Energize Eastside Project

Phase 2 Draft Environmental Impact Statement

Volume 2: Appendices

May 8, 2017

Prepared for the Cities of Bellevue, Newcastle, Redmond and Renton

Prepared by:
ESA

DSD 010775

A

General Construction and Access Description

energize EASTSIDE EIS

APPENDIX A. GENERAL CONSTRUCTION AND ACCESS DESCRIPTION

Note: Information provided by PSE

Construction of transmission lines require pre-construction field surveying, site preparation, construction (i.e., installation of new structures, removal of existing structures), demobilization, and property restoration, which are performed following a relatively standardized sequence.

In general, construction activities include the installation of new structures, removal of existing structures, and property restoration. PSE aims to avoid or minimize impacts where practicable through project design considerations (e.g., pole types and access routes). Along some route segments, PSE has easement rights that outline access agreements for the purpose of maintaining PSE's existing facilities and/or accessing PSE's right-of-way (ROW). Depending upon the segments chosen for the preferred route option, PSE plans to exercise these rights and, if necessary, acquire additional rights for construction of the project. To the extent possible, PSE uses existing or acquires new easement rights to provide access necessary to maintain and/or construct facilities.

TYPICAL CONSTRUCTION SEQUENCING

Construction of a transmission line typically occurs in the following sequence:

1) Pre-construction surveying
    a. Conducting environmental surveys and obtaining geotechnical data by conducting soil borings
    b. Identifying pole locations
    c. Surveying, including ROW and boundary and structure locations (i.e., footings, underground utilities)
2) Site preparation
    a. Staking the ROW, critical areas, and pole locations
    b. Installing temporary erosion control measures
    c. If necessary, constructing access routes to the pole sites and developing installation sites
    d. Brushing, trimming, and clearing of vegetation in the ROW to ensure the safe operation of the line
3) Construction
    a. Installing pole foundations or auger holes for direct embedment
    b. Assembling and erecting the poles
    c. Stringing the conductor and wires
    d. Removing existing structures, if necessary

4) Demobilization and clean up
5) Restoration and re-planting vegetation

The general process for the various types of poles being proposed are essentially the same, except for poles with engineered foundations (e.g., drilled piers), which require additional steps.

The subsequent sections describe specific construction activities in further detail.

PRE-CONSTRUCTION - IDENTIFYING POLE LOCATIONS

The placement, or "spotting," of poles depends upon factors such as available ROW width, location of access routes, topography, and obstacle avoidance. In turn, the height, loading, foundation type, and overall size of each structure will be greatly affected by the location of the structures.

The process for the spotting of poles is as follows:

- PSE will work with individual landowners to adjust pole locations where practicable to reduce impacts for the landowners.
- Proposed pole locations discussed with landowners will represent where poles are generally expected to be located, pending geographical and site-specific environmental review following city or county approval of a route. Unforeseen subsurface obstacles, such as geologic erratics, can cause a pole to be moved up or down the corridor (typically less than 20 feet).

In general, PSE considers the following factors when locating poles:

- **Technical considerations**, including electrical clearances, severe terrain accommodations, structural loading, manufacturability of structures, constructability of the line, and code requirements.
- **Critical Areas (e.g., wetlands and streams)** so as to locate poles outside of critical areas and their buffers to the extent possible.
- **Electrical effects** to maintain additional buffers or install mitigation measures when co-located with other facilities (e.g., pipelines).
- **Landowner considerations** by moving poles farther away from residences and/or locating poles on property lines and edges of tree lines.
- **Cost** to provide a cost efficient and feasible design within set parameters.

To reduce the environmental impacts of pole locations, where practicable, PSE will:

- Place new poles in approximately the same location of the existing poles;
- Locate poles near existing accessible routes to minimize construction traffic impacts;
- Avoid placing poles in areas that require significant access disturbance;
- Avoid environmental features by making small adjustments in the route and through careful structure placement; and
- Avoid critical areas unless another constraint forces a pole into such areas.

SITE PREPARATION

Vegetation Management and Maintenance

Using the existing transmission line ROW is one of PSE's preferred routing criteria, as the vegetation in such corridors is already maintained to some degree. This includes selective removal of problem trees from beneath power lines or removal of hazardous trees that may fall into the electrical system as part of regular maintenance on all power line ROW. Proper pruning and discriminating use of growth regulators and herbicides are also among the methods employed. The method selected is dependent upon factors such as location, property use, and access. Growth regulators and herbicides are not commonly used in urban environments.

Emphasis is placed on removal of large, problem-tree species, especially in the case of those that have disease or insect infestation that can result in irreversible decline. Tree removal is especially important where pruning alone cannot achieve safe clearance from power lines.

Trimming, natural pruning techniques, or directional trimming will be used if proper line clearances can be achieved. Directional trimming concentrates on removing limbs and branches where the tree would normally shed them and direct future growth out and away from the electrical wires. While a newly pruned tree might look different to some, natural pruning is designed to protect the health of the tree. It minimizes re-growth and reduces trimming costs.

Directional trimming is the recommended method of the International Society of Arboriculture (ISA), American National Standards Institute (ANSI), and the National Arbor Day Foundation.

Both tree removal and natural pruning would be performed by specially trained contract crews. Upon completing of tree work, the crews would clean up the site and any wood that is cut would be left on site in pieces of manageable size at the property owner's request.

Guidelines for 230 KV Lines

Vegetation within a utility corridor that has transmission line(s) with an operational voltage of more than 200 kV must be managed in compliance with federal requirements. The fines/penalties associated with having a power outage caused by vegetation can be substantial. To ensure compliance with the North American Electric Reliability Corporation (NERC) standard, PSE allows vegetation with a mature height of no greater than 15 feet within the wire zone. For evaluation purposes, the same vegetation requirement was applied to the managed ROW zone. The area outside of the managed ROW, but still within the legal ROW, is subject to select clearing of trees that pose a risk of damaging the line.

The wire zone is the area measured 10 feet away from the outermost conductor(s) in a static position, whereas the managed ROW zone is the area that extends roughly 16 feet from the outside of the transmission wires in their static position.

The vegetation impact assessment used GIS analysis to evaluate the tree inventory data and the preliminary transmission line design to assess the number of trees that would likely require removal within a specific route.

Guidelines for 115 kV Lines

Some of the alternatives for the Energize Eastside project include rebuilding or relocating 115 kV lines. NERC vegetation standards do not apply to PSE's 115 kV transmission or distribution line rights-of-way; however, in general, PSE will remove trees that mature at a height of greater than 25 feet near 115 kV lines. It should be noted that, some trees within the corridor or along roadways with a height of greater than 25 feet, may be allowed to remain in the wire zone if they can be pruned in a manner that allows sufficient clearance from the lines.

Access

Use of existing access routes is preferred as that is typically the best way to minimize impacts. When a project entails replacement of an existing transmission line, such as Energize Eastside, efforts are made to identify the existing or historic access routes. During initial construction of the transmission line, access routes are established along the corridor. As an area develops and structures are built along the corridor, some of the original access points are no longer viable and new ones need to be established to replace or maintain existing transmission line equipment.

Access to each structure location is identified in the field with a preference to those areas that require the least amount of improvement (e.g., use of existing roads or trails). The field identified access routes are mapped using hand held GPS units. The GPS data is imported into the surveyed route maps for reference. Each route will be assessed on site with the affected property owners to gather site specific limitations and if necessary, identify improvement and restoration details.

Along the corridor, the access and pole locations are identified by the land surveyor and engineering team. As necessary, the access to each pole location is improved or created. Preliminary access routes for construction and maintenance are shown on figures at the end of this appendix, by segment.

Utility Locates and Civil Work

As required by state law, utility locates are performed prior to ground disturbing activities. Appropriate temporary erosion control measures may be installed prior to and during work activities. Initial vegetation management activities then commence, removing those species that are incompatible with the safe operation of the transmission line. If civil work is required to establish either a temporary or permanent construction area, that work typically takes place following vegetation removal.

A work area with an approximate radius of 50 feet around the new pole location would be typical. This area would provide a safe working space for placing equipment, vehicles, and materials.

CONSTRUCTION

PSE will work to restore property impacted by construction to its previous or an improved state, as practical and required under applicable law. PSE will mitigate in-kind when restoration is not possible, as required by applicable law. PSE will comply with local codes related to construction noise. PSE will work with property owners to minimize impacts during construction as much as practicable.

DSD 010780

Pole Installation

Each steel pole will be installed either by direct embedment or placed on a drilled pier foundation. The type of foundation that will be used to support the poles will be dependent upon the structural loading, structural strength of the soil, and site accessibility. In areas near co-located underground utilities, such as the Olympic pipelines, the proposed pole location is reviewed in the field with BP, the pipeline operator. As appropriate, BP's general construction procedures will be followed when construction activities are to take place in the area of the Olympic pipelines.

The hole for the transmission pole is typically initiated using a vactor truck, which is one of the least invasive methods of excavation. If soil conditions allow, the entire hole could be excavated using a vactor truck; however, it may be necessary to use traditional auger equipment to achieve the necessary depth. Typical hole diameter is approximately 18-inches greater than the diameter of the base of the pole. Generally, the depth of the hole will be 10 percent of the pole height plus 2 feet.

In areas of soft soils, a steel casing may be used during drilling to hold the excavation open, after which the steel casing would be cut below grade and backfilled upon completion.

For direct embed poles, the base section of the pole is installed in the hole and the annulus filled with select backfill. When backfill must be imported, material is obtained from commercial sources.

For poles that require drilled pier foundations, the hole is advanced in the same manner as that for the direct embed poles. Reinforced-steel anchor bolt cages are then installed in the excavation. These cages are inserted in the holes prior to pouring concrete and are designed to strengthen the structural integrity of the foundations and are delivered to the structure site via flatbed truck. The excavated holes containing the reinforcing anchor bolt cages would be filled with concrete and be left to cure for 28 days.

To construct the actual steel structure, two methods of assembly can be used, the first of which is to assemble the poles, braces, cross arms, hardware, and insulators on the ground. A crane is then used to set the fully framed structure by placing the poles in the excavated holes or on the drilled pier foundation. Alternatively, aerial framing can be used by setting the first pole section in the ground or on the foundation, and subsequently adding the remaining sections and equipment via a crane.

Stringing

Installation of the conductor, shield wire, and communication fiber on the transmission line support structures is called stringing. The first step of wire stringing would be to install insulators (if not already installed on the structures during ground assembly) and stringing pulleys, which are temporarily attached to the lower portion of the insulators at each transmission line support structure to allow conductors to be pulled along the line. When an existing transmission line is being replaced, the new poles will be installed and the existing wires would be transferred to them from the existing poles that will be removed. This is done so that the existing conductor can be used to pull in the new conductor in a more efficient manner.

Once the existing conductors have been transferred to the stringing sheaves, they would be attached to the new conductors and used to pull them through the sheaves into their final location. Pulling the lines may be accomplished by attaching them to a specialized wire stringing vehicle. Following the initial stringing operation, pulling and sagging of the line would be required to achieve the correct tension of the transmission lines between support structures. After the new lines have been set, the existing poles are then removed.

Pulling and tensioning sites are expected to be required approximately every 2 miles along the corridor. Equipment at sites required for pulling and tensioning activities would include tractors and trailers with spooled reels that hold the conductors and trucks with the tensioning equipment. To the extent practicable, pulling and tensioning sites would be located within the existing corridor.

Depending on topography, minor grading may be required at some sites to create level pads for equipment. Finally, the tension and sag of conductors and wires would be fine-tuned, stringing sheaves would be removed, and the conductors would be permanently attached to the insulators at the support structures.

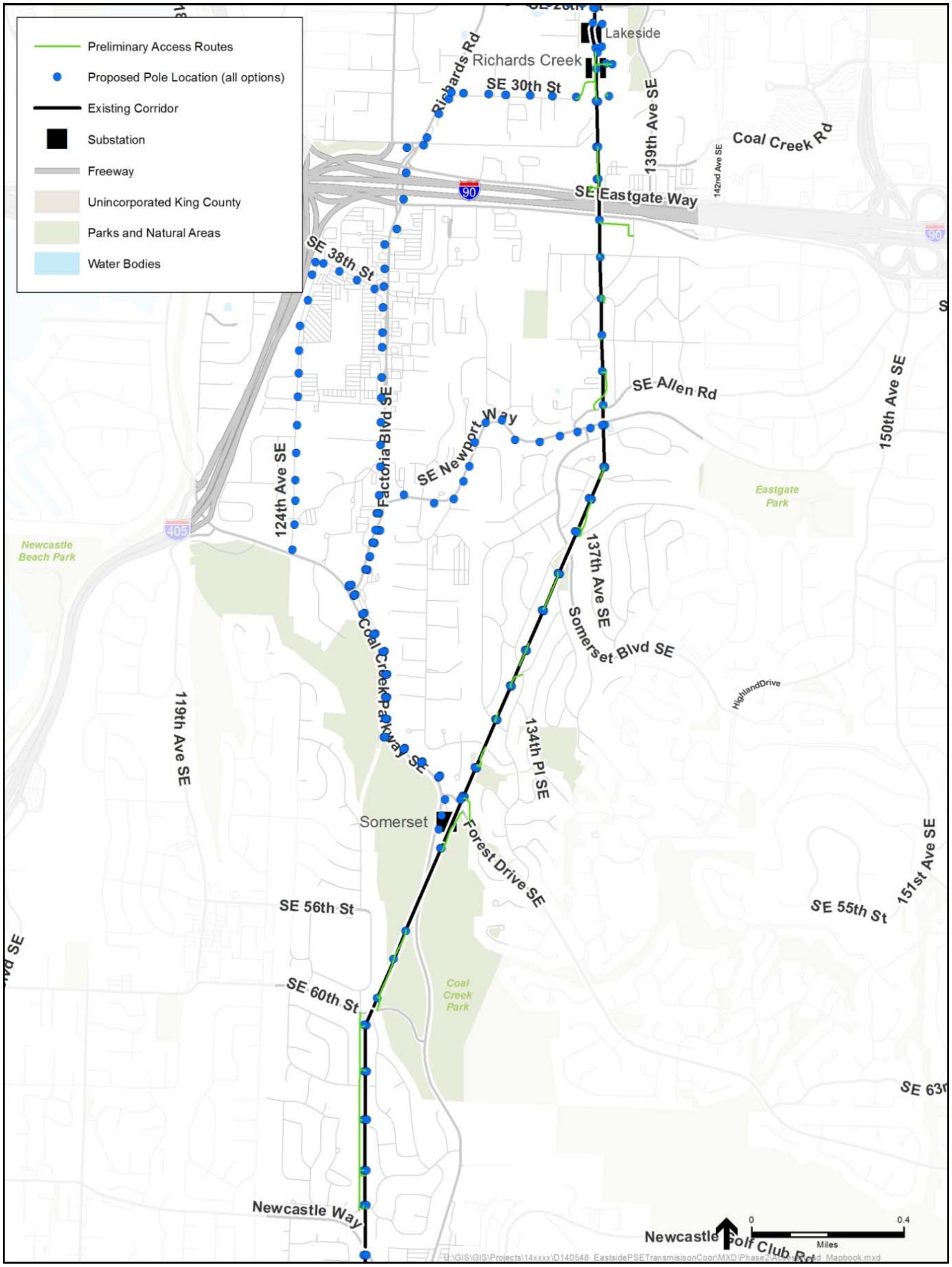
Demobilization and Restoration

Construction sites, staging areas, material storage yards, and access roads would be kept in an orderly condition throughout the construction period. Disturbed areas not required for access roads and maintenance areas around structures would be restored and revegetated, as agreed to with the property owner or land management agency.

Preliminary Construction Access Routes Prior to Property Owner Consultation – Redmond Segment

Preliminary Construction Access Routes Prior to Property Owner Consultation – Bellevue North Segment

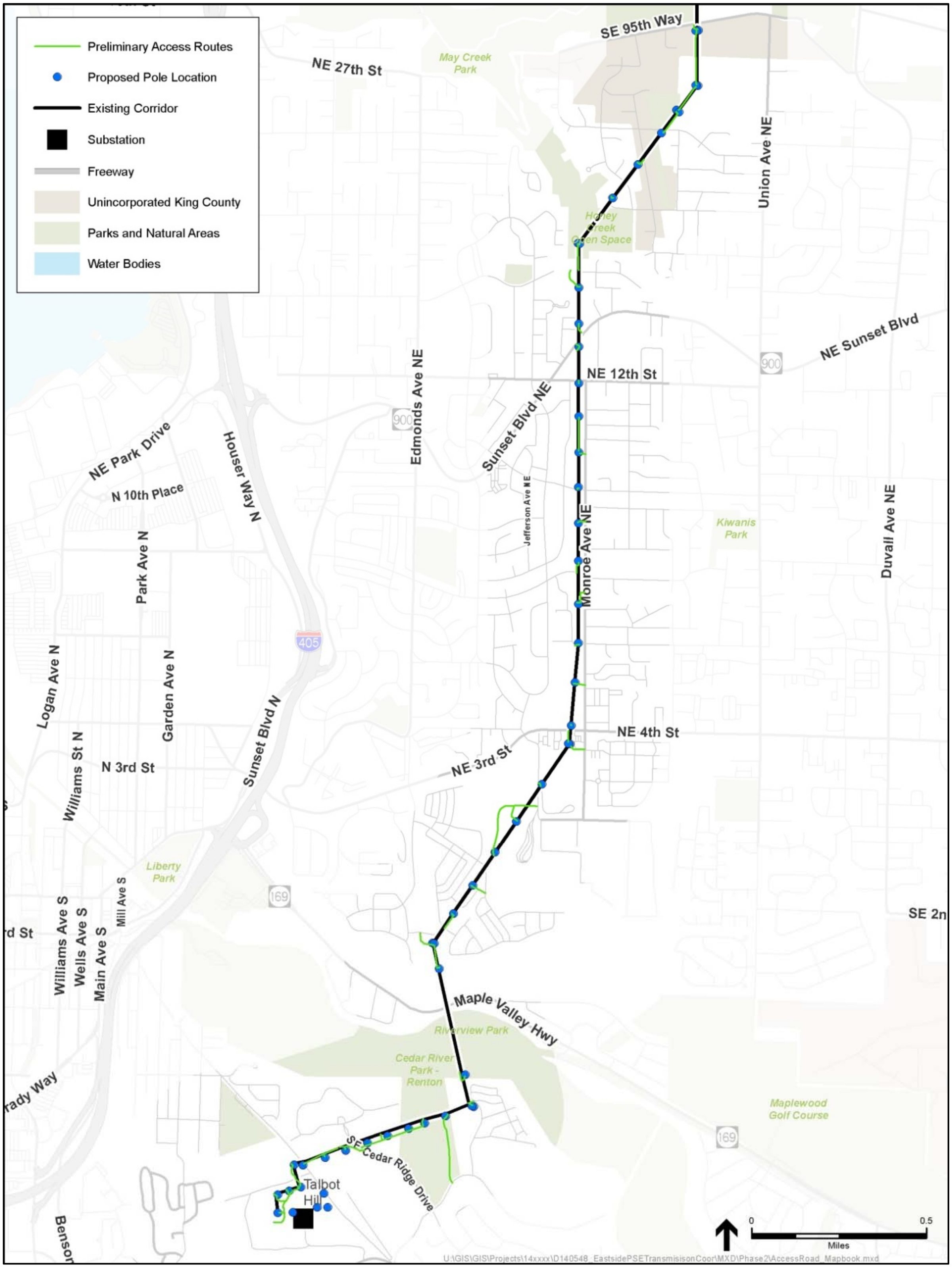
Preliminary Construction Access Routes Prior to Property Owner Consultation – Bellevue Central Segment



Preliminary Construction Access Routes Prior to Property Owner Consultation – Bellevue South Segment

DSD 010786

Preliminary Construction Access Routes Prior to Property Owner Consultation – Newcastle Segment



Preliminary Construction Access Routes Prior to Property Owner Consultation – Renton Segment

B

Supplemental Information: Land Use

energize EASTSIDE EIS

APPENDIX B-1. METHODS FOR DETERMINING STUDY AREA

The adjacent parcel study area was created for the right-of-way by selecting all parcels adjoining the right-of-way where the corridor will be running. For areas not in a current right-of-way, a qualitative approach was used. The goal was to capture all of the parcels that were next to or adjoining the PSE easement. This included both the parcel the easement runs through (easement parcel) and the adjoining parcels, within a reasonable distance. A reasonable distance methodology assumes that if the easement parcel is large, the adjoining parcels on the nearby side are brought in, while those on the far side are left out. A common example is represented in Figure B-1. Here, it is reasonable to assume that the parcels on the east are close enough to be adjacent, but the parcels on the west are not.

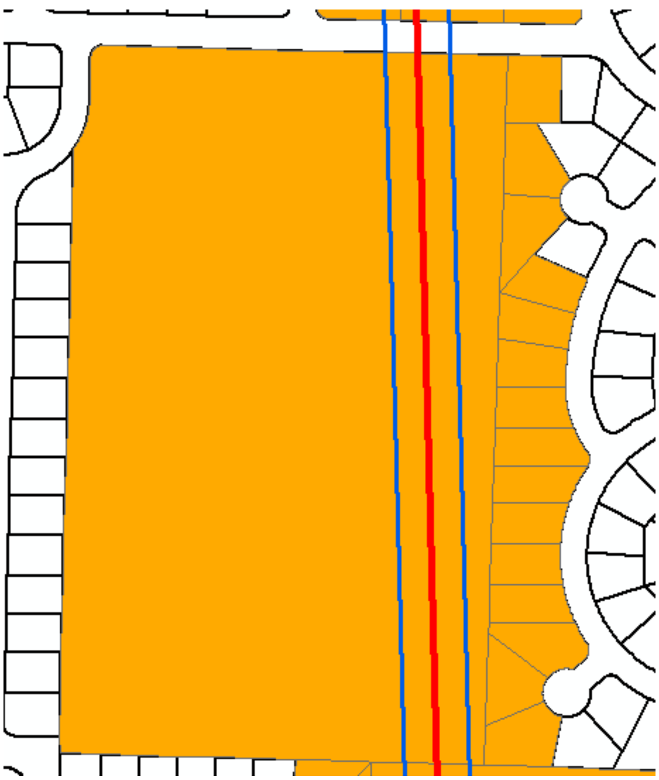


Figure B-1. Adjacent Parcels for Study Area Example

APPENDIX B-2. APPLICABLE ZONING REGULATIONS BY STUDY AREA CITY

The tables below list the zoning districts of parcels included in the study area, shown by segment and option. In each zoning district, an electric utility facility would either be designated as a permitted, conditional, or prohibited use. If an electrical facility is considered a conditional use, the applicable jurisdiction would require a level of review to determine whether the facility should be granted a permit. This review can either be an administrative review or one that would require a public hearing in front of the hearing examiner. Also included in the tables is each jurisdiction's definition of an electrical utility facility or utility.

Redmond Segment			
Electrical Utility Facility	Electrical Utility Facility defined as: unstaffed facilities, except for the presence of security personnel, that are used for or in connection with or to facilitate the transmission, distribution, sale, or furnishing of electricity, including but not limited to electric power substations (RZC 21.78)		
Zoning Districts	**Permitted**	**Conditionally Permitted**	**Prohibited**
R-1		X	
R-4		X	
R-5		X	
R-6		X	
R-12		X	
BP	X		
MP	X		

Source: City of Redmond Municipal Code. Accessed August 2016. Available at: http://online.encodeplus.com/regs/redmond-wa/doc-viewer.aspx?tocid=003#secid-1067.

