3.9 ENVIRONMENTAL HEALTH – PIPELINE SAFETY

This section evaluates the human health, safety, and environmental risks associated with the existing Olympic Pipeline system within PSE’s corridor, and identifies the incremental change in these risks associated with the Energize Eastside project. Two petroleum pipelines are co-located with PSE’s existing corridor within all of the segments; through the Renton Segment, however, it is only co-located in the north part of the segment. As part of the EIS Consultant Team, EDM Services, a firm specializing in pipeline safety, conducted a probabilistic pipeline risk assessment (risk assessment). This section summarizes the results of the risk assessment, and provides an analysis of long-term impacts on resources in the event of a pipeline incident related to the project. As a factor considered in EDM’s risk assessment, this section also summarizes the results of an electrical interference study conducted by the firm DNV GL, an engineering consultant working for PSE on the Energize Eastside project (DNV GL, 2016). The EDM Services Pipeline Safety Technical Report (EDM Services, 2017) is included in full in Appendix I.

The study area for pipeline safety focuses on the area potentially affected by an Olympic Pipeline leak or fire caused by the construction or operation of the Energize Eastside project. The study area for this analysis is the transmission line corridor, including all segments and options, and the surrounding area including human populations, urban environment, and natural resources that could be affected by an incident. Although the probability of a leak or fire caused by the project is low, the potential damage from such an incident could be high, given the population density in the study area. The potential magnitude of such an event, if it did occur, would be the same regardless if it were the result of construction or operation of the project. For this reason, the analysis of the environmental consequences of such an incident is presented in Section 3.9 along with a description of the operational concerns for the Energize Eastside project that affect pipeline safety. Section 4.9 addresses the construction aspects of the project that affect pipeline safety, and refers back to this section with regard to the consequences of a leak or fire.

3.9.1 Relevant Plans, Policies, and Regulations

As described in Chapter 8 of the Phase 1 Draft EIS, environmental health and safety issues related to pipeline safety are regulated at federal, state, and local levels. Table 3.9-1 summarizes the applicable laws and regulations addressing pipeline safety, which is followed by a detailed summary of the major pipeline safety regulations. More information about the applicable laws and regulations is provided in Chapter 8 of the Phase 1 Draft EIS and the Pipeline Safety Technical Report (Appendix I). Federal and state regulations apply to the operation of existing pipelines, and the regulations identified below apply to the Olympic Pipeline located in the transmission line corridor.
### Table 3.9-1. Pipeline Safety Regulations

<table>
<thead>
<tr>
<th>Regulation</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Federal</strong></td>
<td></td>
</tr>
<tr>
<td>Hazardous Liquid Pipeline Safety Act of 1979 (Public Law 96-129)</td>
<td>Granted authorization to the U.S. Department of Transportation to develop minimum safety standards for oil and hazardous liquid pipelines.</td>
</tr>
<tr>
<td>49 CFR, Parts 190 through 199</td>
<td>Primary U.S. Code sections that cover pipeline safety.</td>
</tr>
<tr>
<td>Pipeline Safety, Regulatory Certainty, and Jobs Creation Act of 2011 (Public Law 112-90)</td>
<td>Increased the number of pipeline inspectors and mandated a variety of new safety measures. Required studies of pipeline safety.</td>
</tr>
<tr>
<td>Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016</td>
<td>Reauthorized the Pipeline Safety, Regulatory Certainty, and Jobs Creation Act of 2011; reaffirmed mandates of the 2011 act; and established new mandates.</td>
</tr>
<tr>
<td>Pipeline Safety Improvement Act of 2002 (CFR 192 Subpart O, Pipeline Integrity Management)</td>
<td>Strengthened federal pipeline safety programs, state oversight of pipeline operators, and public education regarding gas pipeline safety. Required gas pipeline operators to conduct a risk assessment and implement integrity management programs for pipelines in high consequence areas.</td>
</tr>
<tr>
<td>Oil Pollution Act of 1990 (49 CFR Part 194)</td>
<td>Expanded EPA’s oversight of oil storage facilities and vessels. Required some oil storage facilities to prepare Facility Response Plans.</td>
</tr>
<tr>
<td>2006 Pipeline Inspection, Protection, Enforcement and Safety Act (Public Law 109-468)</td>
<td>Created state grant system to improve damage prevention programs, and established the national “Call Before You Dig” program. Required a review of the adequacy of federal pipeline safety regulations related to internal corrosion control.</td>
</tr>
<tr>
<td><strong>State</strong></td>
<td></td>
</tr>
<tr>
<td>WAC, Title 480, Chapter 480-75, Hazardous Liquid Pipelines</td>
<td>Adopted the federal hazardous liquids pipeline regulations.</td>
</tr>
<tr>
<td>Underground Utilities – Damage Prevention Law (RCW 19.122)</td>
<td>Established a comprehensive damage prevention program. Required pipeline companies, underground facility owners, and excavators to participate in protecting the public health and safety when excavating.</td>
</tr>
<tr>
<td>Regulation</td>
<td>Summary</td>
</tr>
<tr>
<td>------------</td>
<td>---------</td>
</tr>
<tr>
<td>WAC 173-182 – Oil Spill Contingency Plan</td>
<td>Established covered vessel and facility oil spill contingency plan requirements, drill and equipment verification requirements, primary response contractor standards, and recordkeeping and compliance information.</td>
</tr>
</tbody>
</table>

## Local

<table>
<thead>
<tr>
<th>Regulation</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>Redmond Zoning Code (RZC) 21.26.040 Setback Requirements</td>
<td>Established minimum setback requirements from the hazardous pipeline corridors. Purpose is to minimize risk to public health, safety, and welfare due to hazardous liquid pipelines. No construction or expansion of structures is allowed in the pipeline corridor. No setback is required for utilities for areas along the hazardous liquid corridor, but the Director of Planning and Community Development (or their designee) may require a setback based on site-specific conditions.</td>
</tr>
</tbody>
</table>

### 3.9.1.1 Federal

The U.S. Department of Transportation oversees the nation’s pipeline system. Its responsibilities were established under the Pipeline Safety Act of 1968 (49 USC Section 60101). The Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety, administers the national regulatory program to ensure the safe transportation of gas and other hazardous materials by pipeline. The Office of Pipeline Safety shares this responsibility with state agency partners and others at federal, state, and local levels.

The Pipeline Safety Act of 1968 and the Hazardous Liquid Pipeline Safety Act of 1979 provide the framework for federal pipeline regulations. Federal pipeline regulations are published in Title 49 CFR, Parts 190 through 199. Many of these pipeline regulations are performance standards. These regulations set the level of safety to be attained and allow the pipeline operator to use various methods and technologies to achieve the desired level of safety.
Due to concerns surrounding pipeline ruptures in 2010 (in Marshall, Michigan, and San Bruno, California), Congress passed the Pipeline Safety, Regulatory Certainty, and Jobs Creation Act of 2011. This law mandated a variety of new safety measures, and directed the Pipeline and Hazardous Materials Safety Administration (PHMSA) to evaluate concerns surrounding the pipeline ruptures and to submit a report to Congress. Based on those findings, PHMSA is developing rule changes to 49 CFR Part 195, Hazardous Liquid Pipeline Safety Regulations.

The Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 reauthorized the Pipeline Safety, Regulatory Certainty, and Jobs Creation Act of 2011, and directed PHMSA to accomplish the mandates of the 2011 act. It also created new mandates in response to the 2015 gas leak in Aliso Canyon, California.

**Pipeline Integrity Management**

Pipeline integrity management, which “provides for continual evaluation of pipeline condition; assessment of risks to the pipeline; inspection or testing; data analysis; and follow-up repair; as well as preventive or mitigative actions,” has been a part of PHMSA requirements for the pipeline industry since 1997 (CRS, 2010). In 2002, Congress passed the Pipeline Safety Improvement Act to strengthen pipeline safety laws following two major pipeline incidents (see Appendix I for descriptions of these incidents, which occurred in Bellingham, Washington and Carlsbad, New Mexico). CFR 192 Subpart O, Pipeline Integrity Management, was established to promulgate rules implementing the act. This subpart requires operators of liquid or natural gas pipeline systems in high consequence areas to develop a written integrity management program and to significantly increase their minimum required maintenance and inspection efforts. For example, all existing pipelines in high consequence areas must be analyzed by conducting a baseline risk assessment. In general, the integrity of the pipelines must also be evaluated using an internal inspection device or a direct assessment. The federal Pipeline Safety Improvement Act of 2002 also enabled shared oversight of hazardous liquid pipelines with authorized state agencies.

**Pipeline Offsets**

Requirements for minimum offsets (or clearance) between any underground structures and hazardous liquid pipelines are 12 inches (49 CFR 195.250). Olympic Pipe Line’s practice is to require a minimum of 24 inches of clearance between underground structures and the pipeline, and 10 feet of clearance aboveground, to facilitate access to the pipeline for maintenance purposes. Alternative

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**Proposed Rule Changes to Hazardous Liquid Pipeline Regulations are to:**

1. Extend reporting requirements;
2. Require inspections of pipelines in areas affected by extreme weather and natural disasters;
3. Require periodic inline integrity assessments for lines that are outside of high consequence areas;
4. Require the use of leak detection systems in all locations;
5. Modify pipeline repair provisions; and
6. Expand requirements for accommodating use of inline inspection tools. If enacted as published in the Federal Register, the existing Olympic Pipelines would be subject to these new requirements.

**High Consequence Areas** are defined under the Pipeline Integrity Management Program as either:

- High population areas, defined by the Census Bureau as urbanized areas.
- Other populated areas, defined by the Census Bureau as places that contain a concentrated population.
- Unusually sensitive areas.
- Commercially navigable waterways.

The study area for this project is entirely within a high consequence area and is covered under Pipeline Integrity Management Program requirements.
plans for aboveground clearance can be developed on a case-by-case basis where access is more limited (Olympic, 2016).

**Oil Spill Prevention and Response**

The Oil Pollution Act of 1990 (49 CFR Part 194) streamlined and strengthened EPA's ability to prevent and respond to catastrophic oil spills. This legislation requires pipeline operators to prepare oil spill response plans for onshore oil pipelines (including pipelines transporting petroleum, fuel oil, etc.). The intent of the regulations is to reduce the environmental impact of oil discharged from onshore pipelines. The operator is required to determine the worst-case discharge in each response zone and meet specified criteria. The completed plan must be submitted to the U.S. Department of Transportation Pipeline Response Plans Officer for review and approval. These spill response plans must be consistent with the National and Area Contingency Plans for oil spill response (see state regulations below establishing the Northwest Area Contingency Plan).

### 3.9.1.2 State

The State of Washington’s Utilities and Transportation Commission (UTC) is responsible for the administration and oversight of hazardous liquid pipeline operations in the state as authorized by the U.S. Department of Transportation. The following section summarizes state regulations addressing hazardous liquid pipelines, damage prevention, and contingency plan requirements in the event of a spill.

**Hazardous Liquid Pipeline Regulations**

The state has adopted the federal hazardous liquids pipeline regulations as a part of its own enhanced regulations contained in WAC, Title 480.

- **Chapter 480-73: Hazardous Liquid Pipeline Companies** – Defines the applicability of the regulations and the administrative guidelines and rules that hazardous liquid pipeline companies must follow.

- **Chapter 480-75: Hazardous Liquid Pipelines, Safety** – Provides pipeline safety rules specific to Washington State. This regulation contains requirements similar to 49 CFR Part 195 for the design, construction, operation and maintenance, and reporting for hazardous liquid pipelines. The Chapter requires compliance, by reference, with 49 CFR Part 195.

**Damage Prevention**

The Underground Utilities – Damage Prevention Law (RCW 19.122) addresses one of the assigned responsibilities of the UTC for administering hazardous liquids pipelines. This responsibility includes requiring pipeline companies, underground facility owners, and excavators to participate in protecting the public health and safety when excavating. As a result of several high-profile fatal pipeline failures related to excavator damage (including the incident in Bellingham- see Appendix 1), Congress mandated that each state address criteria included in the 2006 Pipeline Inspection, Protection, Enforcement and Safety Act to ensure the adequacy of state damage prevention laws. As
a result of this legislation, the State of Washington passed the Underground Utilities Damage Prevention Act in 2011 that revised RCW 19.122 in the following ways:

- Specifies that failure by an underground facility operator to subscribe to a one-number locator service constitutes a willful intent to avoid compliance with underground utilities damage prevention law.
- Requires that damage to underground utilities be reported to the UTC, and for the UTC to evaluate damage data.
- Establishes the Damage Prevention Account, funded by penalties, and specifies that expenditures from the Account by the UTC must be used to educate excavators and operators to improve safety and compliance.
- Establishes a Safety Committee of stakeholder representatives to advise on underground utility safety and to review complaints of alleged underground utility violations.
- Establishes enforcement procedures for the UTC or Attorney General to address violations.

