The individual risk is the likelihood of fatality at a specific point along the pipeline; it does not take into account the length of the line segment, nor the population density.)

The aggregate risk of annual fatality for the pipeline segments would be 1.43×10^{-6}, about 11% less than the Proposed Project. The aggregate risk for the well site would remain unchanged. The total aggregate risk of annual fatality for this alternative would be 6.85×10^{-6}, about 2% less than the Proposed Project.

The societal risk posed by this alternative is presented in the following figure. As indicated, the risks are below the significant threshold, although one risk scenario falls above the negligible risk threshold established by the California Department of Education and Santa Barbara County. This risk scenario includes the potential impacts of torch fires from pipeline releases.

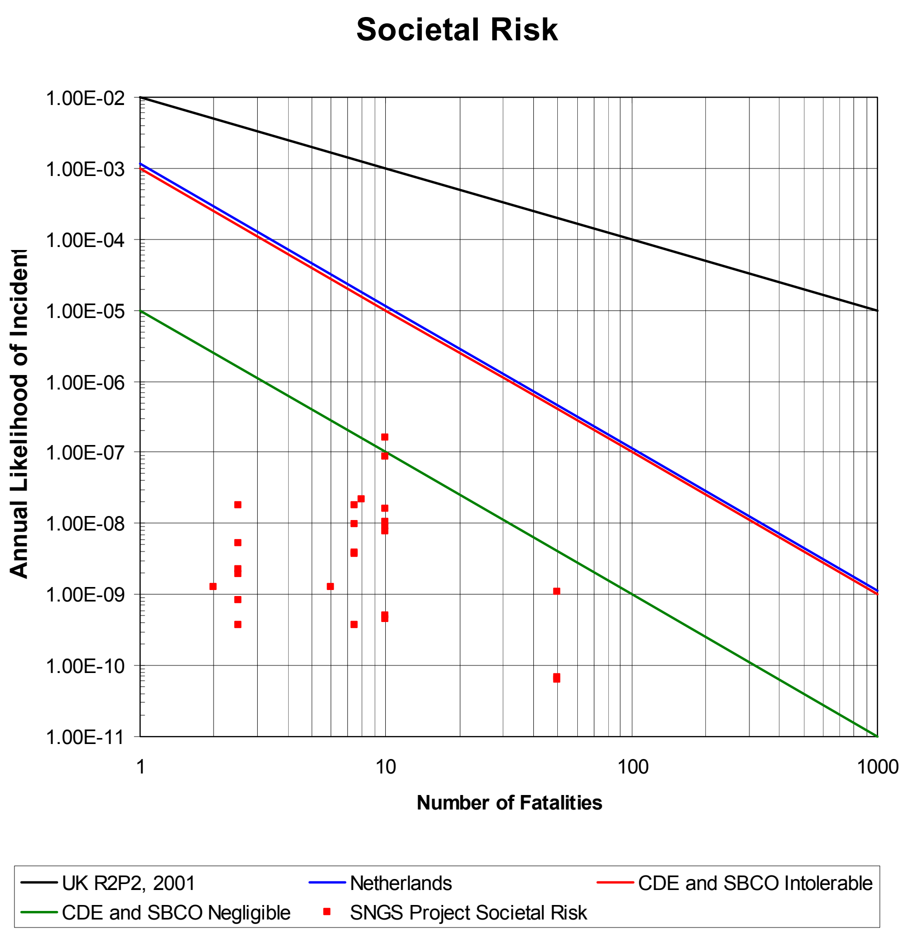


Figure 8.2.2-1 Societal Risk Results, Alternative 2

~~This project alternative reduces the individual impacts posed by the 16-inch line segments by 13%. The total individual risk of serious injury or fatality for this alternative is approximately 6.5 x 10^-6^, roughly 6% less than the proposed project. This represents a 1:154,000 likelihood of a serious injury or fatality annually. This value is six and one-half times the generally accepted significance criteria~~

~~of one in one million per year (1:1,000,000). As a result, the individual risk from this alternative is considered significant.~~

8.2.3 Alternative Pipeline Route 3

Environmental Setting

This alternative would utilize the same construction locations for the wellhead site, compressor station, and SMUD Line 700 tie-in. Only the pipeline route would differ from the Proposed Project. From the northwest corner of the wellhead site, this alignment would run north approximately 1,650 feet within an existing utility alignment and then approximately 650 feet north along Power Inn Road to Elder Creek Road. From that intersection, the pipeline would be installed within Elder Creek Road, for approximately 1,800 feet, to the intersection with the UPRR tracks. This alternative would be approximately 7,100 feet long. This alternative would be approximately 250 feet shorter in length than the Proposed Project pipeline.

Environmental Impacts and Mitigation Measures

The potential impacts for this alternative are similar to those posed by the proposed project. However, the lengths of line posing potentially serious impacts to building and vehicle occupants are different. The primary changes are an increase in exposure to vehicle occupants along Power Inn Road and Elder Creek Road and a longer exposure to residential development. ~~These data are summarized in the following tables.~~

~~Table 8.2.3-1~~
~~Length of 16-inch Line Posing Potentially Serious Impacts to Building Occupants~~

~~Event~~	~~Length of 16-inch Line Posing Potentially Serious Impact~~	
	~~Residential Buildings~~	~~Commercial Buildings~~
~~1-inch Diameter Flash Fire~~ ~~25-foot Impact Distance~~	~~0~~	~~0~~
~~1-inch Diameter Torch Fire~~ ~~80-foot Impact Distance~~	~~0~~	~~700~~
~~Rupture Flash Fire~~ ~~110-foot Impact Distance~~	~~0~~	~~700~~
~~Rupture Torch Fire~~ ~~600-foot Impact Distance~~	~~3,000~~	~~9,200~~
~~1-inch Diameter Explosion~~ ~~50-foot Impact Distance~~	~~0~~	~~0~~
~~Rupture Explosion~~ ~~200-foot Impact Distance~~	~~2,500~~	~~2,600~~

~~Table 8.2.3-2~~

~~Length of 16-inch Line Posing Potentially Serious Impacts to Vehicle Occupants~~

~~Event~~	~~Width of Exposure (feet)~~	~~Length of 16-inch Line Posing Potentially Serious Impact~~		
		~~Power Inn Road Exposure Probability = 50% (one side)~~	~~Fruitridge Road Exposure Probability = 50% (one side)~~	~~Elder Creek Exposure Probability = 100% (both sides)~~
~~1-inch Diameter Flash Fire 25-feet Impact Distance~~	~~15-feet Vapor Cloud Minimum 1 Vehicle Exposed~~	~~2,500~~	~~25~~	~~1,400~~
~~1-inch Diameter Torch Fire 60-feet Impact (Flame) Distance~~	~~800-feet (8,000 btu/hr-ft²)~~	~~2,500~~	~~50~~	~~1,400~~
~~Rupture Flash Fire 110-feet Impact Distance~~	~~70-feet Vapor Cloud Minimum 1 Vehicle Exposed~~	~~2,600~~	~~100~~	~~1,600~~
~~Rupture Torch Fire 500-feet Impact (Flame) Distance~~	~~600-feet (8,000 btu/hr-ft²)~~	~~2,900~~	~~520~~	~~2,200~~
~~1-inch Diameter Explosion 40-feet Impact Distance~~	~~80-feet @ 1 psig Overpressure Minimum 1 Vehicle Exposed~~	~~2,500~~	~~45~~	~~1,400~~
~~Rupture Explosion 200-feet Impact Distance~~	~~300-feet @ 1 psig Overpressure Minimum 1 Vehicle Exposed~~	~~2,600~~	~~150~~	~~1,600~~

Comparison to the Proposed Project

The individual risk would not be affected by this alternative, since the pipeline segment lengths would be essentially the same as those for the Proposed Project. (The individual risk is the likelihood of fatality at a specific point along the pipeline; it does not take into account the length of the line segment, nor the population density.)