Bellevue Segments			
Electrical Utility Facility	Electrical Utility Facility defined as: distribution substations, transmission stations, transmission switching stations, or transmission lines that are built, installed, or established. (Bellevue LUC 20.50.018 E)		
Zoning Districts	**Permitted**	**Conditionally Permitted**	**Prohibited**
R-1		X	
R-1.8		X	
R-2.5		X	
R-3.5		X	
R-4		X	
R-5		X	
R-7.5		X	
R-10		X	
R-15		X	
R-20		X	
R-30		X	
BR-GC		X	
CB		X	
F-2		X	
F-3		X	
GC		X	
OLB		X	
PO		X	
BR-GC		X	
LI		X	
F-1		X	
BR-OR		X	
BR-OR-2		X	
BR-RC-1		X	
BR-RC-2		X	
BR-CR		X	
BR-ORT		X	

Source: http://www.codepublishing.com/WA/Bellevue/LUC/BellevueLUC2020.html#20.20.255

DSD 010792

Newcastle Segment			
Electrical Utility Facility (Regional)	Electrical Utility Facility (Regional) defined as: a facility for the distribution or transmission of services from or to an area beyond Newcastle; including but not limited to: electrical distribution substations, electrical transmission stations, electrical transmission switching stations, electrical transmission lines greater than 115 kV and maintenance and utility yards (NMC 18.96.689).		
Zoning Districts	**Permitted**	**Conditionally Permitted**	**Prohibited**
R-1		X	
R-4		X	
R-6		X	
R-6-P		X	
R-18		X	
CB		X	
O		X	
LOS		X	

Source: http://www.codepublishing.com/WA/Newcastle/#!/Newcastle18/Newcastle1808.html#18.08.060

Renton Segment			
Utilities Large	Utilities Large defined as: Utilities Large includes large-scale facilities with either major above-ground visual impacts, or serving a regional need such as two hundred thirty (230) kV power transmission lines, natural gas transmission lines, and regional water storage tanks and reservoirs, regional water transmission lines or regional sewer collectors and interceptors. (RMC4-11-210)		
Zoning Districts	**Permitted**	**Conditionally Permitted**	**Prohibited**
R-1		X	
R-4		X	
R-6		X	
R-8		X	
R-10		X	
R-14		X	
IL		X	
RC		X	
COR		X	
CV		X	
CA		X	

Source: http://www.codepublishing.com/WA/Renton/#!/renton04/Renton0403/Renton0403090.html#4-3-090

APPENDIX B-3. APPLICABLE POLICIES BY STUDY AREA CITY

Subarea Plan	Policy
Renton	
No applicable subarea plans.	
Bellevue	
Comprehensive Plan	UT-67: Encourage consolidation on existing facilities where reasonably feasible and where such consolidation leads to fewer impacts than would construction of separate facilities. Examples of facilities that could be shared are towers, electrical, telephone and light poles, antenna, substation sites, trenches, and easements.
	UT-98: Discourage new aerial facilities within corridors that have no existing aerial facilities.
Bel-Red Corridor Plan	Utility-related cabinets that occur in the right-of-way should not call attention to themselves, and therefore should not be decorated.
Wilburton Grand Connection Initiative	N/A
Bel-Red Subarea Plan	N/A
Bridle Trails Subarea Plan	Policy S-BT-34: Provide Bellevue-owned utility service to surrounding jurisdictions in accordance with the Annexation Element of the Comprehensive Plan.
Eastgate Subarea Plan	N/A
Factoria Subarea Plan	Policy S-FA-24: Encourage the undergrounding of utility distribution lines in areas of new development and redevelopment.
	Policy S-FA-35: Minimize disruptive effects of utility construction non property owners, motorists, and pedestrians.
	Policy S-FA-49: Incorporate infrastructure improvements and implement design guidelines that will enhance pedestrian crossings (respecting the significant traffic volumes and multiple turning movements at these intersections), improve transit amenities, and develop an active building frontage along Factoria Boulevard with direct pedestrian routes to retail storefronts from the public sidewalk and weather protection for pedestrians.
	Policy S-FA-52. Allow buildings to abut the Factoria Boulevard public right-of-way, so long as there is adequate space for the arterial sidewalks.
	Policy S-FA-51: Consider establishing a maximum building setback from the right-of-way for structures along the Factoria Boulevard commercial

Subarea Plan	Policy
	corridor.
Newport Hills Plan	Policy S-NH-55: Encourage undergrounding of utility distribution lines on existing development where reasonably feasible.
	Policy S-NH-50. Include the following elements in a redeveloped commercial district: new commercial buildings at the street edge
Richards Valley Plan	Policy S-RV-19. Encourage the combination of utility and transportation rights-of-way in common corridors and coordinate utility construction with planned street and bike lane improvements which could result in a more efficient allocation of funds.
	Policy S-RV-20. Use common corridors for new utilities if needed. *Discussion: If new power lines are needed in the Subarea, they should be developed in areas that already contain power lines, rather than causing visual impacts in new areas.*
SE Bellevue Plan	N/A
Wilburton/NE 8th St Plan	Policy S-WI-43: Encourage the undergrounding of utility distribution lines in developed areas and require the undergrounding of utility distribution lines in new developments when practical.
	Policy S-WI-49. Allow flexibility for commercial buildings to be sited near frontage property lines.
Newcastle	
Newcastle Subarea Plan	Policy S-NC-44: Encourage the use of utility and railroad easements and rights-of-way for hiking, biking, and equestrian trails wherever appropriate in the Subarea.
Redmond	
No applicable subarea plans.	

APPENDIX B-4. APPLICABLE SHORELINE REGULATIONS

City of Bellevue

Part 20.25E Shoreline Overlay District

20.25E.010 Definition of district.

The Shoreline Overlay District encompasses those lake waters 20 acres in size or greater and those stream waters with a mean annual water flow exceeding 20 cubic feet per second; the lands underlying them; the lands extending landward for 200 feet in all directions as measured on a horizontal plane from the ordinary high water mark; floodways and contiguous floodplain areas landward 200 feet from such floodways associated with such streams and lakes; and marshes, bogs, swamps and river deltas associated with such streams and lakes. Specifically included within the district are the following:

A. Lake Washington, including Mercer Slough upstream to Interstate 405 – The lake waters, underlying lands and the area 200 feet landward of the ordinary high water mark, plus associated floodways, floodplains, marshes, bogs, swamps, and river deltas;

B. Lake Sammamish – The lake waters, underlying lands and the area 200 feet landward of the ordinary high water mark, plus associated floodways, floodplains, marshes, bogs, swamps and river deltas;

C. Lower Kelsey Creek – The creek waters, underlying lands, and territory between 200 feet on either side of the top of the banks, plus associated floodways, floodplains, marshes, bogs, swamps and river deltas; and

D. Phantom Lake – The lake waters, underlying lands and the area 200 feet landward of the ordinary high water mark, plus associated floodways, floodplains, marshes, bogs, swamps and river deltas.

Development within the Shoreline Overlay District may also be subject to the requirements of Part 20.25H LUC. In the event of a conflict between the provisions of this Part 20.25E and Part 20.25H LUC, the provisions providing the most protection to critical area functions and values shall prevail. (Ord. 5681, 6-26-06, § 1; Ord. 4055, 3914, 9-25-89, § 1)

Part 20.30C Shoreline Conditional Use Permit

20.30C.155 Decision criteria.

The City may approve or approve with modifications an application for a Shoreline Conditional Use Permit if:

A. The proposed use will be consistent with the policies of RCW 90.58.020 and the policies of the Bellevue Shoreline Master Program; and

B. The proposed use will not interfere with the normal public use of public shorelines; and

C. The proposed use of the site and design of the project will be compatible with other permitted uses within the area; and

D. The proposed use will cause no unreasonably adverse effects to the shoreline environment designation in which it is to be located; and

E. The public interest suffers no substantial detrimental effect; and

F. The proposed use complies with all requirements of WAC 173-14-140; and

G. The proposed use is harmonious and appropriate in design, character and appearance with the existing or intended character and quality of development in the immediate vicinity of the subject property and with the physical characteristics of the subject property; and

H. The proposed use will be served by adequate public facilities including streets, fire protection, water, stormwater control and sanitary sewer; and

I. The proposed use will not be materially detrimental to uses or property in the immediate vicinity of the subject property; and

J. The proposed use has merit and value for the community as a whole; and

K. The proposed use is in accord with the Comprehensive Plan; and

L. The proposed use complies with all other applicable criteria and standards of the Bellevue City Code.

City of Renton

4-3-090 Shoreline Master Program Regulations

Part 4-3-090(C)(2)(c) Shoreline High Intensity Overlay District Acceptable Activities and Uses

Acceptable Activities and Uses: As listed in RMC 4-3-090E Use Regulations.

Part 4-3-090(C)(4)(c) Shoreline High Intensity Overlay District Acceptable Activities and Uses

Subject to RMC 4-3-090E Use Regulations, which allows land uses in RMC Chapter 4-2 in this overlay district, subject to the preference for water-dependent and water-oriented uses. Uses adjacent to the water's edge and within buffer areas are reserved for water oriented development, public/community access, and/or ecological restoration.

Part 4-3-090(D)(2)(a) General Development Standards, Environmental Effects, No Net Loss of Ecological Functions

i. No net loss required: Shoreline use and development shall be carried out in a manner that prevents or mitigates adverse impacts to ensure no net loss of ecological functions and processes in all development and use. Permitted uses are designed and conducted to minimize, in so far as practical, any resultant damage to the ecology and environment (RCW 90.58.020). Shoreline ecological functions that shall be protected include, but are not limited to, fish and wildlife habitat, food chain support, and water temperature maintenance. Shoreline processes that shall be protected include, but are not limited to, water flow; erosion and accretion; infiltration; ground water recharge and discharge; sediment delivery, transport, and storage; large woody debris recruitment; organic matter input; nutrient and pathogen removal; and stream channel formation/maintenance. ii. Impact Evaluation Required: In assessing the potential for net loss of ecological functions or processes, project-specific and cumulative impacts shall be considered and mitigated on- or off-site. iii. Evaluation of Mitigation Sequencing Required: An application for any permit or approval shall demonstrate all reasonable efforts have been taken to provide sufficient mitigation such that the activity does not result in net loss of ecological functions. Mitigation shall occur in the following prioritized order: (a) Avoiding the adverse impact altogether by not taking a certain action or parts of an action, or moving the action. (b) Minimizing adverse impacts by limiting the degree or magnitude of the action and its implementation by using appropriate technology and engineering, or by taking affirmative steps to avoid or reduce adverse impacts. (c) Rectifying the adverse impact by repairing, rehabilitating, or restoring the affected environment. (d) Reducing or eliminating the adverse impact over time by preservation and maintenance operations during the life of the action. (e) Compensating for the adverse impact by replacing, enhancing, or providing similar substitute resources or environments and monitoring the adverse impact and taking appropriate corrective measures.

Part 4-3-090(D)(2)(c) General Development Standards, Environmental Effects, Critical Areas within Shoreline Jurisdiction

i. Applicable Critical Area Regulations: The following critical areas shall be regulated in accordance with the provisions of RMC 4-3-050 Critical Area Regulations, adopted by reference except for the provisions excluded in subsection 2, below. Said provisions shall apply to any use, alteration, or development within shoreline jurisdiction whether or not a shoreline permit or written statement of exemption is required. Unless otherwise stated, no development shall be constructed, located, extended, modified, converted, or altered, or land divided without full compliance with the provision adopted by reference and the Shoreline Master Program. Within shoreline jurisdiction, the regulations of RMC 4-3-050 shall be liberally construed together with the Shoreline Master Program to give full effect to the objectives and purposes of the provisions of the Shoreline Master Program and the Shoreline Management Act. If there is a conflict or inconsistency between any of the adopted provisions below and the Shoreline Master Program, the most restrictive provisions shall prevail.

  (a) Aquifer protection areas.

  (b) Areas of special flood hazard.

  (c) Sensitive slopes, twenty-five percent (25%) to forty percent (40%), and protected slopes, forty percent (40%) or greater.

  (d) Landslide hazard areas.

  (e) High erosion hazards.

  (f) High seismic hazards.

  (g) Coal mine hazards.

  (h) Fish and wildlife habitat conservation areas: Critical habitats.

(i) Fish and wildlife habitat conservation areas: Streams and Lakes: Classes 2 through 5 only.

ii. Inapplicable Critical Area Regulations: The following provisions of RMC 4-3-050 Critical Area Regulations shall not apply within shoreline jurisdiction:

(a) RMC 4-3-050N Alternates, Modifications and Variances, Subsections 1 and 3 Variances, and

(b) RMC 4-9-250 Variances, Waivers, Modifications and Alternatives.

(c) Wetlands, including shoreline associated wetlands, unless specified below.

iii. Critical Area Regulations for Class 1 Fish Habitat Conservation Areas: Environments designated as Natural or Urban Conservancy shall be considered Class 1 Fish Habitat Conservation Areas. Regulations for fish habitat conservation areas Class 1 Streams and Lakes are contained within the development standards and use standards of the Shoreline Master Program, including but not limited to RMC 4-3-090F.1 Vegetation Conservation, which establishes vegetated buffers adjacent to water bodies and specific provisions for use and for shoreline modification in Subsections 4-3-090E and 4-3-090F. There shall be no modification of the required setback and buffer for non-water dependent uses in Class 1 Fish Habitat Conservation areas without an approved shoreline conditional use permit.

iv. Alternate Mitigation Approaches: To provide for flexibility in the administration of the ecological protection provisions of the Shoreline Master Program, alternative mitigation approaches may be applied for as provided in RMC 4-3-050N Alternates, Modifications and Variances, subsection 2. Modifications within shoreline jurisdiction may be approved for those critical areas regulated by that section as a Shoreline Conditional Use Permit where such approaches provide increased protection of shoreline ecological functions and processes over the standard provisions of the Shoreline Master Program and are scientifically supported by specific studies performed by qualified professionals.

C

Scenic Views and Aesthetic Environment Methodology

energize EASTSIDE EIS

APPENDIX C. SCENIC VIEWS AND AESTHETIC ENVIRONMENT METHODOLOGY

1. INTRODUCTION

This appendix describes the process for assessing impacts to scenic views and the aesthetic environment as a result of the Energize Eastside project. Scenic views are the observation of a visual resource from a particular location, with visual resources generally defined as natural and constructed features of a landscape that are viewed by the public and contribute to the overall visual quality and character of an area. Such features often include distinctive landforms, water bodies, vegetation, or components of the built environment that provide a sense of place, such as city skylines. The aesthetic environment is the portion of the environment that influences human perception of the world. It is comprised of the natural (topography, presence of trees, water bodies) and built (buildings, utility infrastructure) environments. This appendix details the process used to identify impacts to scenic views and the aesthetic environment and how significance was assigned.

2. GUIDANCE USED

SEPA (WAC 197-11) requires all major actions sponsored, funded, permitted, or approved by state and/or local agencies to undergo planning to ensure that environmental considerations, such as impacts related to scenic views and the aesthetic environment, are given due weight in decision-making. Because the value of scenic views and the aesthetic environment is subjective, based on the viewer, it is difficult to quantify or estimate impacts. In particular, little guidance exists supporting a standard methodology for assessing visual impacts associated with transmission line projects. A number of methodologies were reviewed to inform the methodology used for this project. For this project, the assessment of impacts was generally based on methods described in the Federal Highway Administration (FHWA) *Guidelines for Visual Impact Assessment* (FHWA, 2015). FHWA guidelines do not specify thresholds for determining significant impacts, nor do state or local regulations. Therefore, significance was assigned based on criteria similar to those described in *The State Clean Energy Program Guide: A Visual Impact Assessment Process for Wind Energy Projects* (Vissering et al., 2011).

3. STUDY AREA

The FHWA Guidance suggests identifying an Area of Visual Effect (AVE) based on the physical constraints of the environment and the physiological limits of human sight (FHWA, 2015). This concept was used for determining the study area, which takes into account where the project would be visible given the topographical and human sight constraints. Impacts to scenic views and the aesthetic environment would only occur in places where the project would be visible. To identify areas where the project would be visible, a geographic information system (GIS) analysis was conducted.

Data Used to Determine Study Area

King County 2002/2003 Digital Surface Model (DSM)(King County, 2003a)

PSE GIS Alignment Data (PSE, 2016a)

Two sets of tools in ArcMap allow a user to run such an analysis: (1) Viewshed, and (2) Observer Points (ESRI, 2016). For this analysis, the viewshed tool was used because it allows use of lines as key visual elements. The viewshed tool creates a raster[1] that records the number of times an input point or polyline feature[2] can be viewed from a particular area. When polyline input is used, every node[3] and vertex[4] along each input line is processed as an individual observation point, so an area where multiple vertices can be viewed would have a higher raster value.

For this analysis, the EIS Consultant Team used the PSE alignment data (a GIS file that shows where the project would be located) as the input polyline to determine what areas of the landscape have line of sight to the proposed transmission line.[5] Applying an offset informs the viewshed model that the line being observed would be located above the ground (Figure C-1). The heights identified in Table C-1 were used to prescribe an offset height to the polyline in the viewshed analysis.[6]

Table C-1. PSE GIS Alignment Data - Proposed Maximum Pole Height by Segment

Segment	Option(s)	Proposed Maximum Pole Height (feet)
Redmond	N/A	120’
Bellevue North	N/A	100’
Bellevue Central	Existing Corridor	115’
Bellevue Central	Bypass 1	115’
Bellevue Central	Bypass 2	115’
Bellevue South	Existing Corridor	95’
Bellevue South	SE Newport Way	80’
Bellevue South	SE 30th St | Factoria Blvd | Coal Creek Parkway	125’
Bellevue South	124th Ave SE	80’
Newcastle	N/A	100’
Renton	N/A	125’

Source: PSE, 2016b.

[1] A raster is a matrix of cells (or pixels) organized into a grid where each cell contains a value representing information, such as whether or not a view can be seen.
[2] A polyline feature is a continuous line composed of one or more line segments.
[3] A node is a point at which lines intersect or branch.
[4] A vertex is an angular point of a polygon.
[5] Note: line of sight does not necessarily mean the object is within the range of human sight.
[6] Pole heights were assigned at the “option(s)” level, with the highest proposed pole option being used.

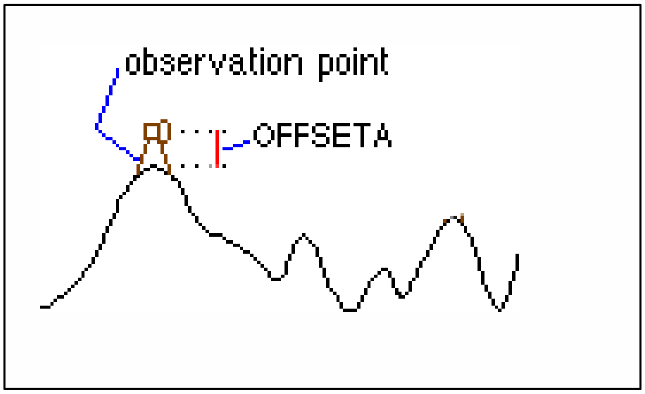


Figure C-1. Factoring Line Heights (ESRI, 2016)

The data used as the "ground" for this analysis were the King County Digital Surface Model (DSM). The King County DSM was used instead of bare earth data because it gives the heights of vegetation and buildings, in addition to taking into account the underlying topography. The EIS Consultant Team used DSM data because in urban environments views are often obstructed by vegetation and buildings, rather than by the topography of the landscape alone (GIS Geography, 2016).

Figure C-2 shows the output from the GIS analysis described above. The GIS analysis provides a rough approximation of where the project would be visible. It includes areas where the line would be so small that it is unrealistic that it would be distinguishable on the horizon. Also, in some instances dense areas of tree stands were misinterpreted by the GIS analysis as being a rise in topography from which views could be had, skewing the results to show more areas as being potentially impacted than would actually occur. In general, the highest concentrations of areas with views of the project corridor would be within one-quarter mile of the corridor. This is consistent with what is commonly found for transportation projects (FHWA, 2015).

For the purposes of this project, a study area with a one-quarter mile radius from the edge of the proposed transmission line corridor (including all segment options) was used. However, Interstate 405 (I-405) and all areas to the west of I-405 were removed because the freeway provides such a wide separation that the project is not expected to visually impact I-405 drivers or the neighborhoods west of the freeway. The study area focuses on areas where the proposed transmission line would be within the foreground view, where viewers are most likely to experience the scale of the project and observe details and materials. While the project would be visible at greater distances, significant scenic or aesthetic impacts are not probable given the project's scale relative to its largely mixed urban context.

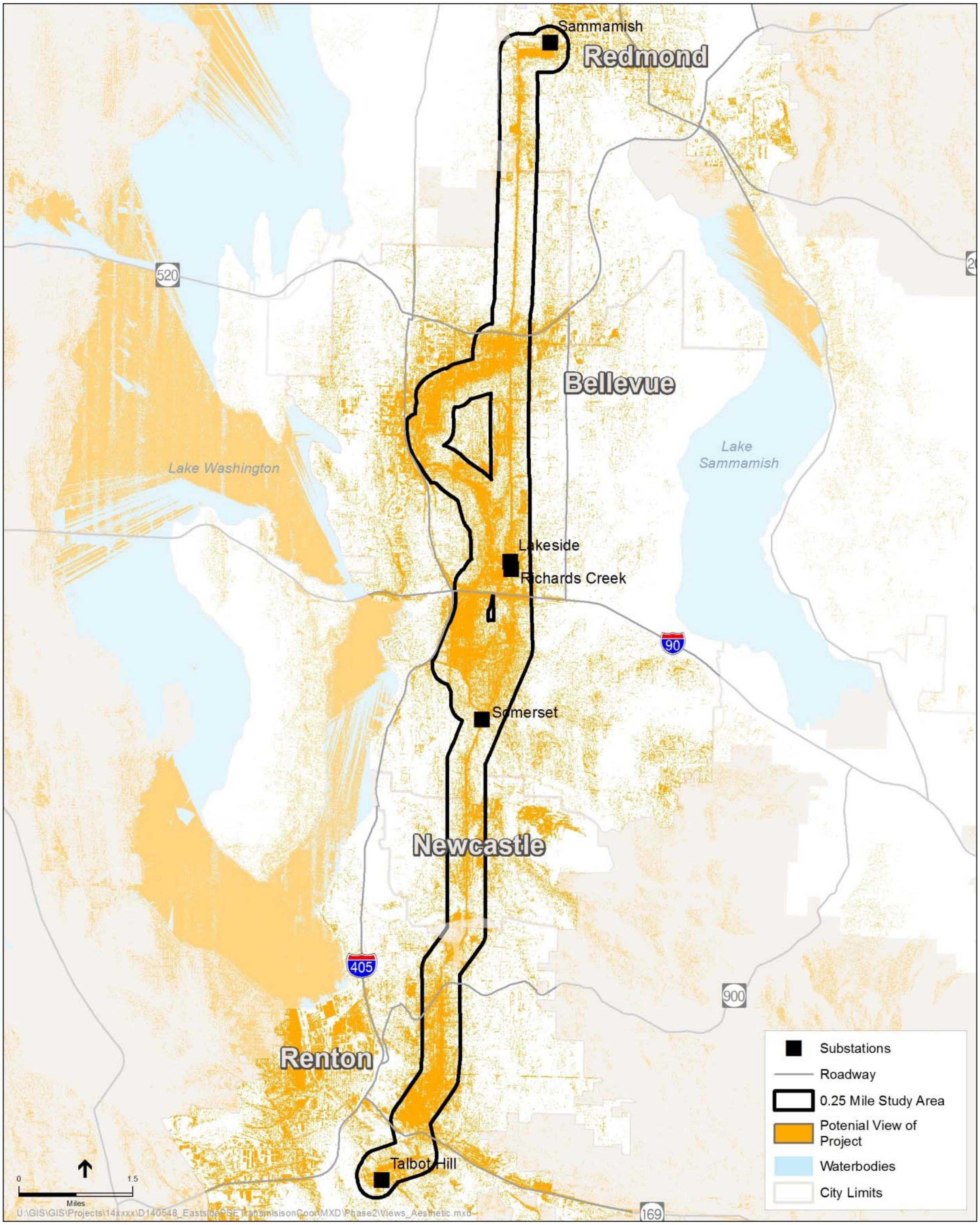


Figure C-2. Study Area

4. CHARACTERIZING THE AESTHETIC ENVIRONMENT

The existing aesthetic environment was characterized through an assessment of the visual character (what is present in the built and natural environments), the affected population (viewers), and the existing visual quality. Visual quality is based on consistency of visual character with viewer preferences. To assess the visual quality of the study area, the visual quality criteria described in the FHWA Guidance were used. These concepts were applied by the EIS Consultant Team in the manner described in the table below based on professional experience and consideration of viewer preferences stated in study area comprehensive plans and public comments received during the EIS process.

Table C-2. Application of FHWA Methodology to Determine Visual Quality

FHWA Visual Quality Criteria	FHWA Description	Application
Natural Harmony	What a viewer likes and dislikes about the natural environment. The viewer labels the natural environment as being either harmonious or inharmonious. Harmony is considered desirable; disharmony is undesirable.	**High:** A natural area that is relatively undisturbed by development. Could include secluded lakes, open plains, forests, etc. **Medium:** An area with a small amount of development that blends with the natural environment and does not disrupt the natural harmony of the area. **Low:** An area with a large amount of development where the built environment takes precedence in the viewshed over the underlying natural environment.
Built Order	What a viewer likes and dislikes about the built environment. The viewer labels the built environment as being either orderly or disorderly. Orderly is considered desirable; disorderly is undesirable.	**High:** A built environment with urban design that is identified in a comprehensive plan or other planning document as being aesthetically pleasing. **Medium:** An area with consistent building height and form. It does not overtly meet any set design standards, but also is not inconsistent with set design standards. **Low:** An area with inconsistent building height and form that does not meet set design standards (if they exist).
Utility Coherence	What the viewer likes and dislikes about the utility environment, which is comprised of the utility's geometrics, structures, and fixtures. The viewer labels the utility environment as being either coherent or incoherent. Coherent is considered desirable; incoherent is undesirable.	**High:** Minimal utility presence, small poles with few wires*. Configuration is consistent in height and form. Utility infrastructure blends with the rest of the aesthetic environment. **Medium:** Moderate utility presence. There could be larger, taller poles or more wires.* Configuration is consistent in height and form. Utility infrastructure blends with the rest of the aesthetic environment for the most part.

