APPENDIX B

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

2.1 Federal

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 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

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, the proposed 16-inch pipeline facilities are located within Class 2 and 3 areas. 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, 489-feet and 261-feet for the 16-inch line with a 1,000 psig MAOP, 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.

2.2 State

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.

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

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:

- 8,000 btu/hr-ft^2 (25.1 kW/m^2) – 50% mortality (CDE 2007).
- 3,500 btu/hr-ft^2 (11.0 kW/m^2) - Second degree skin burns after ten seconds of exposure, 15% probability of fatality. 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

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

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 2007.

- 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 2007

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:

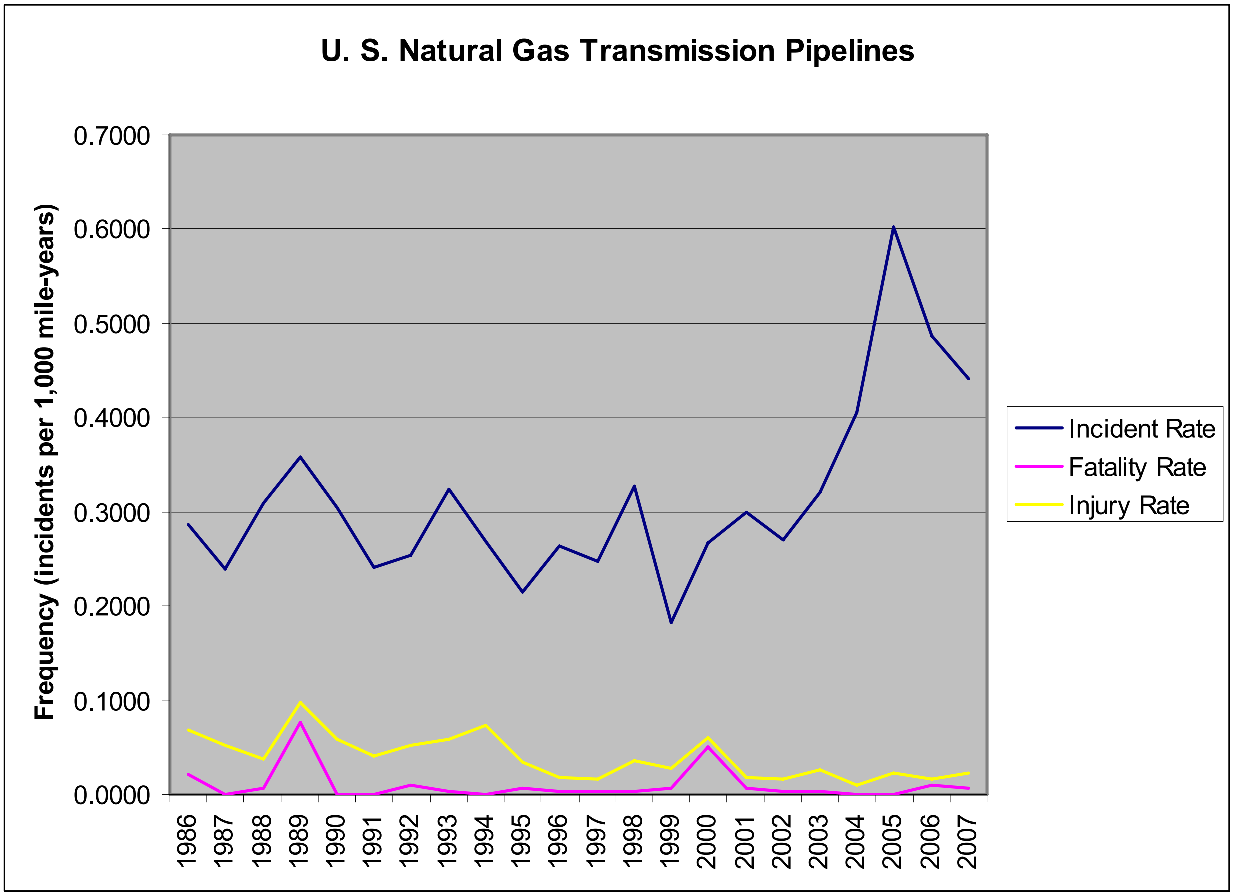
- Events which involved a release of gas from a pipeline, or of liquefied natural gas (LNG) or gas from an LNG facility, which caused: (a) a fatality, or personal injury necessitating inpatient hospitalization; or (b) estimated property damage, including costs of gas lost by the operator, or others, 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. These data are summarized below for the 22-year period from January 1, 1986 through December 31, 2007.

- Reportable Unintentional Releases - 0.31 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 six year period, since the change in the USDOT reporting form (January 2002 through December 2007), there were a total of 761 reportable incidents from natural gas transmission pipelines, including 35 reportable injuries, and 7 fatalities. The average property damage was nearly $820,000 per incident. The average annual transmission pipeline mileage was 301,373 miles for this six year period. Using these data, the frequency of reportable incidents during this most recent five year period was up slightly when compared to the 22-year period presented above - 0.42 incidents per 1,000 mile-years for 2002 through 2007 versus 0.27 incidents per 1,000 mile-years for 1986 through 2002. The injury and fatality rates were 0.019 and 0.004 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 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 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 report. However, making the maximum correction for these incidents does not significantly affect the results. The 2002 through 2007 data would be affected as follows, if the 92 incidents which occurred on lines identified as "Gathering" were deleted:

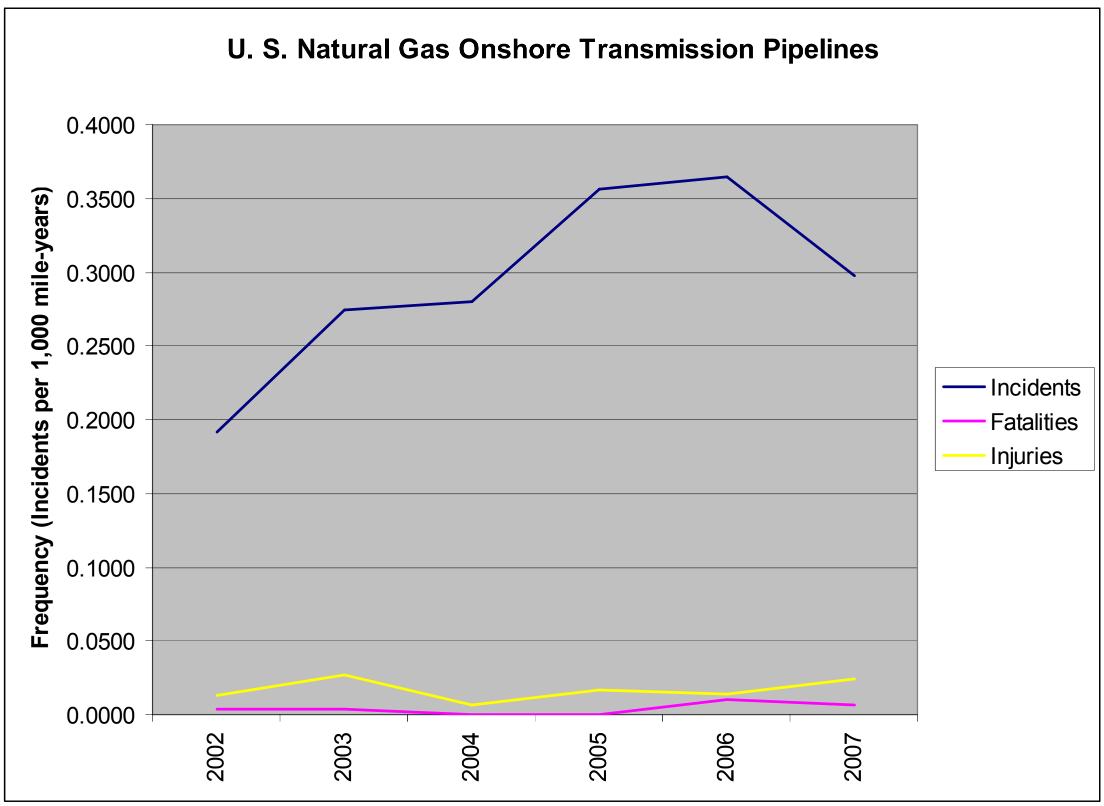
- Reportable Unintentional Releases – This figure would be reduced from 0.42 to 0.37 incidents per 1,000 mile-years

- Reportable Injuries - This figure would be reduced from 0.019 to 0.017 injuries per 1,000 mile-years
- Fatalities – This figure would be unchanged at 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 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 July 1984 thru 2007 (As Reported by USDOT)	U.S. Natural Gas Onshore Transmission 2002 thru 2007	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)
Injuries regardless of severity	N/A	N/A	N/A	N/A	0.685
Injury requiring hospitalization	0.096	0.040	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	0.004	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 2007 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 520 releases remaining from onshore transmission pipelines. Of there, the two major causes of releases were excavation damage and external corrosion. 113 (22%) of the releases were caused by excavation damage from a third party and the pipeline operator. 71 (14%) of the releases were caused by external corrosion. The remaining 336 (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 – 7%
- vehicles not related to excavation – 6%
- internal corrosion – 5%
- butt weld failure – 5%
- rain and flooding – 4%
- body of pipe failure – 4%
- incorrect operation – 3%
- pipe weld seam failure – 3%
- earth movement – 2%
- component failure – 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 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. A 33% reduction for the combined effectiveness of these two mitigation measures was assumed.

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 0.043 incidents per 1.000 mile years (0.29 per 1,000 mile years baseline x 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
3rd Party - Train Derailment	0.00	0.00	0.00	0.05	0.25	0.00
3rd Party - External Corrosion	0.45	0.00	0.10	0.33	0.00	0.00
3rd Party - Other	0.30	0.13	0.05	0.05	0.00	0.00
Human Operating Error	0.30	0.13	0.00	0.11	0.25	0.00
Design Flaw	0.08	0.00	0.00	0.00	0.00	0.14
Equipment Malfunction	0.38	0.53	0.10	0.60	1.24	0.00
Maintenance	0.00	0.00	0.24	0.00	0.00	0.00
Weld Failure	0.38	0.27	0.15	0.44	0.25	0.00
Other	0.83	0.13	0.24	0.27	0.25	0.28
Total	19.71	8.09	4.18	4.14	3.73	0.98

Source: Payne 1993

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

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

Table 4.6.2-2
Incident Rate by Operating Temperature

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

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 have 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 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 externally 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 0.124 incidents per 1.000 mile years (0.29 per 1,000 mile-years baseline x 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 facilities is 0.194 incidents per 1.000 mile years (0.043 from third party damage, 0.027 from external corrosion, and 0.124 from other causes).