RCW 19.122.033 (4) specifies that when permitting construction or excavation within 100 feet, or greater distance if required by local ordinance, of a right-of-way or utility easement containing a transmission pipeline, local governments must:

(a) Notify the pipeline company of the permitted activity when it issues the permit; or
(b) Require, as a condition of issuing the permit, that the applicant consult with the pipeline company.

Oil Spill Contingency Plans

WAC 173-182 – Oil Spill Contingency Plan establishes oil spill contingency plan requirements, drill and equipment verification requirements, private response contractor standards, and recordkeeping and compliance information. On October 12, 2016, Ecology amended the Oil Spill Contingency Plan rule to update standards to ensure that required oil spill response equipment is appropriate for the pipeline risks and operating environments (both marine and inland). The amendments enhance oil spill contingency plan requirements for hazardous liquids pipelines, and for primary response contractors that support the implementation of pipeline plans. This amendment requires pipeline operators to update their contingency plans (e.g., facility response plans) in accordance with the applicable area plan, and submit them to Ecology for approval. The Northwest Area Contingency Plan is the applicable area plan for Washington State.

3.9.3 Local

The Partner Cities generally do not directly regulate pipeline safety, but they have the authority to regulate land uses near pipelines within their jurisdictions to protect public health and safety. The City of Redmond establishes minimum setback requirements from hazardous liquid pipelines with the expressed purpose of minimizing risk to public health and safety (see Table 3.9-1). Other planning policies and regulations of King County and the Partner Cities related to co-location of transmission lines with pipelines, are described in the Phase 1 Draft EIS, Chapter 8 and Appendix F. Setback requirements established by the City of Newcastle are described in Section 3.1 in the Phase 2 Draft EIS.
**Franchise Agreements**

The Partner Cities have franchise agreements, established by ordinance, with Olympic Pipe Line Company that cover its existing petroleum pipelines. These agreements grant the company the right to construct, operate, maintain, and improve its facilities within the cities’ boundaries while adhering to applicable local, state, and federal laws. They state that the company must comply with the duties imposed on pipeline operators by 49 CFR Part 195, including the requirement of regular inspections and testing to determine whether the pipeline was damaged by excavation work in the vicinity. In the event of a leak or other emergency, the company is required to investigate and report on the incident, and is responsible for all costs relating to the spill response effort. Both the City of Bellevue’s and City of Redmond’s agreements state that, if the company is aware that a third party conducts any excavation or other significant work that may affect the pipelines, the company must conduct inspections and/or testing as necessary to determine that no direct or indirect damage was done and that the work did not abnormally load the pipelines or impair the effectiveness of the cathodic protection system.

**3.9.1.4 Non-Regulatory Guidance**

PSE follows non-regulatory guidance included in the Interstate Natural Gas Association of America (INGAA) report (INGAA Report) *Criteria for Pipelines Co-Existing with Electric Power Lines* (DNV GL, 2015). The report presents the technical background, and provides best practice guidelines and summary criteria for pipelines co-located with high-voltage alternating current (AC) power lines. PSE retained DNV GL (the author of the INGAA Report) to develop a detailed analysis of risks and recommendations for the Energize Eastside project. DNV GL produced *A Detailed Approach to Assess AC Interference Levels Between the Energize Eastside Transmission Line Project and the Existing Olympic Pipelines, OLP16 & OPL20*, referred to in this Draft EIS as the *AC Interference Study* (DNV GL, 2016), which was also used in preparing the analysis for the EIS. Recommendations from that analysis are included under Section 3.9.7, *Mitigation Measures*.

**3.9.2 Pipelines in the Study Area**

**3.9.2.1 Study Area Characteristics**

The study area contains both natural gas and petroleum pipelines (Figure 3.9-1). Natural gas lines that cross the study area are owned by PSE and Northwest Pipeline. See the Phase 1 Draft EIS Chapter 8, *Environmental Health*, and Chapter 16, *Utilities*, for more details on the natural gas pipelines. Scoping comments expressed particular concern about the potential for the Energize Eastside project to damage the co-located petroleum pipelines (Olympic Pipelines). As
a result, this section focuses on safety issues related to petroleum pipelines.

During the Phase 2 Draft EIS scoping period, several members of the community expressed concern about pipeline safety at unique sites, such as schools, parks, and other facilities where the public congregates. Together with residential uses, such unique sites potentially increase the exposure of the general public to pipeline safety risks. Figure 3.9-1 identifies unique sites within the study area (see Section 3.6.2, Recreation Resources in the Study Area for a list of parks and trails located in or adjacent to the transmission line corridor).

### 3.9.2.2 Petroleum Pipelines in the Study Area

Petroleum pipelines in the study area include the Olympic Pipeline system. The Olympic Pipeline system consists of 400 miles of high-strength carbon steel underground pipeline located within a 299-mile corridor. It connects four refineries in northwestern Washington near the Canadian border to markets throughout western Washington and Portland, Oregon. Approximately 4.5 billion gallons of refined petroleum products are transported through the pipelines on an annual basis. As described in Chapter 2, BP is the operator of the Olympic Pipeline system, and partial owner of the Olympic Pipe Line Company, with Enbridge, Inc. (Olympic Pipe Line Company, 2017). In the EIS, the pipeline ownership and operator are collectively referred to simply as Olympic. Olympic has been working with PSE in connection with PSE’s Energize Eastside project, sharing information and supporting requests for information about its facilities and operations. Olympic and PSE meet regularly to discuss, identify, and develop mitigation strategies for potential threats to the pipeline’s integrity.

In the Energize Eastside study area, the Olympic Pipeline system includes two pipelines (16-inch and 20-inch diameter). One or both of the pipelines are co-located with PSE’s transmission line within all
of the segments, although in the Renton Segment it is only co-located in the north part of the segment (Figure 3.9-1). In most of the segments, the pipelines are along either the east or west side of the right-of-way, crisscrossing the right-of-way from east or west in numerous locations. In parts of the corridor (especially the Newcastle Segment), however, the pipelines are in the center of the right-of-way. In the Bellevue South Segment, one of the pipelines is along PSE’s existing corridor while the other follows Factoria Blvd SE and Coal Creek Parkway SE before rejoining the corridor (Stone, pers. comm., 2016). Construction of the pipeline began in 1964 after PSE’s transmission line corridor was built in the late 1920s and early 1930s (Newton, 1965).

Both pipelines are constructed of welded carbon steel and were generally installed at depths of 3 to 4 feet. They carry diesel, jet fuel, and gasoline and operate about 95 percent of the time (West, pers. comm., 2016).

Preventing Unintentional Releases

As the pipeline operator, Olympic is responsible for operating and maintaining their pipelines in accordance with or to exceed PHMSA’s Minimum Federal Safety Standards in 49 CFR 195. The regulations are intended to protect the public and prevent pipeline accidents and failures. PHMSA specifies minimum design requirements and protection of the pipeline from internal, external, and atmospheric corrosion. In addition, 49 CFR 195 established the following broad requirements that apply to Olympic as the pipeline operator:

- 49 CFR 195.577(a) requires, “For pipelines exposed to stray currents, you must have a program to identify, test for, and minimize the detrimental effects of such currents.”
- 49 CFR 195.401 (b) (1) requires, “Non Integrity Management Repairs, whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it must correct the condition within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.”

In response to these federal requirements, Olympic has a number of programs and systems in place to prevent unintentional releases, as summarized below.

Integrity Management Program. Pipelines and high voltage AC transmission lines often share the same corridor. As a result, the industry implements numerous practices and guidelines to mitigate potential electrical interference-related-corrosion on pipelines. In connection with the governing federal safety requirements, including 49 CFR 195, Olympic has an Integrity Management Program to monitor and, where necessary, mitigate the impact of electrical interference on its pipelines. In accordance with program requirements, Olympic patrols the pipeline corridor on a weekly basis and periodically inspects its pipelines using in-line inspection, pressure testing, and other direct inspection methods. The last in-line inspections of the 16-inch and 20-inch pipelines were in April 2014, and the next planned in-line inspections are in early 2019 (West, pers. comm., 2016).
Figure 3.9-1. Existing Electric Transmission Lines and Natural Gas/Petroleum Pipelines in the Study Area
Bellevue Central Segment, Existing Corridor Option

Bellevue Central Segment, Bypass Option 1

Source: King County, 2015; Ecology, 2014; PSE, 2015; SCL, 2015; WA UTC, 2015.

Figure 3.9-1. Existing Electric Transmission Lines and Natural Gas/Petroleum Pipelines in the Study Area (continued)
Bellevue Central Segment, Bypass Option 2

Bellevue South Segment, Oak 1 Option

Source: King County, 2015; Ecology, 2014; PSE, 2015; SCL, 2015; WA UTC, 2015.

Figure 3.9-1. Existing Electric Transmission Lines and Natural Gas/Petroleum Pipelines in the Study Area (continued)
Bellevue South Segment, Oak 2 Option

Bellevue South Segment, Willow 1 Option

Source: King County, 2015; Ecology, 2014; PSE, 2015; SCL, 2015; WA UTC, 2015.

Figure 3.9-1. Existing Electric Transmission Lines and Natural Gas/Petroleum Pipelines in the Study Area (continued)
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Bellevue South Segment, Willow 2 Option

Newcastle Segment

Source: King County, 2015; Ecology, 2014; PSE, 2015; SCL, 2015; WA UTC, 2015.

Figure 3.9-1. Existing Electric Transmission Lines and Natural Gas/Petroleum Pipelines in the Study Area (continued)
Figure 3.9-1. Existing Electric Transmission Lines and Natural Gas/Petroleum Pipelines in the Study Area (continued)
Electrical Interference Protection. Federal regulations also require control of external corrosion via cathodic protection. Electrical interference, external corrosion, and cathodic protection are described below in Section 3.9.3.3 and in Section 16.3.37 of the Phase 1 Draft EIS. Additional information is provided in the AC Interference Study (DNV GL, 2016).

Pipeline Leak Detection System and Controls. Olympic monitors system pressures, flows, and customer deliveries on its entire system. The 16-inch and 20-inch pipelines in the study area are within the coverage area for Olympic’s Pipeline Leak Detection System, which is a real-time pipeline simulation in Olympic’s Control Center that detects and locates leaks by comparing a modeled flow rate to the measured flow balance in a defined pipeline section. When the difference exceeds a defined loss threshold, the software declares a warning, followed by an alarm if the condition persists. Alarms are communicated through the supervisory control and data acquisition (SCADA) alarm and event system. The Pipeline Leak Detection System meets and in some cases exceeds state and federal requirements for pipeline leak detection, including WAC 480-75-300: “Leak detection systems must be capable of detecting an eight percent of maximum flow leak within fifteen minutes or less” (West, pers. comm., 2016). Information on shut-off valves and response systems was not available from Olympic. Olympic treats these data as confidential information that is not available for public disclosure due to potential security risks.

General Construction Requirements. Olympic has a general list of requirements as part of BP Pipelines (North America) General Construction Requirements for all work proposed near the pipelines (see Appendix I). These include specific requirements related to excavation near the pipelines and transport of construction materials or equipment over the pipelines. The requirements also prohibit the placement of foreign utility lines underground within the pipeline easement. It also includes specific notification and monitoring requirements, consistent with federal, state, and local requirements. Individuals, businesses, and government entities planning to excavate within the corridor in proximity to the pipelines are required to notify Olympic at least 48 hours prior to the start of any work to comply with the state’s “one-call” locator service law (Chapter 19.122 RCW). Local governments must also notify Olympic when they issue a permit that allows construction or excavation within 100 feet, or condition the permit to require the permit applicant to consult with Olympic (RCW 19.122.033[4]; see Section 3.9.1.2, Damage Prevention, for more detail). As company practice, if a project is within 100 feet of the pipeline, Olympic’s Damage Prevention Team will meet the construction crew on-site at the beginning of the project and weekly thereafter. If excavation has the potential to be within 10 feet of the pipeline, the Damage Prevention Team would be on-site to monitor excavation.

**Protections in Place to Prepare for and Respond to an Incident**

Several Phase 2 Draft EIS scoping comments requested additional information on emergency response procedures, which are summarized below.