DSD 010805

FHWA Visual Quality Criteria	FHWA Description	Application
		Low: High utility presence. There are larger, taller poles with configurations that are inconsistent in height and form. The utility infrastructure is the prominent feature in the viewshed and does not blend with the rest of the aesthetic environment.

*Note: Changes in wire diameter are not expected to be perceivable and therefore are not considered as part of this analysis (See Attachment 1).

5. CHARACTERIZING SCENIC VIEWS

Scenic views are views of visual resources that are considered special attributes of the study area and region. Visual resources associated with the study area were identified in the Phase 1 Draft EIS based on study area plans, regulatory codes (as summarized in Section 9), and scoping comments. These are listed in Table C-3. The visual resources evaluated in the Phase 2 Draft EIS were selected because there was the potential for significant scenic view impacts under the proposed project. The EIS Consultant Team determined that some of the visual resources identified in the Phase 1 Draft EIS were no longer applicable due to distance, topographic constraints, or the presence of dense vegetation between viewers and the visual resources. Table C-3 details why scenic views of certain Phase 1 visual resources were not evaluated further in the Phase 2 EIS.

Table C-3. Identification of Study Area Scenic Views

Visual Resource Identified in Phase 1	Included in Phase 2 GIS Analysis?	Reason
Mount Rainier	Yes	Scenic views could be impacted by the project.
Cascade Mountain Range	Yes	Scenic views could be impacted by the project.
Issaquah Alps (Cougar Mountain, Tiger Mountain, and Squak Mountain)	Yes	Scenic views could be impacted by the project. Used Cougar Mountain because it is in the foreground.
Lake Washington	Yes	Scenic views could be impacted by the project.
Lake Sammamish	Yes	Scenic views could be impacted by the project.
Seattle skyline	Yes	Scenic views could be impacted by the project.
Bellevue skyline	Yes	Scenic views could be impacted by the project.
Lake Sammamish	Yes	Scenic views could be impacted by the project.
Sammamish Valley	No	Topography makes is unlikely that scenic views would be impacted with the powerline in the foreground and background views would not be significant because the line would be too far away from the viewer.

Visual Resource Identified in Phase 1	Included in Phase 2 GIS Analysis?	Reason
Cedar River	No	Due to topographic constraints and the presence of dense vegetation within the Cedar River ravine, scenic views of the Cedar River are unlikely from outside of the ravine. No residential views of the river would be obstructed by the lines and, due to the topography, the line would be located high enough above the roadway that it would not impact drivers' views of the river. Therefore, impacts to views of the Cedar River are assessed as impacts to the aesthetic environment, with the primary viewers considered being users of the Cedar River Trail or Riverview Park.
Beaver Lake	No	Visual resource would not be visible from the Phase 2 study area.
Pine Lake	No	Visual resource would not be visible from the Phase 2 study area.

6. IMPACTS TO THE AESTHETIC ENVIRONMENT

The assessment of impacts to the aesthetic environment was based on the FHWA concepts of compatibility of impact (degree of contrast), sensitivity to the impact (viewer sensitivity), and degree of impact (whether it would result in a beneficial, neutral, or adverse impact).

6.1 Degree of Contrast

To assess impacts to the aesthetic environment, visual simulations were used to determine the degree of contrast produced by the project. The degree of contrast is the extent to which a viewer can distinguish between an object and its background. It was assessed by taking into consideration the project form, materials, and visual character in comparison to existing conditions and the surrounding areas.

Data Used To Assess Impacts to the Aesthetic Environment

GIS Shapefiles:

- ***Parks*** (Bellevue, 2015; Newcastle, 2015; Renton, 2015; Issaquah, 2015; Kirkland, 2015; Redmond, 2015; King County, 2015b)
- ***Water Bodies*** (Ecology, 2014)
- ***Land Use*** (King County, 2015a)
- ***Land Cover*** (NOAA, 2011)
- ***Topography*** (King County, 2003b)

Public Comments

The tool of identifying landscape units was not employed due to the length of the corridor and the diversity of the natural, cultural, and project landscapes; however, the concept of identifying unique natural, cultural, and project landscapes to select key views was used. For this assessment, the discussion was divided into the natural (topographic, land cover, water bodies) and built (building form, utility infrastructure) environments to reduce confusion associated with use of the terms "cultural" and "project" environments.

To assess changes to each component of the aesthetic environment, viewpoints were selected at various locations along the transmission line corridor to show different ways the natural and built environments could be impacted; for instance, areas where the project corridor would cross unique topography, water bodies, vegetation, land uses (different land uses typically have different building forms and impacted viewers), or where the existing transmission infrastructure would be changed (e.g., different pole heights or configurations). Areas identified as being sensitive during the public scoping period were also used as viewpoints (Table C-4).

Visual simulations of what the project would look like at these viewpoints provide the foundation for assessing aesthetic impacts. The concept of discussing dynamic versus static viewsheds was adopted as part of the impacts analysis (view duration), but viewsheds were not identified as being dynamic or static.

Table C-4. Public Comments that Requested Visual Simulations

Suggested Viewpoint Location	Rationale behind why it was or was not included
Lower Somerset homeowners' view of Willow 2.	**Included** – covered via the Somerset Drive SE simulation.
Factoria Boulevard and Coal Creek Pkwy.	**Included** – covered via the 5365 Coal Creek Parkway simulation.
West viewing section of Somerset in Bellevue.	**Included** – covered via the Somerset Drive SE simulation.
Newport Way SE corridor from the on the west side of the street.	**Included** – covered via the 12919 SE Newport Way simulation.
Public parks and rights-of-way.	**Included** – covered via the Lake Boren Park simulation and 8030 128th Ave SE simulation.
Because of the topography of Newcastle, vantage points should include locations on the west and east boundaries of the route.	**Included** – 8030 128th Ave SE simulation looks to the east and Lake Boren Park simulation looks to the west.
Because of the topography of Newcastle, vantage points should include vantage points to the east of Coal Creek Parkway from which the project would be visible.	**Not included** – the transmission line would not be visible due to topography and the presence of dense vegetation.
Houses that line Somerset Drive SE, all of which will have the lines parallel to the view sides of the houses.	**Included** – covered via the Somerset Drive SE simulation.
Newport Way at the driveway of Monthaven Community.	**Included** – covered via the 13357 SE Newport Way simulation.
Skyridge/College Hill and Sunset communities.	**Included** – covered via the Skyridge Park (1990 134th Pl SE, Bellevue) simulation.
Skyridge hiking trail, which starts at the end of 134th Ave SE (dead end) and ends at the Skyridge Park playground. This is a new trail and has views of Richard's Valley, especially in the winter.	**Included** – covered via the Skyridge Park (1990 134th Pl SE, Bellevue) simulation.
Sunset Park should be considered for Route 2.	**Not included** – Sunset Park was considered, but

Suggested Viewpoint Location	Rationale behind why it was or was not included
	a simulation was not created. The EIS Consultant Team visited that portion of the site and determined that the presence of dense vegetation would reduce the likelihood that the project would be visible. The substation simulation provides a representative simulation.
Grand Connection just east of I-405 and the viewing platform at the western edge of the Bellevue Botanical Garden are two of these -- and high tension poles are unsightly.	**Not included** – There are no aesthetic guidelines applicable to the project that are associated with the Grand Connection. The Lake Hills Connector simulation is considered to be sufficient for representing the highest degree of adverse aesthetic impacts in this portion of the study area.
The viewing platform at the western edge of the Bellevue Botanical Garden.	**Not included** – EIS Consultant Team visited the site and confirmed that the project would not be visible due to the topography and presence of dense vegetation.
Residents east of 108th Street.	**Not included** – outside of study area. Assume commenter meant "108th Avenue."
Residents in western Wilburton.	**Included** – covered via NE 8th Street simulation.
Residents in the Spring District.	**Included** - covered via Spring District simulation.
Residents looking east from the central business district, west from Wilburton and southwest and south from the Spring District.	**Not included** – outside of study area.
Drivers on I-405.	**Not included** – outside of study area.

Table C-5 provides the list of viewpoints used in the EIS, the segment they are viewing, and the reasons supporting the selection of each viewpoint (i.e., unique natural or built environment or scoping comment). Table C-6 provides a list of viewpoints that were used to inform the analysis, but were not incorporated directly into the EIS. Figure C-3 shows all of the simulations created by Power Engineers and their locations, and the simulations area included as Attachment 2.

To the extent possible, these viewpoints were selected to align with visual simulations that had already been completed for the project. The visual simulations were created by Power Engineers. Their methods for creating the visual simulations are detailed in Attachment 2. Power Engineers collected photos using a full frame Canon 5D Mark II or III professional Digital Camera. All photos were taken with a 50mm. lens. In some extreme foreground situations a 28mm. lens may be used. Power Engineers developed an existing conditions 3D Model of the study area, including terrain and structures. The photos were registered into a 3D modeling program and 3D sun and atmosphere conditions were applied based on notes taken when the photo was shot. Power Engineers then used PLS-CAD model data (3D engineering designs developed for each transmission line structure) provided by PSE to create a 3D rendering. Photoshop was used to create foreground screening elements (e.g., trees, structures, etc.) (Power Engineers, 2016). All of the renderings show brown poles because Patina[7] would be applied under all of the segment options.

6.2 Viewer Sensitivity

The evaluation of viewer sensitivity was also based on FHWA guidance, and considered viewer exposure and viewer awareness. Exposure considers the proximity, extent, and duration of views. Awareness considers viewer attention and focus, and whether affected views are protected by policy, regulation, or custom (FHWA, 2015). All viewers within the study area were considered to be close to the project. Viewer extent is specific to each component because it depends on the number of viewers impacted. This was assessed by identifying areas with higher residential density and recreational resources that are heavily used. The viewer extent of residential viewers was determined by assigning areas of high, medium, and low population density by assessing American Community Survey 2014 Census block data on a segment-by-segment basis within the quarter-mile radius study area (U.S. Census Bureau, 2014). Figure C-4 shows areas with high, medium, and low population density. The viewer extent of recreational users was assessed by identifying those recreation areas (parks, trails, outdoor recreation facilities) that lie within the study area, and determining whether or not the view or natural setting of the recreation areas is identified as a defining feature (based on findings in the Phase 1 Draft EIS; see Table 11-1 in the Phase 1 Draft EIS, and the recreation analysis in the Phase 2 Draft EIS; see Section 3.6)[8]. If a recreation area that is used for its views or natural setting would be impacted, how frequently the recreation area is used was assessed. The duration of views is consistent for all components, with residential viewers experiencing the longest view duration due to their stationary nature and fixed views of the transmission line. Recreational users have a shorter view duration that is confined to the time spent at the recreational resource, with park users having longer view duration and trail users, who are more mobile, having shorter view duration. Drivers would have the shortest view duration due to the speed at which they travel.

It was assumed that two groups were the most sensitive to changes in the aesthetic environment and scenic views: residents and recreational users in parks and other recreational settings. These two groups would have the greatest exposure to the project because they are often located near the project and would observe the project for longer durations (particularly residential viewers). They would also likely have the greatest awareness, given that these two types of viewers are most often protected by city policies (Section 9).

[7] Patina is a film applied to the surface of metals that turns brown as oxidation occurs over long periods of time.

[8] Please note: the study area for the scenic views and aesthetic environment assessment is larger than the study area used for the recreation analysis.

Table C-5. List of Viewpoints and Rationale for Selection

Key Viewpoint (KVP)	Location	Segment/ Option	Reason for selecting viewpoint (Natural Environment or Built Environment and why)
1	SE 30th St	All Segments/ Options	• Shows the new substation when taking into account grading and clearing.
2	Redmond Way	Redmond	• Representative of the natural environment along the segment (topography and vegetation). • Representative of the built environment (shows project configuration and height for entire segment).
3	13540 NE 54th Pl	Bellevue North	• Representative of the natural environment along the segment (topography and vegetation). • Representative of the built environment (single-family residential development; project configuration and height for entire segment).
4	13606 Main St	Bellevue Central – Existing Corridor	• Shows project from rise in topography. • Is identified in the Wilburton Subarea Plan as a key view.
5	13636 Main St	Bellevue Central – Existing Corridor	• Shows project from rise in topography, but from a side view. • Is identified in the Wilburton Subarea Plan as a key view.
6	12828 Bel-Red Rd	Bellevue Central – Bypass 1 and 2 Options	• Shows project surrounded by commercial and industrial uses. • Shows project from an area slated for increased density.
7	12253 NE 8th St	Bellevue Central – Bypass 1 and 2 Options	• Identified in the Wilburton Subarea Plan as a key view.
8	Lake Hills Connector	Bellevue Central – Bypass 1 and 2 Options	• Identified in the Wilburton Subarea Plan as a key view. • Shows how project would be viewed by future users of the Eastside Rail Corridor.
9	1680 Richards Rd	Bellevue Central– Bypass 2 Option	• Richards Rd is identified in Richards Valley Subarea Plan as an area where the City wants to preserve the vegetated appearance. • Shows impacts to an area with wetland land cover.

Key Viewpoint (KVP)	Location	Segment/ Option	Reason for selecting viewpoint (Natural Environment or Built Environment and why)
			• Shows the project impacts near the Woodridge Trail trailhead.
10	4122 Factoria Blvd SE	Bellevue South - Oak 1 and Oak 2 Options (Only used Oak 1 Option for EIS)	• Visual connections along Factoria Blvd are protected in the Factoria Subarea Plan. • Oak 1 Option was used in EIS because it is a taller pole configuration with a higher likelihood of aesthetic impacts.
11	5365 Coal Creek Pkwy	Bellevue South - Willow 2, Oak 1, Oak 2 Options (Only used Oak 1 Option for EIS)	• Identified via a public comment. • Oak 1 Option was used in EIS because it is a taller pole configuration with a higher likelihood of aesthetic impacts.
12	12513 SE 38th St	Bellevue South - Oak 2 Option	• Shows construction of poles where they do not currently exist.
13	4730 134th PL SE	Bellevue South Segment - All Options (Only used Willow 1 Option for EIS)	• Identified via public comment. • Shows the option with the tallest poles in the Somerset neighborhood.
14	12892 SE Newport Way	Bellevue South Segment - Willow 2 Option	• Shows a change in built environment from a 40-foot 12.5kV line on wooden poles to 75-foot steel monopoles. • Shows removal of underbuild and reduction in clutter.
15	8446 128th Ave SE	Newcastle	• Representative of the built environment (single-family residential development; project configuration and height for entire segment). • Shows the project from the ridge near the corridor.
16	Lake Boren Park	Newcastle	• View from recreational use. • Shows the project from a lower elevation looking up at the project.
17	1026 Monroe Ave NE	Renton	• Shows project surrounded by institutional and single-family residences.
18	318 Glennwood Court SE	Renton Segment	• Shows project surrounded by single-family residential development and placed on a ridge.

Table C-6. List of Other Simulations that Informed the Analysis

Location	Segment/Option
13505 NE 75th St	Redmond
267 140th Ave NE	Bellevue Central – Existing Corridor
106 136th Ave SE	Bellevue Central – Existing Corridor
13600 SE 5th St	Bellevue Central – Existing Corridor
13633 SE 5th St	Bellevue Central – Existing Corridor
13810 Lake Hills Connector	Bellevue Central – Existing Corridor
13711 SE 18th St	Bellevue Central – Existing Corridor
1990 134th Pl SE	Bellevue Central – Existing Corridor
2160 135th PL SE	Bellevue Central – Existing Corridor
1227 124th Ave NE	Bellevue – Bypass Options 1 and 2
11757 SE 5th St	Bellevue – Bypass Options 1 and 2
SE 8th St and Lake Hills Connector	Bellevue – Bypass Options 1 and 2
2070 132nd Ave SE	Bellevue Central Segment – Bypass Option 2
13630 SE Allen Rd	Bellevue South Segment - All Options
13744 SE Allen Rd	Bellevue South Segment - All Options
4411 137th Ave SE	Bellevue South Segment - All Options
4489 137th Ave SE	Bellevue South Segment - All Options
4901 Coal Creek Parkway	Bellevue South Segment - All Options
13300 SE 42nd PL	Bellevue South Segment - Willow 2 Option
13371 SE Newport Way	Bellevue South Segment - Willow 2 Option
13357 SE Newport Way	Bellevue South Segment - Willow 2 Option
4256 134th Ave SE	Bellevue South Segment - Willow 2 Option
12919 SE Newport Way	Bellevue South Segment - Willow 2 Option
12727 SE 73rd Pl	Newcastle
SE 84th St	Newcastle
12732 SE 80th Way	Newcastle
7954 129th Pl SE	Newcastle
3000 NE 4th St	Renton

DSD 010813

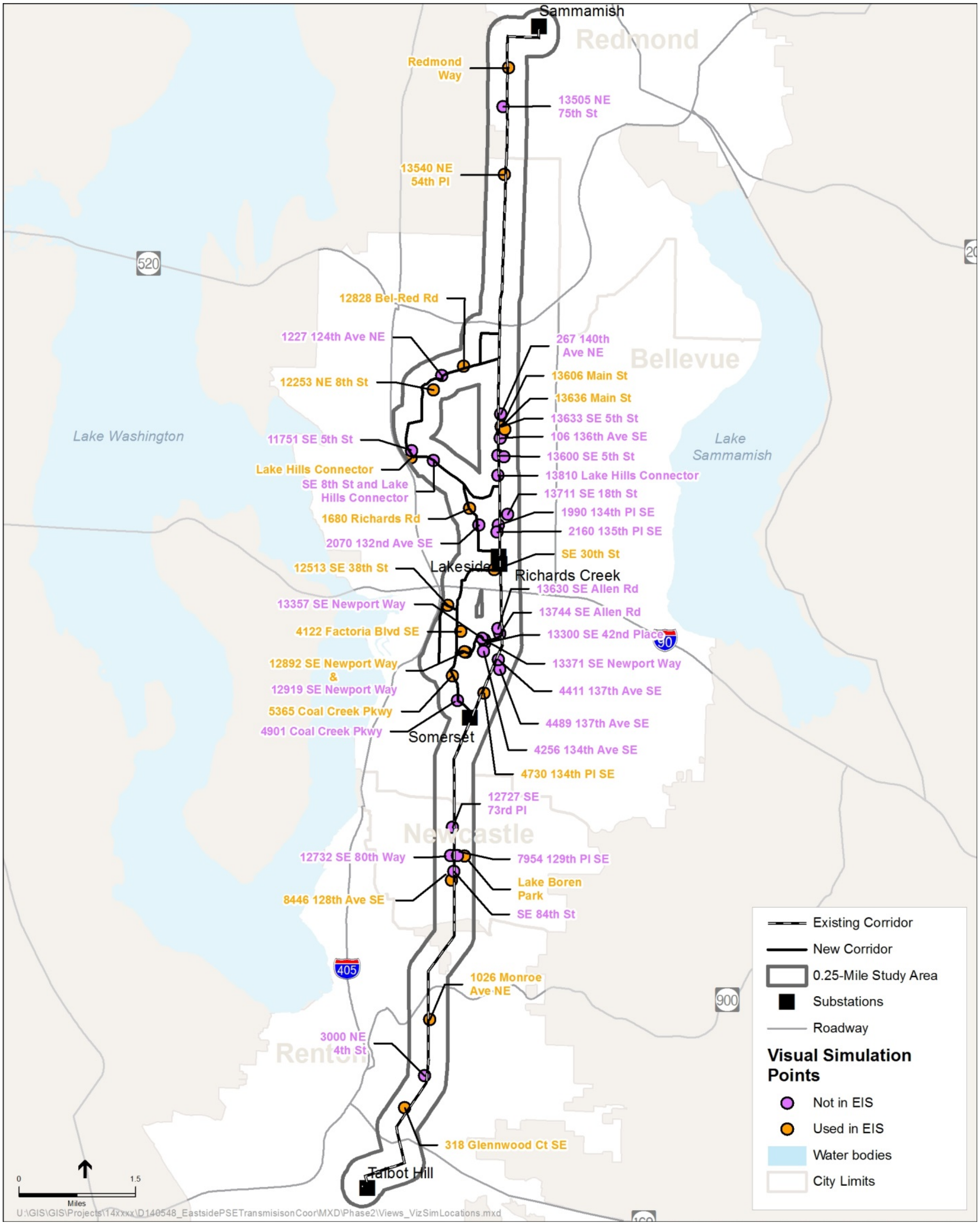


Figure C-3. Viewpoint Map

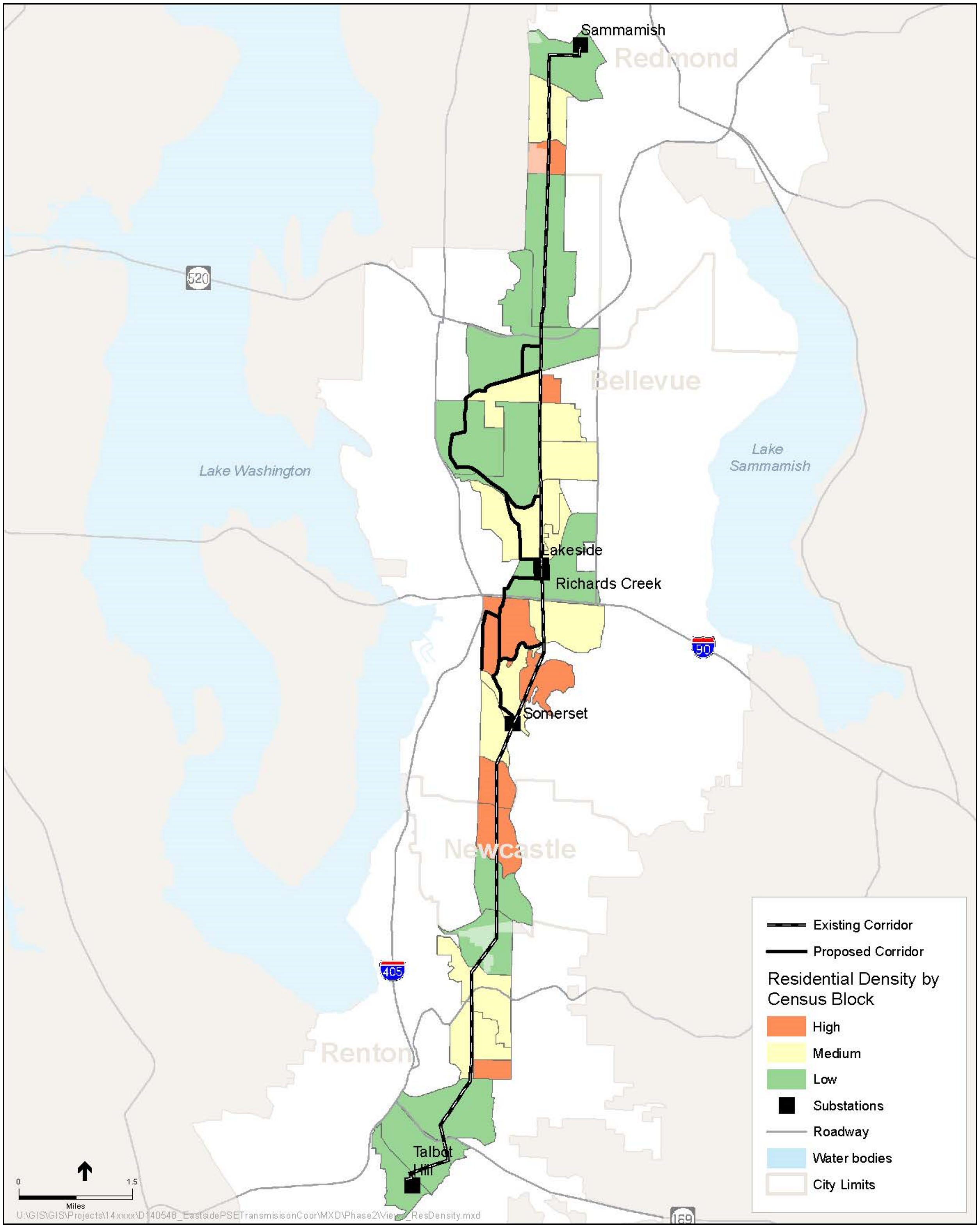


Figure C-4. Population Density Map

7. IMPACTS TO SCENIC VIEWS

The assessment of impacts to scenic views was based the potential for view obstruction and the FHWA concept of sensitivity to the impact (viewer sensitivity).

7.1 Scenic View Obstruction

A GIS analysis was conducted to identify areas from which a portion of the proposed transmission line would obstruct the view of an identified visual resource. This GIS analysis identified where visual resources can be seen based on the location and height of the visual resource and the topography of the surrounding area. This area was further refined based on a similar analysis that determined where the proposed transmission line could be seen based on the location of the segment, the proposed height of the poles, and the surrounding topography. The outputs from these two analyses were overlaid to determine where the project may impact scenic views. This is a conservative estimate that was qualitatively refined through identification of barriers to views (dense tree stands, etc.).

For this analysis, the viewshed tool was also used. To determine the area where scenic views can be observed, a process similar to the one used for the aesthetic environment study area was adopted. However, for this analysis, visual resources were used as observation points and their unique offsets were applied (Table C-7).