4.6.5 Well Site Incident Rate

The anticipated annual failure rate for the well site is 4.9E-04. (Weatherwax 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;
- 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	0.0081	1 in 120
USDOT Reportable Gas Releases - 1970 thru June 1984 criteria (>$5,000 damage)	1.30 per 1,000 mile-years	0.0035	1 in 280
USDOT Reportable Gas Releases - Current Criteria (>$50,000 damage)	0.194 per 1,000 mile-years	0.0005	1 in 1,900
Well Site	0.49 per 1,000 years	0.0005	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.

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	0.0019	1 : 530
Injuries requiring hospitalization	0.017 incidents per 1,000 mile years	0.000046	1 : 22,000
Fatalities (from pipeline components only, excludes well site)	0.004 fatalities per 1,000 mile years	0.000011	1 : 93,000

As indicated in the table above, the annual probability of a fatality is 1 : 93,000, based on the qualitative risk assessment. 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, which is much more likely to result in serious impacts due to 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. 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.

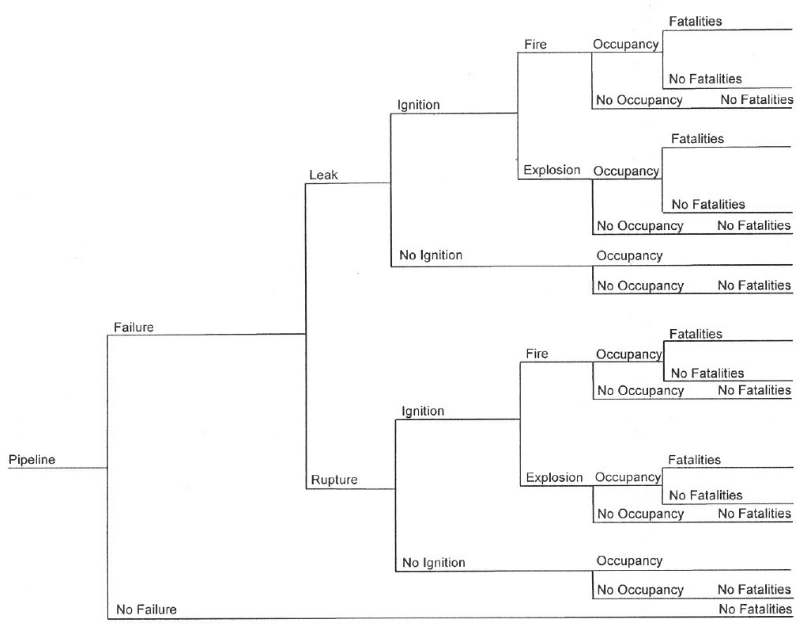


Figure 6-1 Consequence Event Tree

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.

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
Conditional Probabilities

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

Table 6.2-2
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%

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 4.2 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
Maximum Operating Pressure	1,000 psig for 16-inch segment between compressor station and SMUD Line 7008 1,965 psig for 16-inch segment between well site and compressor station 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.
Typical Flow Rate	100 MMSCFH injection and 200 MMSCFH 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
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

Table 6.3-1 (Continued)

Parameter	Model Input
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.
Relative Humidity	70%
Air and Surface Temperature	72° F
Continuous Release Duration	Two (2) hours
Duration of Normal Flow after Leak Initiation	Two (2) hours for release, five (5) minutes for rupture
Pipe Length Upstream and Downstream of Break	0.4-mile for 16-inch segment between compressor station and SMUD Line 7008 0.75-mile for 16-inch segment between well site and compressor station 0.2-mile for 12-inch segment between Line 700 to PG&E meter station
Release Angle	45° above horizontal
Fuel Reactivity	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. High reactivity fluids include hydrogen, acetylene, ethylene oxide, and propylene oxide.
Obstacle Density	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.
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.

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 residential, heavy commercial, warehouse, 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 1.5 psig for the 16-inch segments, due to the relatively open industrial and commercial development. This level is high enough to 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 the compressor station is sufficient to provide a 5.5 psig peak over-pressure in the vicinity of the compressors and other equipment. This level can result in serious injuries to those outdoors. 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 release from a rupture of the 16-inch line between the compressor station and the well site, while operating at 1,000 psig. (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.