The aggregate risk of annual fatality for the pipeline segments would be 8.19×10^{-6}, about 73% more than the Proposed Project. The aggregate risk for the well site would remain unchanged. The total aggregate risk of annual fatality for this alternative would be 6.85×10^{-6}, about 17% more than the Proposed Project.

The societal risk posed by this alternative is presented in the following figure. As indicated, the risks are below the significant threshold.

~~This project alternative increase the individual impacts posed by the 16-inch line segments by 35%. The individual risk of serious injury or fatality for this alternative is approximately 7.8 x 10^{-6}, roughly 13% greater than the proposed project. This represents a 1:128,000 likelihood of a serious injury or fatality annually. This value is roughly eight times the generally accepted significance criteria of one in one-million per year (1:1,000,000). As a result, the individual risk from this alternative is considered significant.~~

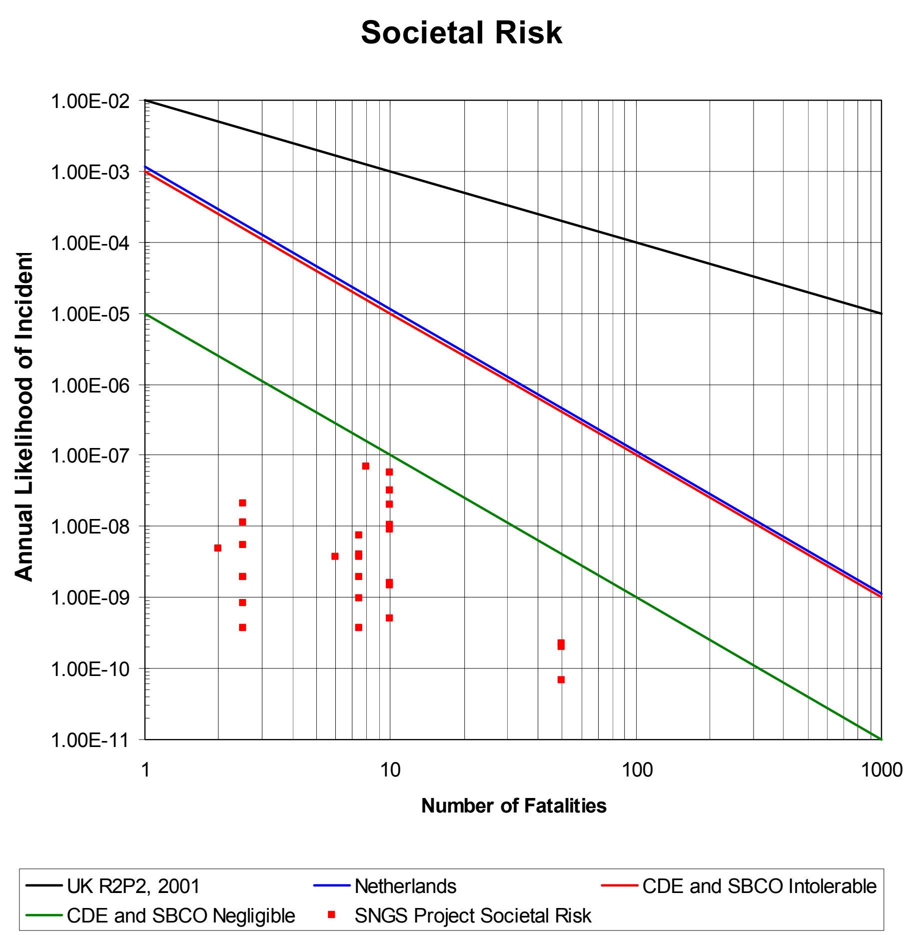


Figure 8.2.3-1 Societal Risk Results, Alternative 3

8.3 Environmental Impacts of the No Project Alternative

Under the No Project Alternative, none of the facilities associated with the project or alternatives evaluated in this EIR would be developed; therefore none of the impacts in this section would occur to systems safety. However, in the event of disruption of the Pacific Gas and Electric (PG&E)

natural gas pipelines 400/401, SMUD may be required to implement cutbacks on non-essential energy use and may run out of natural gas at some locations.

9.0 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 from the pipeline, 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.

9.1 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 9.1-1 and 9.1-2 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 9.1-1
Low Pressure Line Segment, Flash Fire Impact Distances (feet), Rupture, Release 45° Above Horizon, Downwind

Atmospheric Stability[3]	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	183	45	31	24	29	18
B	183	45	31	24	21	18
C	183	60	43	35	39	27
D	183	**76**	57	48	42	38
E	N/A	76	57	N/A	N/A	N/A
F	183	76	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 Final EIR analysis.
5. N/A indicates wind and stability combinations that do not normally occur.

[3] 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 9.1-2
Low Pressure 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	19	18	17	17	16	16
B	19	18	17	17	16	16
C	19	18	17	17	16	16
D	19	**18**	17	17	16	16
E	N/A	18	17	N/A	N/A	N/A
F	19	18	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 Final EIR analysis.
5. N/A indicates wind and stability combinations that do not normally occur.

9.2 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. This method 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 9.2-1 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.