Table C-7. Visual Resources input into Viewshed Tool

Visual Resource	Offset Applied
Mount Rainier	Line of frontage at 14,411 feet (based on mountain height)
Cascade Mountain Range	Line of frontage at 5,000 feet (based on Typical King County DEM data height)
Issaquah Alps (Cougar Mountain)	Line of frontage at 1,600 feet (based on Typical King County DEM data height)
Lake Washington	Line along the eastern shoreline at 20 feet above sea level
Lake Sammamish	Line along the western shoreline at 30 feet above sea level
Seattle skyline	Line of downtown frontage with a height of 650 feet (slightly higher than Safeco Plaza)
Bellevue skyline	Line encompassing downtown Bellevue at 460 feet (slightly higher than Bellevue Towers Two)

To assess the areas that would be affected under different build scenarios, the heights of the existing and proposed lines were “burned” into the DSM to identify which areas with scenic views are already impacted by views of a transmission line and which areas with scenic views are not currently impacted, but would be after construction of the project (Table C-8). The heights used for the “proposed maximum pole heights” for the GIS analysis differ slightly from the final proposed maximum heights, due in part to design changes made during the course of the EIS assessment. These design changes were considered qualitatively as part of the impacts assessment, but the EIS Consultant Team decided not to rerun the scenic view obstruction analysis because in some instances a more conservative pole height was used. In the instances where a less conservative pole height was used, the difference was considered to not substantially change the results of the GIS analysis.

Table C-8. Existing and Proposed Maximum Pole Height by Roadway

Segment	Height Used for the GIS Analysis
Redmond	120'
Bellevue North	100'
Bellevue Central Existing	115'
Bellevue Central Bypass 1	115'
Bellevue Central Bypass 2	115'
Bellevue South Oak 1	*Corridor:* 90’ *SE 30th St /Factoria Blvd/Coal Creek Pkwy:* 125'
Bellevue South Oak 2	*Corridor:* 90’ *SE 30th St /Factoria Blvd/Coal Creek Pkwy:* 125' *124th Ave SE:* 80'
Bellevue South Willow 1	95'
Bellevue South Willow 2	*Corridor:* 95' *Newport Way:* 80' *Factoria Blvd/Coal Creek Pkwy:* 90'
Newcastle	100'
Renton	125'

Source: PSE, 2016b.

To burn the lines into the DSM, a raster of the proposed alignment was created with a value of 0 assigned to everywhere except along the line, which was assigned a value equal to pole height (specified in Table C-8). Then, using a raster calculator, the line height was burned into the DSM to get a DSM+LINE (DLI) raster (Figure C-5).

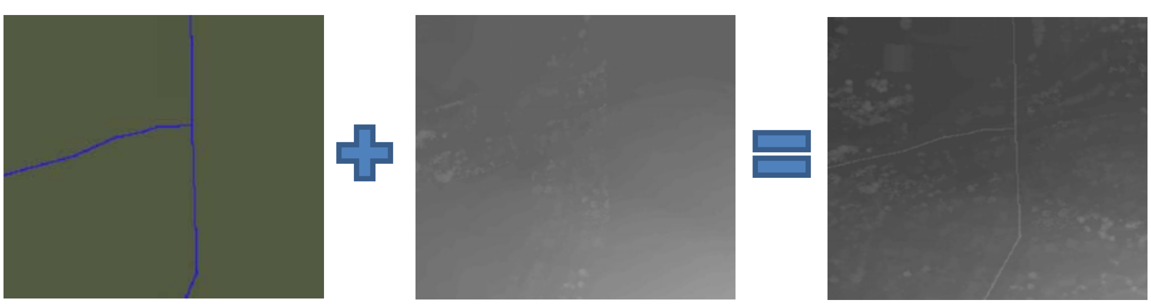


Figure C-5. Factoring Line Heights

The following DLIs were created:

- One DLI as if no lines were present.
- One DLI where the existing transmission heights would be burned in.
- One DLI with the heights for the Redmond, North Bellevue, Newcastle, and Renton segments. These segments can be grouped into one DLI because there are no different pole height options.
- Four DLIs for the Bellevue South Segment options.
- Three DLIs for bypass Bellevue Central Segment options.

Each of the DLIs was used as the ground raster for a viewshed analysis to identify where the scenic resources would be viewable on the landscape, creating results for each pole height scenario. To understand the areas where views would be negatively impacted by the project, areas where scenic views are already impacted by the transmission line were subtracted from the area with scenic views that would be impacted by the proposed transmission line.

Figure C-6 shows the output from the GIS analysis described above. Similar to the GIS analysis conducted for the study area, some areas may have been identified as having scenic view impacts but in reality should not have been included because the line would be so small that it is unrealistic that it would be distinguishable on the horizon, or dense areas of tree stands were misinterpreted by the GIS analysis as being a rise in topography from which views could be had (rather than being considered hindrances to views). For areas where it was questionable if scenic views would actually be impacted, a field survey was conducted to verify. In general, areas where potential scenic views were identified had scenic views in the approximate vicinity; however, in some cases these views were less frequent than may have been shown by the analysis depending on the presence of dense vegetation. The only area that was completely eliminated from consideration was where scenic views were identified in the Liberty Ridge area. A field visit conducted on October 7, 2016 confirmed that scenic views from that location were not present due to the topography of the area. The EIS Consultant Team believes that the reason the GIS analysis identified this area as an area with potential scenic view impacts was because the DSM used was from 2002/2003. Since that time, significant grading has occurred to support development of the Liberty Ridge neighborhood. These changes to the topography are thought to have resulted in the loss of scenic views. In general, the highest concentrations of areas with scenic views that could be impacted by the project were within approximately 550 feet of the corridor.

7.2 Viewer Sensitivity

Viewer sensitivity was evaluated as described in Section 6.2.

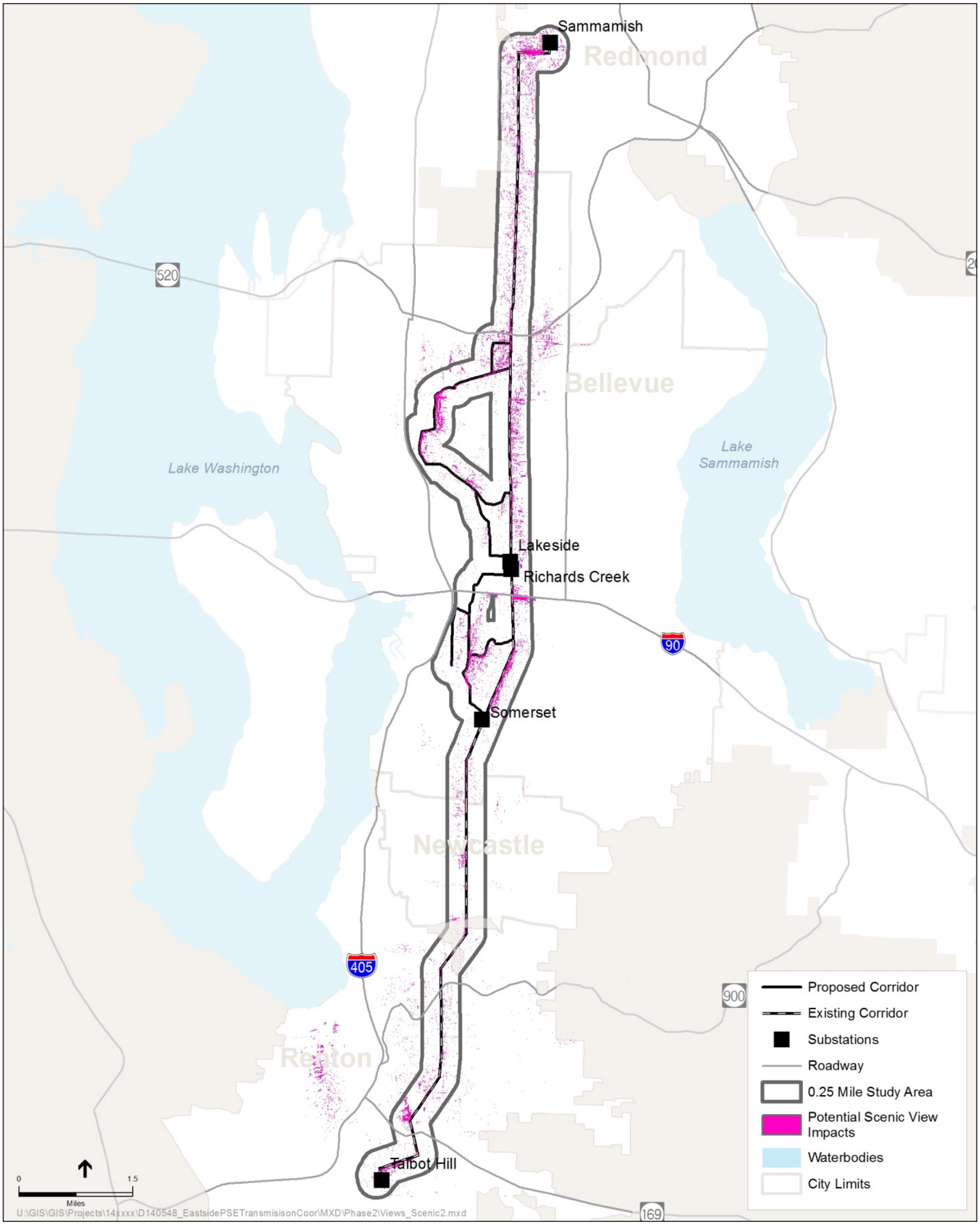


Figure C-6. Potential Areas Where Scenic Views May Be Impacted

8. THRESHOLD OF SIGNIFICANCE

The value of scenic views and the aesthetic environment is subjective, making it difficult to quantify or estimate impacts. There is no widely accepted definition of significant visual effects because the significance of an activity varies with the setting and viewer preferences. For this project, significance was determined based on criteria similar to those described in *The State Clean Energy Program Guide: A Visual Impact Assessment Process for Wind Energy Projects* (Vissering et al., 2011). These criteria, while not developed for transmission lines, were used for wind turbines, which can be similar in height and scale to utility poles and are widely studied for visual impacts. This guide suggests that the following criteria be considered when determining if a project would result in undue or unreasonable visual impacts: violation of aesthetic standards, dominance of the project in views from highly sensitive viewing areas, and failure to take reasonable mitigation measures (Vissering et al., 2011).

A review of policies and regulations applicable to the study area revealed that the existing regulatory framework was insufficient for determining significance because no clear written standards are included for impacts to scenic views or the aesthetic environment.

To develop a threshold for significance that reflects the policies of the Partner Cities, the EIS Consultant Team held a workshop in August 2016 with staff from the Partner Cities that would potentially experience scenic view or aesthetic impacts (Redmond, Bellevue, Newcastle, and Renton). The purpose of the workshop was to collaboratively define significance thresholds based on policies, past precedent, and practice within the Partner City jurisdictions.

During the workshop, city staff were provided with the following:

- A map showing where scenic views would be impacted along the entire corridor.
- Visual simulations showing key examples of how the project could change the aesthetic environment.
- A handout with each city's applicable policies and regulations.

The EIS Consultant Team walked through examples for each segment/option, and the group as a whole refined a set of significance criteria. The following significance criteria were adopted for the EIS evaluation and incorporate findings from the Partner Cities workshop:

Less-than-Significant:

- **Aesthetic environment -** The degree of contrast between the project and the existing aesthetic environment would be minimal, or viewer sensitivity is low.
- **Scenic views -** The area with impacted scenic views would not include a substantial number of sensitive viewers, including residential viewers, viewers from parks and trails, or viewers from outdoor recreation facilities; or the degree of additional obstruction of views compared to existing conditions would be minimal.

Significant:

- **Aesthetic environment -** The degree of contrast between the project and the existing aesthetic environment would be substantial and viewer sensitivity is high.
- **Scenic views -** The area with scenic views impacted includes a substantial number of sensitive viewers, including residential viewers, viewers from parks and trails, or viewers from outdoor recreation facilities; and the degree of additional obstruction of views compared to existing conditions would be substantial.

It was agreed that significant impacts should be assigned on a sub-option level.

9. SUMMARY OF PLANNING POLICIES AND CODE REQUIREMENTS

Table C-9. Planning Policies and Code Requirements

Plans	Protected Views and Visual Resources	Guidance for Reducing Visual Impacts
King County		
Eastside Rail Corridor Master Plan 2016	In some cases, bridges may also be locations for viewpoints.	N/A
	Existing landscape that does not need to be removed for trail construction will be evaluated to determine if it is consistent with public use, including aesthetics and overall trail design.	N/A
Redmond		
Vision 2030 City of Redmond Comprehensive Plan	Views of Mount Rainier, the Cascade Mountains, and Lake Sammamish.	N/A
	Unique public views that provide a sense of place	N/A
	Scenic, public view corridors toward the Cascades and the Sammamish Valley (Plan Policy NR-10).	N/A
	Views of surrounding hillsides, mountains, and tree line	N/A
	Tree stands and views from the valley (Plan Policy N-SV-4)	N/A
	Woodland views from neighborhood residences	N/A
	N/A	Throughout the plan, landscaping is encouraged to provide aesthetic value, unify site design, and soften or disguise “less aesthetically pleasing features of a site” (Policy CC-23). The Plan requires “reasonable screening or

Plans	Protected Views and Visual Resources	Guidance for Reducing Visual Impacts
		architecturally compatible design of above ground utility facilities, such as transformers and associated vaults" (Policy UT-15). It suggests promoting well-designed utility facilities through use of color, varied and interesting materials, art work, and superior landscape design.
Redmond Zoning Code (RZC) *Current through June 16, 2015*	Appearance of Public Ways	Underground electrical facilities if economically-feasible (RZC 21.17).
	Public view corridors and gateways should be protected (RZC 21.42)	N/A
Bellevue		
Bellevue Comprehensive Plan 2015	Urban design that exemplifies a "City in a Park" with tree-lined streets, public art, vast parks, natural areas, wooded neighborhoods, two large lakes, and mountain views.	N/A
	Views of water, mountains, and skylines from public places (Plan Policy UD-62).	Link increased intensity of development with increased view preservation (Plan Policy UD-48).
	N/A	Implement new and expanded transmission and substation facilities in such a manner that they are compatible and consistent with the local context and the land use pattern established in the Comprehensive Plan (Plan Policy UT-95).
	N/A	Conduct a siting analysis for new facilities and expanded facilities at sensitive sites (areas in close proximity to residentially-zoned districts) (Plan Policy UT-96).
	N/A	States preference for use of new technology to reduce visual impacts.
	Green belts and open spaces per Parks and Open Space System Plan.	Avoid locating overhead lines in greenbelts or open spaces (Plan Policy UT-69).
	Distinctive neighborhood character within Bellevue's diverse neighborhoods (Plan Policy N-9).	Design, construct, and maintain facilities to minimize their impact on surrounding neighborhoods (Plan Policy UT-8).

Plans	Protected Views and Visual Resources	Guidance for Reducing Visual Impacts
	Design boulevards adjacent to parks, natural areas and open spaces to reflect scenic elements of the surrounding areas and neighborhoods. Streetscape design should promote a safe and comfortable park-like experience for all users (Plan Policy UD-70). This includes: • Bel-Red Road • Lake Hills Connector • Richards Road • Factoria Blvd SE • Coal Creek Parkway • SE Newport Way	N/A
Bridle Trails Subarea Plan 2015	Wooded, natural, rural, and equestrian character of the Subarea (Plan Policy S-BT-3).	N/A
	N/A	Encourage retention of vegetation on the lower slopes of the bluff adjacent to SR 520 at approximately 136th Avenue NE to provide a visual separator between residential areas and the freeway (Plan Policy S-BT-42).
	Roadsides in Bridle Trails Subarea.	Improve roadsides to create a unified visual appearance (Plan Policy S-BT-43).
Bel-Red Subarea Plan 2015	Bel-Red Subarea street environment (Plan Policy S-BR-25; S-BR-39; S-BR-59).	N/A
	Bel-Red Subarea parks and open space system (Plan Policy S-BR-35).	N/A
Wilburton/NE 8th St Subarea Plan 2015	N/A	Utilities should be provided to serve the present and future needs of the Subarea in a way that enhances the visual quality of the community (where practical) (Plan Policy S-WI-44)
	Significant views from park lands (Plan Policy S-WI-11)	N/A

Plans	Protected Views and Visual Resources	Guidance for Reducing Visual Impacts
	Views of prominent landforms, vegetation, watersheds, drainage ways, Downtown and significant panoramas in the Subarea (Plan Policy S-WI-40). Key views include: • West from NE 8th Street and NE 5th Street on the ridge between 122nd and 123rd Avenue, • South from the Lake Hills Connector north of SE 8th Street, and • From SE 1st Street and Main Street at the power line right-of-way at 136th Avenue.	N/A
Southeast Bellevue Subarea Plan 2015	Existing residential character (Plan Policy S-SE-2)	N/A
Richards Valley Subarea Plan 2015	Views from Woodridge Hill and the wooded areas and wetlands in the valley.	
	Retain the remaining wetlands within the 100-year floodplain along Richards Creek and Kelsey Creek for the aesthetic value and character of the community (Plan Policy S-RV-5).	Develop sites in accordance with Sensitive Areas Regulations (Plan Policy S-RV-12).
	N/A	Use common corridors for new utilities if needed (Plan Policy S-RV-20).
	N/A	New development, should install a dense visual vegetative screen along Richards Road (Plan Policy S-RV-31).
	Eastgate I-90 Corridor	Encourage site design that includes visibly recognizable natural features such as green walls, façade treatments, green roofs, and abundant natural landscaping (Plan Policy S-RV-24).

Plans	Protected Views and Visual Resources	Guidance for Reducing Visual Impacts
	Streets and arterials	Disturb as little of the natural character as possible when improving streets and arterials (Plan Policy S-RV-26).
	Green and wooded character of the Richards Road corridor (Plan Policy S-RV-30).	N/A
Eastgate Subarea Plan 2015	View amenities of adjacent single-family neighborhoods (Plan Policy S-EG-22).	N/A
	N/A	Discourage new development from blocking existing views from public spaces (Plan Policy S-EG-23).
Factoria Subarea Plan 2015	Natural setting for residential areas	N/A
	Cohesiveness and compatibility of commercial districts	Manage change in the commercial district
	N/A	Protect single family neighborhoods from encroachment by more intense uses (Plan Policy S-FA-2).
	Pathways and access points with views of Sunset Creek, Richards Creek, Coal Creek, (Plan Policy S-FA-18).	N/A
	Visual connections along Factoria Boulevard (Plan Policy S-FA-32).	N/A
	N/A	Minimize disruptive effects of utility construction on property owners, motorists, and pedestrians (Plan Policy S-FA-35).
Newport Hills Subarea Plan 2015	Emphasize as a distinct visual element the preservation of existing trees on protected slopes and hilltops (Plan Policy S-NH-44).	Use these trees to screen incompatible land uses.
	N/A	Make edges between different land uses distinct without interfering with security or visual access (Plan Policy S-NH-48).
	Existing visual features such as trees and hilltops, views of water, and passive open	N/A

Plans	Protected Views and Visual Resources	Guidance for Reducing Visual Impacts
	space (Plan Policy S-NH-54).	
Bellevue City Code *Current through August 3, 2015*	N/A	Electrical utility facilities shall be sight-screened through landscaping and fencing (BCC 20.20.255.F).
City of Bellevue Draft SMP 2013	Shoreline	New or expanded utility systems and facilities shall be designed and aligned to minimize impacts to natural systems and features and shall minimize topographic modification.
		New or expanded utility systems and facilities shall be co-located underground and within existing or planned improved rights-of-way, driveways, and/or utility corridors whenever possible.
		Where the visual quality of the shoreline or surrounding neighborhood will be negatively impacted, new or expanded utility systems and facilities shall incorporate screening and landscaping sufficient to maintain the shoreline aesthetic quality and shall provide screening of facilities from the lake and adjacent properties in a manner that is compatible with the surrounding environment.
		New or expanded utilities shall incorporate shoreline public access, consistent with the requirement contained in LUC 20.25E.060.I, (Public Access). When allowed, utility facilities located above ground shall be: (1) Housed in a building that incorporates design features that are compatible with the character of the surrounding neighborhood or area, unless housing the facility in a structure would fundamentally interfere with the maintenance and operation of the facility. (2) Sight-screened, if the facility does not conform with the standards in paragraph E.3.b.ix.(1) of this section, with evergreen trees, shrubs, and other native landscaping

DSD 010827

Plans	Protected Views and Visual Resources	Guidance for Reducing Visual Impacts
		materials planted in sufficient depth to form an effective sight barrier within five (5) years.
Newcastle		
City of Newcastle 2035 Comprehensive Plan	Existing character, scale, and neighborhood quality (Plan Policy LU-G3).	N/A
	Open space, wildlife habitats, recreational areas, trails, connection of critical areas, natural and scenic resources, as well as shoreline areas (Plan Policy LU-G6).	N/A
	Natural features that contribute to the City's scenic beauty (Plan Policy LU-G8).	N/A
	N/A	The City shall require that the undergrounding of new utility distribution lines, with the exception of high voltage electrical transmission lines (Plan Policy UT-P1).
	N/A	The City shall require the undergrounding of existing utility distribution lines where physically feasible as streets are widened and/or areas are redeveloped based on coordination with local utilities (Plan Policy UT-P2).
	N/A	The City shall promote collocation of major utility transmission facilities such as high voltage electrical transmission lines and water and natural gas trunk pipe lines within shared utility corridors, to minimize the amount of land allocated for this purpose and the tendency of such corridors to divide neighborhoods (Plan Policy UT-P3).
	N/A	The City shall encourage utility providers to limit disturbance to vegetation within major utility transmission corridors to what is necessary for the safety and maintenance of transmission facilities (Plan Policy UT-P8).
	N/A	The City should encourage utility providers to exercise restraint and sensitivity to neighborhood character in planting appropriate varieties and trimming tree limbs around aerial lines (Plan Policy UT-P9).

Plans	Protected Views and Visual Resources	Guidance for Reducing Visual Impacts
	N/A	The City should require utility providers to design and construct overhead transmission lines in a manner that is environmentally sensitive, safe, and aesthetically compatible with surrounding land uses (Plan Policy UT-P10).
	N/A	The City should require utility providers to minimize visual and other impacts of transmission towers and overhead transmission lines on adjacent land uses through careful siting and design (Plan Policy UT-P14).
	N/A	The City should require new, modified, or replacement transmission structures (such as lattice towers, monopoles, and the like) to be designed to minimize aesthetic impacts appropriate to the immediate surrounding area whenever practical (Plan Policy UT-P16).
	N/A	The City shall, where appropriate, require reasonable landscape screening of site-specific above-ground utility facilities in order to diminish visual impacts (Plan Policy UT-P20).
Renton		
City of Renton Comprehensive Plan (2015)	High volume of trees and clear mountain views.	N/A
	Public scenic views and public view corridors, such as "physical, visual, and perceptual linkages to Lake Washington and Cedar River" (Plan Policy L-55).	N/A
	Natural forms, vegetation, distinctive stands of trees, natural slops, and scenic areas that "contribute to the City's identity, preserve property values, and visually define the	N/A

Plans	Protected Views and Visual Resources	Guidance for Reducing Visual Impacts
	community neighborhoods” (Plan Policy L-56).	
	Lakes and shorelines.	N/A
	Views of the water from public property or views enjoyed by a substantial number of residences.	N/A
	N/A	Design shoreline developments to maintain or enhance aesthetic values and scenic views (Plan Policy SH-16).
	N/A	Make facility improvements and additions within existing corridors wherever possible (Plan Policy U-73).
City of Renton Municipal Code (RMC) *Current through November 16, 2015*	Shoreline	Design shoreline use and development to maintain shoreline scenic and aesthetic qualities derived from natural features, such as shore forms and vegetative cover (RMC 4-3-090.D.3.a).
		Prohibits utilities in the Shoreline Natural shoreline environment designation (RMC 4-3-090.E.1).
	N/A	Visual prominence of structures must be minimized, including light, glare, and reflected light (RMC 4-3-090.D.3.b.vii).
	N/A	Aboveground utilities must be screened with masonry, decorative panels, and/or evergreen trees, shrubs, and landscaping sufficient to form an effective sight barrier within a period of five (5) years (RMC 4-6-090.11.a.xvi).
City of Renton SMP 2011	Scenic and aesthetic qualities derived from natural features of the shoreline, such as vegetative cover and shore forms (Ordinance No. 5633).	N/A

10. REFERENCES

City of Bellevue. 2015. Parks GIS Data

City of Issaquah. 2015. Parks GIS Data.

City of Kirkland. 2015. Parks GIS Data.

City of Newcastle. 2015. Parks GIS Data.

City of Redmond. 2015. Parks GIS Data.

City of Renton. 2015. Parks GIS Data.

ESRI. 2016. Using Viewshed and Observer Points for visibility analysis. http://pro.arcgis.com/en/pro-app/tool-reference/3d-analyst/using-viewshed-and-observer-points-for-visibility.htm.