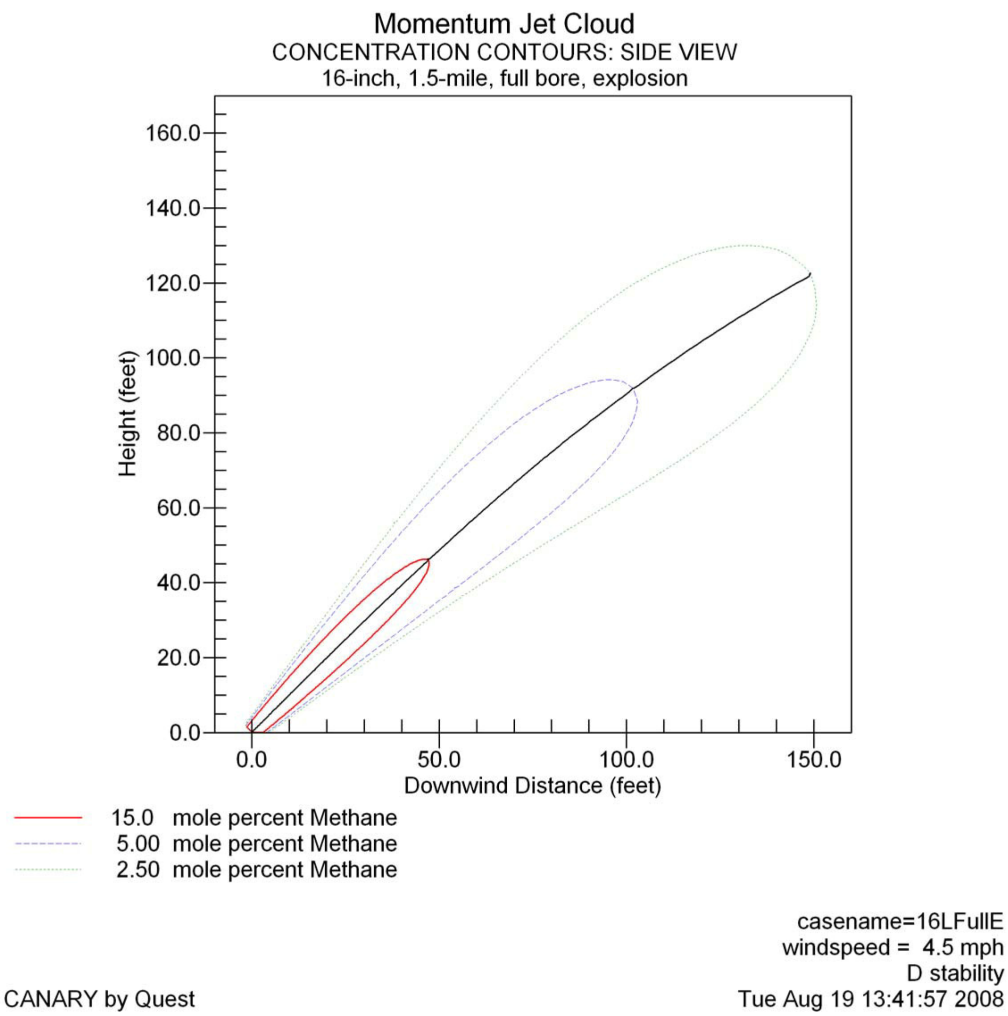


Figure 6.3.1-1 16-inch Compressor to Well Site Line Segment, Rupture Explosion, Elevation

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
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 modeling results for a vertical well casing rupture at 1,995 psig are depicted in the figures below.