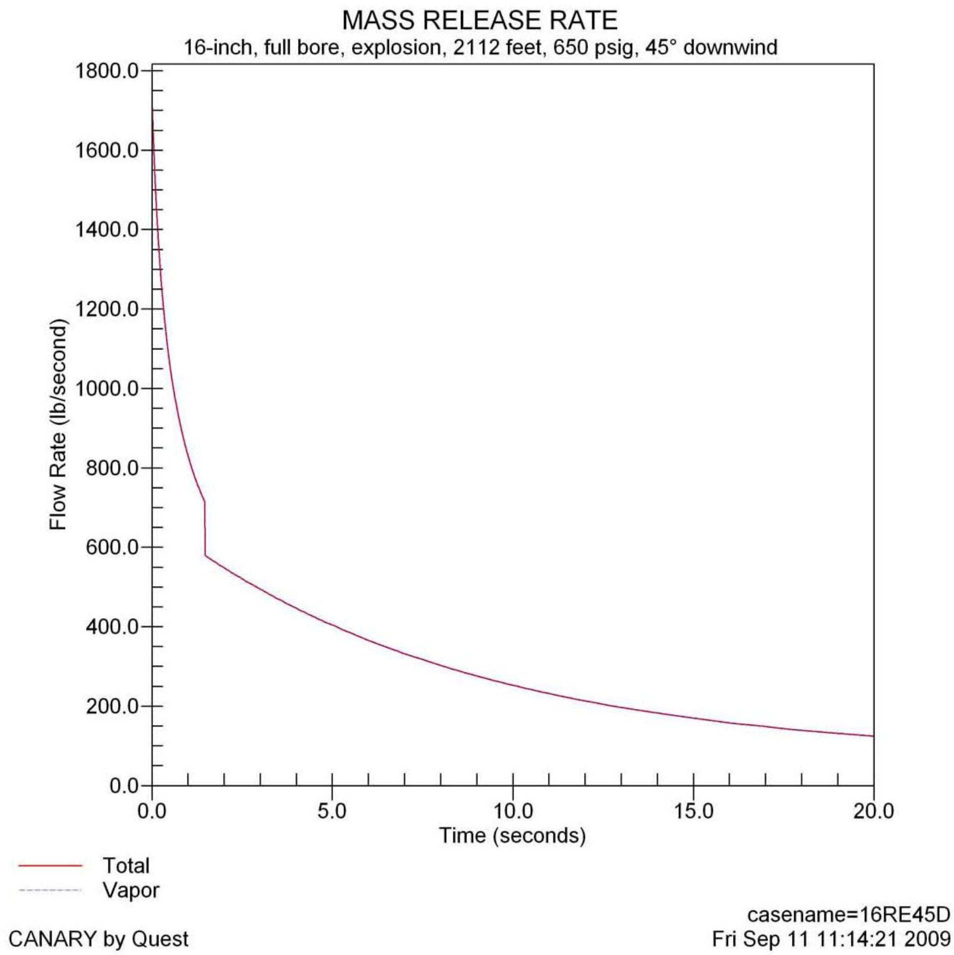


Figure 9.2-1 Low Pressue Line Segment, Mass Release Flow Rate

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

Table 9.2-1
Low Pressure 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	70	98	130	144	155	160	165	168	175
50% Mortality 8,000 btu/hr-ft^2	124	150	169	178	183	187	190	192	198
1% Mortality 5,000 btu/hr-ft^2	187	201	211	214	217	219	221	222	222

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

Table 9.2-2
Low Pressure 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	19	33	44	49	51	51	52	51	56
50% Mortality 8,000 btu/hr-ft^2	27	42	50	53	54	54	54	54	56
1% Mortality 5,000 btu/hr-ft^2	38	51	57	59	58	58	58	58	58

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 Final EIR and the analyses presented herein used a wind speed of 20 mph.

9.3 Vapor Cloud Explosions

As noted in the previously, the maximum anticipated peak overpressure level was only 0.38 psig. This value is not sufficient to result in fatalities to those located outdoors. In the rural areas and relatively open residential and commercial areas along the pipeline corridor, the peak overpressure levels will range from 0.02 to 0.38 psig, due to the lack of confinement. These overpressure levels will not result in fatalities. The anticipated frequencies of fatalities resulting from explosions are presented in Table 9.3-1 below.

Table 9.3-1
Explosion Overpressure Levels

Mortality Rate	Outdoor Exposure (psig)	Indoor Exposure (psig)
99% Mortality	72	13
50% Mortality	13	5.7
1% Mortality	2.4	1.0

(CDE 2007)

10.0 MODELING ASSUMUPTIONS

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 was immediate 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. Specifically, for a rupture release at 45° above the horizon from Line 406, the bottom of the combustible portion of the vapor cloud would be 230-feet above grade at 300-feet from the release. As a result, one would not be exposed to flash fire impacts at this location; the flash fire would be located overhead. 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.

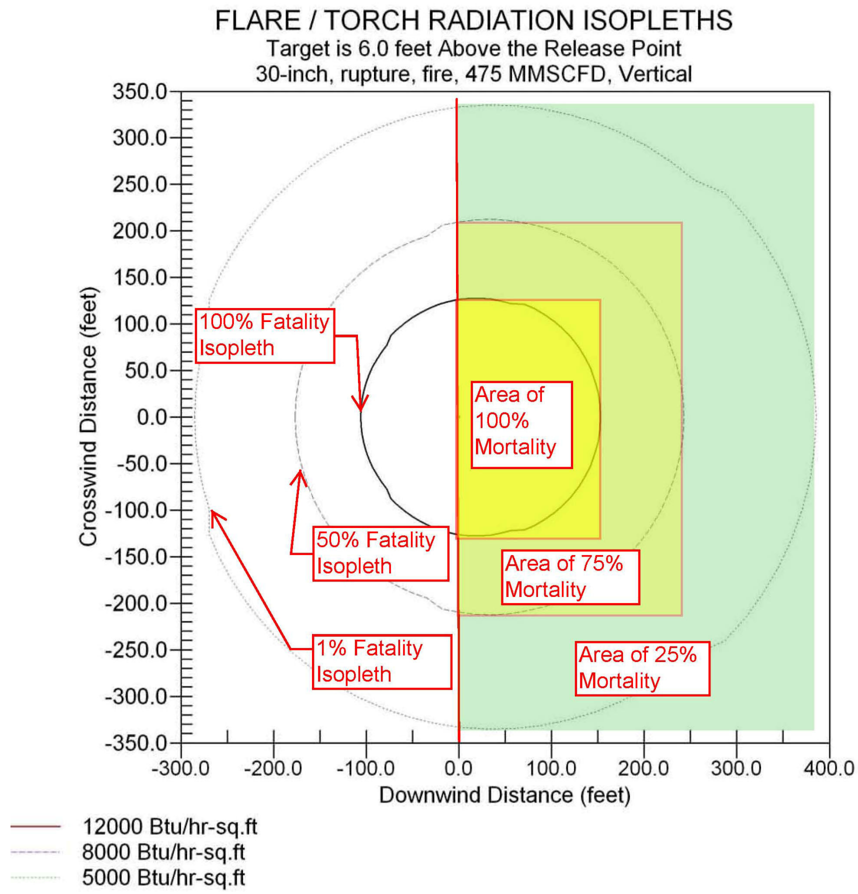


Figure 10.0-1 Typical Pipeline Rupture Mass Release Flow Rate

- 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.

11~~9~~.0 REFERENCES

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APPENDIX B-2

Peer Review of Appendix B-1, System Safety and Risk of Upset

Prepared by Atkins
May 2010

ATKINS

920 Memorial City Way
Suite 700
Houston, TX 77024

18th May 2010

To: **John Westermeier**
Dudek
111 Pacifica, Suite 220
Irvine, California, 92618

Subject: **Peer Review –Environmental Impact Report – Final Draft Report Sacramento Natural Gas Storage LLC's, Sacramento Natural Gas Storage Project Appendix B - System Safety and Risk of Upset**

Dear Mr. Westermeier:

I have completed my review of Appendix B ("Document for Review") and the associated comments in the main body of the Environmental Impact Report for the Sacramento Natural Gas Storage LLC's Sacramento Natural Gas Storage Project.