FHWA (Federal Highway Administration). 2015. Guidelines for the Visual Impact Assessment of Highway Projects.

GIS Geography. 2016. DEM, DSM, DTM Differences. http://gisgeography.com/dem-dsm-dtm-differences/.

King County. 2003a. King County 2002/2003 Digital Surface Model (DSM).

King County. 2003b. King County 100-foot contours. GIS Data.

King County. 2015a. 2012 Assessor Real Property Data and 2015 Parcel Data, updated July 10, 2015.

King County. 2015b. Parks GIS Data.

NOAA (National Oceanic and Atmospheric Administration). 2011. LandCoverClip.tif. GIS Data.

PSE (Puget Sound Energy). 2016a. Segment Alignment GIS Data. Provided to ESA in June 2016.

PSE (Puget Sound Energy). 2016b. Segment Data Table. Provided to ESA on July 15, 2016.

Power Engineers. 2016. Energize Eastside Photo Simulation Methodology. Memorandum from Jason Pfaff, Department Manager, to Puget Sound Energy. June 10, 2016.

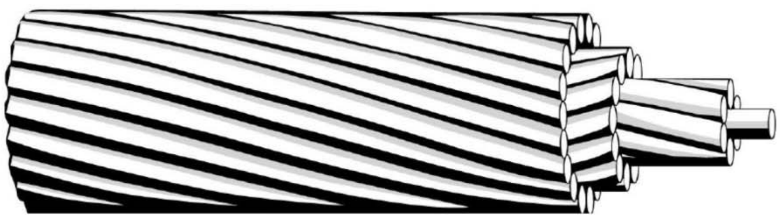
U.S. Census Bureau. 2014. Total Population, 2010–2014 American Community Survey 5-Year Estimates. Available: http://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=ACS_10_5YR_B01003&prodType=table. Accessed: Aug. 16, 2016.

Vissering, Jean; Mark Sinclair; and Anne Margolis. 2011. State Clean Energy Program Guide: A Visual Impact Assessment Process for Wind Energy Projects. Clean Energy States Alliance. May 2011.

Ecology (Washington State Department of Ecology). 2014. Water Resources GIS Data.

Attachment 1. Diameter of Existing Wire and Proposed Wire

Proposed 1.545 inches in diameter (Shown actual size)



Existing 1.063 inches in diameter (Shown actual size)

DSD 010832

Attachment 2. Methodology and Visual Simulations

POWER ENGINEERS, INC.

2041 SOUTH COBALT POINT WAY
MERIDIAN, ID 83642 USA

PHONE 208-288-6100
FAX 208-288-6199

POWER ENGINEERS

ENERGY
FACILITIES
COMMUNICATIONS
ENVIRONMENTAL

MEMORANDUM

DATE: June 10, 2016

TO: Puget Sound Energy

C:

FROM: Jason Pfaff, Department Manager

SUBJECT: Energize Eastside Photo Simulation Methodology

MESSAGE

POWER Engineers Used the Following Photo Simulation Approach on the Energize Eastside Transmission Line Project:

1. Key Observation Point Identification (KOPs) – POWER worked with PSE to determine KOP locations. KOPs are loaded into Google Earth, and discussed as a team to ensure all visual issues are addressed. KOP coordinates and markers were prepared for the field photo shoot.
2. Photo Collection – During the field Photo Shoot, POWER collected the following information:
   - **a.** Camera – POWER uses a full frame Canon 5D Mark II or III professional Digital Camera. All photos are taken with a 50mm. lens. In some extreme foreground situations a 28mm. lens may be used. Up to 3 images were taken from a single location.
   - **b.** Atmospheric Conditions – POWER documented the following information, as it has an impact of the photo simulation accuracy.
     - **i.** Date, Time of Day (Hour/Minutes) – Determines color of sunlight, shadow location and irradiance levels.
     - **ii.** Atmospheric conditions – Haze and light diffusion has an impact on contrast at distance
     - **iii.** Lens length (50 mm is typical, in some cases 28mm)
3. Post field photo shoot – After the photography collection, representative photography from each KOP were compiled into a photo KMZ for PSE to review photography and locations.
4. 3D Existing Conditions Model – POWER developed an existing conditions 3D Model of the study areas including terrain and structures. The existing conditions models were used in the 3D photo registration process. Once the 3D existing conditions model has been developed using a minimum of 30 meter contour elevation data, GPS data was be imported into the 3D model and checked for spatial accuracy.
5. 3D Photo Registration – All photos carried forward for photo simulation development were registered into a 3D modeling program. Virtual Cameras were aligned with the field camera (Canon 5D Mark II, 5D Mark III) through the use of GPS, compass heading and horizontal angle information. Accuracy was further refined by importing and aligning the existing 3D model information into the 3D Program and ensuring it aligned exactly with the photographic background.

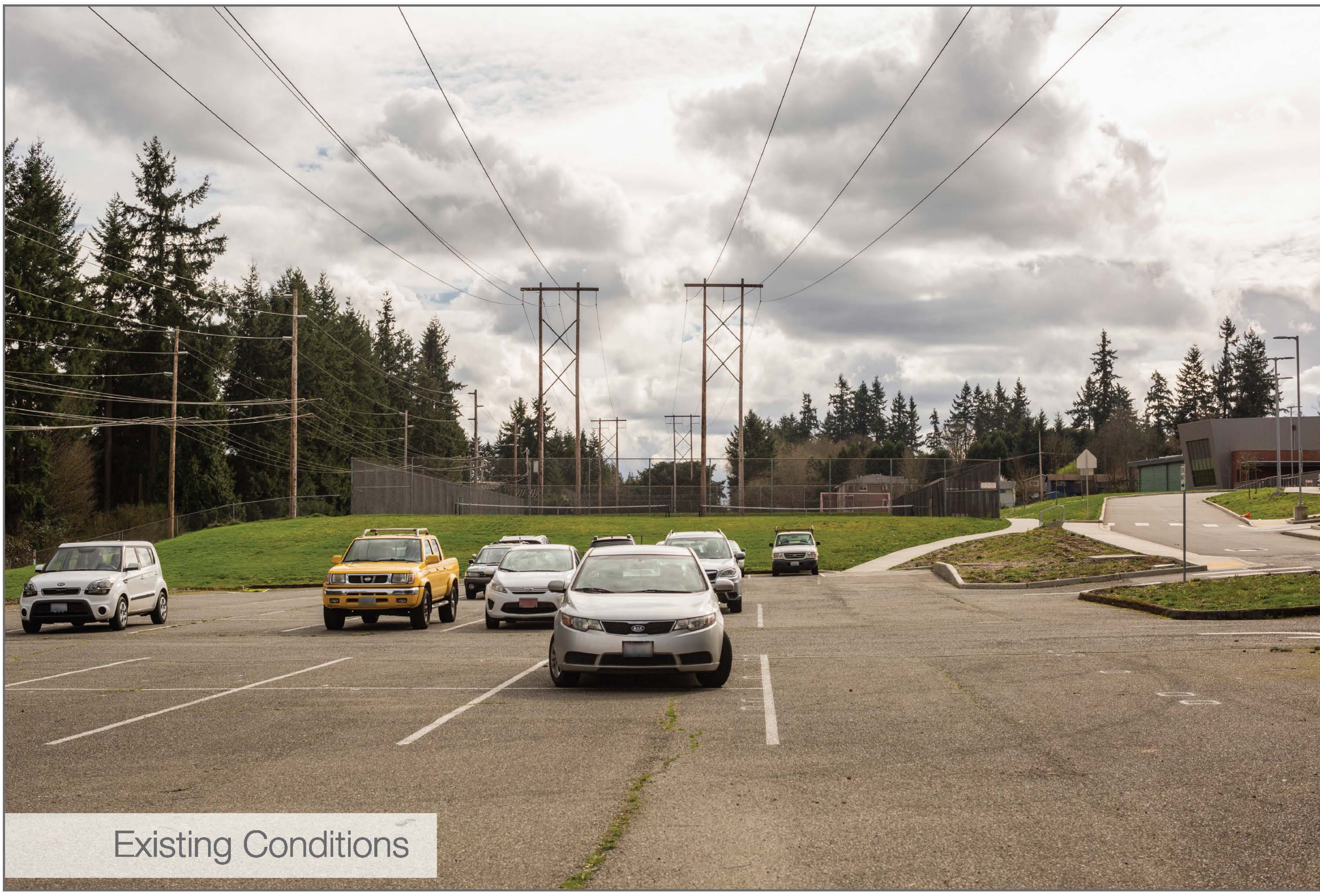
6. 3D Sun and Atmospheric Conditions – POWER imported all atmospheric data into the 3D Software to develop a sun and atmospheric system that matched the photography.
7. 3D Proposed Project Development – POWER developed the proposed project into a 3D Model. PSE worked with POWER to provide the PLS-CAD model data, as with any other CAD and GIS data available. PLS-CAD models are 3D engineering designs developed for each transmission line structure. All information was imported into the 3D existing conditions model and checked for accuracy. 3D materials (Corten Steel or Wood), and associated specular reflectance information were applied to the proposed 3D information.
8. 3D Rendering – After all information has been properly aligned, atmospherics checked and materials applied, POWER "rendered" the 3D information over the top of the 2D photography. The result was a new 3D image with an alpha channel allowing existing and proposed information to be separated different layers.
9. Photoshop – Photoshop was used in the last step of the process. Foreground screening elements such as trees, structures, etc are extracted and placed on separate layers. Proposed transmission line information was placed on separate layers, and background information is placed on their own layers. Separation of layers is an important step; as it allows for fine-tune adjustments to color, grain, and depth of field, atmospherics and contrast. Once all elements have been correctly adjusted and masking elements correct, all layers were merged into one single photo simulation.
10. Board Layouts – POWER created existing and proposed layouts, showing both images side by side in a PDF form.

Sincerely,

Jason Pfaff
Director of Visualization Services

Address	**Redmond Way, Redmond**
Date	**3/8/2016**
Time	**2:59 PM**
Viewing Direction	**Northwest**
Pole Heights: Existing Conditions	**~50 feet**
Pole Heights: Conceptual Project	**~85 feet**

KOP NORTH 15
SEGMENT 1



Address	**13505 NE 75th St, Redmond**
Date	**3/8/2016**
Time	**2:41 PM**
Viewing Direction	**South**
Existing Pole Heights	**~75 feet**
Proposed Pole Heights	**~110 feet**

KOP NORTH 14
SEGMENT 1

energizeEASTSIDE

PSE PUGET SOUND ENERGY

Existing Conditions

Conceptual Project

Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review 3/14/2016

Address	**13540 NE 54th Pl, Bellevue**
Date	**3/31/2014**
Time	**10:49 AM**
Viewing Direction	**North**
Pole Heights: Existing Conditions	**~55 feet**
Pole Heights: Conceptual Project	**~90 feet**

KOP North 3
SEGMENT 1

Existing Conditions

Conceptual Project

Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review

5/25/2016

Address	267 140th Ave NE, Bellevue
Date	5/13/2016
Time	10:40 AM
Viewing Direction	North
Existing Pole Heights	~60 feet
Proposed Pole Heights	~95 feet

KOP CENTRAL 22
SEGMENT 1

energizeEASTSIDE

PUGET SOUND ENERGY

Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review

5/5/2016

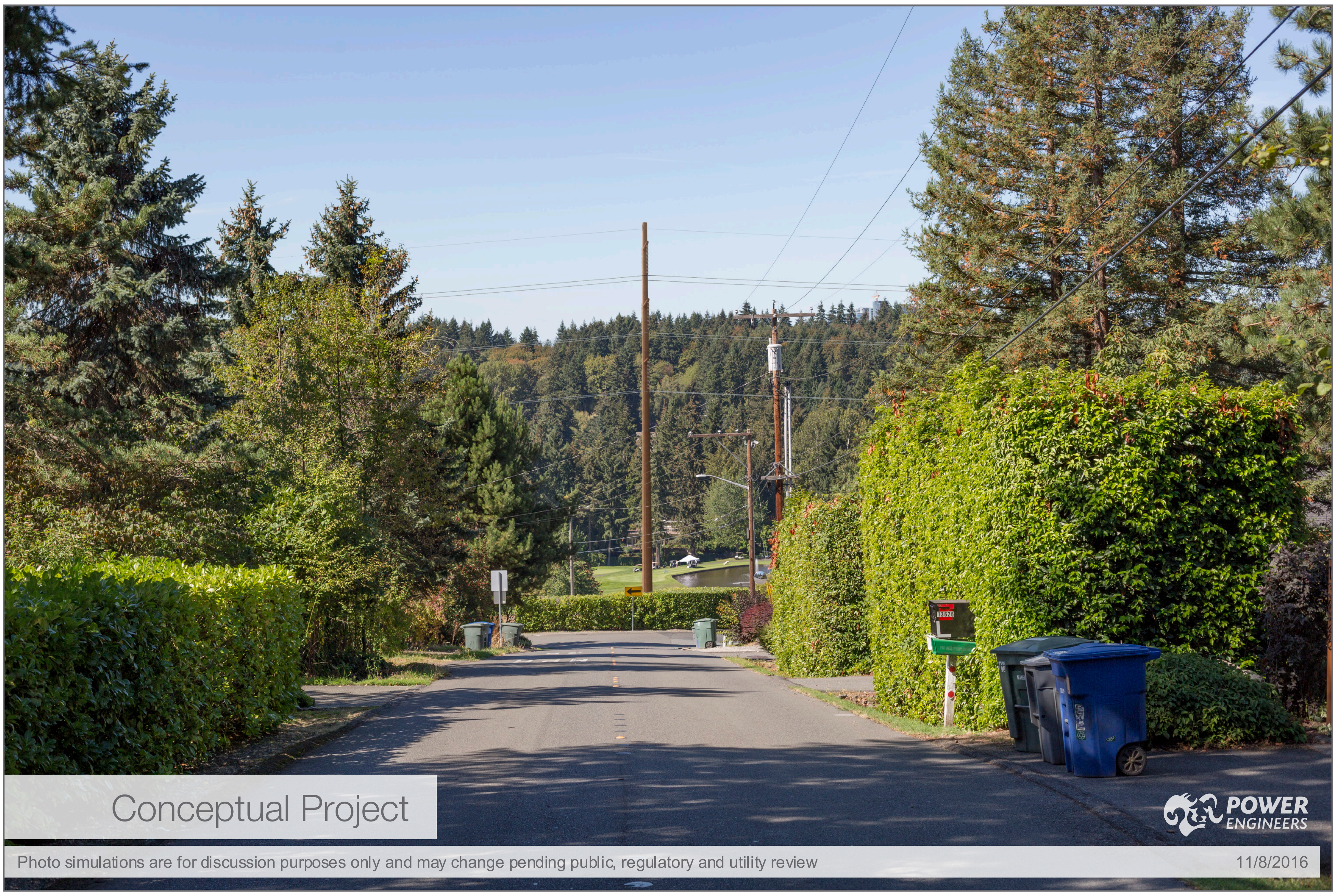
Address	**13606 Main St, Bellevue**
Date	**3/30/2016**
Time	**3:52 PM**
Viewing Direction	**North**
Existing Pole Heights	**~50 feet**
Proposed Pole Heights	**~100 feet**

KOP CENTRAL 20
SEGMENT 1

energize**EASTSIDE**

PSE PUGET SOUND ENERGY

Existing Conditions



Conceptual Project

Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review 11/8/2016

Address	13636 Main St, Bellevue
Date	9/12/2016
Time	12:02 PM
Viewing Direction	West
Existing Pole Heights	~55 feet
Proposed Pole Heights	~105 feet

KOP CENTRAL 31
SEGMENT 1

Address	13633 SE 5th St, Bellevue
Date	9/12/2016
Time	12:12 PM
Viewing Direction	West
Existing Pole Heights	~55 feet
Proposed Pole Heights	~100 feet

KOP CENTRAL 32
SEGMENT 1

energizeEASTSIDE

PSE PUGET SOUND ENERGY

Address	106 136th Ave SE, Bellevue
Date	3/30/2016
Time	3:48 PM
Viewing Direction	South
Existing Pole Heights	~75 feet
Proposed Pole Heights	~110 feet

KOP CENTRAL 21
SEGMENT 1

energizeEASTSIDE

PUGET SOUND ENERGY

Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review 5/3/2016

Address	**13600 SE 5th St, Bellevue**
Date	**4/2/2014**
Time	**2:54 PM**
Viewing Direction	**North**
Pole Heights: Existing Conditions	**~60 feet**
Pole Heights: Conceptual Project	**~100 feet**

KOP Central 3
SEGMENT 1

energizeEASTSIDE

PUGET SOUND ENERGY

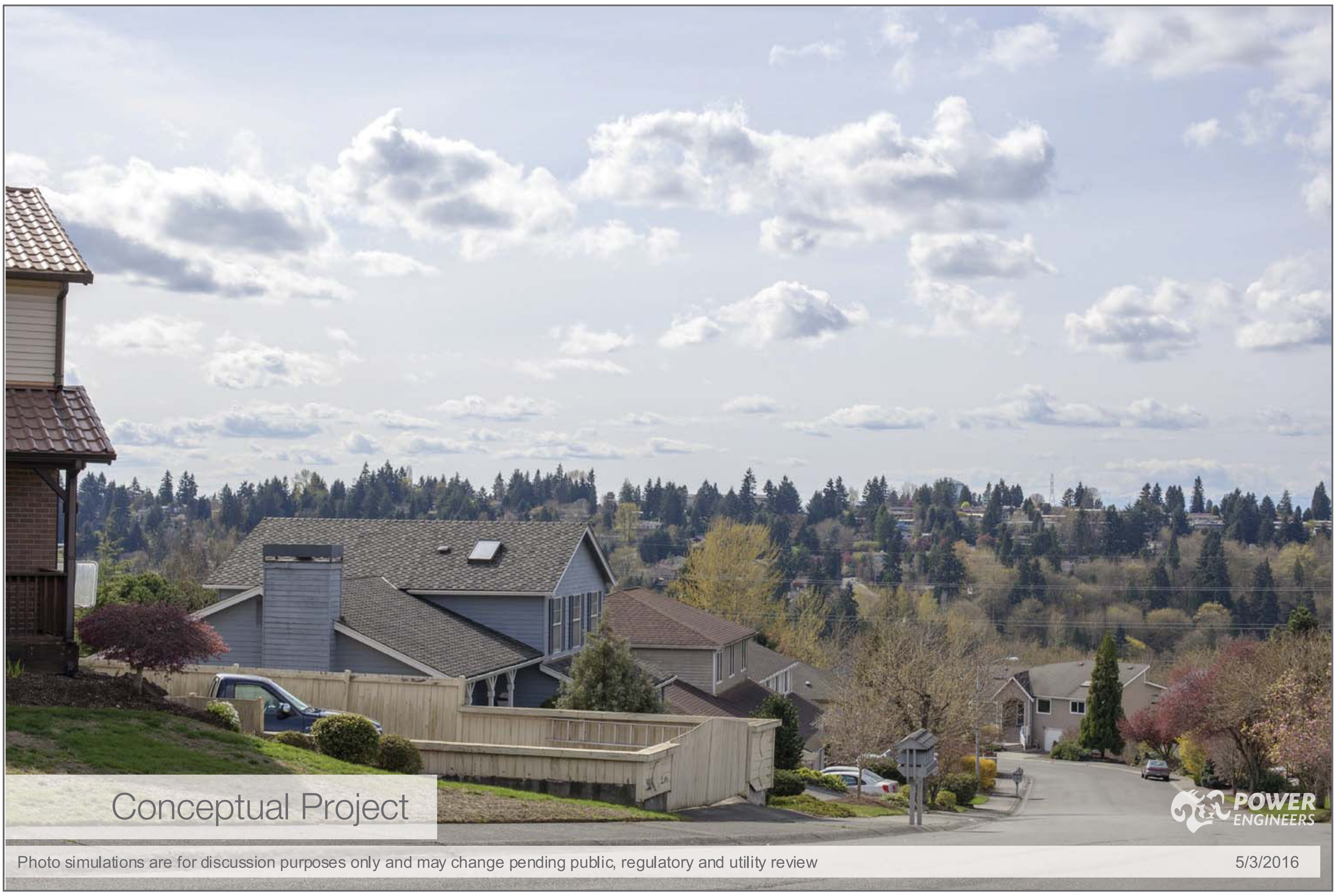
Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review 8/10/2016

Address **13810 Lake Hills Connector, Bellevue**	
Date	**6/7/2016**
Time	**2:09 PM**
Viewing Direction	**West**
Existing Pole Heights	**NA**
Proposed Pole Heights	**~100 feet**

KOP CENTRAL 25 BYPASS

energizeEASTSIDE

PSE PUGET SOUND ENERGY



Address	**13711 SE 18th St, Bellevue**
Date	**4/2/2014**
Time	**3:19 PM**
Viewing Direction	**West**
Pole Heights: Existing Conditions	**~55 feet**
Pole Heights: Conceptual Project	**~90 feet**

KOP CENTRAL 4
SEGMENT 1

Address	1990 134th Pl SE, Bellevue
Date	3/30/2016
Time	3:22 PM
Viewing Direction	South
Existing Pole Heights	55 feet
Proposed Pole Heights	~95 feet

KOP CENTRAL 28
SEGMENT 1

energizeEASTSIDE

PSE PUGET SOUND ENERGY

Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review 5/3/2016

Address	**2160 135th Pl SE, Bellevue**
Date	**3/31/2014**
Time	**4:00 PM**
Viewing Direction	**Southeast**
Pole Heights: Existing Conditions	**~55 feet**
Pole Heights: Conceptual Project	**~95 feet**

KOP CENTRAL 5
SEGMENT 1

Address	**SE 30th Street, Bellevue**
Date	**7/25/2016**
Viewing Direction	**East**
Pole Heights: Existing Conditions	**~65-70 feet**
Pole Heights: Conceptual Project	**~70-90 feet**

Richards Creek SUBSTATION

energize**EASTSIDE**

PUGET SOUND ENERGY

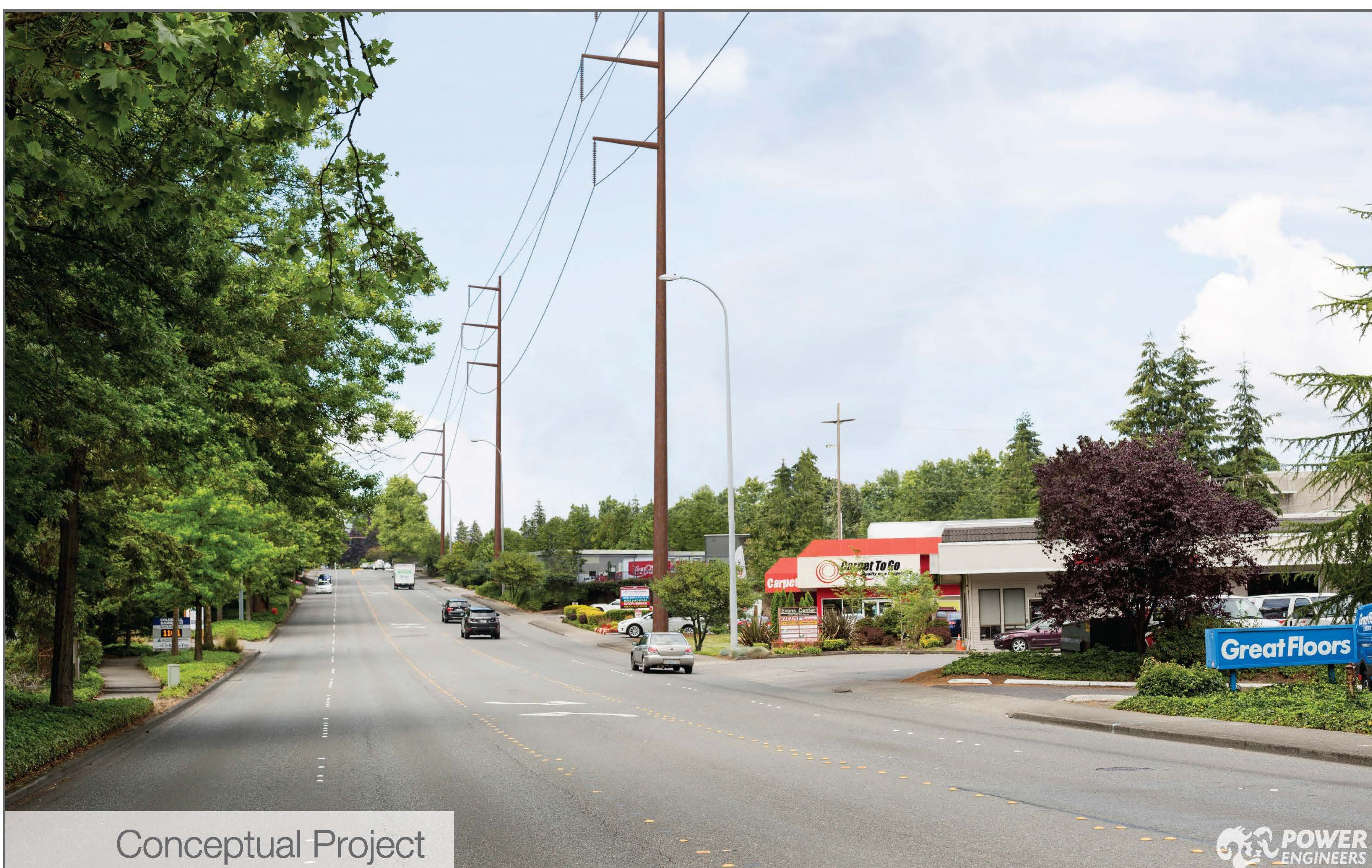


Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review 8/10/2016

Address	**12828 Bel-Red Rd, Bellevue**
Date	**7/15/2016**
Time	**11:30 AM**
Viewing Direction	**Southwest**
Existing Pole Heights	**NA**
Proposed Pole Heights	**~120 feet**