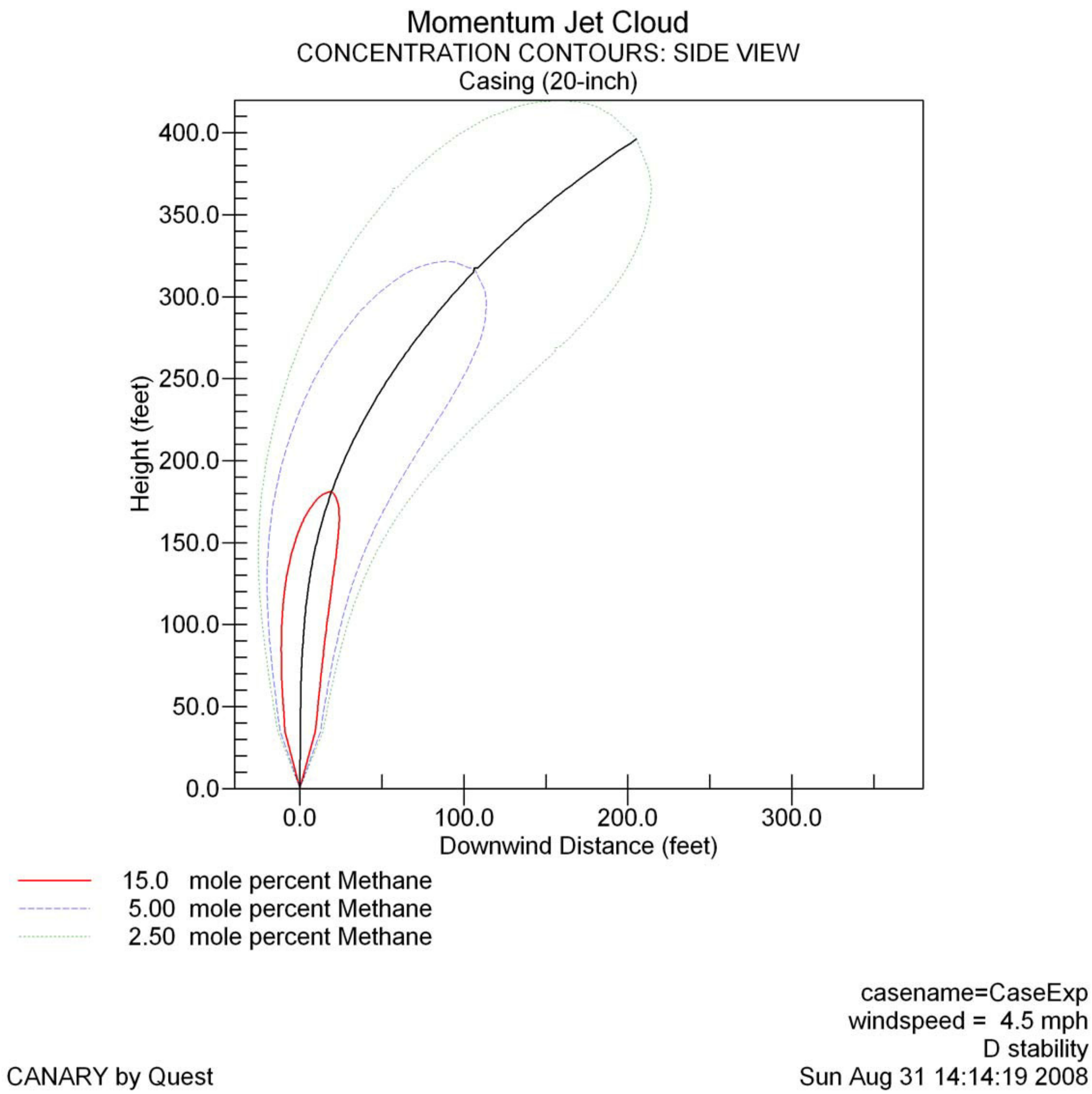


Figure 6.3.1-2 Well Head Casing Rupture Explosion, Elevation

As indicated above, the flammable portion of the vapor cloud (5 mole percent), would extend downwind about 100-feet and rise to about 320-feet above the ground surface. The side-on over-pressure 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.

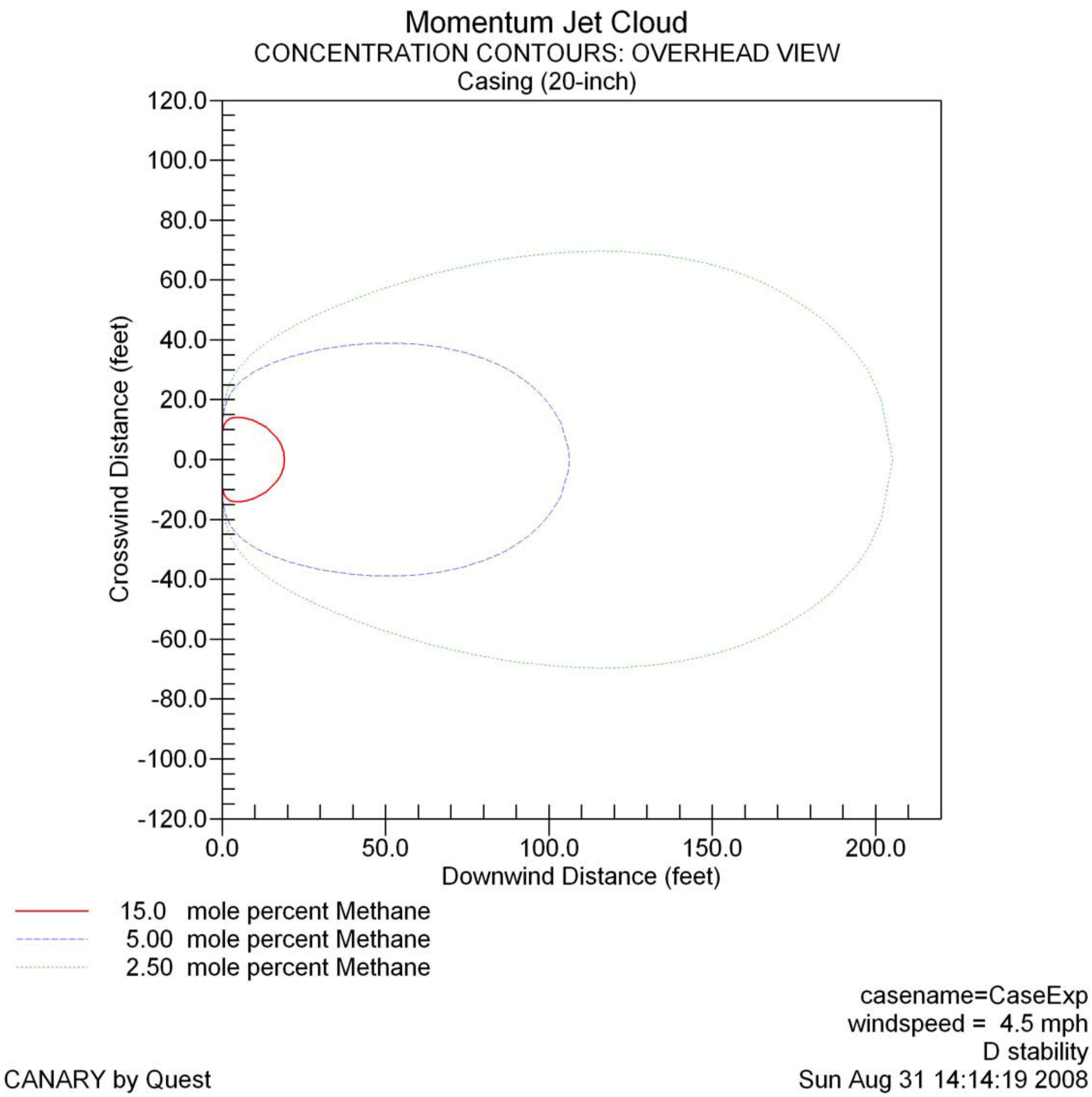


Figure 6.3.1-3 Well Head Casing Rupture Explosion, Plan

6.3.2 Fire Modeling Results

Torch Fires

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

Release	Maximum Operating Pressure	Flame Length (feet)	Horizontal Distance from Unintentional Release (feet)		
			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.

The results for a torch fire resulting from a full bore rupture of the 16-inch pipe segment between the compressor station and the well sites, while operating at 1,965 psig, are depicted 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.