Frameworks for preparing for and responding to emergency incidents (including pipeline incidents) are specified in each local jurisdiction’s Comprehensive Emergency Management Plan (City of Bellevue, 2013; City of Newcastle, 2008; City of Redmond, 2015; and City of Renton, 2012). The Comprehensive Emergency Management Plans are reviewed and updated periodically. All applicable personnel receive annual training on the Emergency Management Plans, and the area offices conduct emergency response exercises on an annual basis. Chapter 15 of the Phase 1 Draft EIS provided additional information on emergency response procedures of local jurisdictions within the corridor.
Olympic’s *Facility Response Plan* provides guidelines to prepare for and respond to a spill from the Olympic Pipeline system. The Facility Response Plan, which received final 5-year approval by Ecology in 2016, serves as Olympic’s oil spill contingency plan under WAC 173-182. The Facility Response Plan is based on the Northwest Area Contingency Plan (Regional Response Team 10 and Northwest Area Committee, 2016), as approved by Ecology and the federal PHMSA (see Section 3.9.1). The Facility Response Plan is not made available to the public, but is shared with federal, state, and local officials, including emergency planning agencies and first responders, to strengthen and coordinate planning and prevention activities, with certain key information redacted due to potential security risks.

As described in Chapter 15 of the Phase 1 Draft EIS, in the event of an incident requiring evacuation along the pipeline right-of-way, local first responders and the Olympic Pipeline response team would set up exclusion zones to evacuate and prevent public access in potentially unsafe areas. Affected homeowners may be notified door-to-door if appropriate staffing levels are available and the area would be safe to access. The City of Bellevue and King County recently acquired an emergency notification software system called “Code Red” (referred to respectively as Bellevue Inform/Alert King County) that permits phone, text, and email alerts to be sent to specific geographical areas very quickly. In most cases, the local first responders would use this tool to contact people should a large-scale event occur. Air monitoring would be conducted and documented throughout the entirety of the incident to ensure that the exclusion zones are properly identified in accordance with the conditions of the day (wind speed, direction, etc.). Olympic maintains a 24-hour Emergency Hotline (1-888-271-8880).

### 3.9.3 Hazardous Liquid Pipeline Incident Data

Scoping comments expressed concern about the potential for the Energize Eastside project to damage the co-located Olympic Pipelines, resulting in releases. In response, EDM Services conducted a risk assessment to evaluate what could go wrong (causes of pipeline incidents), how likely those are to occur (probability of incidents), and what the consequences would be if there were an unintentional release.

The baseline data used for the risk assessment are summarized below, and include information on the frequency, major causes, and major risks associated with pipeline releases. The *Pipeline Safety Technical Report* (Appendix I) presents additional information on the baseline data used.

### 3.9.3.1 Reported Incidents in the United States

PHMSA categorizes pipelines as hazardous liquid, liquefied gas, and natural gas distribution and transmission. The Olympic Pipelines are categorized as hazardous liquid pipelines. In general, a small percentage of pipelines in Washington (2%) and nationally (by mileage) are hazardous liquid pipelines (PHMSA, 2016a). Natural gas distribution lines make up the majority of all pipelines, are in most residential streets, and do not have large rights-of-way and pipeline markers common to
regulated transmission pipelines (Rathbun, pers. comm., 2016). In contrast, hazardous liquid pipelines are present in a limited number of rights-of-way and routinely patrolled by the operator to inspect surface conditions on or adjacent to the pipeline right-of-way. For these reasons, incidents are much less common with hazardous liquid pipelines than with natural gas distribution lines.

Pipeline companies are required to report hazardous liquid pipeline failures to PHMSA (49 CFR 195.50). Table 3.9-2 lists the unintentional release incidents (in the PHMSA database) for hazardous liquid pipelines from 2010 to 2015, which is the most recent data range under current rules. During this reporting period, there were 2,362 reported hazardous liquid pipeline incidents and seven fatalities nationwide associated with hazardous liquid pipelines (EDM Services, 2017; PHMSA, 2016b).

When there is a change in pipeline operator requirements, PHMSA often begins a new database to ensure that all data within a given database are consistent. This most recent database began in January 2010 following new requirements established as a result of several pipeline incidents (see Appendix I). Using this current database (2010 to 2015) is appropriate for conducting a risk assessment because it allows for estimating risks based on rules currently in place. To use a broad analogy, if one were to estimate the rate of wetlands loss in the U.S., using data prior to the 1990s would overestimate the rate of wetland loss, compared to using data for the most recent period of time when more stringent regulations are in place. Although the current database only provides a 6-year timeframe (2010–2015), the reported incidents and fatalities are associated with hundreds of thousands of miles of pipeline (see total pipeline mileage in Table 3.9-2), providing a large and appropriate sample size for conducting a risk assessment.

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**Pipeline and Hazardous Materials Safety Administration, (PHMSA)**

The PHMSA Office of Pipeline Safety administers the national regulatory program to ensure the safe transportation of gas and other hazardous materials by pipeline. PHMSA uses incident data to assess safety trends and guide the development of new initiatives to enhance safety.

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**In accordance with 49 CFR 195.248:**

- All pipes must have a minimum cover of 3 feet.

**In accordance with 49 CFR 195.250**

- All pipes must have a minimum clearance of 12 inches from any other underground structure.

<table>
<thead>
<tr>
<th>Reported Incidents</th>
<th>General Public Fatalities</th>
<th>Total Fatalities&lt;sup&gt;2&lt;/sup&gt;</th>
<th>Total Pipeline Mileage</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Hazardous Liquid Pipelines (total)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2,362</td>
<td>4</td>
<td>7</td>
<td>1,143,831&lt;sup&gt;3&lt;/sup&gt;</td>
</tr>
<tr>
<td><strong>Refined Petroleum Products (only)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>805</td>
<td>0</td>
<td>0</td>
<td>379,086&lt;sup&gt;4&lt;/sup&gt;</td>
</tr>
</tbody>
</table>

1 Because pipeline safety is expected to improve with each successive change in federal safety rules, PHMSA reports data based on the period reflecting the most recent rule changes to ensure consistent data (see further explanation above).

2 Includes pipeline operator employees, contractor employees, and the general public.

3 This is a sum of the individual pipeline mileages for each year, from 2010 through 2015.

4 This is a sum of the individual pipeline mileages for each year, from 2010 through 2015.

Source: PHMSA, 2016b.

Of the incidents for hazardous liquid pipelines, 805 were on pipelines or facilities that carry refined petroleum products; of these, 648 occurred at facilities (e.g., tank farm, station equipment, pump station, appurtenance piping, and valve station) and 157 occurred along pipeline rights-of-way. The number of incidents over the total mileage of refined petroleum product pipelines indicates that the likelihood is low for an incident at any given location.

The frequency of incidents along refined petroleum product pipeline systems was 2.12 incidents per 1,000 mile years. For those incidents occurring on pipeline rights-of-way only (and not at facilities), this rate was 0.51 incidents per 1,000 mile years; none resulted in fatalities. The average spill size of these incidents<sup>1</sup> was 306 barrels (12,900 gallons). The largest reported unintentional release was 9,000 barrels (378,000 gallons).

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<sup>1</sup> This is the average spill size inclusive of incidents that occurred within pipeline rights-of-way and incidents that occurred at pipeline facilities (e.g., valve stations) where the release migrated beyond the parcel boundary.

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**Mile Years**

A means of predicting the number of incidents for a given length of line, over a given period of time. For example, if one considered an incident rate of 1.0 incident per 1,000 mile years, one would expect one incident per year on a 1,000-mile pipeline.
3.9.3.2 Reported Olympic Pipeline Incidents

Table 3.9-3 shows data on releases from the Olympic Pipeline system (the entire 400-mile system) provided by the PHMSA incident database for hazardous liquid pipeline releases. The data show that the Olympic Pipeline system has had incidents at about the same frequency as the national average during the reporting period, but with far smaller average volume of spilled product per incident. All of the releases occurred at valve stations. There were no reported releases along the pipeline right-of-way.

Table 3.9-3. Olympic Pipeline Reported Releases, January 2010 through December 2015

<table>
<thead>
<tr>
<th>Date</th>
<th>Release Volume (barrels)</th>
<th>Location</th>
<th>Cause</th>
</tr>
</thead>
<tbody>
<tr>
<td>9/19/2011</td>
<td>0.29</td>
<td>MP 7 Block Valve</td>
<td>Instrumentation Connection Failure</td>
</tr>
<tr>
<td>3/31/2012</td>
<td>1.96</td>
<td>Allen Station</td>
<td>Threaded Connection/Coupling Failure</td>
</tr>
<tr>
<td>4/1/2012</td>
<td>0.97</td>
<td>Allen Station</td>
<td>Instrumentation (Pressure Gauge) on Pig Trap Door</td>
</tr>
<tr>
<td>7/20/2014</td>
<td>0.19</td>
<td>Renton Station</td>
<td>O-Ring Connection Failure on Pig Trap Door</td>
</tr>
<tr>
<td>11/10/2014</td>
<td>7.49</td>
<td>Allen Station</td>
<td>Threaded Connection Failure</td>
</tr>
</tbody>
</table>

1 Reported releases between January 1, 2010 and December 31, 2015. No reported releases were identified for 2010 and 2015. Source: EDM Services, 2017.

The resulting frequency of unintentional release along the Olympic Pipeline system was estimated at 2.08 incidents per 1,000 mile years over this reporting period; this is a slightly lower frequency of unintentional release compared to the frequency of incidents that occurred along U.S. refined petroleum product pipeline systems over this same period (2.12 incidents per 1,000 mile years). The average spill size was 2.2 barrels (92 gallons), less than the national average of 306 barrels (12,900 gallons).

Olympic Pipe Line Company Violations (2012 – 2016)

The Washington UTC inspects pipelines to assess compliance with federal and state pipeline safety rules in accordance with WAC, Title 480. Several Phase 2 scoping comments referred to or requested information on Olympic’s past violations of these safety rules. The inspection reports on UTC’s website for Olympic’s facilities in Washington State are only available for the years 2012 through 2016. In these inspection reports, several violations and areas of concern were noted (as summarized in Table 3.9-4). These inspections included a review by UTC of Olympic’s records, operation and maintenance, emergency response, and field inspection of the pipeline facilities. Violations included late reporting and defects at test sites.
### Table 3.9-4. UTC Reports on Olympic Pipeline Violations and Areas of Concern, 2012–2016

<table>
<thead>
<tr>
<th>Violation or Area of Concern</th>
<th>Code Section</th>
<th>Explanation of Violation or Area of Concern</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>2012</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Area of Concern</td>
<td>49 CFR 195.432 (operators must inspect in-service atmospheric and low-pressure steel aboveground breakout tanks, and conditions must be documented for follow-up action by authorized inspector).</td>
<td>The seal for a breakout tank in Anacortes was faulty. After the inspection, a new sealant was applied.</td>
</tr>
<tr>
<td>Area of Concern</td>
<td>49 CFR 195.430 (adequate firefighting equipment must be maintained at each pump station and in proper operating condition).</td>
<td>Some fire extinguishers had missing inspection tags. After the inspection, the missing tags were reattached to the fire extinguishers.</td>
</tr>
<tr>
<td><strong>2013</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Area of Concern</td>
<td>N/A</td>
<td>Incident at Allen Station resulted in a release of 84 gallons of diesel, which the Programmable Logic Controller did not register the pressure data correctly. UTC recommended that personnel trained in Programmable Logic Controllers be available to assist investigations of future incidents that involve the SCADA system.</td>
</tr>
<tr>
<td>Area of Concern</td>
<td>49 CFR 195.446 (operators must submit Control Room Management procedures to PHMSA or state agency).</td>
<td>BP would not provide a copy of their Control Room Management procedures prior to inspection.</td>
</tr>
<tr>
<td><strong>2014</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Violation</td>
<td>49 CFR 195.583 (mandates that pipeline company must inspect onshore pipelines that are exposed to the atmosphere for evidence of atmospheric corrosion once every 3 years, not to exceed an interval of 39 months).</td>
<td>For the Seatac Delivery Facility, Tacoma Junction, and Tacoma delivery facility, the required atmospheric corrosion reads for 2014 were late (should have been read by March, but were read in November instead).</td>
</tr>
</tbody>
</table>
### Table 3.9-1: Violations and Area of Concern

<table>
<thead>
<tr>
<th>Violation or Area of Concern</th>
<th>Code Section</th>
<th>Explanation of Violation or Area of Concern</th>
</tr>
</thead>
<tbody>
<tr>
<td>Violation</td>
<td>WAC 480-75-510 (mandates that pipeline companies must initiate remedial action to correct deficiencies within 90 days of detection).</td>
<td>Defective test sites were noted. It could not be determined whether the pipeline was adequately protected in these areas. Olympic needs to ensure their pipelines are adequately cathodically protected and to repair, as necessary, the defective test sites.</td>
</tr>
<tr>
<td>Area of Concern</td>
<td>49 CFR 195.573 (pipeline company must test protected pipelines at least once a year and not to exceed an interval of 15 months to determine whether cathodic protection complies with Section 195.571).</td>
<td>BP self-reported instances where they were late in conducting pipe-to-soil readings. BP presented a list of changes made to ensure compliance with this section in the future.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year</th>
<th>Violation Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>None</td>
</tr>
<tr>
<td>2016</td>
<td>Violation 49 CFR 195.583 (mandates that pipeline company must inspect onshore pipelines that are exposed to the atmosphere for evidence of atmospheric corrosion once every 3 years, not to exceed an interval of 39 months)</td>
</tr>
<tr>
<td></td>
<td>For the Seattle Delivery Facility, corrosion was noted coming from under a non-adjustable pipe support. Olympic is required to inspect each portion of the pipeline that is exposed to atmospheric corrosion. Olympic is also required to evaluate the condition of the coating under pipe support and determine if the pipeline integrity is compromised. Olympic is also required to inspect its other non-adjustable pipe supports in their other intrastate facilities to ensure pipeline integrity is not compromised.</td>
</tr>
</tbody>
</table>

1 Inspection reports on UTC’s website for Olympic’s facilities in Washington State are only available for the years 2012 through 2016.