KOP CENTRAL 26 BYPASS

energizeEASTSIDE

PSE PUGET SOUND ENERGY

Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review 11/4/2016

Address	**1227 124th Ave NE, Bellevue**
Date	**8/24/2016**
Time	**5:31 PM**
Viewing Direction	**South**
Existing Pole Heights	**NA**
Proposed Pole Heights	**~90 feet**

KOP CENTRAL 36 BYPASS

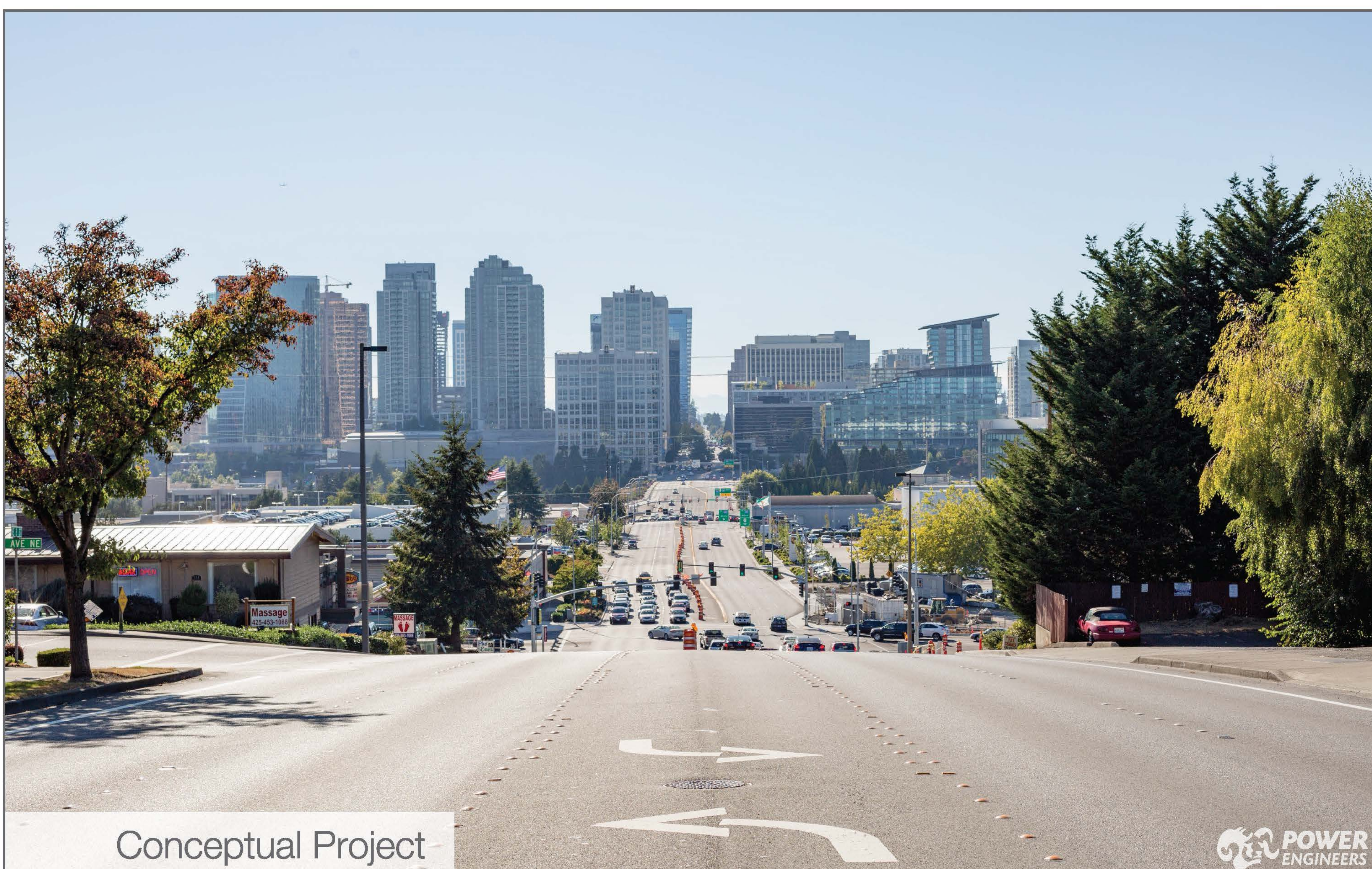


Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review 9/16/2016

Address	12253 NE 8th St, Bellevue
Date	8/24/2016
Time	5:10 PM
Viewing Direction	West
Existing Pole Heights	NA
Proposed Pole Heights	~100 feet

KOP CENTRAL 29 BYPASS

energizeEASTSIDE

PSE PUGET SOUND ENERGY

Address	11751 SE 5th Street, Bellevue
Date	9/12/2016
Time	1:58 PM
Viewing Direction	Northwest
Existing Pole Heights	NA
Proposed Pole Heights	100-105 feet

KOP CENTRAL 33 BYPASS

energizeEASTSIDE

PSE PUGET SOUND ENERGY

Address	**Lake Hills Connector, Bellevue**
Date	**6/7/2016**
Time	**2:58 PM**
Viewing Direction	**East**
Existing Pole Heights	**NA**
Proposed Pole Heights	**~100 feet**

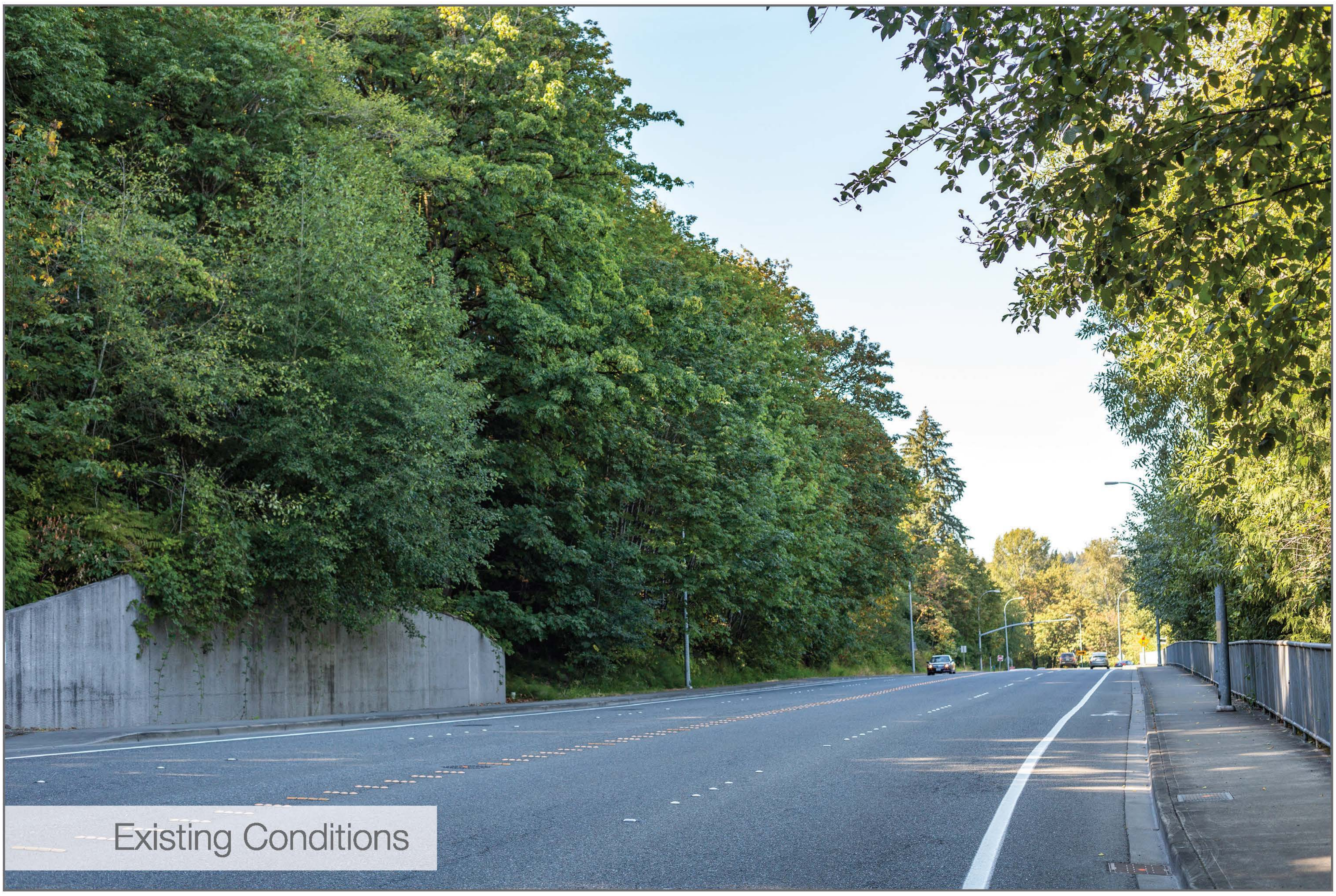
KOP CENTRAL 38 BYPASS

Address	**SE 8th St and Lake Hills Connector, Bellevue**
Date	**6/7/2016**
Time	**2:20 PM**
Viewing Direction	**Northwest**
Existing Pole Heights	**NA**
Proposed Pole Heights	**~110 feet**

KOP CENTRAL 23 BYPASS

energize**EASTSIDE**

PSE *PUGET SOUND ENERGY*



Address	**1680 Richards Rd, Bellevue**
Date	**8/24/2016**
Time	**4:09 PM**
Viewing Direction	**Northwest**
Existing Pole Heights	**NA**
Proposed Pole Heights	**~110 feet**

KOP CENTRAL 27 BYPASS

Address	2070 132nd Ave SE, Bellevue
Date	6/7/2016
Time	1:37 PM
Viewing Direction	North
Existing Pole Heights	NA
Proposed Pole Heights	~100 feet

KOP CENTRAL 24 BYPASS

energizeEASTSIDE

PSE PUGET SOUND ENERGY

Address	13630 SE Allen Rd, Bellevue
Date	3/30/2016
Time	1:44 PM
Viewing Direction	Northeast
Pole Heights: Existing Conditions	~60 feet
Pole Heights: Conceptual Project	~95 feet

KOP SOUTH 24
SEGMENT 2

Existing Conditions

Conceptual Project

Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review

4/13/2016

Address	**13744 SE Allen Rd, Bellevue**
Date	**3/30/2016**
Time	**1:42 PM**
Viewing Direction	**Northeast**
Pole Heights: Existing Conditions	**~65 feet**
Pole Heights: Conceptual Project	**~95 feet**

KOP SOUTH 25
SEGMENT 2

KOP CENTRAL 18
SEGMENT 2

Address	**4411 137th Ave SE, Bellevue**
Date	**5/7/2014**
Time	**10:53 AM**
Viewing Direction	**Northwest**
Pole Heights: Existing Conditions	**~50 - 60 feet**
Pole Heights: Conceptual Project	**~65 feet**

energizeEASTSIDE

PSE PUGET SOUND ENERGY

DSD 010860

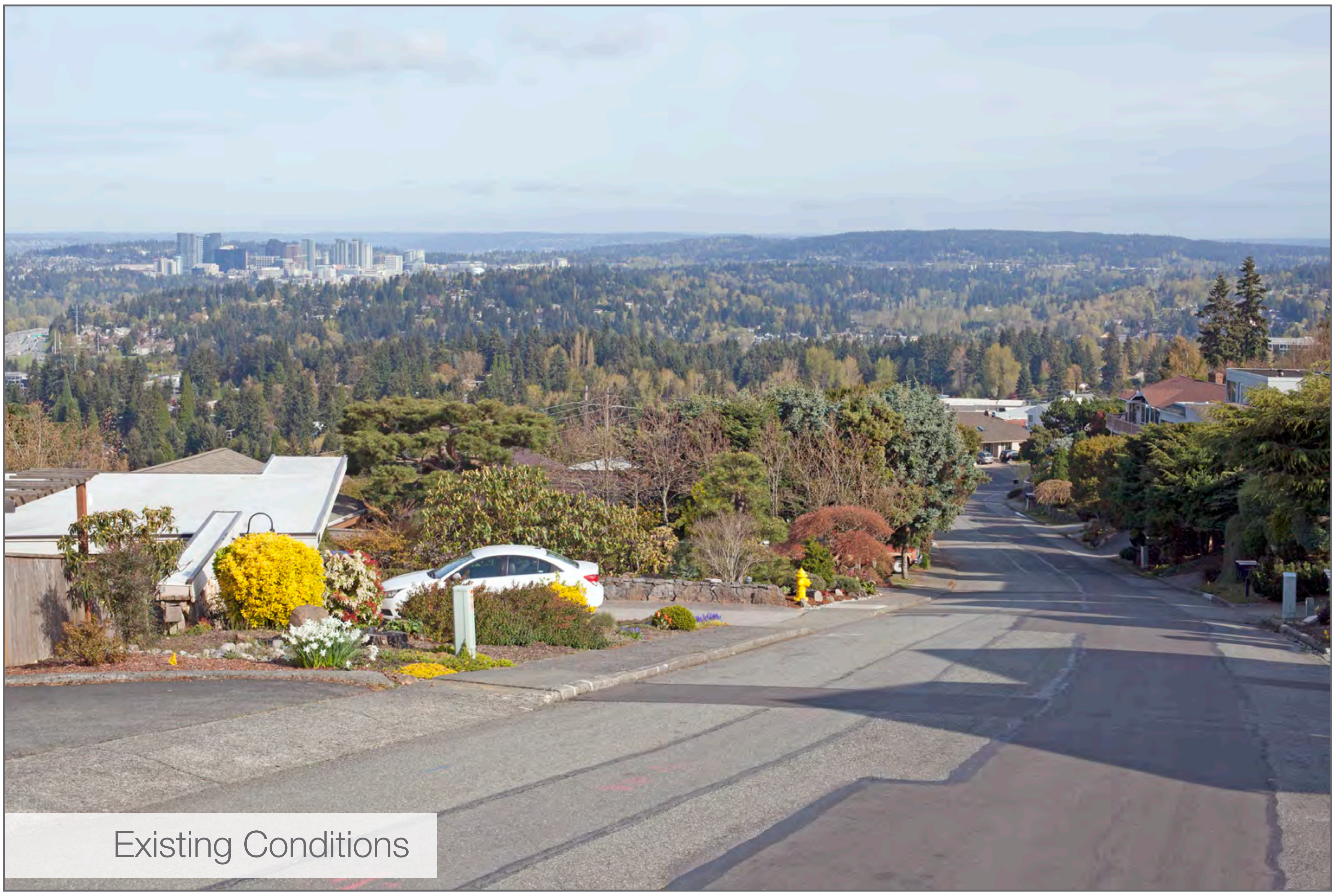


Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review | 5/09/2016

Address	**4489 137th Ave SE, Bellevue**
Date	**4/10/2014**
Time	**9:32 AM**
Viewing Direction	**North**
Pole Heights: Existing Conditions	**~50 - 60 feet**
Pole Heights: Conceptual Project	**~65 feet**

KOP CENTRAL 15
SEGMENT 2

energizeEASTSIDE

PUGET SOUND ENERGY

Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review 11/16/2016

Address	4730 134th Place SE, Bellevue
Date	8/24/2016
Time	3:28 PM
Viewing Direction	West
Existing Pole Heights	44 feet
Proposed Pole Heights	85 feet

KOP CENTRAL 30
WILLOW 1 - SEGMENT 2

energizeEASTSIDE

PSE PUGET SOUND ENERGY

DSD 010862

Address	**4730 134th Place SE, Bellevue**
Date	**8/24/2016**
Time	**3:28 PM**
Viewing Direction	**West**
Existing Pole Heights	**44 feet**
Proposed Pole Heights	**65 feet**

KOP CENTRAL 30
WILLOW 2 - SEGMENT 2

energizeEASTSIDE

PSE PUGET SOUND ENERGY

DSD 010863

Existing Conditions

Conceptual Project

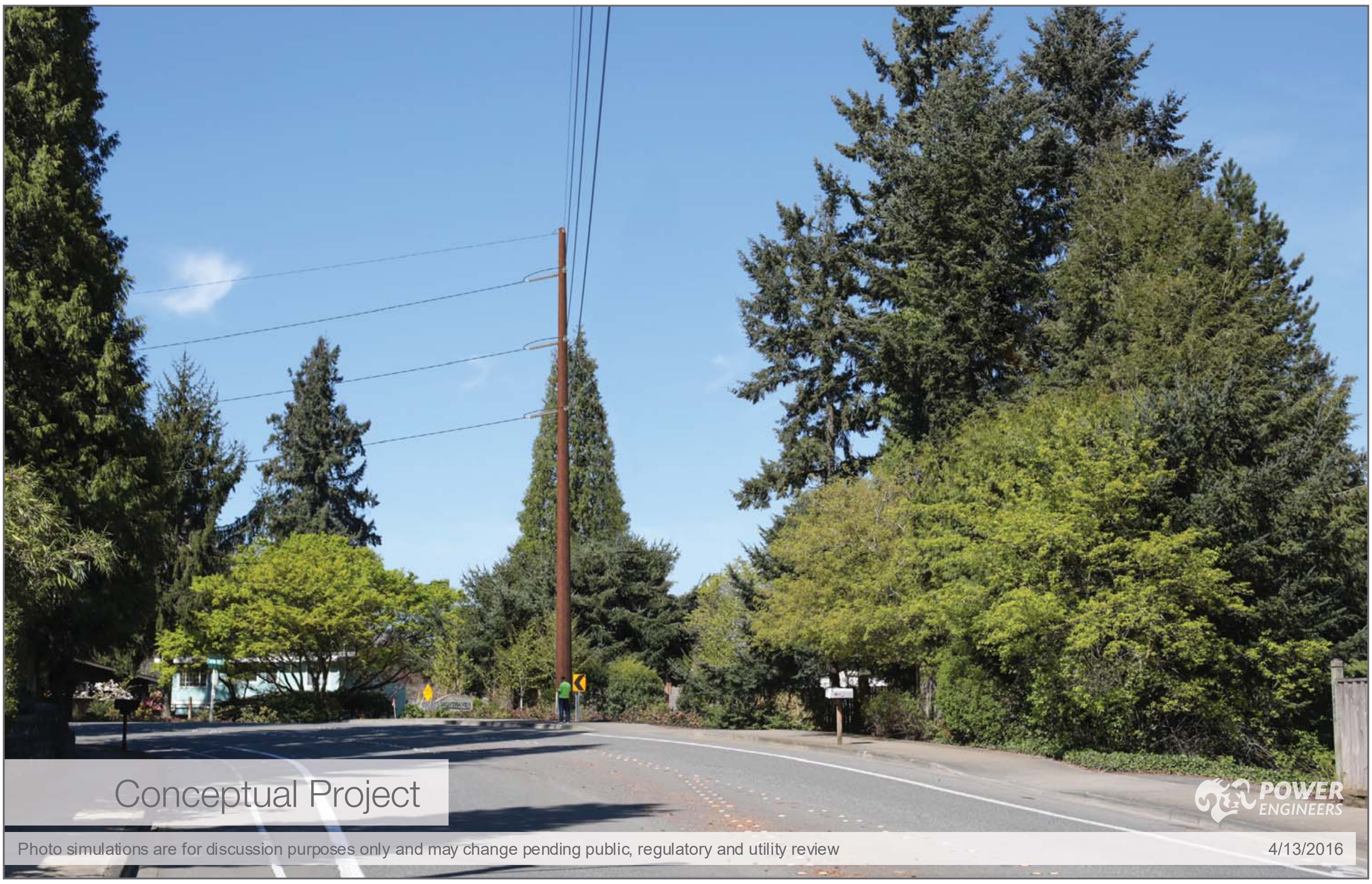
Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review 4/19/2016

Address	**13300 SE 42nd Place, Bellevue**
Date	**3/30/2016**
Time	**1:00 PM**
Viewing Direction	**Northwest**
Pole Heights: Existing Conditions	**NA**
Pole Heights: Conceptual Project	**~70 feet**

KOP SOUTH 28
SEGMENT 2

Address	**13371 SE Newport Way, Bellevue**
Date	**3/30/2016**
Time	**1:30 PM**
Viewing Direction	**Northeast**
Pole Heights: Existing Conditions	**~40 - 50 feet**
Pole Heights: Conceptual Project	**~70 feet**

KOP SOUTH 26
SEGMENT 2



Address	**13357 SE Newport Way, Bellevue**
Date	**3/30/2016**
Time	**1:25 PM**
Viewing Direction	**Northwest**
Pole Heights: Existing Conditions	**~40 - 50 feet**
Pole Heights: Conceptual Project	**~70 feet**

KOP SOUTH 27
SEGMENT 1

Address	**4256 134th Ave SE, Bellevue**
Date	**3/30/2016**
Time	**1:04 PM**
Viewing Direction	**Northwest**
Pole Heights: Existing Conditions	**~40 - 50 feet**
Pole Heights: Conceptual Project	**70 feet**

KOP SOUTH 29
SEGMENT 2

Address	**12919 SE Newport Way, Bellevue**
Date	**3/30/2016**
Time	**2:02 PM**
Viewing Direction	**East**
Pole Heights: Existing Conditions	**~40 feet**
Pole Heights: Conceptual Project	**~70 feet**

KOP SOUTH 31
SEGMENT 2

Existing Conditions

Conceptual Project

Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review

4/19/2016

Address	**12892 SE Newport Way, Bellevue**
Date	**3/30/2016**
Time	**2:01 PM**
Viewing Direction	**West**
Pole Heights: Existing Conditions	**~40 feet**
Pole Heights: Conceptual Project	**~75 feet**

KOP SOUTH 30
SEGMENT 2

Address	**4122 Factoria Blvd SE, Bellevue**
Date	**5/7/2016**
Time	**12:24 PM**
Viewing Direction	**North**
Existing Pole Heights	**~80 feet**
Proposed Pole Heights	**~90 feet**

KOP CENTRAL 13
OAK 1 - SEGMENT 2

energizeEASTSIDE

PSE PUGET SOUND ENERGY

Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review 8/18/2016

Address	**4122 Factoria Blvd SE, Bellevue**
Date	**5/7/2016**
Time	**12:24 PM**
Viewing Direction	**North**
Existing Pole Heights	**~80 feet**
Proposed Pole Heights	**~90 feet**

KOP CENTRAL 13
OAK 2 - SEGMENT 2

energizeEASTSIDE

PSE PUGET SOUND ENERGY

Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review 6/3/2016

Address	12513 SE 38th St, Bellevue
Date	3/30/2016
Time	3:00 PM
Viewing Direction	Southeast
Existing Pole Heights	NA
Proposed Pole Heights	~70 feet

KOP SOUTH 34
SEGMENT 2

energizeEASTSIDE

PSE PUGET SOUND ENERGY

Existing Conditions

Conceptual Project

Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review 6/3/2016

Address	**12513 SE 38th St, Bellevue**
Date	**3/30/2016**
Time	**3:00 PM**
Viewing Direction	**Southeast**
Existing Pole Heights	**NA**
Proposed Pole Heights	**~70 feet**

KOP SOUTH 34
SEGMENT 2

energizeEASTSIDE

PUGET SOUND ENERGY

DSD 010873

Address	**5365 Coal Creek Parkway, Bellevue**
Date	**9/12/2016**
Time	**4:36 PM**
Viewing Direction	**Northwest**
Existing Pole Heights	**65 feet**
Proposed Pole Heights	**75-80 feet**

KOP CENTRAL 35
OAK 1 - SEGMENT 2

energizeEASTSIDE

PSE PUGET SOUND ENERGY

Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review 10/28/2016

Address	5365 Coal Creek Parkway, Bellevue
Date	9/12/2016
Time	4:36 PM
Viewing Direction	Northwest
Existing Pole Heights	65 feet
Proposed Pole Heights	75-80 feet

KOP CENTRAL 35
OAK 2 - SEGMENT 2

energizeEASTSIDE

PSE PUGET SOUND ENERGY

Address	**5365 Coal Creek Parkway, Bellevue**
Date	**9/12/2016**
Time	**4:36 PM**
Viewing Direction	**Northwest**
Existing Pole Heights	**65 feet**
Proposed Pole Heights	**75-80 feet**