The information in the main report and "Appendix B -System Safety and Risk of Upset" is insufficient to perform a comprehensive review of the detailed work upon which the analysis is based. Details on population densities and assumptions used to develop the densities, as well as details used to determine leak frequencies and ignition probabilities for the system's wellhead operations and compressor system were unavailable in the Document for Review. Nevertheless, a quantitative comparison to values that might be typically expected for the assessment could be made by combining the data that was available in the report with assumptions about process piping and instrumentation at the wellhead site, land use based on Google Maps satellite images, and assumptions about population density based on those images. Sufficient detail was provided to check the consequence modeling results used in the assessment. It should be noted that the assessment carried out as part of the evaluation process was for the limited purpose of understanding the calculations and conclusions presented in the Document for Review. The quantitative assessment in this report should not be used as a final assessment of the hazards due to the facility under review.

Overall, individual risks to the public from the system appear low, below the negligible risk value of $1x10^{-6}$ per year presented in the report, a value consistent with general practice for assessing public risk. Our assessment suggests public individual risk is below $1x10^{-6}$ per year for the entire system and its surroundings, except perhaps from compressor explosion, which is not assessed by Atkins, due to lack of information. The risks within the report's wellhead analysis are much higher than the rest of the system, but the reasons why are not clear and inconsistent with our estimates. Based on our calculations, the wellhead risks appear inflated by about 600 times by our calculations. (The Environmental Impact Report estimate is $5x10^{-5}$ per year vs.

$8x10^{-8}$ per year by our calculations). Our calculations of individual risks from the pipeline areas produce similar values for risk as in the Document for Review.

Societal risk calculations in the Document for Review appear to be incorrectly represented. They are presented as plots of individual incidents and not as a cumulative project sum up to a certain number of fatalities. Societal risk to the individual residences west of Power Inn Road at the southern end of the project may be significant, as they seem to lie between negligible intolerable societal risk curves for California Department of Education (CBE) and Santa Barbara County Planning and Development (SBCO), depending upon assumed outdoor population density. The assessment of the Societal Risk is very sensitive to the population densities assumed for the various areas impacted. Variations in assumptions could result in a variation in the conclusions on societal risk from the tolerable to the intolerable. The assumptions around these population densities must be verified and agreed upon with the relevant stakeholders.

The Document for Review does not address the potential for explosion in the compressor building and its impact potential outside of the property borders, particularly its impact on industrial properties to the north. From our review of the consequence modeling, if the building acts as a complete enclosure, the potential overpressures could be strong enough to pose a risk to the buildings to the north of the compressor station. The predicted consequence results are very sensitive to the amount of confinement and congestion specific to the building. It is recommended that the project take a more detailed look at this potential risk if an enclosed building is used for this system.

Due to a lack of detailed engineering information, Section 8, the comparison to alternatives, was not assessed in detail, except for noting the Societal Risk presentations appear to be incorrectly represented.

There are several sections in the Document for Review in which the same technical discrepancies are repeated in regards to consequences of high-pressure natural gas releases and risk in general. These are:

- Explosions are assumed to be possible due to natural gas releases in locations where there is insufficient congestion to develop a vapor cloud explosion. Overall historical frequencies are used to lend the explosion scenarios credibility, not recognizing site-specific circumstances (lack of congestion) that would eliminate this as a credible event. For instance, the wellhead site does not appear to be a credible explosion hazard, due to lack of congestion and the directionality of releases, yet given a release occurs and ignites, they are assigned a high likelihood of explosion.
- Releases are referred to as drifting clouds, and methane is described as being buoyant (e.g., see Section 1.2 of "Appendix B – System Safety and Risk of Upset"). All systems are pressurized gas and would result in high momentum jet releases that are very directional, and do not develop flammable drifting, buoyant clouds in these circumstances. Figure 6.3.1-1 of "Appendix B – System Safety and Risk of Upset" illustrates this with a 45-degree release profile.
- There are several locations in the Document for Review that speak of fatalities occurring if a release ignited, yet they are locations that have no identified population within the exposed area. For a fatality to occur, people must be present. The report would be less inflammatory and more accurate if the wording was modified to reflect this fact.
- The Document for Review presents Probable Loss of Life estimates, but offers nothing to compare these results to or assess their acceptability. It is recommended they be removed.

- The Document for Review would benefit from more and greater justification of the safety features, presentation of project benefits to the public, and comparisons to other risks to offer perspective.

In conclusion, the above review comments need to be addressed before a final conclusion can be drawn on the Document for Review. This is due to the fact that the some of the conclusions could change based on a verification of the assumptions made, particularly around the population densities.

I have attached a more detailed technical note with my comments, plus an attached original report Appendix B, with my comments inserted, for your consideration.

Please feel free to contact me in regards to any questions or comments.

Yours sincerely,

Richard M. Gustafson, C.S.P.
Principal Consultant

HSE Group
Energy - Americas

Subject:	Dudek – Peer review "Appendix B – System Safety and Risk of Upset" portion of the Sacramento Natural Gas Storage Project Environmental Impact Report				
Reference:		**Rev:**	G	**Date:**	May 18, 2010
Client:	Dudek	**Contact:**	John Westermeier		
Installation:	Sacramento Natural Gas Storage	**Query Reference:**			
Written:	R. M. Gustafson	**Checked:**		**Approved:**	
Reference Documents:	Revised Draft Final Environmental Impact Report Sacramento Natural Gas Storage, LLC's Sacramento Natural Gas Storage Project. CPCN Application No. A.07-04-013 SCH No. 2007112089 Volume 2. Executive Summary and Appendix B.				
Attachments:	Commented Executive Summary and Appendix B of Draft Final Environmental Impact Report				

1. Background

Sacramento Natural Gas Storage, LLC intends to install a natural gas storage facility in a depleted underground gas field in the Sacramento area. As part of the permitting process, the State of California used their contractor, Dudek, to prepare an Environmental Impact Review (EIR) of the project. Dudek, in turn, hired a second party contractor, EDM Services, to perform a System Safety and Risk of Upset study for acute hazards, including a quantitative risk assessment (QRA) from the risks of accidental releases of natural gas. Historical data and results from Quest Consultant's model, CANARY, run by EDM, were used to prepare the QRA. The Draft EIR was released for public review; responses to the results of the QRA, particularly from SNGS, resulted in a revision of the report. Prior to reissue of the report, the California Public Utilities Commission (CPUC) requested an independent peer review of the revised System Safety and Risk of Upset (Appendix B) and the corresponding Executive Summary components by a qualified consultant. Due to familiarity with the CANARY model, oil and gas risk assessment and operations, and availability as an independent consultant, Richard Gustafson of Atkins (the author) was hired to perform the review.

Overall comments have been made in a separate summary letter. Detailed comments are presented in this technical note. In addition, a separate word document with individual line comments has been developed. Please note that this assessment of the report utilized estimates of risk made by us for comparison purposes. Risk assessment estimates are very sensitive to population densities, and assumed failure and ignition rates. Details on population densities and assumptions used to develop the densities, details used to determine leak frequencies and ignition probabilities for the system's wellhead operations and compressor system were unavailable to us in the Revised Draft Final Environmental Impact Report (Document for Review), The independent risk calculations undertaken by us and presented in this document were for the limited purpose of understanding the calculations and conclusions presented in the Document for Review. The quantitative assessment presented by us in this Technical Note should not be used as a final assessment of the hazards due to the facility under review.