Source: UTC, 2017.

#### 3.9.3.3 Reported Causes of Unintentional Pipeline Damage

In addition to incident frequency, the risk assessment considered major causes of unintentional pipeline damage as included in the PHMSA incident database for refined petroleum product pipeline releases. The dominant causes of pipeline incidents are equipment failure (25 percent), *external corrosion* (22 percent), outside force/excavation (20 percent), and *material failure* (17 percent). Figure 3.9-2 shows the distribution of these incidents by cause. Figure 3.9-3 shows the volume (barrels) of reported incidents by cause.
Note: this data set excludes incidents that were limited to pipeline facilities (e.g., tank farm, station equipment, pump station, appurtenance piping, and valve station); the Energize Eastside project would not affect pipeline facility operation.

“Equipment failure” can occur on any part of the system, including valve stations, junctions, pump stations, or the pipeline itself. This includes items such as defective or loose components, malfunction of control or relief equipment, and other equipment failures.

“Incorrect operation” includes items such as incorrectly installed equipment, over-pressure, overfill tank or vessel, valve left in wrong position, wrong equipment installed, etc.

“Natural force” includes earthquakes, floods, lightning, extreme temperature, etc.

Source: EDM Services, 2017.

**Figure 3.9-2. Number of Reported Incidents by Cause, 2010–2015**

Of the causes of unintentional pipeline damage identified, the Energize Eastside project could affect pipeline safety primarily in three ways: outside force/excavation, external corrosion of the pipeline, and natural forces. These causes could result in unintentional releases from the pipeline, placing the public at risk. Natural forces, specifically lightning strikes or wires downed by extreme weather events, present risks of *arching* from the transmission lines to the pipelines. For the risk assessment, the causes of unintentional pipeline damage associated with external corrosion and natural forces were included under the topic of electrical interference. The ways that the Energize Eastside project could affect pipeline safety are described in more detail below.
Chapter 3: Long-Term (Operation) Impacts and Potential Mitigation

May 2017

Environmental Health - Pipeline Safety

Surcharge Loading

Equipment and other loads on the soil surface (surcharge loads) can place stress on the underlying substructures, including pipelines. These stresses can over-stress the pipe, causing damage.

Outside Force/Excavation

Outside force/excavation hazards generally relate to construction activities near pipelines. Commonly referred to as third party damage, pipelines can be damaged by excavation and other heavy equipment operation near pipelines. Excavation or construction near a hazardous liquid pipeline carries a risk that the line will be directly hit or damaged. Also, equipment operating over or near a pipeline can cause pipe stresses due to surcharge loading.

The Energize Eastside project would involve excavation and heavy equipment to construct the project, and occasional truck activity during operation for maintenance and repair (as currently occurs within the corridor). Risks to pipeline safety associated with construction of the project are addressed in Section 4.9.

Note: this data set excludes incidents that were limited to pipeline facilities (e.g., tank farm, station equipment, pump station, appurtenance piping, and valve station); the Energize Eastside project would not affect pipeline facility operations.

Source: EDM Services, 2017.

Figure 3.9-3. Average Volume (Barrels) Per Release by Cause, 2010–2015

Outside Force/Excavation hazards generally relate to construction activities near pipelines. Commonly referred to as third party damage, pipelines can be damaged by excavation and other heavy equipment operation near pipelines. Excavation or construction near a hazardous liquid pipeline carries a risk that the line will be directly hit or damaged. Also, equipment operating over or near a pipeline can cause pipe stresses due to surcharge loading.

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Note: this data set excludes incidents that were limited to pipeline facilities (e.g., tank farm, station equipment, pump station, appurtenance piping, and valve station); the Energize Eastside project would not affect pipeline facility operations.

Source: EDM Services, 2017.

Figure 3.9-3. Average Volume (Barrels) Per Release by Cause, 2010–2015
**Electrical Interference**

*Electrical interference* can occur during normal high voltage AC transmission line operation, which can contribute to accelerated external corrosion damage on the pipeline, or as a result of *fault conditions*. Fault conditions, usually initiated by lightning, result in the transfer of electrical power indirectly from one or more AC powerline conductors (i.e., wire) via the metallic transmission line pole to the ground, or directly to the ground as a result of an overhead conductor falling to the ground.

**External Corrosion.** *External corrosion* occurs when the metal of the pipeline reacts with the environment, causing the pipeline to corrode (or rust) on the outside of the pipe. It can be influenced by a number of conditions, including soil conditions and electrical interference.

**Soil Conditions.** The moisture, temperature, and chemical content of soil, also referred to as soil resistivity, can have an effect on external corrosion. Typically, the lower the soil resistivity, the higher the potential for corrosion. Soil resistivity generally decreases with increasing water content and the concentration of ionic species (chemically identical ions). For example, sandy soils are high on the resistivity scale and therefore considered the least corrosive, while clay soils, especially those contaminated with saline water, are low on the resistivity scale and considered the most corrosive.

**Electrical Interference.** High voltage AC power lines near pipelines can be a source of electrical interference. In the study area, the existing transmission lines and substations can cause electrical interference. This includes areas immediately under and adjacent to PSE’s existing 115 kV transmission lines, as well as areas near the Sammamish, Lakeside, Somerset, and Talbot Hill substations.

*AC current density* is a measure of electrical interference adjacent to the pipeline. AC current density levels less than 20 amps per square meter do not cause AC-induced corrosion. The AC current density is related to soil conditions, voltage, and the presence and size of any flaws in the pipeline’s protective coating (DNV GL, 2016).

**Cathodic protection systems** are used to reduce the potential for corrosion from occurring on the exterior of pipes, by substituting a new source of electrons, commonly referred to as an anode (Figure 3.9-4). Throughout the study area, the Olympic Pipelines are externally coated and cathodically protected, primarily with *overlapping impressed current systems* (West, pers. comm., 2016). These systems consist of an array of metallic anodes buried in the ground along the pipeline with a connection to a source of electric direct current (DC) to drive the protective electrochemical reaction.
Fault Damage. Faults (or fault currents) are an abnormal current flow from the standard intended operating conditions. These faults are typically caused by lightning, insulator failure, mechanical failure, and transformer failure. For example, a lightning strike on a pole can cause current to travel through the pole and into the soil, where it may transfer to an adjacent steel pipeline.

Under fault conditions, elevated electric currents can lead to fault damage (related to coating stress) or direct arcing damage (see arc damage below) to the pipeline.

The Olympic Pipelines have an exterior coating to protect against corrosion. The susceptibility of this coating to breakdown is based on the type and thickness of the coating and the voltage the pipeline is subject to (coating stress voltage).
In many cases, a shield wire on transmission poles is used to provide multiple pathways to carry a fault current to the ground thereby diffusing the strength of the current (Figure 3.9-5). In the absence of a shield wire, the entire fault current returns to ground at a single location where it could arc through the ground to the pipeline causing damage to the pipeline over time. While other protective measures are in place along the Olympic Pipelines, such as exterior coating, the existing transmission lines do not have a shield wire.

![Figure 3.9-5. Shield Wire](image)

**Figure 3.9-5. Shield Wire**

**Arc Damage.** High currents from a fault condition can cause arcing damage to the pipeline. The distance the current can travel to the ground (the arc distance) can be calculated based on pole configurations and shield wire characteristics. As noted previously, soil conditions also influence the amount of current that travels through the ground to the pipeline. If transmission line poles are within the arc distance, arc shielding protection is typically installed, often consisting of a zinc ribbon extending past the transmission line pole grounding cables.

External corrosion is described in Section 16.3.37 of the Phase 1 Draft EIS, and additional information is provided in the AC Interference Study (DNV GL, 2016).

### 3.9.4 Major Risks to Public from Unintentional Pipeline Release

Major risks to the public from unintentional pipeline releases relate to the characteristics of the pipeline product, the presence of ignition sources, and the release setting. Depending on these characteristics and conditions, pipeline releases can result in a *pool fire*, *flash fire*, or explosion, as described below.

The Olympic Pipelines transport refined petroleum products, including diesel, jet fuel, and gasoline. The product or the mix of products transported varies. The National Fire Protection Association assigns hazard ratings for each of these fuels, as depicted in Figure 3.9-6. For each hazard, the severity ranges from 0 (no hazard) to 4 (severe risk).
Long-Term (Operation) Impacts and Potential Mitigation

**Pool Fires**

For a buried pipeline transporting refined petroleum product, the greatest risk to the public is posed by pool fires. When a release occurs, the pipe contents are released into the soil. Depending on the release rate, soil conditions, groundwater level, and other factors, the released material may come to the surface. Depending on local terrain, it may flow for some distance away from the location of the release. If an ignition source is present, the accumulated pool could catch fire (the pipeline itself would not be expected to catch on fire, just the released material).

EDM Services (2017) used a number of reasonable assumptions and data inputs, including the estimated release rate and pipe contents of the Olympic Pipelines, to model a release and subsequent pool fire as described in Sections 7.1 and 8.3 of their report (see Appendix I). Based on these inputs, EDM Services estimated the following maximum release volume:

- 372,162 gallons

Figure 3.9-7 is a graphical depiction of the estimated pool fire size based on the maximum release volume (yellow circle) and the resulting heat flux zones. The yellow, orange, blue, and green heat flux zones are where the heat from the fire would cause fatalities. The area outside of these rings would be hot but typically would not result in fatalities.

The estimated maximum downward distance to potentially fatal impacts, measured from the center of the pool fire, is 113 feet. This distance represents the area where released pipe contents would spread (or pool) and result in a fire (if an ignition source is present). This

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**Spill Release Volume**

For reference, the Bellingham incident of June 10, 1999 released about 237,000 gallons of gasoline. Because the release migrated along a waterbody, pool fire characteristics were different than the depiction in Figure 3.9-7.
Heat Flux

Humans in the vicinity of a fire receive heat from the fire in the form of thermal radiation. Radiant heat flux decreases with increasing distance from a fire. Those close to the fire would receive thermal radiation at a higher rate than those farther away.

Figure 3.9-7. Typical Pool Fire and Heat Flux Areas Diagram
The effects of radiant heat flux to humans are summarized below. The following three endpoints are commonly used to evaluate the risk of public fatalities (CDE, 2007).

- 12,000 Btu (British thermal unit)/ft²-hr (combined yellow pool and orange band) – 100% mortality after 30-second exposure.
- 8,000 Btu/ft²–hr (blue band) – 50% mortality after 30-second exposure.
- 5,000 Btu/ft²-hr (green band) – 1% mortality after 30-second exposure.

**Flash Fires**

Flash fires can occur when a vapor cloud is formed, with some portion of the vapor cloud within the combustible range, and the ignition is delayed. To be in the combustible range, the fuel vapor must be sufficiently concentrated; therefore, flash fires only occur when the liquid fuel has a high enough evaporation rate and the vapor cloud is not dispersed by wind. In a flash fire, the portion of the vapor cloud within the combustible range burns very quickly, minimizing the potential impact to humans. For gasoline, diesel fuel, and jet fuel, the potential for extensive vapor migration is limited by their relatively low evaporation rates when in liquid pools.

**Explosions**

Gasoline, jet fuel, and diesel fuel generally do not explode, unless the vapor cloud is confined in some manner, called a vapor cloud explosion. For the most recent PHMSA incident database (2010 – 2015), there were no reported explosions for refined petroleum product pipelines. Impacts for vapor cloud explosions are expressed in terms of a shock wave measured as overpressure (pounds per square inch) above atmospheric pressure. EDM Services modeled the potential releases from each of the refined petroleum products transported by the Olympic Pipelines within the project corridor. The resulting peak overpressure level was 0.38 pounds per square inch due to the relatively open environment (medium fuel reactivity and low obstacle density). This overpressure level is not high enough to pose potential explosion risks. As a result, explosions are not described any further in this EIS chapter. For additional information on explosions, see the Pipeline Safety Technical Report (Appendix I).