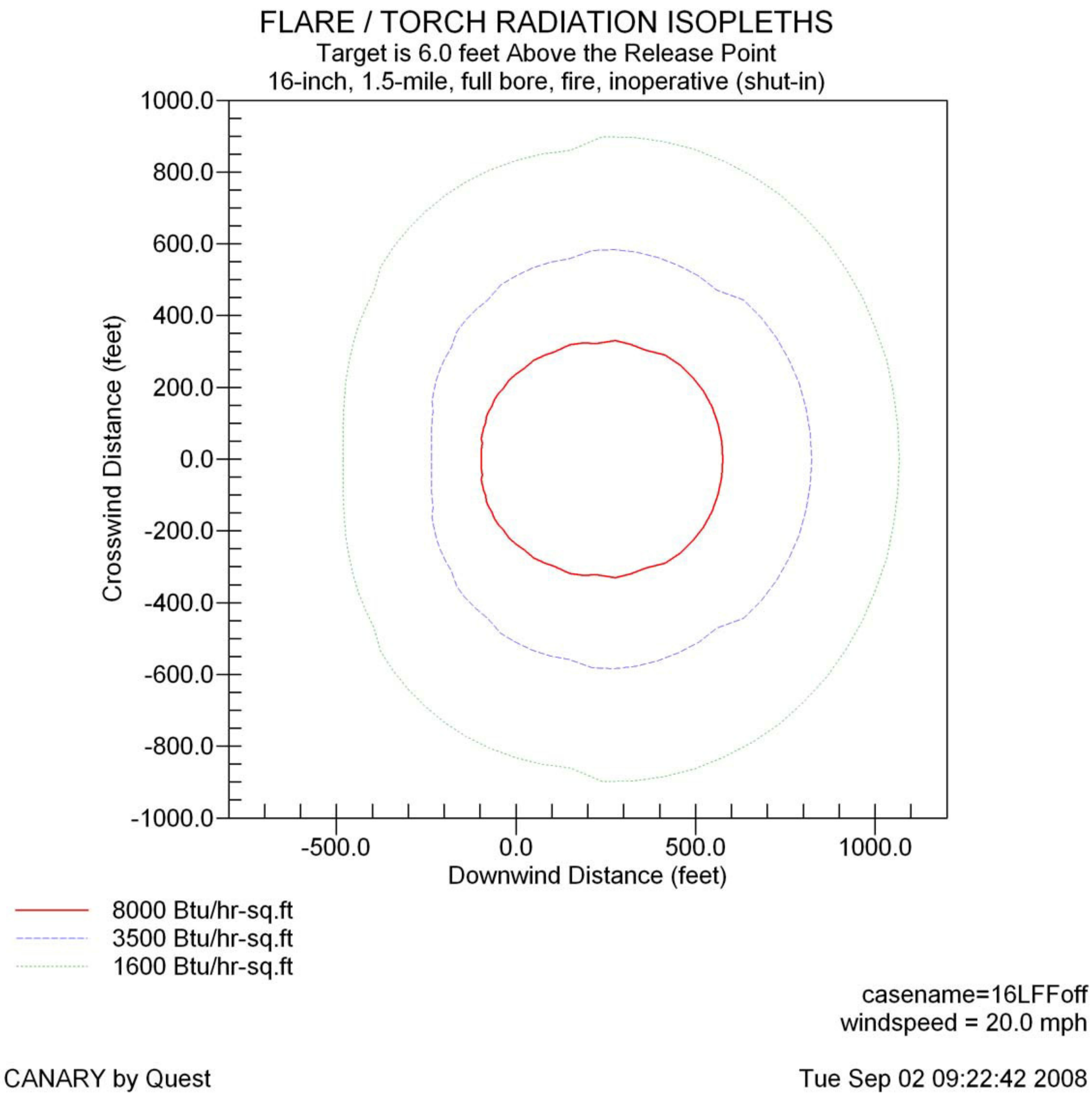


Figure 6.3.2-1 16-inch Compressor to Well Site Line Segment, Rupture Torch Fire, Plan

The results for a torch fire resulting from a casing rupture are depicted in the figure below. As indicated, the 3.500 btu/hr-ft^2 isopleths extend roughly 600-feet from the release (downwind) and aver 400-feet to either side.