KOP CENTRAL 35

WILLOW 1 - SEGMENT 2

energizeEASTSIDE

PSE PUGET SOUND ENERGY

Address	5365 Coal Creek Parkway, Bellevue
Date	9/12/2016
Time	4:36 PM
Viewing Direction	Northwest
Existing Pole Heights	65 feet
Proposed Pole Heights	75-80 feet

KOP CENTRAL 35
WILLOW 2 - SEGMENT 2

energizeEASTSIDE

PSE PUGET SOUND ENERGY

Existing Conditions

Conceptual Project

Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review

10/28/2016

Address	**4901 Coal Creek Parkway, Bellevue**
Date	**9/12/2016**
Time	**4:09 PM**
Viewing Direction	**Southeast**
Existing Pole Heights	**65 feet**
Proposed Pole Heights	**80 feet**

KOP CENTRAL 34

OAK 1 - SEGMENT 2

energize**EASTSIDE**

PUGET SOUND ENERGY

Address	4901 Coal Creek Parkway, Bellevue
Date	9/12/2016
Time	4:09 PM
Viewing Direction	Southeast
Existing Pole Heights	65 feet
Proposed Pole Heights	80 feet

KOP CENTRAL 34
OAK 2 - SEGMENT 2

energizeEASTSIDE

PSE PUGET SOUND ENERGY

Address	4901 Coal Creek Parkway, Bellevue
Date	9/12/2016
Time	4:09 PM
Viewing Direction	Southeast
Existing Pole Heights	65 feet
Proposed Pole Heights	80 feet

KOP CENTRAL 34

WILLOW 1 - SEGMENT 2

energizeEASTSIDE

PSE PUGET SOUND ENERGY

Address	4901 Coal Creek Parkway, Bellevue
Date	9/12/2016
Time	4:09 PM
Viewing Direction	Southeast
Existing Pole Heights	65 feet
Proposed Pole Heights	80 feet

KOP CENTRAL 34

WILLOW 2 - SEGMENT 2

Existing Conditions

Conceptual Project

Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review

1/6/2017

Address	12727 SE 73rd Pl, Newcastle
Date	3/8/2016
Time	11:42 AM
Viewing Direction	South
Existing Pole Heights	~55 feet
Proposed Pole Heights	~95 feet

KOP SOUTH 20
SEGMENT 3

energizeEASTSIDE

PSE PUGET SOUND ENERGY

DSD 010882

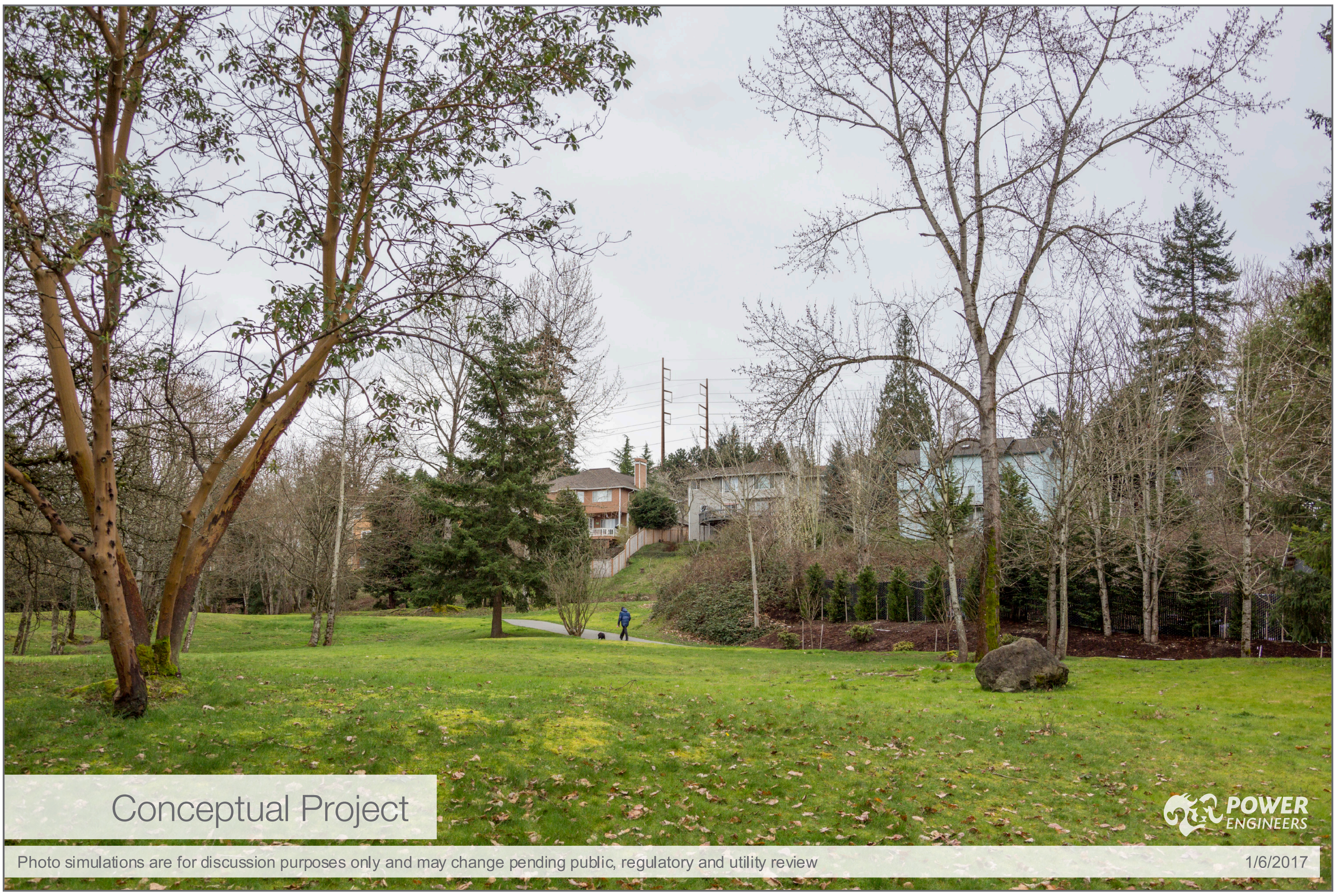
Address	**7954 129th Pl SE, Newcastle**
Date	**1/5/2017**
Time	**10:48 AM**
Viewing Direction	**Southwest**
Existing Pole Heights	**~52 feet**
Proposed Pole Heights	**~95 feet**

KOP SOUTH 27
SEGMENT 3

energizeEASTSIDE

PUGET SOUND ENERGY

Existing Conditions



Conceptual Project

Address	**Lake Boren Park, Newcastle**
Date	**3/8/2016**
Time	**11:20 AM**
Viewing Direction	**Southwest**
Existing Pole Heights	**~50 feet**
Proposed Pole Heights	**~95 feet**

KOP SOUTH 21
SEGMENT 3

Existing Conditions

Conceptual Project

Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review 9/12/2016

Address	**12732 SE 80th Way, Newcastle**
Date	**9/12/2016**
Time	**5:28 PM**
Viewing Direction	**Southeast**
Existing Pole Heights	**~52 feet**
Proposed Pole Heights	**~95 feet**

KOP SOUTH 25
SEGMENT 3

energize**EASTSIDE**

PSE PUGET SOUND ENERGY

Existing Conditions

Conceptual Project

Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review

1/6/2017

Address	**SE 84th St, Newcastle**
Date	**3/8/2016**
Time	**10:28 AM**
Viewing Direction	**South**
Existing Pole Heights	**~55 feet**
Proposed Pole Heights	**~95 feet**

KOP SOUTH 19
SEGMENT 3

energizeEASTSIDE

PSE PUGET SOUND ENERGY

KOP SOUTH 26
SEGMENT 3

Address	**8446 128th Ave SE, Newcastle**
Date	**1/5/2017**
Time	**2:24 PM**
Viewing Direction	**Northeast**
Existing Pole Heights	**~55 feet**
Proposed Pole Heights	**~95 feet**

energize**EASTSIDE**

PSE PUGET SOUND ENERGY

Address	1026 Monroe Ave NE, Renton
Date	**4/1/2014**
Time	**3:07 PM**
Viewing Direction	**North**
Pole Heights: Existing Conditions	**~55 feet**
Pole Heights: Conceptual Project	**~90 feet**

KOP SOUTH 12
SEGMENT 3

Existing Conditions

Conceptual Project

Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review 8/19/2016

Address	3000 NE 4th St, Renton
Date	3/8/2016
Time	1:55 PM
Viewing Direction	North
Existing Pole Heights	~65 feet
Proposed Pole Heights	~100 feet

KOP SOUTH 23
SEGMENT 3

energizeEASTSIDE

PUGET SOUND ENERGY

Existing Conditions

Conceptual Project

Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review

9/9/2016

Address	318 Glennwood Ct SE, Renton
Date	8/24/2016
Time	10:20 AM
Viewing Direction	North
Existing Pole Heights	~50-70 feet
Proposed Pole Heights	~90 feet

KOP SOUTH 24 - W
SEGMENT 3

energizeEASTSIDE

PSE PUGET SOUND ENERGY

D

Critical Areas Regulations by City

APPENDIX D. CRITICAL AREAS REGULATIONS BY CITY

City/County	Critical Area	Description	Mitigation
City of Redmond (Redmond Zoning Code (RZC) Section 21.64.010)			
	General (applicable to all critical areas)	Utility installation, construction, and associated facilities and lines are exempt from CAO regulations if located in City road ROWs and are subject to restoration. If not exempt, then utilities project (facilities and poles) are prohibited from locating in critical areas but are allowed in critical area buffers provided mitigation standards are met. A critical areas permit is required.	Mitigation is required (for all critical areas) to be provided on-site, in-kind if feasible. If not feasible, then off-site (within Redmond city limits), out-of-kind mitigation may be considered.
RZC 21.64.030	Wetlands	Wetlands are categorized according to Class I, II, III, and IV based on the Ecology Wetland Rating System. Buffers range from 25-300 feet. Alterations to category I wetlands are prohibited, alterations to II, III, and IV may be allowed subject to performance standards and mitigation.	Wetland acreage replacement ratios are required for mitigation (in addition to general mitigation requirements) and determined according to mitigation activity (creation, reestablishment, rehabilitation, and/or enhancement) and Category.
RZC 21.64.020	Streams	Streams are classified according to Class I, II, III, and IV based on fish use. Buffers range from 25 to 200 feet. Utility facilities and poles may be permitted within the stream buffer if no feasible alternative location exists.	Additional specific mitigation standards (outside of general requirements) apply in restoration or enhancement of stream corridors, including: using native, adaptable, and perennial plants; depth and type of substrate; planting densities; fertilizer application; pesticide use limitations, etc.

DSD 010892

City/County	Critical Area	Description	Mitigation
RZC 21.64.020	Fish and Wildlife Habitat Conservation Areas (FWHCAs)	Classification of FWHCAs determined by adopted City maps, Washington Department of Fish and Wildlife Priority Habitats and Species maps, Washington State Conservation Commission habitat-limiting factors reports, federal and state info, and technical reports. Alterations to FWHCAs may be permitted subject to mitigation.	Additional mitigation measures are required during mitigation planning: a)consider habitat in site planning and design; b) locating buildings and structures that preserve and minimize adverse impacts to important habitat areas; c)integrate retained habitat into open space and landscaping consistent with RZC 21.32; d)where possible, consolidate habitat and vegetated open space in contiguous blocks; e)Locate habitat contiguous to other habitat, open space, or landscaped areas to contribute to a continuous system or corridor that provides connections to adjacent habitat areas; f) Use native species in any landscaping of disturbed or undeveloped areas and in any enhancement of habitat or buffers; g) Emphasize heterogeneity and structural diversity of vegetation in landscaping; h) Remove and/or control any noxious weeds or animals as defined by the City; and i). Preserve significant trees, preferably in groups, consistent with RZC 21.72, Tree Preservation, and with achieving the objectives of these standards.
RZC 21.64.050	Critical Aquifer Recharge Areas (CARAs)	CARAs are classified into Wellhead Protection Zone 1, 2, 3, and 4 based on proximity to and travel time of groundwater to City's public water source wells. Utility facilities and poles are permitted for location within these zones subject to the performance standards specific to each zone in RZC 21.64.050.D.	No additional mitigation measures.

City/County	Critical Area	Description	Mitigation
City of Bellevue Land Use Code (LUC) Part 20.25H			
LUC 20.25H.215 (mitigation sequencing) 20.25H.220 (Mitigation and restoration plan requirements)	General	Critical Areas Land Use Permit is required for any utility facilities and poles located in any of the designated critical areas and/or buffers.	Require mitigation or restoration plan, and mitigation sequencing
LUC 20.25H.095 (designation of critical area and buffers) 20.25H.100 (performance standards) 20.025H.105 (Mitigation and monitoring - additional provisions)	Wetlands	Wetlands are classified according to Category I, II, III, and IV using the Ecology Wetland Rating System. Buffers range from 40 to 225 feet. Structure setbacks range from 0-20 feet. Utility facilities and poles may be allowed in a wetland and/or wetland buffer subject to performance standards (20.25H.100) and mitigation.	Mitigation actions that require compensation of impacted critical area buffer are required to occur in the following order of preference and in the following locations: a. On-site, through replacement of lost critical area buffer; b. On-site, through enhancement of the functions and values of remaining critical area buffer; c. Off-site, through replacement or enhancement, in the same sub-drainage basin; d. Off-site, through replacement or enhancement, out of the sub-drainage basin but in the same drainage basin. Wetland Acreage replacement ratios apply to creation or restoration mitigation activities: Category I, 6-to-1; Category II, 3-to-1; Category III, 2-to-1; Category IV, 1.5-to-1. Enhancement of existing significantly degraded wetlands may also be allowed subject to a critical areas report.

City/County	Critical Area	Description	Mitigation
LUC 20.25H.075 (designation of critical areas and buffers) 20.25H.080 (performance standards)	Streams	Streams are classified according to Type S, F, N and O based on the Washington State Department of Natural Resources (WDNR) typing. Buffers range from 25-100 feet. Structure setbacks range from 0-50 feet. Stream channels can be modified for new or expanded utility facilities and poles, subject to performance standards (LUC 20.25H.080) and mitigation.	A. Mitigation plans for streams and stream critical area buffers are required to provide mitigation for impacts to critical area functions and values in the following order of preference: 1. On-site, through replacement of lost critical area buffer; 2. On-site, through enhancement of the functions and values of remaining critical area buffer; 3. Off-site, through replacement or enhancement, in the same sub-drainage basin; 4. Off-site, through replacement or enhancement, out of the sub-drainage basin but in the same drainage basin. Mitigation off-site and out of the drainage basin shall be permitted only through a critical areas report. B. Buffer Mitigation Ratio. Critical area buffer disturbed or impacted under this part shall be replaced at a ratio of one-to-one.
LUC 20.25H.150 (Designation of critical area) 20.25H.155 (uses in habitat for species of local importance) 20.25H.160 (performance standards)	Habitat Associated with Species of Local Importance	Buffers depend if they're required for known species or are 35 feet for naturally occurring ponds w/o any other CA designation. Utility facilities and poles are allowed within habitat associated with species of local importance subject to the following performance standards (LUC 20.25H.160) : If habitat associated with species of local importance will be impacted by a proposal, the proposal shall implement the wildlife management plan developed by the Department of Fish and Wildlife for such species. Where the habitat does not include any other critical area or critical area buffer, compliance with the wildlife management plan shall constitute compliance with this part.	No additional mitigation measures.

City/County	Critical Area	Description	Mitigation
City of Newcastle Municipal Code (NMC), Chapter 18.24 Critical Areas			
NMC 18.24.130 (mitigation and monitoring) 18.24.135 (off-site mitigation)	General		A. If mitigation is required to compensate for adverse impacts, unless otherwise provided, an applicant shall: 1. Mitigate adverse impacts to: a. Critical areas and their buffers; and b. The development proposal as a result of the proposed alterations on or near the critical areas; and 2. Monitor the performance of any required mitigation. On-site mitigation is preferred, but off-site mitigation (in same drainage subbasin as development proposal site) can be approved if on-site isn't practical and off-site mitigation will achieve equivalent or greater hydrological, water quality and wetland or aquatic area functions.

City/County	Critical Area	Description	Mitigation
NMC 18.24.310 (categories) 18.24.315 (Buffers) 18.24.316 (development standards) 18.24.320 (permitted alterations) 18.24.325 (specific mitigation requirements)	Wetlands	Wetlands are classified into Category I, II, III, and IV based on the Ecology Wetland Rating System. Buffers range between 25 and 225 feet depending on Category and land use. If no practical alternative location exists utility facilities and poles can be located within wetland buffers if: 1. The utility corridor is not located in a buffer where the buffer or associated wetland is used as a fish spawning area or by species listed as endangered or threatened by the state or federal government or contains critical or outstanding actual habitat for those species or heron rookeries or raptor nesting trees; 2. The construction area and resulting utility corridor are the minimum widths practical; 3. Except as provided in subsection (G) of this section, the utility corridor is located within the outer 25 percent of the buffer or within a roadway, the improved area of an existing utility corridor or the improved area of an approved trail; 4. The wetland and its buffer are protected during utility corridor construction and maintenance; 5. The utility corridor is aligned to avoid cutting significant trees, to the maximum extent practical; 6. Vegetation removal is limited to the minimum necessary to construct the corridor; 7. Vegetation removal for the purpose of corridor maintenance is the minimum necessary to maintain the utility's function; 8. Any corridor access for maintenance is at specific points into the buffer rather than by a parallel road, to the maximum extent practical; 9. If the department determines that a parallel maintenance road is necessary, the following conditions shall be complied with: a. The width of the roadway shall be as small as possible and not greater than 15 feet; and b. The location of the roadway shall be contiguous to the utility corridor on the side farthest from the wetland; Development subject to performance standards (18.24.316) and mitigation.	In addition to general mitigation requirements, mitigation for wetland or wetland buffer impacts: A. Mitigation measures must achieve equivalent or greater wetland functions, including, but not limited to: 1. Habitat complexity, connectivity and other biological functions; and 2. Seasonal hydrological dynamics, as provided in the King County Surface Water Design Manual; B. The following ratios of area of mitigation to area of alteration apply to mitigation measures: 1. For alterations to a wetland buffer, a ratio of one to one; and 2. For alterations to a wetland, proposed mitigation shall be in compliance with the acreage replacement ratios in NMC 18.24.325. C. Credit/Debit Method. To more fully protect functions and values, and as an alternative to the mitigation ratios found in the joint guidance Wetland Mitigation in Washington State Parts I and II (Ecology Publication No. 06-06-011a-b, Olympia, WA, March 2006), the administrator may allow mitigation based on the "credit/debit" method developed by the Department of Ecology in Calculating Credits and Debits for Compensatory Mitigation in Wetlands of Western Washington: Final Report.

City/County	Critical Area	Description	Mitigation
NMC 18.24.306 (classifications) 18.24.307 (development standards) 18.24.308 (permitted alterations) 18.24.309 (specific mitigation requirements)	Streams	Streams are classified as Types, F, Np, and Ns based on the WDNR typing system. Buffers range between 25 and 200 feet. If no practical alternative location exists utility corridors in stream buffers are allowed if: 1. The utility corridor is not located in a buffer where the buffer or associated stream is used by species listed as endangered or threatened by the state or federal government or contains critical or outstanding actual habitat for those species or heron rookeries or raptor nesting trees: 2. The construction area and resulting utility corridor are the minimum widths practical; 3. Except as provided in subsection (E) of this section, the utility corridor is located within the outer 25 percent of the buffer or within a roadway, the improved area of an existing utility corridor or the improved area of an approved trail; 4. The stream and its buffer are protected during utility corridor construction and maintenance; 5. The utility corridor is aligned to avoid cutting significant trees, to the maximum extent practical; 6. Vegetation removal is limited to the minimum necessary to construct the corridor; 7. Vegetation removal for the purpose of corridor maintenance is the minimum necessary to maintain the utility's function; 8. Any corridor access for maintenance is at specific points into the buffer rather than by a parallel road, to the maximum extent practical; 9. If the department determines that a parallel maintenance road is necessary, the following conditions shall be complied with: a. The width of the roadway shall be as small as possible and not greater than 15 feet; and b. The location of the roadway shall be contiguous to the utility corridor on the side farthest from the stream; and subject to mitigation	In addition to general mitigation requirements, mitigation for streams or their buffers is required to include: 1. For permanent alterations, restoration or enhancement of the altered stream or buffer, as determined by the city, using the following formulae: a. For mitigation on site: i. Correcting the adverse impact to any class of stream by repairing, rehabilitating or restoring the affected stream or buffer shall be on a 1:1 areal and functional basis; ii. Enhancement or restoration which is not mitigation of an alteration associated with a Type F, Np or Ns stream shall be on a 1.5:1 area and functional basis; iii. Enhancement or restoration which is not mitigation of an alteration associated with a Type S stream shall be on a 2:1 area and functional basis; b. For mitigation off site: i. Enhancement or restoration which is not mitigation of an alteration associated with a Type F, Np or Ns stream shall be on a 2:1 area and functional basis; ii. Enhancement or restoration which is not mitigation of an alteration associated with a Type S stream shall be on a 3:1 area and functional basis; and 2. For temporary alterations, restoration of the altered stream or buffer, as determined by the city; Off-site mitigation is only approved if it isn't practical to mitigate on site and it will achieve biologic, habitat, and hydrologic functions equivalent to or better than on-site mitigation.

City/County	Critical Area	Description	Mitigation
NMC 18.24.302	Fish and Wildlife Habitat Conservation Areas	Designated FWHCAs include: areas with which state or federally designated endangered, threatened, and sensitive species have a primary association; state priority habitats and areas associated with state priority species; state-designated priority habitat or critical habitat for state-designated species; habitats and species of local importance; naturally occurring ponds under 20 acres; waters of the state; lakes, ponds, streams, and rivers planted with game fish; and land useful for preserving habitat and open space connections. Buffers based on a CAR. Utility facilities and poles located in FWHCAs subject to development standards (18.24.305) and mitigation.	Mitigation of alterations to habitat conservation areas shall achieve equivalent or greater biological functions. Mitigation shall address each function affected by the alteration to achieve functional equivalency or improvement on a per function basis. Mitigation shall be detailed in a fish and wildlife habitat conservation area mitigation plan, which may include the following as necessary: a. A native vegetation plan; b. Plans for retention, enhancement or restoration of specific habitat features; c. Plans for control of nonnative invasive plant or wildlife species; and d. Stipulations for use of innovative, sustainable building practices.
City of Renton Municipal Code (RMC) Chapter 4-3-050			
RMC 4-3-050.C.3 (exemptions - critical areas and buffers) RMC 4-3-050.G.2 (critical area buffers and structure setbacks from buffers) RMC 4-3-050.L. (mitigation maintenance and monitoring)	General	Utilities may be located within geologic hazard areas, habitat conservation areas, streams and lakes (Types F, Np, & Ns), and wetlands when they area within existing and improved public road rights-of-way or easements. If activities exceed the existing improved area or the public right-of-way, this exemption does not apply. Where applicable, restoration of disturbed areas would need to be conducted. Overbuilding or replacement of existing utility systems may occur in geologic hazard areas, habitat conservation areas, or wetlands if the work does not increase the footprint of the structure or line by more than 10% within the critical area and/or buffer areas, and occurs in the existing right-of-way boundary or easement boundary.	Mitigation shall be provided on site, unless on-site mitigation is not scientifically feasible due to physical features of the property. The burden of proof shall be on the applicant to demonstrate that mitigation cannot be provided on site. When mitigation cannot be provided on site, mitigation shall be provided in the immediate vicinity of the permitted activity on property owned or controlled by the applicant, and identified as such through a recorded document such as an easement or covenant, provided such mitigation is beneficial to the habitat area and associated resources. In-kind mitigation shall be provided except when the applicant demonstrates and the City concurs that greater functional and habitat value can be achieved through out-of-kind mitigation.

City/County	Critical Area	Description	Mitigation
			When a mitigation plan is required, the proponent shall submit a final mitigation plan for the approval of the Administrator prior to the issuance of building or construction permits for development. The proponent shall receive written approval of the mitigation plan prior to commencement of any construction activity. Where the City requires increased buffers rather than standard buffers, it shall be noted on the subdivision plan and/or site plan.
RMC 4-3-050.G.2 (critical area buffers and structure setbacks from buffers) RMC 4-3-050.6	Habitat Conservation Areas	Critical Habitats are habitats that have a primary association with the documented presence of non-salmonid or salmonid species (RMC 4-3-090.L1)) species proposed or listed by the Federal government or State of Washington as endangered, threatened, sensitive and/or of local importance. Buffers consist of an undisturbed area of native vegetation, or areas identified for restoration, established to protect the integrity, functions and values of the affected habitat. Critical area buffer widths are established based on: (1) the type and intensity of human activity proposed, (2) recommendations contained within a habitat assessment report, and (3) management recommendations issued by the Washington Department of Fish and Wildlife. Structure setback beyond the buffer is 15 ft.	The Administrator may approve mitigation to compensate for adverse impacts of a development proposal to habitat conservation areas through use of a federally and/or state certified mitigation bank or in-lieu fee program. See RMC 4-3-050.L.