2. Detailed Comments

2.1 Project Societal Risk Calculations Seem to be Miscalculated and Low

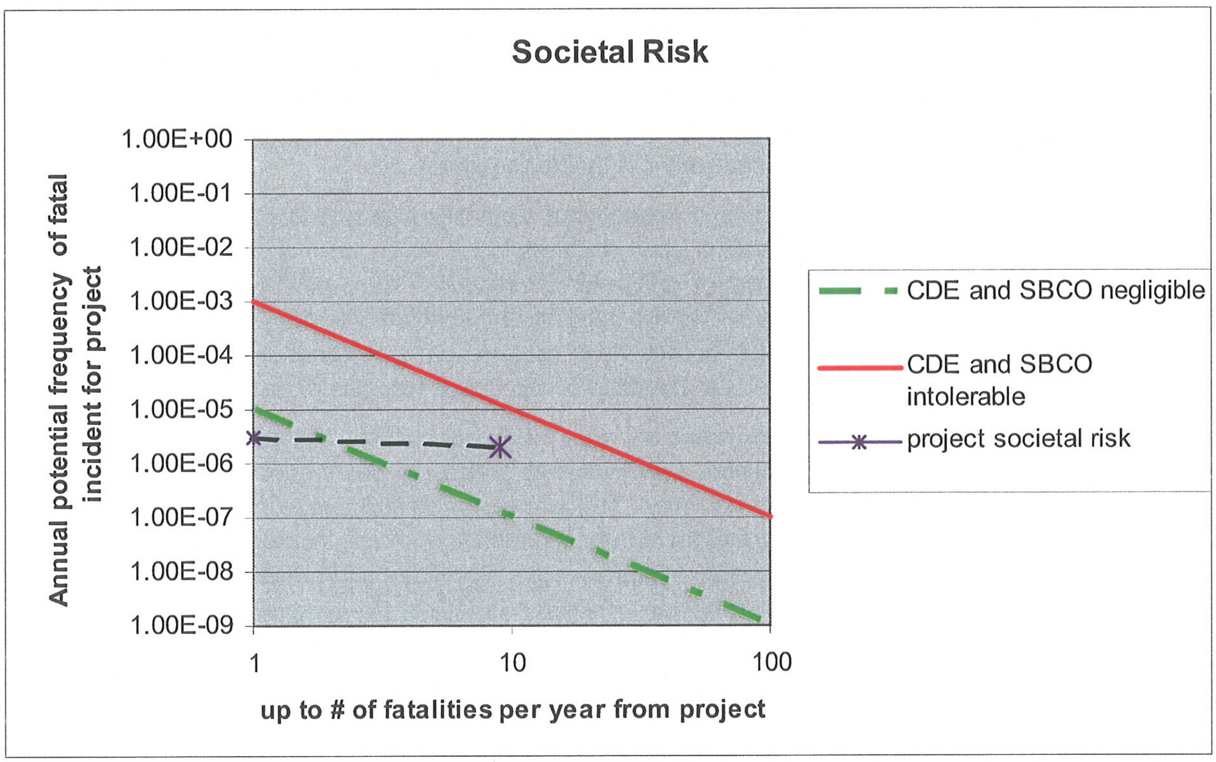
The societal risk calculations seem low. The values may not be calculated correctly, based on Figure 8.2.2-1 pg B-101 of the report. In the figure, individual dots of each incident seem to have been plotted vs. the societal risk curve. In a societal risk curve, a cumulative sum of all incidents up to a certain population size is plotted for all incidents as a connected curve, not values for each incident.

The societal risk values are driven by the population assumptions, particularly in the residential area on the western side of Power Inn Road across from the wellhead area via risks from pipeline ruptures. Thus the population density assumptions are critical to the results, and should be agreed upon or verified by all stakeholders.

For example, If a constant exposure of one individual per residence outdoors during the day is assumed for each in the building opposite the wellhead facility on the west side of Power Inn Road, the societal risk estimate predicts a total value of up to 9 fatalities at 7×10^{-6} per year. This is significantly into the negligible to intolerable zones on the societal risk curve. If there is 1 person outside at every 10 residences, then the value is about 1 fatality every $7x10^{-7}$ per year, which is just below the negligible (de-minimus) value for the societal risk curve. Thus, depending upon the population assumptions, the societal risk could lie in the significant region. According to our estimates, the sustained radiation levels are not sufficient to ignite unpiloted wood; therefore conventional residences should offer shelter and not escalate from fire exposure. As the population description in "Appendix B System Safety and Risk of Upset", Section 6.7.1 suggests higher assumed population exposures than we have used in our estimate (i.e., 4 per residence and 10 per commercial building outdoors, vs. 1 per residence and 2 per the only exposed commercial building for our estimates), and we show non-negligible risks, the societal risk calculations should be revisited.

The CDE and SBCO negligible and intolerable societal risk curves vs. the project societal risk are presented in Figure 2-1. The values shown are based on 7 individuals spread along the pipeline route in 2.7 mile length, plus 1 individual outside at each residence across from Power Inn Road at the wellhead. Radiation hazard footprints are determined from releases at a 45 degree angle are modeled using the 30 second flow rate.

Figure 2-1 Estimated Societal Risk for Project vs. CDE and SBCO curves,



2.2 Observations on Pipeline Risk Assessment Calculations

Pipeline frequencies for release and ignition seem reasonable, consistent, and justified by the presented data. The assumption for ignition probability seems somewhat higher than what could be found for an historical average (17% vs. 4-5%). However, this also does not seem unreasonable given the urban setting, which could result in more ignition sources, (e.g., road traffic). The inclusion of explosions as a credible event for the pipeline route is probably not appropriate, due to a lack of congestion in the hazardous region. However, since the results are below the de-minimus value, the impact is insignificant to the conclusion that the risks are tolerable in comparison to accepted de-minimus values.

2.3 Observations on Individual Risk Values.

Based on land use, pedestrian density is assumed to be fairly low. Based on a density of 400 feet between each pedestrian, we calculate that predicted frequency of an individual fatality along the route from a pipeline failure is 1.7×10^{-7} per year, value well below the de-minimus of 1×10^{-6} individual risk per year. Within the neighborhood across from Power Inn Road, our calculations estimate the maximum individual risk at 6.7×10^{-7} per year, still below the de-minimus value of 1×10^{-6} per year, 8.4×10^{-8} per year south of the wellheads. Because the population is assumed to be spread out along the route, each event is assumed in this estimate to be an individual fatality. However, as in the societal risk values presented in Figure 2.1, the individual risk values are very sensitive to population assumptions, which are only estimates here, and have not been evaluated in detail and accepted by interested parties. Any final assumptions on project risk can only be made if the population distribution assumptions are verified.

2.4 The Analysis Does not Assess Compressor Building Explosion Risk Effects Outside the Building

The compressors are to be housed in building of dimensions 110x60x24 feet. Although a leak at the compressor station and subsequent ignition might be a low frequency event, it could result in a confined explosion within the compressor enclosures with the potential for significant overpressures damaging adjacent buildings with the potential for fatalities. Whether or not the overpressure could reach significant overpressure offsite depends on building construction details, which were not available at the time of this review. Thus any final overall conclusions about risks for the project cannot be made without this assessment.