**3.9.5 Risks During Operation**

This section addresses the potential pipeline safety risks associated with the operation of the project within the study area. The section begins with a description of the methodology used to conduct a risk assessment, identification of the key risk assessment steps that were followed by EDM Services, limitations of the data used to inform the risk assessment, and a description of key terms used to present the risk assessment results. The existing pipeline safety risks that would remain under the No Action Alternative are presented in this section as baseline information. The section then describes the incremental change in risks from baseline conditions under Alternative 1. This section addresses the potential risk of human fatalities occurring as a result of a pipeline leak or pool fire; the impacts of a leak or pool fire on environmental resources are addressed in Section 3.9.6.
3.9.5.1 Methodology

As described in the Phase 1 Draft EIS, and as addressed in numerous scoping comment letters for the Phase 2 Draft EIS, the Energize Eastside project could pose additional risks to the public. For example, if the Energize Eastside project were to damage one or both of the Olympic Pipelines, refined petroleum product could be released. If the fluid reached a combustible mixture and an ignition source were present, a fire could occur, resulting in possible injuries and/or fatalities.

To quantify this risk, EDM Services conducted a probabilistic pipeline risk assessment for the following conditions:

- Olympic Pipelines Co-located with Existing Transmission Lines (No Action).
- Olympic Pipelines Co-located with Proposed Transmission Lines (Alternative 1).

A probabilistic pipeline risk assessment is a type of risk assessment used to estimate event frequencies or probabilities, for a specified time period, associated with specific, measurable consequences. The pipeline industry commonly uses such assessments to rank and manage risk, and to establish priorities for inspection, testing, and repairs.

To identify the change in risk associated with Alternative 1, the risk assessment estimated the change in frequency of pipeline incidents for the following three main causes of pipeline damage resulting from electrical interference:

1. External Corrosion
2. Fault Damage
3. Arc Damage

The estimated change in frequency for each of these main causes was considered in combination with all other causes of pipeline damage identified in Section 3.9.3.3 in order to present the overall pipeline safety risk associated with Alternative 1. For results of the risk assessment related to outside force/excavation, see Chapter 4.

Risk Assessment Steps

EDM Services completed the risk assessment using the five steps described below (and illustrated in Figure 3.9-8).

1. **Baseline Data Compilation** – To estimate the probability of pipeline failures, historical data on similar systems are most commonly used in conjunction with information on the characteristics of the pipeline system being evaluated. However, it should be acknowledged that using this information has limitations, as described in more detail in the next section.
Limitations relate to the national database, which does not independently collect and evaluate co-location of pipeline and transmission line systems information, and certain data not provided by Olympic. As an initial step, baseline data were compiled from sources summarized in Section 3.9.3, including historic release data. EDM Services also reviewed information provided by Olympic on the operating conditions of the Olympic Pipelines in the study area (West, pers. comm., 2016; Stone, pers. comm. 2016). This information was used to estimate:

- Frequency of release
- Frequency of public injuries and fatalities
- Spill size distribution
- Causes of release
- Likelihood of fires or explosions following a release.

2. **Probability Analysis** – Using the above baseline data, estimates of the likelihood of various size releases, fires, and public fatalities resulting from unintentional releases from the Olympic Pipelines were developed. This included a review of a number of publications and reports, including DNV GL’s *AC Interference Study* (2016), to identify the potential change in risk associated with the proposed high-voltage AC transmission lines.

3. **Consequence Analysis** – Using Olympic Pipeline operating parameters, EDM performed release modeling to evaluate the potential impacts from unintentional releases (leaks) alone, as well as leaks that result in a pool fire. For a buried refined petroleum product pipeline, the greatest risk to the public is posed by pool fires.

4. **Conditional Probabilities** – Using the above data, the probabilities for a number of conditions were estimated, including:

   - Probability of various size unintentional releases from the Olympic Pipelines.
   - Probability of fires following an unintentional release.
   - Probability of fatal injuries following a fire.

5. **Risk Determination** – The risks were then calculated to present a numerical combination of both the probability of an event and its consequences. The presentation of risk results and the terminology used in this assessment are described below.

These risk assessment steps are described in more detail in Sections 6.0 through 11.0 of the *Pipeline Safety Technical Report* (EDM Services, 2017).
Figure 3.9-8. Conceptual Illustration of the Risk Assessment Methodology
**Limitations of the Baseline Data**

The baseline data used for the EDM Services risk assessment have a number of limitations. These are described below and relate to the following: (1) limitations of the national database for addressing co-located pipeline and transmission line systems, and (2) limited data provided by Olympic.

**Limitations of PHMSA Incident Database**

Despite it being relatively common for transmission lines and underground pipelines to be co-located, the available data sources on release incidents do not distinguish between co-located and non-co-located pipelines. The PHMSA incident database does not include an inventory of pipelines that are co-located with high-voltage transmission lines, nor do the incident data reports identify incidents that occurred where the pipeline was co-located with high-voltage transmission lines. As a result, it is not possible to directly develop and quantify the difference in risk that may exist between a co-located pipeline system and those that are not co-located with transmission lines.

In the absence of national collocation data, EDM Services used national data on releases associated with all pipelines and attempted to identify releases that may have been caused by a pipeline’s proximity to electrical utility facilities. Unfortunately, the reports on external corrosion-caused releases do not include data to identify whether releases were caused by electrical interference with cathodic protection systems. The reports also do not identify whether releases caused by excavation damage were related to overhead power line construction.

**Limited Olympic Pipeline Data**

To provide a more project-specific risk assessment, information was requested from Olympic on the Olympic Pipelines in the study area to supplement the national data (information requested and received is identified in Appendix I). Some of the requested information was provided; however, for some information requests, only partial responses or no response were provided due, in part, to information being identified as confidential for security reasons. In the risk assessment field, it is not uncommon for certain pipeline information to be unavailable from the pipeline operator due to proprietary or security reasons (CDE, 2007). In the absence of specific information, the risk assessment largely relied on actual reported pipeline release volumes from national data.

To address the lack of available data related to coating stress and arc distance information for the existing 115 kV corridor (presented below as the No Action condition), several assumptions were used in the risk assessment. To estimate the maximum, or worst-case, incremental change in risk from the No Action Alternative to Alternative 1, the risk assessment included an assumption that the coating stress voltages and resulting coating stress caused pipeline releases for the existing 115 kV corridor are the same as those for the proposed 230 kV corridor. Similarly, the risk assessment included an assumption that the ground fault arc distances and arc caused frequency of unintentional releases for the existing 115 kV corridor are the same as those for the proposed 230 kV corridor. Using these assumptions likely understates the existing risk (No Action), thereby overstating the actual difference in risk between the No Action Alternative and Alternative 1.
**Risk Terminology**

Results of the risk assessment are presented in two main forms: individual risk and societal risk.

**Individual risk** is most commonly defined as the frequency that an individual may be expected to sustain a given level of harm from the realization of exposure to specific hazards, at a specific location. The individual risk results can be expressed as likelihood of a specific outcome (e.g., fatalities per year).

**Societal risk** builds on the individual risk results by considering the number of people in proximity to a potential pipeline safety hazard and groups of people in the surrounding study area. Societal risk is expressed as the cumulative risk to a group of people who might be affected by an unintentional release.

Risk is calculated by first estimating the frequency of pipeline incidents (see below incident frequency) and is presented as an annual probability of fatality (see below risk results).

**Incident Frequency**

The risk assessment developed anticipated frequencies of pipeline incidents for various causes (called “incident frequency” in this EIS). Causes of pipeline damage include external corrosion, fault damage, and arc damage that have the potential to cause an unintentional release of pipeline contents. Incident frequencies are described (and presented below for the No Action alternative and Alternative 1) in terms of mile years. Mile years are a standard measure for pipeline risk assessments and describe the number of predicted incidents for a given length of pipeline (one mile), over a given period of time expressed in years. For example, for an incident frequency of 1.0 incident per 1,000 mile years, one would expect one incident per year on 1,000 miles of pipeline, or 0.001 incidents on 1 mile of pipeline per year. Pipeline incidents are in reference to any unintentional release of pipeline contents, which could be a minor or major spill. Not all incidents result in fires that could cause injury or fatality.

**Risk Results**

Individual risk results are presented as the annual probability of fatality (e.g., 1 in 1.0 million). The results are developed and presented using a standard risk assessment method, which allows for comparison with other risk results or with risk criteria in use by other jurisdictions for other settings. There are no adopted federal or Washington State criteria for acceptable levels of individual risk. Several jurisdictions have adopted criteria (or thresholds) for use in siting new facilities or sensitive land uses (e.g., schools) near pipelines. There are no known criteria in use by other jurisdictions that address modifications to existing transmission lines co-located with pipelines.

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**Individual Risk**

Annual probability of fatality resulting from a pipeline failure and release for an individual, at a specific location.
Figure 3.9-9 presents the individual risk thresholds for several jurisdictions where such thresholds have been adopted. Risk values for the jurisdictions are depicted by green (broadly acceptable risk), red (unacceptable risk), or yellow (tolerable risk). For example, the California Department of Education and Santa Barbara County have established as their threshold between acceptable and unacceptable risk a 1 in 1.0 million likelihood that an individual at a specific location would be fatally injured over a 1-year period. This risk criterion has the highest factor of safety in use by other jurisdictions. This criterion was originally in use by the United Kingdom and the Netherlands for siting certain industrial facilities. It was later adopted by the California Department of Education for siting new schools within 1,500 feet of pipelines.

Figure 3.9-9. Individual Risk Criteria by Jurisdiction

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2 Generally, risks within the yellow area may be tolerable only if risk reduction is impractical or if its cost is grossly disproportionate to the risk improvement gained.

Source: EDM Services, 2017.
Societal risk is expressed as the cumulative risk to a group of people who might be affected by an unintentional release. As with individual risk, there are no adopted federal or Washington State criteria for acceptable levels of societal risk. As shown in Figure 3.9-10, the acceptable values for societal risk vary greatly by different agencies and jurisdictions where risk criteria have been adopted. The California Department of Education (shown on the figure as CDE) and the County of Santa Barbara (shown on the figure as SBCO), California have upper and lower bounds for unacceptable (intolerable) as shown in red and acceptable (negligible) as shown in green societal risk levels. Between these two bounds is a “yellow area” similar to the tolerable risk category described above for individual risks. For example, for 100 fatalities, as shown the “x” axis, the threshold for California Department of Education (green line) is 1.00E-09 (or 1:1.0 billion), as shown on the “y” axis. In other words, if the likelihood of 100 fatalities is less than one in one billion, the risk is deemed negligible. If greater than 1 in 10 million, the risk is considered intolerable. Between these levels, the risk may be considered acceptable only after additional analysis and alternatives are examined. For the United Kingdom (shown on the figure as UK) and the Netherlands, risks above the lines are considered unacceptable, and risks below the line are considered acceptable.

Source: EDM Services, 2017.

Figure 3.9-10. Societal Risk Criteria by Jurisdiction Significance Thresholds

A review of policies and regulations applicable to the study area revealed that the existing regulatory framework was insufficient for determining significance thresholds because there are no clear written standards addressing pipeline safety in adopted plans, programs, or ordinances for the Partner Cities. To develop a threshold for significance that reflects the policies of the Partner Cities, the EIS Consultant Team held two workshops with staff from the Partner Cities, one in November 2016 and one in February 2017. The threshold for significance established below is based on the Partner Cities workshop discussions.
For this analysis, project-related risks are classified as being significant or less-than-significant as follows:

**Less-than-Significant**

- With implementation of mandatory safety standards and design measures, there would be no substantial increase in risk of pipeline release or fire as a result of project operation that could result in public safety impacts or damage to property and environmental resources.

**Significant**

- Even with the implementation of mandatory safety standards and design measures, there would be a substantial increase in risk of pipeline release or fire as a result of project operation that could result in public safety impacts or damage to property and environmental resources.

### 3.9.5.2 Risk Assessment Results

The results of the risk assessment (as described in Section 3.9.5.1, *Methodology*) are presented in this section beginning with the incident frequencies for each of the three electrical-interference-related causes of pipeline damage (external corrosion, fault damage, arc damage). These frequencies were used to develop the final risks results, which follow.

The incident frequencies (or estimated number of incidents per 1,000 mile years) were developed for individuals (individual risk) and groups of people (societal risk) for each of the electrical-interference-related pipeline damage (external corrosion, fault damage, arc damage) and are presented in Figure 3.9-11. The incident frequencies are presented for the No Action Alternative and Alternative 1, and the change in frequency is presented in the far right column. For two of the causes (fault damage and arc damage), data were not made available from Olympic to quantify the No Action Alternative.