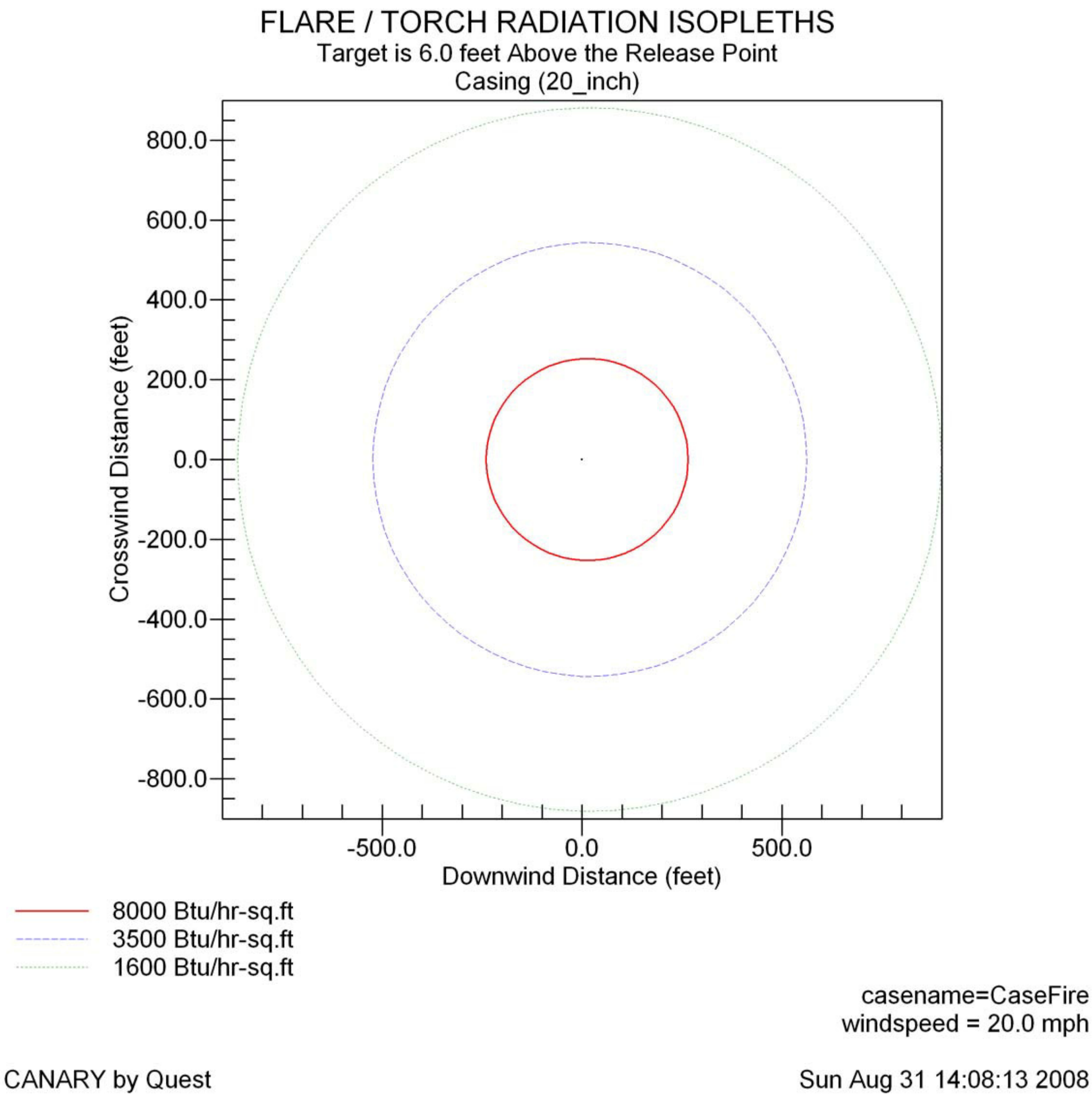


Figure 6.3.2-2 Well Head Casing Rupture Torch Fire, Plan

Flash Fires

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 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 concentrations below the lower flammability limit. The results of the flash fire modeling are shown below:

Table 6.3.2-2
Flash Fire Modeling Results

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

6.4 Analysis Assumptions and Methodology

In order to quantify the potential risk 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 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.

6.4.2 Proximity to 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 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 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.

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). The overpressure levels are expected to be below the threshold required to cause serious injuries or fatalities to those outdoors.

6.4.3 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 at the modeled conditions, the flammable concentration of the vapor cloud would be less than 100-feet wide (measured 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 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 casing failure are negligible. As shown earlier, the vapor cloud resulting from a vertical release at the well site would not 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 Table 6.3.2-1 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, 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 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.

6.4.4 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 table 6.5.2-1. For flash fires and vapor cloud explosions, a minimum exposure of 1 vehicle was used, since a passing vehicle is a likely source of ignition for an unignited vapor cloud.

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

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-ft^2 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 psig)	600-feet (8,000 btu/hr-ft^2)	2.320	520	1,070
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 6.9×10^{-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 Societal Risks

Societal risk is the probability that a specified number of people will 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.

6.6.1 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 and 33-feet of the 12-inch line segments. 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 110 feet of the 16-inch line segments and 84-feet of the 12-inch line. 950 lineal feet of the 16-inch line are located within 110-feet of existing commercial buildings. The width of exposure extends approximately 80-feet (8,000 btu/hr-ft^2 isopleth) and about 120-feet (3,500 btu/hr-ft^2 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 80 feet of the 16-inch line segments and 67-feet of the 12-inch line. None of proposed facilities would be located within this proximity of existing residences or commercial buildings to pose a public risk.

Torch Fire, Full Bore Release – These impacts could be significant within 600 feet of the 16-inch line segments 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 to the existing commercial building. The 3,500 btu/hr-ft^2 isopleth extends about 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-ft^2 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 600-foot-long potentially significant exposure for the 16-inch line, the analysis assumed that up to six residences and up to two commercial structures 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 - 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 - 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 8,000 btu/hr-ft^2 isopleth extends 266 feet from the release. The analysis assumed that three commercial building could be impacted by a release, with up to 10 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).

6.6.2 Exposures to Vehicle Occupants

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

6.6.3 Societal Risk Results

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 risk for these potential hazards are not considered significant, using the stated societal risk criteria.