At the flow rate from a 1" hole, a release at the pipeline pressure is capable of filling the building to the stoichiometric concentration (the concentration at which there is just enough fuel to consume all of the oxygen, in the event of ignition) in 88 seconds. At a release rate corresponding to full rupture of the pipeline, it would fill the building to the stoichiometric concentration in 8 seconds. Thus, for larger releases, it is unrealistic to assume that a detection and shutdown system would react rapidly enough to prevent a buildup of significant volumes of flammable gas.

The report does discuss explosion hazards inside the building, but assumes the overpressure would be limited to the building. However, overpressures would not be confined to the building if the building is of normal construction. To the north, there are exposures where there may exist the potential for public exposure of an industrial population to overpressure risk, depending upon the degree of building confinement. Whether or not significant overpressures could reach offsite from a compressor explosion depends on the design details of the compressor building. If it is a completely enclosed conventional building, the build up of higher overpressures is possible. If it is a partially enclosed (open at the sides with roof) type compressor shed, then the potential overpressures are estimated to be low enough as to not seriously threaten the public next door. There is park land, primarily undeveloped, to the south and to the east.

To estimate the significance of a compressor building explosion, we modeled an explosion in the building using the CANARY Baker-Strehlow-Tang model. Details on the explosion assessment are:

- Distances to potential sources were calculated using CANARY with the fuel gas set at low reactivity

- Congestion set at medium and volume of gas clouds assessed at ¼ the building volume and the entire building volume
- Reactivity of the fuel set at low[1]

Modeling results are presented in Table 2-1.

[1] The choice of a low reactivity for the mixture was in contrast to Quest's modeling, which set it at medium due to the presence of ethane. The justification for low reactivity is from on an assessment for 96% methane and 4% ethane (typical of natural gas) based on recommendations in a 1998 paper on the Baker-Strehlow-Tang model by the model developers. This paper recommends predicting the laminar burning velocity for the mixture based on Le Chatelier's law mixing rule, and comparing the mixture value to a threshold of 40 cm/s for medium reactivity gases. The rule was applied to an assumed gas composition of 96% methane and 4% ethane release. This composition was chosen as approximate values for a typical natural gas mixture with a methane composition typical of natural gas, recognizing the dominant second component is usually ethane. Based on laminar burning velocities from “Loss Prevention in the Process Industries 3rd Edition” by M. Sam Mannan, the burning velocity of the mixture was predicted to be 36.5 cm/s, below the 40 cm/s threshold and very close to pure low reactivity methane (35.1 cm/s).

Table 2-1 Distances to Overpressures for Explosions in the Compressor Building, vs. Degree of Confinement.

	1/4 building Volume =cloud size			Full building = cloud size		
	Confinement factor (1 = total confinement, 2 = Ceiling and floor. 2.5 = traditional compressor shed.					
Indoor (overpressures, lbf/in2)	**1D**	**2D**	**2.5D**	**1D**	**2D**	**2.5D**
	Predicted Distances to threshold from building center, feet					
13 (99 % lethal)	69.5	0	0	110.2	0	0
5.7 (50% lethal)	138.8	0	0	219.8	0	0
2.4 (1% lethal)	607.3	301.8	173.9	961.3	478.0	287.4
Outdoor	**Predicted Distances to threshold from building center, feet**					
72 (99% lethal)	0	0	0	0	0	0
13 (50% lethal	69.6	0	0	110.6	0	0
2.4 (1% lethal)	223.8	128.0	74.8	459.0	205.0	118.8

The distance from the center of the compressor skids to Saipan Street is approximately 300 feet. The distance to the closest building is 560 feet. The distance from the center of the compressor skids to the closest park land is 150 feet (distance to the hurricane fence to the south). Thus, a maximum release with total confinement is predicted to exceed the 1% lethality level for the closest building to the north.

Unfortunately, the models available in the CANARY suite are not capable of resolving what overpressures might be for a particular design, beyond a screening estimate. Should the building be a total enclosure, Computational fluid dynamics modeling (CFD), such as the package FLACS, coupled with a review of the level of overpressures required to fail the building skin can be used to more accurately determine the consequences of a compressor release and subsequent explosion. If the building is an enclosed design, it is recommended that the building be evaluated for potential overpressure hazards using detailed modeling or at a minimum, assess the significance of the offsite risks in the QRA and address the issue in the design if the risks are significant, especially if the building is to be enclosed.

2.5 Failure Frequency Assumptions for Wellhead and Compressor Systems are Undocumented

The wellhead system is poorly documented. The least amount of system information is presented for this system as compared to the pipeline and compressor systems. Yet the report presents this section as the dominant risk and the only section to expose the public to levels above de-minimus individual risk levels. The key drivers behind this conclusion have not been clearly stated and are difficult to decipher given the level of documentation.

For instance, the wellhead failure frequency basis is undocumented and is significantly higher than the independent government sources that are available for gas storage wellhead failures presented in the report. It is unexplained why the release frequencies are modified upwards in the analysis. For instance, in the 2008 published report, "Failure Rates for Underground Gas Storage" RR671, the UK HSE reports an anticipated well head failure for a major release of $1\text{x}10^{-5}$

per wellhead year. This is over 8 times lower than the reported rate in the EIR of 8.17×10^{-5} per well-year.

Overall failure frequencies are presented as "well head failure frequencies". Yet the system is composed of additional equipment, including incoming piping, pig launcher/receiver, heat exchangers, and process piping. It remains unclear as to whether failures from these additional systems are included in 8.17×10^{-5} per year estimate.

The design includes a 10-foot-high wall. This could be a barrier to direct exposure from a jet fire of natural gas from a leak, depending upon the release height. From the equipment layout, it appears most equipment (except for perhaps the very tops of the wellheads) would be below the 10-foot level. Thus, the wall is likely to provide an effective passive barrier to the public from straight-on exposure to furthest possible (horizontal) reaching releases.

To assess the observations in the report for wellhead risks, and independent risk assessment was run by us using the following assumptions:

- The greatest extents of the hazard zones at the individual well delivery rate of 60 million standard cubic feet per day were modeled (one well failure).
- To determine the total maximum hazard zone, the releases were modeled as flame jets released at a 5 degree angle, an angle chosen to represent a 6-foot-high release just clearing the 10-foot-high wall. The total maximum reach from the wellhead is about 120 feet at a 1% lethality level (5000 BTU/hr ft2 F). The closest structure is about 150 feet from the wellheads.
- Anybody located inside the building adjacent to the site would be protected from radiation hazards. To the north, the worst-case footprint reaches about 50 feet over the wall, roughly to the edge of the parking lot of Megacabinet, the business to the north of the site. Thus, only individuals who might be walking in the New Image Foam Products parking lot to the south, or at the edge of the Megacabinet property to the north, might be exposed to anything higher than the lower threshold. Without the presence of people in the hazard zone, there is a negligible risk of injury or fatality to the public.
- The probability of ignition is assumed to be 4%, based on UKOOA estimates for small onshore gas plants.
- Piping failures were based on the U.K. HSE database OIR12 assuming a large release (defined in the database as >2 inches in diameter). Larger leaks, required in this system to reach offsite, would be expected to have lower release frequencies.
- The wellhead failure rate was assumed to be 2×10^{-5} per year for full rupture (based on UK HSE upper limits for natural gas storage).
- The population density in the potentially impacted region was assumed to be 2 people at any time located on the northern edge of the New Image Foam Products open parking plot/work area.
- 100 feet of piping and 1 instrument meter was assumed associated with each of the wellheads. Only the two wellheads systems that can reach offsite were included as sources.
- The risk of fatality was estimated using a 45-degree angled release. This angle was chosen to represent an average release direction. At this angle, the risk zone is within 110 to 90 foot from the wellheads for the target radiation hazard fluxes of 5,000 to 12,000 BTU/hr ft2. Only the southern most two wellheads and associated meters and piping are located such that with the risks from these source extends risk outside the property fence line.