### Key Assumptions

To address the lack of available data related to coating stress and arc distance information for the existing 115 kV corridor, several assumptions were used in the risk assessment. To estimate the maximum, or worst-case incremental change in risk from the No Action Alternative to Alternative 1, the risk assessment included an assumption that the coating stress voltages and resulting coating stress caused pipeline releases for the existing 115 kV corridor the same as those for the proposed 230 kV corridor. Similarly, the risk assessment included an assumption that the ground fault arc distances and arc caused frequency of unintentional releases for the existing 115 kV corridor are the same as those for the proposed 230 kV corridor. Using these assumptions likely understates the existing risk (No Action), thereby overstating the actual difference in risk between the No Action Alternative and Alternative 1.

### Mile Years

A means of predicting the number of incidents for a given length of line, over a given period of time. For example, if one considered an incident rate of 1.0 incident per 1,000 mile years, one would expect one incident per year on a 1,000-mile pipeline.
For the purposes of Figure 3.9-11, the predicted changes in frequency are based on qualitative considerations.

1. As described in Section 3.9.5.1, Olympic did not provide information to estimate the coating stress voltage for the existing 115 kV transmission lines, and the arcing distance of the existing 115 kV transmission lines.

2. While decrease is likely, the results for individual risk and societal risk presented in Figure 3.9-12 below assumed there would be no change in incident frequency related to fault damage or arc damage. This ensures that the change in risk for Alternative 1 is likely overstated while the existing risk is understated.

Source: EDM Services, 2017.

**Figure 3.9-11. Change in Incident Frequency**
In consideration of the separate incident frequencies for individual risk and societal risk developed for the three conditions noted above, Figure 3.9-12 presents the combined incident frequency for the No Action Alternative and Alternative 1, and the change in incident frequency that could be anticipated.

*Under the No Action Alternative, the incident frequencies for societal risk is in fact 0.5193 per 1,000 mile years and for Alternative 1, the incident frequency for societal risk is 0.5235 per 1,000 mile years. The figure shows rounded values.
Source: EDM Services, 2017.

Figure 3.9-12. Change in Incident Frequency (Combined)
Using the incident frequency results in Figure 3.9-12, the individual risk results for Alternative 1 are presented in Figure 3.9-13.

*What is meant by the “increase in risk”?*
Risk is characterized as a 1 in x chance of a specified event occurring. The “increase in risk” is the chance that the specified event (e.g., an individual fatality from an unintentional release from the pipeline) would occur that would not have occurred if the project had not been built. In this case, there is an estimated 1 in 51 million chance that an individual fatality would occur that would not have occurred if the project was not built.

Source: EDM Services, 2017.

Figure 3.9-13. Alternative 1 Individual Risk (of Fatality) Results
The annual individual risk of fatality for operation of the 230 kV lines within the corridor is 1 in 4.5 million (Figure 3.9-13). In other words, it is estimated that there could be a 1 in 4.5 million likelihood that an individual at a specific location would be fatally injured over a 1-year period.
These results are below the common threshold of 1 in 1.0 million used by Santa Barbara County, the California Department of Education, and other jurisdictions in determining unacceptable and acceptable risk. Based on the results of the risk assessment, the individual risk for the proposed 230 kV lines would incrementally increase over that posed by the existing 115 kV lines (No Action). This maximum estimated increase in risk is slight, approximately 1 in 51 million. In other words, the assessment estimates that there would be an approximately 9 percent increase in individual risk during operation of Alternative 1 before any mitigation is applied. Because the risk level is already very low, this 9 percent increase is not considered substantial.

To put individual annual risk results in context, the following are annual risks for a relatively common type of incident (vehicle fatality) and a relatively uncommon type of incident (being struck or being killed by lightning), as illustrated in Figure 3.9-14.

![Annual Risk of Other Incidents, for Comparison](image)


**Figure 3.9-14. Annual Risk of Other Incidents, for Comparison**

The assessment also considered the broader societal risk, or risk to groups of people, which takes into account the number of individuals who may be present near the project corridor at any given time and the duration of their presence. Societal risk takes into account multiple release scenarios. The societal risk results for any 1-mile segment are presented below in Figure 3.9-15 for the maximum and minimum fatalities under the possible release scenarios, which are further described in *Pipeline Safety Technical Report* (EDM Services, 2017). While it is possible that a more severe event could occur, the maximum number of fatalities, 17, is the most severe event estimated by the model based on the data assumptions and event scenarios, and represents a worst-case scenario for purposes of this EIS.

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3 Calculated as: 1 in 51 million / 1 in 4.5 million = 9 percent.
In other words, there is a one in 2 million probability of an event resulting in 17 fatalities occurring in any 1-year time period, and a one in 60,000 probability of an even resulting in a single fatality occurring in any 1-year period. These results are above the thresholds for negligible impacts, and below the thresholds for intolerable impacts as used by Santa Barbara County and the California Department of Education for school siting purposes.

Based on the results of the assessment, the increased societal risk of the proposed 230 kV lines over that posed by the existing 115 kV lines (No Action) is 1 in 253 million (for a scenario resulting in 17 fatalities) and 1 in 7.45 million (for a scenario resulting in one fatality). In other words, the assessment estimates that there would be a 0.8 percent increase in societal risk during operation of Alternative 1. Because the risk level is already very low, this 0.8 percent increase is not considered substantial.
3.9.5.3 No Action Alternative

This section describes the potential pipeline safety risks that could occur under the No Action Alternative.

The pipeline safety risks within the existing corridor are associated with refined petroleum products that are currently transported in the Olympic Pipelines where they are within PSE’s existing transmission line corridor. Safety risks to the public from these materials could occur due to incidents caused by pipeline failure from electrical interference (external corrosion, fault damage and arc damage), outside force/excavation, or other causes either related to (or unrelated to) co-location with the existing 115 kV PSE transmission lines. Depending on the circumstances of an incident and the properties of the pipeline product, incidents could result in the potential for pool fire or flash fire. These existing risks are described at a general level in the Phase 1 Draft EIS, Chapter 8. Safety risks related to outside force/excavation are addressed in Chapter 4 of this Phase 2 Draft EIS.

As described above, the risk assessment estimated the likelihood of potential impacts occurring as a result of the operation of the pipelines co-located with the existing 115 kV transmission lines for the three ways a transmission line can interact with a pipeline to cause damage: (1) external corrosion (related to AC density), (2) fault damage (related to coating stress), and (3) arcing damage (related to arc distances). These conditions are described in Section 3.9.3.3. The estimated incident frequencies (or estimated incidents per 1,000 mile years) for individuals (individual risk) and groups of people (societal risk) are presented above in Section 3.9.5.3.

External Corrosion. There are two short segments in the study area where the estimated AC current density under existing peak winter loads exceeds 20 amps per square meter. (As described above, AC current density levels less than 20 amps per square meter do not cause AC-induced corrosion.) The current densities in these areas are estimated to range from 22 to 35 amps per square meter. The incident frequencies presented above were developed using worst-case assumptions about length of pipeline affected and the duration of peak winter voltages.

Fault Damage. Because no data were available from Olympic to estimate the coating stress voltages on the existing Olympic Pipelines within the existing 115 kV corridor, the existing pipelines were assumed to have the same coating stress voltages and potential for coating stress-caused pipeline releases as for Alternative 1. See Section 3.9.5.2 (Alternative 1) below for information on fault damage. Using this assumption in the risk assessment calculation likely overstates the overall change in risk associated with Alternative 1 because the proposed design for Alternative 1 would include a shield wire, while the existing system does not.

Arcing Damage. Because no data were available from Olympic to estimate the arc distances for the existing Olympic Pipelines within the existing 115 kV corridor, the existing pipelines were assumed to have the same ground fault arc distances and potential for arc-caused pipeline releases as for Alternative 1. See Section 3.9.5.2 (Alternative 1) below for information on arcing damage. Using this assumption in the risk assessment calculation likely overstates the overall change in risk associated with Alternative 1 because the proposed design for Alternative 1 includes a shield wire, the potential arcing distance is known, and most poles would be placed at sufficient distance to avoid arcing damage to the pipeline. The existing transmission line does not have a shield wire, and although other protective measures are in place, information provided by Olympic was insufficient to determine potential arcing distances for the existing pipeline.
Total individual risk and total societal risk are not presented for the No Action Alternative due to the lack of available data from Olympic and uncertain assumptions for the current pipeline related to coating stress and arc distances, as described in Section 3.9.5. Instead of modeling existing conditions to calculate existing risk, worst-case assumptions were used to ensure that project impacts relative to the No Action Alternative were not understated.

For additional details about the analysis of risks under the No Action Alternative, see the Pipeline Safety Technical Report (EDM Services, 2017).

**No Action Alternative Impacts Conclusion**

Based on the limited pipeline data available to the EIS team, it is not possible to calculate exact risks along the existing corridor. Using low estimates of existing risk (to present a worst-case change in risk associated with Alternative 1), the risk of external corrosion is expected to stay the same under the No Action Alternative. Because no data were available to estimate the likelihood of damage as a result of fault conditions on the Olympic Pipelines within the existing 115 kV corridor, the existing pipelines were assumed to have the same risk as for Alternative 1. Even with these low estimates of existing risk, the likelihood of a pipeline rupture and fire would remain low. Under the No Action Alternative, PSE would continue to operate their existing 115 kV transmission lines as described in Chapter 2. The arrangement and spacing of lines and voltage would stay the same and there would be no change in risk. Therefore, under the No Action Alternative, impacts would be less-than-significant.

**3.9.5.4 Alternative 1: New Substation and 230 kV Transmission Lines**

This section describes the potential pipeline safety risks under Alternative 1, focusing on how these risks would change compared to the No Action Alternative.

As described above, the assessment estimated the likelihood of potential impacts from the operation of the pipelines co-located with the proposed 230 kV transmission lines for the three ways the proposed 230 kV transmission lines can interact with a pipeline to cause damage: (1) external corrosion (related to AC density), (2) fault damage (related to coating stress), and (3) arcing damage (related to arc distances). The potential risk and potential impacts were estimated for individuals (individual risk) and groups of people (societal risk) for each of these conditions. In addition, this section describes the design requirements for transmission lines related to extreme weather events and seismic hazards. Because ongoing maintenance activities during operation of Alternative 1 are expected to be the same as the No Action Alternative, no change in risk related to ongoing maintenance activities is anticipated.

In the case of fault damage (related to coating stress), no increase in potential risk of damage was estimated for the proposed 230 kV lines because PSE’s plans to use a shield wire on the new transmission lines. For the other two cases examined, the risk assessment estimated that, without consideration of potential mitigation measures, there could be an increase in potential risk of damage to the pipeline. These include external corrosion (related to AC current density) and arcing damage (related to arc distances). As described in Section 3.9.6.4, the risk assessment was limited by the lack of available data on the existing (No Action) condition related to coating stress and arc distances. The lack of available data for existing conditions required the risk assessment to assume certain conditions in order to provide a worst-case analysis of Alternative 1. Using these assumptions likely understates the existing risk (No Action), thereby overstating the actual difference in risk between the No Action Alternative and Alternative 1.
**External Corrosion.** There are two areas along the corridor where the estimated AC current density would exceed 20 amps per square meter under peak winter loads. The estimated AC current densities at these locations range from 25 to 70 amps per square meter. This current density is higher than that presented in Section 3.9.5.3 for the existing 115 kV corridor (No Action Alternative).

The incident frequencies presented above were developed using worst-case assumptions about length of pipeline affected and the duration of peak winter voltages. These estimates do not reflect the implementation of testing and monitoring once the lines are energized, or measures that may be taken to mitigate potential AC current density levels based on the results of the monitoring (see Section 3.9.7, Mitigation Measures).

As described in Chapter 2, the plan for the Energize Eastside project is to first operate one circuit at 230 kV and the other would remain at 115 kV, then eventually operate both circuits at 230 kV. The imbalance of having two different voltages can have an impact on the overall AC interference on the adjacent pipelines and was a factor in the external corrosion results for Alternative 1. While the total magnitude of current for the 115 kV/230 kV transmission lines is less than both circuits operating at 230 kV, the electrical current imbalance between the two circuits can result in overall higher levels of interference on nearby pipelines.

**Fault Damage.** PSE plans to use a shield wire on the new transmission lines (see also Section 3.9.7, Mitigation Measures). As a result, coating degradation is not anticipated along the corridor (DNV GL, 2016). Given that no shield wire is currently present under the No Action (115 kV) condition, Alternative 1 would likely improve conditions related to fault conditions because the shield wire would reduce the risk of fault damage to the pipeline (Fieltsch and Winget, 2014).