Table 6.6.3-1
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
16-inch Line Segments						
Rupture Flash Fire Commercial Outdoors	3.04e-09	1.00	10	10	600	0.017
Rupture Torch Fire Residential	1.24e-07	0.50	24	12	50	0.240

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	6.61e-07	0.50	20	10	20	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
12-inch Line Segment						
Rupture Torch Fire Commercial	5.34e-08	0.50	10	5	150	0.033
Well Site						
Rupture Torch Fire Commercial	8.09e-11	0.50	30	15	1,500	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 6.6.3-1
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 - Power Inn Road						
1-inch Flash Fire	1.85e-07	0.10	2.96	0.3	70	0.004
1-inch Torch Fire	1.75e-06	0.10	3.74	0.4	20	0.019
Rupture Flash Fire	1.12e-07	0.10	3.62	0.4	100	0.004

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
Rupture Torch Fire	1.24e-06	0.10	9.99	1.0	30	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
16-Inch - Fruitridge						
1-inch Flash Fire	3.46e-09	0.10	2.00	0.2	400	0.001
1-inch Torch Fire	7.47e-08	0.10	2.58	0.3	120	0.002
Rupture Flash Fire	5.93-09	0.10	2.50	0.3	350	0.001
Rupture Torch Fire	2.78e-07	0.10	6.88	0.7	70	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 - Elder Creek						
1-inch Flash Fire	3.32e-08	0.10	1.51	0.2	200	0.001
1-inch Torch Fire	4.50-07	0.10	1.91	0.2	40	0.005
Rupture Flash Fire	3.20e-08	0.10	1.85	0.2	200	0.001
Rupture Torch Fire	1.14e-06	0.10	5.09	0.5	30	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	2.70e-09	0.10	8.79	0.9	600	0.002
Rupture Flash Fire	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

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-inc 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 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

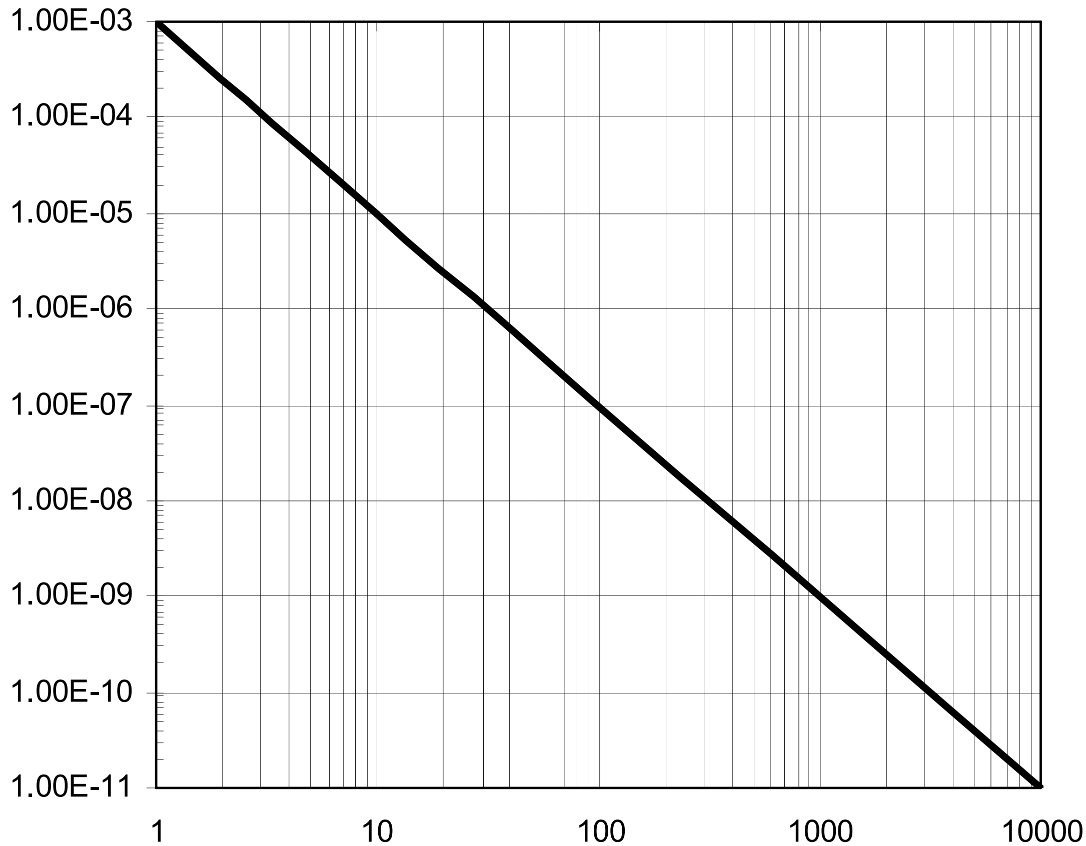
7.1 Definition and Use of Significance Criteria

7.1.1 Individual Risk

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).

7.1.2 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 7.1.2-1 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 7.1.2-1 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 2008; SNGS, LLC 2007):

Pipeline Segments

The following Applicant proposed mitigation 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, 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.

Compressor Station

The following Applicant proposed mitigation 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 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 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. 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 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".

Third Party Damage Mitigation Effectiveness

In 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 individual risk will be reduced somewhat. However, the effect of the Applicant's proposed mitigation has already been considered in the analysis. The residual individual risk will exceed the individual risk significance threshold.

It should be noted that there are a significant number of natural gas pipelines located in similar, and even more heavily urbanized areas. Many of these pipelines 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 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 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 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 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 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 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-ft^2)	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-ft^2)	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

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

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-ft^2)	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-ft^2)	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

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.

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.

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