The failure rates, ignition probability and risk values for the wellhead location are presented in Table 2-2

Based on the above assumptions, the estimated individual risk of fatality was $8.3x10^{-8}$ per year, below the generally accepted de-minimus of $1x10^{-6}$ per year. Hence the high risk levels in Appendix B for the wellhead do not appear justified based on the lack of nearby population.

The risk from the wellheads would be to be individuals in the north parking lot of the firm to the south (New Foam Products according to Google Maps). From the overhead satellite pictures, it appears to be workers who might be present in this area. Thus, it is reasonable to compare the risk of fatality by this activity against other work risks. For instance, the U.S. rate of fatality by vehicle-mile driven is 1.27 per million vehicle-miles per year in 2008, according to the fatal accident reporting system of the U.S. NHTSA. The average U.S. commute is 18 miles. Assuming the commute is similar for nearby workers, the risk of fatality assuming 48 weeks per year at 10 commutes per week is .011 per year. Thus, the risk from the wellhead system being nearby to nearby workers is about $.011/8.4x10^{-8}$ = 131,000 times lower than the risk of an average commute to work.

Any final assumptions about the significance of either societal or individual risk in the vicinity of the wellheads can only be made if defendable population assumptions can be made, as the results are very sensitive to the assumed population density.

Table 2-2 Wellhead Section – Estimated frequency of fatal incident on Property South of Junipero Street

Component	Number of Potentially Contributing Components or Meters of Piping	Failure rate per year per component or length, or Conditional probability	Total Failure rates/year
Wellhead (contributors assume a average release angle or 45 deg)	2	$1.00x10^{-05}$	$2.00x10^{-05}$
Piping	61	$7.37x10^{-06}$	$4.49x10^{-04}$
Meter	2	$1.24x10^{-05}$	$2.48x10^{-05}$
		Total	$1.55x10^{-04}$
		0.05	Probability of ignition for Small LPG Plant, UKOOA
		$7.73x10^{-06}$	Frequency of Jet Fire
		$6.7x10^{-7}$	Frequency of individual being in impacted area of parking lot
		0.25	Average probability of fatality for impacted area
		$8.4x10^{-8}$	Average individual risk or fatality, yr-1
		$1.68x10^{-7}$	Total fatal risk per year assuming two individuals present

2.6 Documentation for Population Densities Used for Risk Analysis is Confusing

The societal risk contribution from the residences to the west of the wellheads on Power Inn Road appears potentially significant and sensitive to the undocumented population assumptions. Thus, the assumptions are important to understanding the results. However, in our reading of the report, the assumptions and how they were applied are confusing (e.g., Sections 6.71 and 6.7.2 of the report), and could not be used to check the results. Therefore, we ran an independent check using the assumptions below and presented in item 2.1.

There is potential public exposure at the City of Sacramento Park closest to the compressor system. However, this section of land appears mostly undeveloped in satellite photos, so how much use it gets by the public is uncertain.

There is also a risk of pedestrian traffic along the street, and exposure of automobiles to radiation hazards given a worst-case release (rupture) and the most inopportune release orientations (vertical or towards the street). There is some potential industrial exposure along the corridors through industrial sections. However, the density of pedestrian traffic on the street would probably be low, mainly as it is a busy street and a mostly industrial area; the industrial use in satellite photos appears mostly to be storage areas or undeveloped land.

Based on assumptions as to what are reasonable potentially exposed population densities (e.g., no more than one pedestrian every 400 feet), our prediction of the individual risk values for pedestrians is below the de-minimus for the compressor and pipeline segments.

The risk estimate calculated south of the wellheads assumes two people present at any time, for which the de-minimus individual risk is just exceeded. Whether or not this exceeds the de-minimus depends on the population assumptions for the parking lot population.

Any final conclusions about the significance of risks for the project can only be made if justifiable population density and distribution data is available, and should not be construed using this document alone.

2.7 Report Lists Safety Features as Significant that are Unlikely to be Effective on the Risks Studied in the Assessment

The report lists various safety features, many of which are standard regulatory requirements or typical engineering practices, as if they were significant safety improvements. Other safety features are claimed to be effective without justification.

Rapid acting shutdown valves are listed as a significant safety feature for the pipeline. Gas detection is listed as a safety feature of the compressor system and shut-in valves are listed as a wellhead safety feature. The systems described are presented as reacting within 30 seconds. However, the study assumes a 30-second exposure after the release begins and ignites, based on an assumption that people will flee the hazard zone within that time (a reasonable assumption). A device that takes 30 seconds to react should not be presented as a safety device to mitigate a hazard anticipated to be limited to 30 seconds of exposure. These would be effective devices to prevent prolonged releases, e.g., at the operating flow rate, which were not assessed in this report.

2.8 The Report Fails to Justify the Effectiveness of Claimed Safety Features

No detection systems are listed for the pipeline and wellhead segments. Without a detection system that has been verified by engineering analysis to work reliably for significant release rates they should not be described as valid safety features. For instance, if the pipeline system leak detection is based on pressure detection, then moderate leaks may go undetected if there is pressure control in the pipeline. If the detection system uses upstream and downstream meter comparisons, then small leaks may be detectable. However, without the engineering basis supplied, these devices should not be presented as valid enhancements to public safety.

The effectiveness of any detection and shutdown system in the compressor building could be minimal if the building was exposed to a major leak. Although detection and shut-in is very important to manage risks from smaller releases, our calculations show a medium to large hole in the system could fill the room to flammable concentrations within a few seconds (e.g., between 8 to 88 seconds, depending on hole size). This may be much quicker than any detection and shutdown system can work. So additional safety factors, including additional preventive detection (e.g., vibration monitoring) and reduction of ignition potential by the use of Class I Division I electrical apparatus and NEMA explosion-proof electrical enclosures throughout the building should be emphasized. These features may already be in the design, but they are not called out in the report. Also, gas detection should be located both high and low in the building, especially if the system is completely enclosed, due to the highly directional behavior of high-pressure natural gas releases.

2.9 Potential Seismic Hazards are not Addressed

The design is probably sufficient to deal with seismic hazards, as the engineering of structures for seismic hazards in California is common practice. However, seismic hazards in general, particularly from soil movement or liquefaction, are credible concerns. Some elaboration as to their significance to the project should be added to the report.