**Arcing Damage.** With a shield wire, the distance an arc can travel from a line fault (arc distance) is estimated to range from 4 to 13 feet under Alternative 1. This would pose a potential risk for pipeline damage at transmission pole locations where the electrical grounding rod might be less than 13 feet from the pipeline. This risk is not posed along the entire length of the corridor; the only affected segments of the pipeline would be those portions of the pipeline located within the arc distance of the grounding rod (4 to 13 feet). Based on worst-case estimates of average pole spacing and pipeline configuration at the grounding rods, EDM Services estimated that 4 percent of the pipelines would be within 13 feet of a grounding rod (see Section 9.3.4 of the Pipeline Safety Technical Report [EDM Services, 2017]).

The results presented above in Section 3.9.5.3 do not reflect the implementation of measures to mitigate potential arc damage to the pipeline. These measures include the installation of arc shielding protection, such as buried zinc ribbons (see Section 3.9.7, Mitigation Measures).

**Extreme Weather Events and Seismic Hazards.** If the overhead transmission lines were damaged during an extreme weather event or natural disaster, there could be risks to public safety if the poles fall and damage the buried pipelines. Safety measures would be incorporated into the project design to address the extreme weather and seismic conditions that occur in western Washington. The final
structural design would comply with NESC 2012 as adopted by the UTC, which also includes seismic standards. PSE would incorporate NESC design cases, Rules 250B for combined ice with wind, 250C for extreme wind, and 250D for extreme ice with wind into their design of the overhead transmission lines. Construction of the overhead transmission lines would satisfy all NESC design cases related to extreme wind and temperature conditions. Rule 250C considers wind velocities of 85 mph. For the transmission lines, NESC 2012 states that the structural requirements necessary for wind/ice loadings are more stringent than seismic requirements and sufficient to resist anticipated earthquake ground motions. In addition, according to ASCE Manual No. 74 (ASCE, 2013), “transmission structures need not be designed for ground-induced vibrations caused by earthquake motion because historically, transmission structures have performed well under earthquake events, and transmission structure loadings caused by wind/ice combinations and broken wire forces exceed earthquake loads.” Nonetheless, load comparisons would be performed between a seismic event and extreme weather conditions to ensure that the appropriate structural design would be able to withstand either of these conditions.

**Alternative 1 Impacts Conclusion**

Based on the results of the risk assessment, the probability of a pipeline release and fire occurring and resulting in fatalities remains low under Alternative 1. However, the potential public safety impacts could be significant if this unlikely event were to occur.

Under Alternative 1, the probability of a pipeline incident could be slightly higher in some locations when compared with the No Action Alternative. In these areas, testing, monitoring, engineering analysis, and implementation of mitigation measures would lower these risks. In areas where AC current density could be a concern, testing and monitoring would be conducted and mitigation measures (e.g., grounding mats) installed to reduce AC currents to acceptable levels. In areas where the pipelines would be within 13 feet of transmission line pole grounds, additional engineering analysis would be conducted and mitigation measures implemented to reduce fault risks (e.g., arc shielding protection). See Section 3.9.7, *Mitigation Measures* for measures that would lower the risks.

The individual and societal risks described above would be similar across all Alternative 1 segments and options. However, the risk would be reduced in segments and options with fewer miles of the transmission line co-located with the Olympic Pipelines. Bypass Option 2 has the lowest number of co-located miles in the Bellevue Central Segment, and the Willow 1 Option has the lowest number of co-located miles in the Bellevue South Segment. Table 3.9-5 lists the length of the Olympic Pipelines (both the 20-inch and 16-inch diameter pipelines) co-located with the transmission lines in the segment options.
### Table 3.9-5. Miles of Transmission Line and Olympic Pipeline Co-location in Study Area with Alternative 1, by Segment Option

<table>
<thead>
<tr>
<th>Location/Segment</th>
<th>20-inch diameter</th>
<th>16-inch diameter</th>
<th>Highest and Lowest Number of Co-Located Miles</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Bellevue Central Segment</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Existing Corridor Option</td>
<td>2.9</td>
<td>2.9</td>
<td>Highest number of co-located miles in segment</td>
</tr>
<tr>
<td>Bypass Option 1</td>
<td>0.91</td>
<td>0.91</td>
<td></td>
</tr>
<tr>
<td>Bypass Option 2</td>
<td>0.60</td>
<td>0.60</td>
<td>Lowest number of co-located miles in segment</td>
</tr>
<tr>
<td><strong>Bellevue South Segment</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oak 1 Option</td>
<td>3.2</td>
<td>3.3</td>
<td></td>
</tr>
<tr>
<td>Oak 2 Option</td>
<td>5.3</td>
<td>3.3</td>
<td>Highest number of co-located miles in segment</td>
</tr>
<tr>
<td>Willow 1 Option</td>
<td>1.2</td>
<td>3.3</td>
<td>Lowest number of co-located miles in segment</td>
</tr>
<tr>
<td>Willow 2 Option</td>
<td>2.1</td>
<td>3.3</td>
<td></td>
</tr>
</tbody>
</table>

As described above, the lack of available data for existing fault and arc distance conditions required the risk assessment to use certain assumptions for the No Action Alternative condition that would allow for a worst-case analysis of Alternative 1. Using these assumptions likely understates the existing risk (No Action), thereby overstating the actual difference in risk between the No Action Alternative and Alternative 1. Even with these assumptions, the likelihood of a pipeline rupture and fire would remain low, and no substantial change in risk has been identified. As a result, the potential risk is not considered significant. With implementation of the mitigation described in Section 3.9.7, conditions related to potential for fault damage due to coating stress and arc distances would likely improve under Alternative 1 over the existing operational baseline condition (No Action Alternative) (DNV GL, 2016).

For additional details about the analysis of risks under Alternative 1, see the *Pipeline Safety Technical Report* (EDM Services, 2017).
3.9.6 Long-term Impacts on Resources

Implementation of the regulatory requirements identified in Section 3.9.1, Relevant Plans, Policies, and Regulations, and the mitigation measures described for pipeline safety in Sections 3.9.7 and 4.9.4, will reduce the chances of a pipeline incident occurring. However, some level of risk would remain, and it is possible that petroleum products transported through the Olympic Pipelines could still enter the environment, or a fire could occur, as a result of proximity to the transmission line under the No Action Alternative or Alternative 1.

In addition to the public safety risks described above, natural resources and other elements of the environment could be significantly affected if an unintentional release or fire were to occur. This section describes the potential impacts of a spill or a fire on the natural and built environment in the unlikely event that a pipeline release were to occur. It describes the types of impacts on each element of the environment addressed in the Phase 2 Draft EIS.

The impacts of a spill depend on the magnitude of the spill (i.e., volume of material released and extent of area affected); the type of material released; and the location (e.g., near a sensitive area). Because the Energize Eastside project does not affect pipeline pressure and flow rates, or other operating parameters of the pipeline, the potential characteristics of a spill or fire would be the same regardless if it occurred under the No Action Alternative or Alternative 1.

The greatest potential for environmental harm would be if a release enters or directly occurs in a water body, as spilled materials can spread more quickly and can be difficult to contain and remove. The Olympic Pipelines carry diesel, jet fuel, and gasoline, which are very light or light oils. These types of oils evaporate within a few days, with the light oils leaving a residue. Very light and light oils can have localized and significant impacts; however, they tend not to persist long-term in the environment, lasting up to a few weeks (Ecology, 2016; NOAA, 2016).

A pool fire (fire) could result from a spill, but not all spills would result in a fire. For a fire to occur, an ignition source would be needed. The potential risk of a fire from a pipeline rupture is described Section 3.9.5, Risks from Operation, and Section 4.9.1, Risks from Construction. Potential impacts would depend on how and if the fire spreads, which would depend on vegetation, structures, and other conditions at the site. The nature and extent of the environmental damage from a fire can be quite varied. For example, the pool fire diagram in Figure 3.9-7 shows an area of approximately 1 acre that could have temperature high enough to cause fatalities. A spill of the same volume could spread over a larger area due to topography, especially if the spill reached a water body. Although the spill would not be as concentrated, the extent of damage could extend to several acres. If in a wooded area and during dry season, a pool fire could spread even farther if not contained by firefighters. Because of these variables, the impacts of a fire on resource areas are described here in general terms.
**Land Use and Housing**

A release of material from the Olympic Pipelines could foul buildings, contaminate soil, and damage vegetation. If residential buildings are fouled by the spill, structures may need to be demolished, which could temporarily reduce available housing units. Planned future development consistent with policies adopted by affected cities may not occur if contaminated properties are not promptly remediated. Depending on the time it takes to remediate the soil and rebuild damaged buildings, there may be a long-term displacement of businesses and residents.

Depending on the location, size, and extent, a fire could destroy or damage houses, commercial buildings, other structures, and vegetation. This would reduce the amount of available housing until structures are rebuilt, displace businesses, and potentially change neighborhood character.

Impacts on land use and housing associated with pipeline spills or fires would be highest if they occurred in areas with high population or employment density, areas with unique land uses (such as hospitals or schools), or areas planned for redevelopment or intensification of land uses.

**Scenic Views and Aesthetic Environment**

A spill has the potential to negatively affect the aesthetic environment, in particular the natural environment (e.g., vegetation). Spilled material can damage vegetation, negatively affecting the visual quality of the area. See the Plants and Animals section below for further explanation. The reduction in visual quality would depend on the type of material spilled, location, and size of the release.

A fire from a pipeline release could substantially degrade the visual quality of surrounding landscape. Visual effects of a fire can include areas with extensive burn damage to structures, facilities, and vegetation. This type of physical damage would alter and degrade the visual quality of the affected area until the landscape is restored. The extent of impact would depend on the size and location of the fire. Areas of higher visual quality would be most susceptible to aesthetic impacts from spills or fires, such as undeveloped wooded areas or areas with orderly urban form.

**Water Resources**

Materials from a spill can directly enter streams, wetlands, and lakes or could be washed into those water bodies by stormwater. The spills could degrade water quality and contaminate sediments, which can be toxic to aquatic plants and animals. Materials could also move downstream, spreading quickly and contaminating a larger area than if a spill occurred on land. Spills also have the potential to infiltrate and contaminate groundwater. In Renton, the drinking water supply comes from groundwater, and aquifer contamination would require expensive cleanup or finding an alternate water supply.

Depending on the location, size, and extent, a fire could destroy or damage vegetation in and adjacent to wetlands and streams. This could expose soils and increase erosion of sediments, which could negatively affect water quality. Damage to vegetation could change the function and extent of wetlands. Reduced riparian vegetation could also increase water temperature in streams. Additionally, byproducts from the fire, or chemicals used in firefighting or cleanup efforts could contaminate water resources. Byproducts or chemicals also have the potential to enter the groundwater and contaminate drinking water.
Impacts on water resources associated with pipeline spills or fires would be highest if they occurred in areas with rivers or streams and associated riparian areas or aquifer recharge areas.

**Plants and Animals**

Vegetation can be damaged by direct physical and chemical interactions associated with a spill. The nature of impacts depends on the duration of exposure, the type and quantity of the material spilled, location of the release, the potential for ignition (described below), and the sensitivity of species. Full restoration to original conditions can take many years. If a spill were to enter a watercourse, it could damage aquatic vegetation and terrestrial vegetation along the shoreline downstream. If the fuel were to persist in the environment, it can affect the long-term ability of vegetation to recover (Hoffman et al., 2003).

A spill can affect terrestrial and aquatic animals by physical smothering or toxic effects. Animals that contact spilled material could be physically coated by petroleum products, inhale vapors, or ingest oil when foraging or grooming. Aquatic-oriented species (including fish, wading birds, waterfowl, frogs, and salamanders) are more susceptible when oil enters a water body because the spill would spread throughout the water body or downstream. Sensitive areas or species as identified in Section 3.4, *Plants and Animals*, are particularly susceptible (Ecology, 2016).

Impacts to plants from a fire would depend on the vegetation species and communities exposed, as well as the duration and temperature that plants are exposed to. Low-lying ground cover and shrubs would recover much quicker than forested areas with mature trees. The longer the exposure and the higher the temperature, the more likely injury or death of plants would occur. The loss of vegetation can also provide an opportunity for invasive non-native species to become established and spread. Also, trees that survive may be more susceptible to disease, fungus, or insects.

Animals can be injured or killed by a fire if they are close enough to the event. Animals that can will move away from a fire; however, some animals with limited mobility, such as newly hatched birds, may not be able to move, and others react to danger by hiding and would be more susceptible to injury or death (USDA, 2000).

Impacts on plants and animals associated with pipeline spills or fires would be highest if they occurred in forested areas with mature trees or aquatic and terrestrial habitats, or during a season critical for the life cycle of a certain species (for example, spawning season for fish).

**Greenhouse Gases**

Activities that release GHGs contribute to the accumulation of GHGs in the atmosphere, a driving force in global climate change. After a spill, gasoline, diesel, and jet fuel would begin to evaporate, releasing greenhouse gases, primarily CO₂, N₂O, and CH₄. The resulting GHG impacts would depend on the amount of GHGs released into the atmosphere.

A fire would also result in the release of GHGs, primarily from burning structures and trees. The resulting GHG impacts would depend on the amount released and amount ignited. The highest amount of GHGs released would occur if the fire damaged a forested area with mature trees.
**Recreation Resources**

If a spill were to occur near a recreation site, it could affect recreation opportunities, depending on the scale of the spill. Small spills may have a temporary impact on access to a site during clean-up efforts. Larger spills may directly harm or kill vegetation. The loss of or damage to vegetation would negatively impact the recreation user experience. People may avoid a site or be prohibited from entering a contaminated area. Recreation sites downstream of the pipeline could be affected if a large spill were to enter a watercourse.

If a fire were to occur near a recreation site, it could substantially degrade the environment and affect recreation opportunities. Impacts on recreational resources would include the destruction or physical damage by the fire to the resource itself. The loss of or damage to vegetation would detract from the aesthetic quality of a recreation site and negatively impact the recreation user experience, or preclude its use altogether. A recreation site may be temporarily closed during cleanup efforts or if the fire were to leave the area unsafe (e.g., damaged trees).

Impacts on recreation associated with pipeline spills or fires would be highest if they occurred in parks or near recreational facilities that receive the highest number of visitors of the parks along the corridor, or parks with mature vegetation that is part of a recreation user’s experience, or occur during a park’s peak visiting season.

**Historic and Cultural Resources**

If material were released in an area where historic or cultural resources are located, these resources could be impacted. Impacts from seepage may damage a resource’s integrity of design, setting, materials, workmanship, and feeling, or its depositional context. Impacts to the depositional integrity of a subsurface cultural resource would be a permanent loss, as these resources are non-renewable. Incident response or cleanup activities such as excavation or other ground disturbance may impact historic and cultural resources, but could be mitigated through a state-issued emergency excavation permit. Damage to elements of vegetation or the natural environment that contribute to the historical significance of a resource could negatively affect these resources.

If a fire were to occur near historic and cultural resources, it could destroy or damage historic structures, buildings, or objects and change the historic character of a landscape. Although structures can be rebuilt, destruction of a historic or cultural resource would be a permanent loss, as the original resources are non-renewable. Damage to the surrounding environment and vegetation could impact a resource’s integrity of setting, and may minimize the resource’s ability to convey its historic significance. Soil disturbance from restoration efforts could also impact the integrity of subsurface cultural resources. Impacts from these efforts may be mitigated through a state-issued emergency excavation permit.

Impacts on historic and cultural resources associated with pipeline spills or fires would be highest if they occurred in areas with a concentration of historic and cultural resources, such as in a historic district.
Economics (Ecosystem Services)

If a spill or a fire were to damage a large number of trees, the ecosystem services associated with those trees (stormwater regulation, pollutant removal, and carbon sequestration) would no longer be available. Impacts on ecosystem services would be highest if a spill or fire occurred in a forested area with mature trees.

Conclusion

As stated above, impacts on these sensitive resources discussed in Section 3.9.6 could be significant if a pipeline incident were to occur. However, the likelihood of a pipeline rupture and release remains low under Alternative 1, and implementation of regulatory requirements (Section 3.9.1) and mitigation measures (Sections 3.9.7 and 4.9.4) would further reduce the probability of a pipeline incident occurring.

3.9.7 Mitigation Measures

This section describes the mitigation measures that would be used during operation of the project and recommends additional measures to avoid, minimize, and mitigate environmental health and safety impacts related to pipeline safety. See Chapter 4, Section 4.9.4 for mitigation measures that would be used during construction. A substantial set of federal, state, and local regulations and practices are in place to minimize the potential for pipeline incidents that could occur as a result of electrical inference from the Energize Eastside project. The design features and BMPs that PSE proposes to use to avoid or minimize impacts during operation and those required by agency standards are assumed to be part of the project and have been considered in assessing the environmental impacts to environmental health and safety.

All mitigation measures would be determined during the permitting process, but may be applied prior to construction, at project start-up, or during operation of the project. For instance, some mitigation measures (such as integrating where applicable the results and recommendations of DNV GL’s AC Interference Study [2016] to the design of pole locations, layout, and configuration) would be incorporated into the project design. Other mitigation measures necessarily would need to be identified and implemented after the project is energized or during peak winter load conditions in order to ensure that mitigation measures are appropriate based on measured field conditions.

Mitigation may include the installation of additional protective measures such as grounding mats, horizontal surface ribbon, and/or deep anode wells based on a detailed mitigation study. Olympic, as pipeline operator, is responsible for operating and maintaining their pipelines in accordance with federal standards. PSE, as project applicant, has responsibilities (some of which may be imposed by jurisdictions with permit authority) to coordinate and cooperate with Olympic, but has limited authority to influence specific mitigation measures undertaken by Olympic related to pipeline operation or monitoring. This section first describes the regulatory requirements and responsibilities of PSE for implementing mitigation measures and of Olympic for operating and maintaining their pipelines in accordance with safety standards and applicable laws. Next, the section identifies additional potential mitigation measures for ensuring that public safety concerns are addressed. As part of ongoing coordination between PSE and Olympic, additional mitigation measures may be identified during final design.
3.9.7.1 Regulatory Requirements

PSE Responsibilities and Requirements

PSE is responsible for the Energize Eastside project’s design, construction, and operational parameters within the shared corridor with the Olympic Pipelines. For PSE, national and state standards, codes, and regulations, and industry guidelines govern the design, installation, and operation of transmission lines and associated equipment. The National Electrical Safety Code (NESC) 2012, as adopted by the UTC, provides the safety guidelines that PSE follows. The NESC contains the basic provisions necessary for worker and public safety under specific conditions, including electrical grounding, protection from lightning strikes, extreme weather, and seismic hazards. PSE would use these in developing final design. The final design of the project has not been completed; therefore, the exact specifications and standards that would be incorporated into the project have not been identified.

To address concerns about potential interaction between the Energize Eastside transmission lines and Olympic Pipelines, PSE and Olympic have coordinated regarding the project since 2012, and both have indicated they would continue their coordination through final design and construction. PSE and Olympic meet regularly to discuss, identify, and mitigate potential threats to the integrity of the pipelines. Over the course of these ongoing discussions, the project plans have evolved to minimize the potential for impact. PSE plans to integrate, where applicable, the results and recommendations of DNV GL’s AC Interference Study (2016) to the design of pole locations, layout, and configuration in order to mitigate potential electrical interference-related impacts on the pipelines (Strauch, pers. comm., 2017).

Olympic Responsibilities and Requirements

As the pipeline operator, Olympic is responsible for operating and maintaining their pipelines in accordance with or to exceed PHMSA’s Minimum Federal Safety Standards in 49 CFR Part 195 (and Washington State UTC’s adopted and enhanced regulations contained in WAC, Title 480). The regulations are intended to ensure adequate protection for the public and to prevent pipeline accidents and failures. PHMSA specifies minimum design requirements and protection of the pipeline from internal, external, and atmospheric corrosion. In addition, 49 CFR 195 established the following broad requirements that are imposed on Olympic as the pipeline operator:

- 49 CFR 195.577(a) requires, “For pipelines exposed to stray currents, you must have a program to identify, test for, and minimize the detrimental effects of such currents.”
- 49 CFR 195.401 (b) (1) requires, “Non Integrity Management Repairs, whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it must correct the condition within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.”

Because Olympic, as the pipeline operator, is responsible for the safety of their pipeline in compliance with federal safety requirements, measures to be used will be determined by Olympic in coordination with PSE and based on their review of final design, site-specific conditions, and field measurements. Certain mitigation measures, such as measures to reduce AC density, necessarily must correspond to specific design and site conditions. Olympic has indicated they will identify specific measures, or a suite of measures, following their detailed engineering analysis of the final
design and based on site-specific conditions and field measurements conducted at project start-up and during peak loading scenarios.

3.9.7.2 Potential Mitigation Measures

Potential mitigation measures are summarized below based on results and recommendations of DNV GL’s AC Interference Study (2016), measures PSE has indicated they will use, and measures the EIS Consultant Team has proposed to provide additional safety assurances. The applicable measures are organized based on the stage at which they would be applied (i.e., before construction, at project start-up, and during operation).

Prior to Construction

- Continue to coordinate with Olympic and include safeguards in the project design to protect nearby pipelines from interaction with the new transmission lines due to AC current density, faults caused by lightning strikes, mechanical/equipment failure, or other causes.
- Apply the results and recommendations of the AC Interference Study (DNV GL, 2016) to the design of pole locations, layout, and configuration.
- Optimize conductor geometry, where a true delta configuration provides the greatest level of field cancellation.
- During project design, field verify the distances between the pipelines and transmission line poles grounding rods.
- Perform an AC interference study incorporating the final powerline route, configuration, and operating parameters.
- Obtain and incorporate all of the pipeline parameters required for detailed modeling and study (i.e., locations and details of above-grade pipeline appurtenances/stations, bonds, anodes, mitigation, etc.). This should include a review of the annual test post cathodic protection survey data.
- Fully assess the safety and coating stress risks for phase-to-ground faults at powerline structures along the entire area of collocation, including both inductive and resistive coupling.
- Fully assess the safety and AC corrosion risks under steady state operating conditions on the powerline.
- Design AC mitigation (as required) to ensure that all safety and integrity risks have been fully mitigated along the collocated pipelines.
- Design monitoring systems to monitor the AC corrosion risks along the pipelines.
- Reassess the safe separation distance to minimize arcing risk based on NACE SP0177 and considering the findings in CEA 239T817.
- Ensure that the separation distance between the pipelines and the powerline structures exceeds the safe distance required to avoid electrical arcing.
- In areas where the pipeline is within 13 feet of transmission line pole grounding rods, incorporate mitigation measures into the project design to prevent ground fault arcing to the pipelines (see Section 3.9.5.5 for information on arcing distances). Recommended measures
to incorporate into the project design include installing arc shielding protection, consisting of a single zinc ribbon extending a minimum of 25 feet past the transmission line pole grounding rods in both directions. The zinc ribbon should be designed so that it is connected to the pipeline through a single direct-current decoupler.

- File a mitigation and monitoring report with the Partner Cities documenting all consultations with Olympic and mitigation measures to address safety-related issues. The report should include a plan that identifies the process for identifying mitigation measures following project start-up, and proposed monitoring to ensure that mitigation related to operational issues is followed.

**At Project Start-up**

- Install and commission the AC mitigation and monitoring systems prior to energization of the 230 kV powerline.
- Install Optical Ground Wire (OPGW) shield wire on the transmission line poles.
- After energization, perform a site survey to ensure that all AC interference risks have been fully mitigated under stead-state operation of the powerline.
- Work with Olympic to evaluate and implement appropriate mitigation measures to reduce electrical interference on the Olympic Pipelines to safe levels. After the system is energized, Olympic has informed PSE that they will conduct an engineering/mitigation analysis based on the field data collected to assess the necessity for the installation of AC grounding, or similar systems along the pipelines. AC grounding systems are commonly installed in connection with power transmission poles to dissipate any energy to ground.
- Install additional grounding based on the results of the detailed engineering/mitigation analysis conducted by Olympic. Final mitigation measures and design would be based on field data collected after the system is energized. Mitigation may include the installation of additional protective measures such as grounding mats, horizontal surface ribbon, and/or deep anode wells based on a detailed mitigation study.

**During Operation**

- Operate both circuits at 230 kV to address the AC current load imbalance between the two circuits (see Section 3.9.5.5 for information on AC current load imbalance). Although the other proposed measures listed in this section are anticipated to fully address potential external corrosion issues related to the current imbalance, this measure is recommended, where feasible, to reduce or eliminate the potential for electrical interference with the pipeline.
- Inform Olympic when the electrical system is operating at, or near, winter peak loading so that Olympic can conduct testing to ensure that AC current densities do not exceed 20 amps per square meter in areas where AC current density has been predicted by the AC Interference Study (DNV GL, 2016) to exceed 20 amps per square meter. PSE would inform the Partner Cities upon completion of Olympic monitoring and/or mitigation.
- Inform Olympic when loading scenarios are expected to be at their greatest to ensure that Olympic conducts field monitoring and/or mitigation for AC potential greater than 15 volts and AC current density greater than 20 amps per square meter throughout the project.
corridor. PSE would inform the Partner Cities upon completion of Olympic monitoring and/or mitigation.

- To detect any unexpected changes between the pipeline and transmission line, provide information to Olympic as necessary for Olympic to record AC pipe-to-soil potentials and DC pipe-to-soil potentials during their annual cathodic protection survey.

- Notify Olympic when there are planned outages on the individual circuits, as the AC induction effects on the pipelines may be magnified when only one circuit (of the double-circuit transmission lines) is energized.