2.10 Risks Presented in the Report are not Compared to Other Risks to Offer Perspective to the Results

The comparison of the pipeline to the California Department of Education's criteria, and the societal risk curve presented in Appendix B are examples of criteria that are consistent with what has been generally accepted by governing bodies as reasonable values for tolerable risk. However, the results may not be well-comprehended by the public.

One common tactic to aid the public in understanding risks is to explain the benefits of risks taken on by a project, and to compare them to similar tolerated risks. In general, a discussion explaining the benefits of the project to the public, and appropriately comparing the project risks to other tolerated risks might enhance the report. This report does not attempt this. I would think such a section might be beneficial.

For instance, natural gas delivery systems, introduction and use of natural gas into the home for heating and cooking is widely used and tolerated by the public. One cannot benefit from natural gas without the presence of transmission lines, compressor systems wellheads, reservoirs, etc. So how do the risks from delivery systems and the presence of natural gas in homes and buildings compare to the risks to the public from the transmission line? If overall, the risks are lower from the transmission line, then a valid argument can be made that relative to the risk accepted by the public from benefit of heating and cooking with natural gas is much greater than the much lower risks from this system. This might be appropriate in discussion of risks related to the residences across the street from the southern end of the pipeline, depending on the use of gas in those buildings.

2.11 The Report Presents Probable Loss of Life Evaluations that Offer Little Value

The lack of available standards for comparison for aggregate or Probable Loss of Life (PLL) values for public exposure is mentioned in the report. To my knowledge, the statement is true, and PLL are used currently used only to assess industrial/occupational exposures, or to compare one system to another. In this report, the PLL values are presented, but since they are not used to assess the other locations, nor are they compared to tolerability criteria, they do not present any real benefit and should be removed from the report.

2.12 The Report Incorrectly Describes High-Pressure Natural Gas Releases as Buoyant and Therefore Dissipating Upwards

Due to the high pressure of a natural gas release, the gas once released to the atmosphere is quite cold, which more than offsets any buoyancy gained by low molecular weight. The location of the released gas is dominated by the high velocity of the release, not by inherent buoyancy. This can be seen in the jet profile presented in the report in Figure 6.3.1-1. High-pressure gas releases to the open atmosphere tend to go where they are pointed, thus high-pressure natural gas releases are not inherently buoyant. Locations in the report that describe the releases as naturally buoyant, such as Section 1.2, should be corrected accordingly.

2.13 The Report Incorrectly Describes Gas Migration of Vapor Clouds as a Hazard

The report incorrectly describes high pressure natural gas releases as migrating to nearby residences so that flash fires and explosions could happen. We do not see a mechanism for this to happen. The high- pressure natural gas jets inherent to this system would not migrate, and do not present an explosion hazard to nearby residences. This is more of a hazard to low-pressure distribution lines, which are not part of this system.

2.14 There Are at Least Two Locations in the Report that Incorrectly State that if a Release Occurs and Ignites, Fatalities or Injuries Would Happen

For a fatality or injury to occur, someone must be present in the hazard zone. Especially in a system that has a low surrounding population density, an ignited release would not necessarily lead to any impact or injury. The wording is inflammatory, untrue, and should be changed or removed.

2.15 Observations on Consequence Assessments

2.15.1 Thermal Radiation Hazard Modeling

Our independent consequence modeling results agree well overall with the reported results. Table 2-3 presents the results. Note that consequence assessment results can be sensitive to the details selected for the analysis. Thus, minor details in assumptions can result in different values from any two assessors, yet none may be "wrong". The results presented in Table 2-3 and Table 2-4 below are based on the flow rates predicted at 30 seconds into the scenario.

Table 2-3 Downwind and Crosswind Distances to Radiation Hazards for 650 psig Pipeline, 16" Diameter, 2.7 miles long

Angle from Horizontal, degrees	Exposure BTU/hr-ft2-F				Exposure BTU/hr-ft2-F		
	12000	8000	5000		12000	8000	5000
	Full rupture						
	Downwind Distance, ft			Crosswind 1/2 width, ft			
10	335	349	360		110	140	190
45	151	210	270		60	110	170
90	38	72	132		38	72	132
	1 " hole						
10	57	59	63		17	27	31

Table 2-4 Downwind Distance to Radiation Hazards for Release at Maximum Wellhead Flow rate.

Angle from Horizontal, degrees	Downwind Distances, feet, Full Wellhead Failure		
	Exposure BTU/hr-ft2-F		
	12000	8000	5000
5	97	108	121
45	80	90	110
90	56	77	100

2.15.2 Comments on the Presence of Road Near the Pipeline

Our calculations suggest the potential for fatal risk to the driving public from flammable releases is very low.

Individuals in vehicles are probably protected from the flammable radiation hazard due to the very brief exposure they would experience should they be exposed to a jet fire and the windows are up (the windows or vehicle structure should protect the occupants). Even if the windows are down, as long as the vehicle is moving, there is such a brief exposure period that fatality is unlikely.

At 40 mph and a worst-case width of 340 feet jet width, the exposure is for 6 seconds, less than the 30 second hazard threshold. Based on the potential for lethality predicted for a 6-second exposure, the 99% normal lethality level at 30 seconds exposure is reduced to about a 40% lethality level, while the 50% lethality level corresponds to about a 1% lethality level. Thus, the road segment on Power Inn Road is exposed to potentially fatal doses, but a much lower probabilities than for a 30-second exposure if traffic is moving at a normal rate. For someone exposed with the windows open, but driving, the individual risk is estimated to be 1.5×10^{-7} per year, below the de- minimus of 1×10^{-6} per year. As the hazards are highly directional, there is little overall risk to the vehicular public from a release from the system.

Pedestrian traffic would be presented with some risk, but the values are low given the low failure rate, ignition probability, and population densities. By comparison, risk of injury or fatality from being struck by vehicular traffic is also present but much higher than the risk from pipeline releases. For instance, in 2003 there were 1.72 pedestrian fatalities per billion vehicle miles. At 30,000 cars per day passing the .375 mile segment of Power Inn Road pipeline (the segment where pedestrians would be most exposed), the potential frequency of a pedestrian fatality along this segment is .007 per year vs. a ($1.72/1x10^{-9}$ fatal pedestrian incidents per mile x 30,000 cars per day x 365 days per year x .375 miles = .007 fatalities per year, compared to the individual risk of $2x10^{-7}$ per year from the pipeline. Thus the pipeline risk is about 35,000 times lower to a pedestrian than being hit by a vehicle.

As our analysis relies on an assumption of seven persons distributed along the corridor, which is an estimate without any data to validate the assumption, final conclusions cannot be made from our comparison analysis regarding the negligibility or significance of the project risks without validated or justified population density estimates.

3. Additional Suggested Safety Devices

These are offered for consideration, but at the discretion of the project, as overall project risk is low. These include:

Body mass sensitive intrusion alarms and remote monitoring and shutdown capabilities should be considered for the compressor building and wellhead locations.

- Multiple line-of-sight gas detectors coupled to below well head and process perimeter shutdown valves may be effective control measures. These may already be present, so the suggestion is offered for consideration as a possible improvement if not already in the design
- Pipeline leak detectors based on metered flow differences between the wellhead and compressor systems.
- Reinforced concrete shielding installed above the pipeline to reduce risk of third-party damage.[2]

4. References

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