City/County	Critical Area	Description	Mitigation
RMC 4-3-050.G.2 (critical area buffers and structure setbacks from buffers) RMC 4-3-050.G.7 (streams and lakes) RMC 4-3-050.J.2 (Alterations to Critical Areas) 4-3-050.I.2 (Alterations to Critical Areas Buffers)	Streams and Lakes	Streams are classified as Type S, F, Np, and Ns based on the WDNR permanent water typing system (WAC 222-16-030). Buffers range between 50 and 175 feet. Structure setback beyond the buffer is 15 ft. Permit approval for projects on or near regulated Type F, Np and Ns water bodies are only granted if no net loss of regulated riparian area or shoreline ecological function in the drainage basin would occur and one of the following conditions is met: (1) project would meet the standard provisions of RMC 4-3-050.7, (2) project would meet alternative administrative standard provisions of RMC 4-3-050.7, or (3) a variance is acquired. New utility lines and facilities may be permitted to cross water bodies in accordance with an approved stream/lake study, if : fish and wildlife habitat areas are avoided to the maximum extent possible; utilities are designed to bore beneath the scour depth and hyporheic zone of the water body and channel migration zone, cross at the centerline of the stream channel at an angle greater than 60 degrees, or have crossings be contained within the footprint of an existing road or utility crossing; new utility routes avoid paralleling the stream or following a down-valley course near the channel; utility installation does not increase or decrease the natural rate of shore migration or channel migration; seasonal work windows are determined and made a condition of approval; and mitigation criteria of subsection L of RMC 4-3-050 are met.	

City/County	Critical Area	Description	Mitigation
RMC 4-3-050.G.2 (critical area buffers and structure setbacks from buffers) RMC 4-3-050.G.8 (wellhead protection areas)	Wellhead Protection Areas	Wellhead Protection Areas are the portion of an aquifer within the zone of capture and recharge area for a well or well field owned or operated by the City. They are delineated into zones based on the Renton Wellhead Protection Plan. These include Zone 1, Zone 1 Modified, and Zone 2. There are no critical area buffers. Construction activities within zones 1 and 2 must comply with RMC 4-3-050.G.8.	
RMC 4-3-050.G.2 (critical area buffers and structure setbacks from buffers) RMC 4-3-050.G.9 (wetlands) RMC 4-3.050.J.4 4-3-050.I.3 (Alterations to Critical Areas Buffers)	Wetlands	Wetlands are classified into Category I, II, III, and IV based on the Ecology Wetland Rating System. Buffers range between 0 and 200 feet depending on Category and land use. Structure setback beyond the buffer is 15 ft. for all uses and all wetland types. Utilities can be located within wetland buffers if they are located within an existing and improved public road rights-of-way or easements. Overbuilding or replacement of existing utility systems may occur in wetlands if the work does not increase the footprint of the structure or line by more than 10% within the critical area and/or buffer areas and occurs in the existing right-of-way or easement boundary. Development subject to performance standards (4-3-050.G) and mitigation.	Compensatory mitigation for wetland alterations shall be based on the wetland category and the type of mitigation activity proposed. The replacement ratio shall be based on wetland category. The created, re-established, rehabilitated, or enhanced wetland area shall at a minimum provide a level of functions equivalent to the wetland being altered and shall be located in an appropriate landscape setting.

E

PSE Vegetation Management Standards

APPENDIX E. PSE VEGETATION MANAGEMENT STANDARDS

Vegetation Management Standards

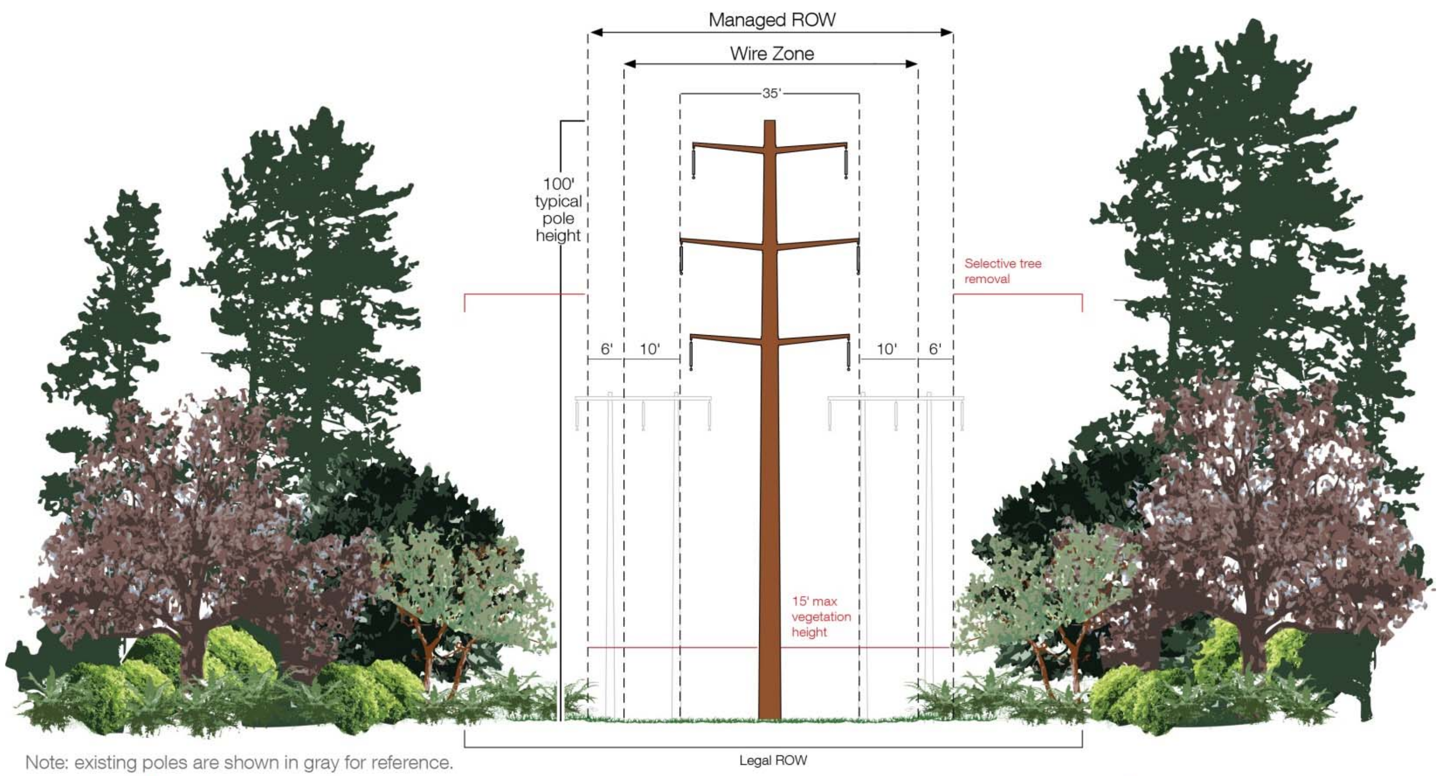
230 kV transmission lines

PSE's 230 kV transmission vegetation management standards generally requires removing trees located in the wire zone that have a mature height of more than 15 feet.

Wire Zone: Section of a utility transmission right of way extending to 10 feet from the outside transmission wire(s). Vegetation with a mature height of 15 feet or less is allowed in this zone.

Managed Right of Way (ROW): The section of a transmission right of way that extends roughly 16 feet from the outside transmission wire(s). Vegetation with a mature height of 15 feet or less is allowed in this zone.

Legal Right of Way (ROW): The full width of the easement. Maximum height of mature vegetation between the Managed ROW and Legal ROW is dependent upon tree species, tree health, and distance from the wires.



Note: existing poles are shown in gray for reference.

energizeEASTSIDE

PSE PUGET SOUND ENERGY

DSD 010904

Vegetation Management Standards

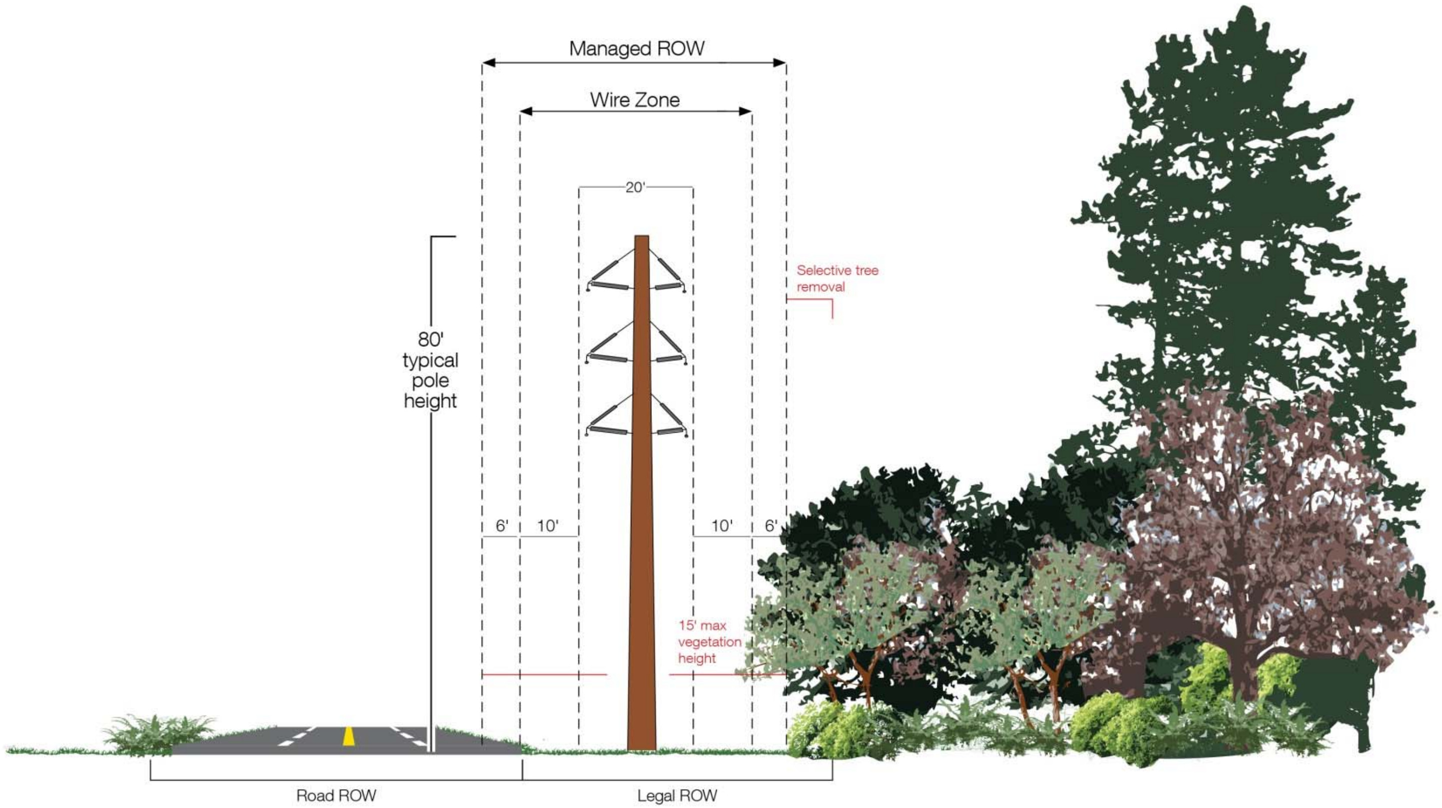
230 kV transmission lines

PSE's 230 kV transmission vegetation management standards generally requires removing trees located in the wire zone that have a mature height of more than 15 feet.

Wire Zone: Section of a utility transmission right of way extending to 10 feet from the outside transmission wire(s). Vegetation with a mature height of 15 feet or less is allowed in this zone.

Managed Right of Way (ROW): The section of a transmission right of way that extends roughly 16 feet from the outside transmission wire(s). Vegetation with a mature height of 15 feet or less is allowed in this zone.

Legal Right of Way (ROW): The full width of the easement. Maximum height of mature vegetation between the Managed ROW and Legal ROW is dependent upon tree species, tree health, and distance from the wires.



energizeEASTSIDE PUGET SOUND ENERGY

Vegetation Management Standards

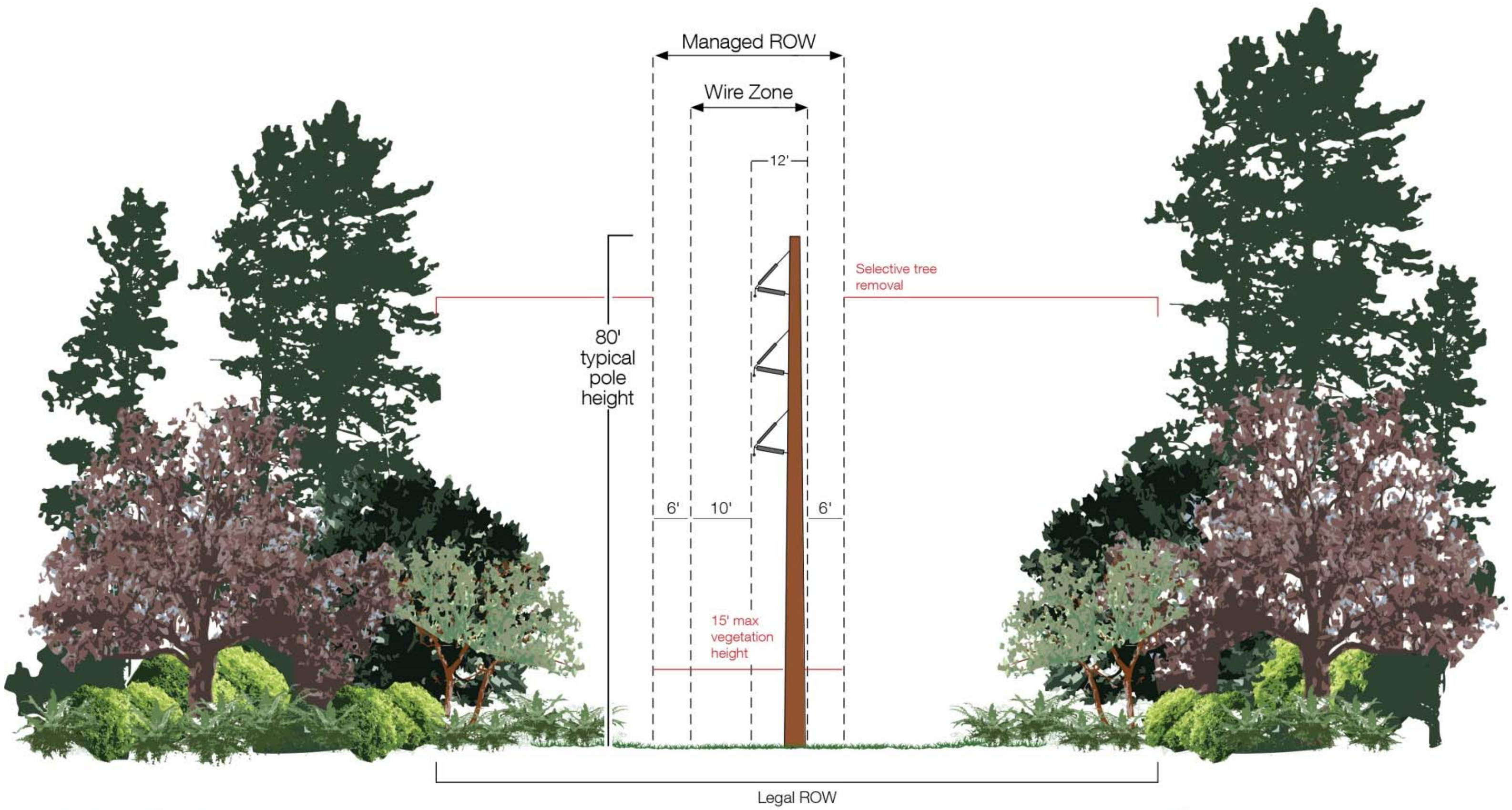
230 kV transmission lines

PSE's 230 kV transmission vegetation management standards generally requires removing trees located in the wire zone that have a mature height of more than 15 feet.

Wire Zone: Section of a utility transmission right of way extending to 10 feet from the outside transmission wire(s). Vegetation with a mature height of 15 feet or less is allowed in this zone.

Managed Right of Way (ROW): The section of a transmission right of way that extends roughly 16 feet from the outside transmission wire(s). Vegetation with a mature height of 15 feet or less is allowed in this zone.

Legal Right of Way (ROW): The full width of the easement. Maximum height of mature vegetation between the Managed ROW and Legal ROW is dependent upon tree species, tree health, and distance from the wires.



energizeEASTSIDE

PSE PUGET SOUND ENERGY

Vegetation Management Standards

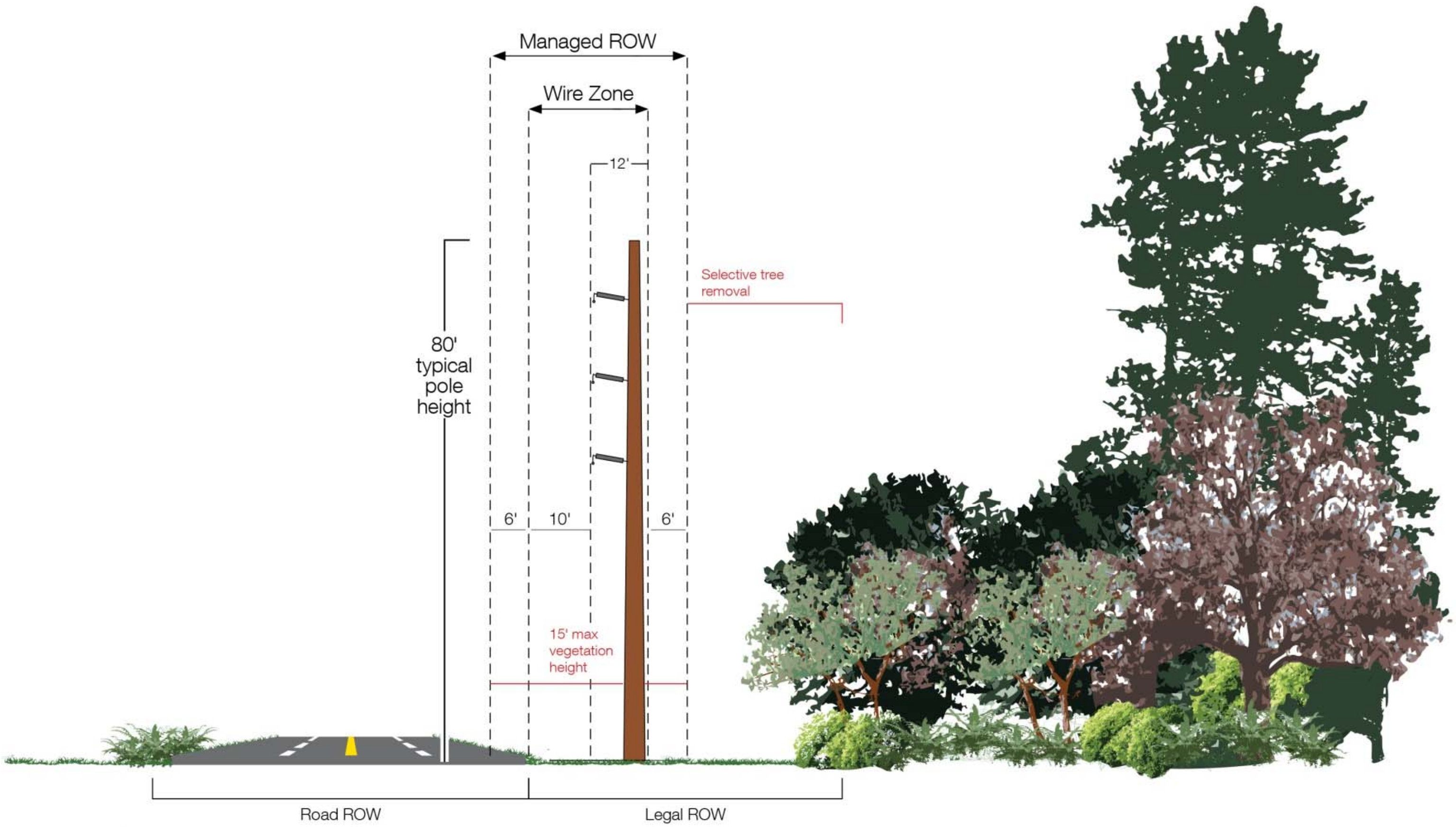
230 kV transmission lines

PSE's 230 kV transmission vegetation management standards generally requires removing trees located in the wire zone that have a mature height of more than 15 feet.

Wire Zone: Section of a utility transmission right of way extending to 10 feet from the outside transmission wire(s). Vegetation with a mature height of 15 feet or less is allowed in this zone.

Managed Right of Way (ROW): The section of a transmission right of way that extends roughly 16 feet from the outside transmission wire(s). Vegetation with a mature height of 15 feet or less is allowed in this zone.

Legal Right of Way (ROW): The full width of the easement. Maximum height of mature vegetation between the Managed ROW and Legal ROW is dependent upon tree species, tree health, and distance from the wires.



energizeEASTSIDE

PSE PUGET SOUND ENERGY

Vegetation Management Standards

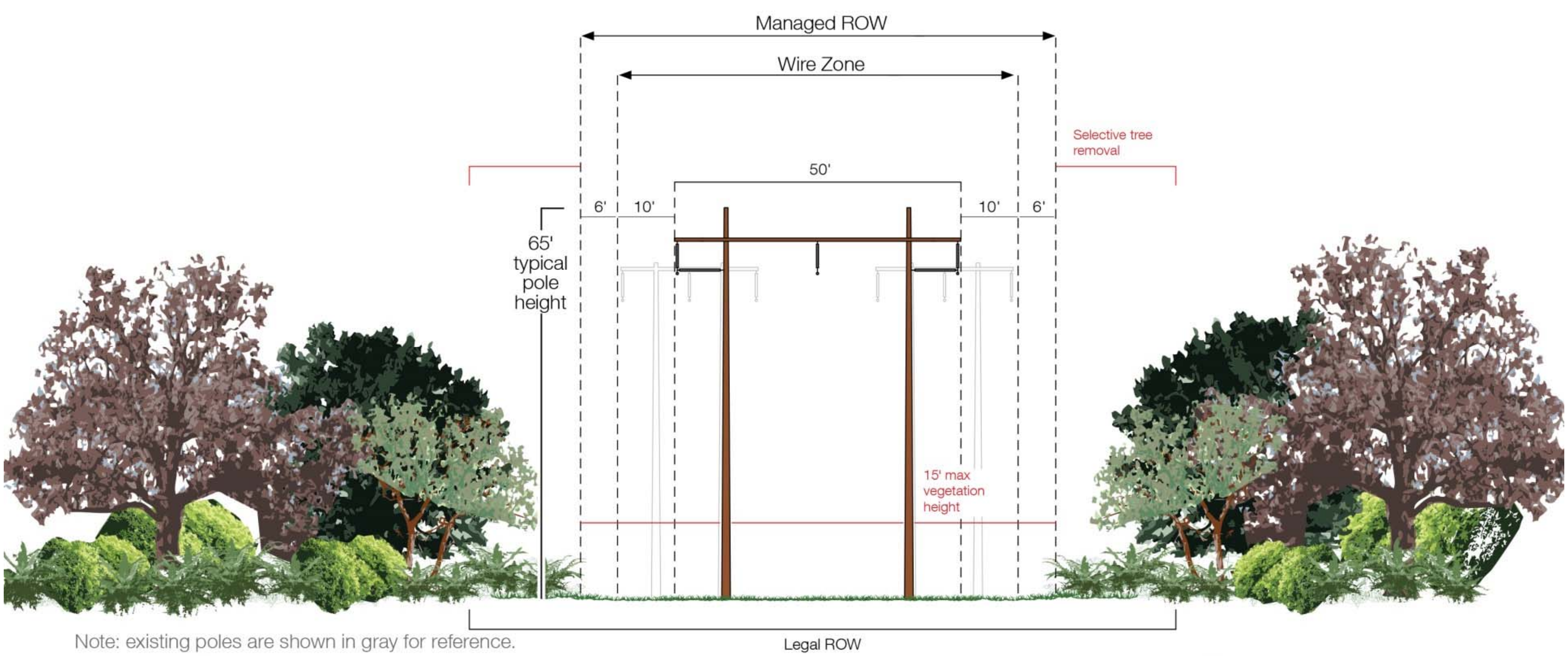
230 kV transmission lines

PSE's 230 kV transmission vegetation management standards generally requires removing trees located in the wire zone that have a mature height of more than 15 feet.

Wire Zone: Section of a utility transmission right of way extending to 10 feet from the outside transmission wire(s). Vegetation with a mature height of 15 feet or less is allowed in this zone.

Managed Right of Way (ROW): The section of a transmission right of way that extends roughly 16 feet from the outside transmission wire(s). Vegetation with a mature height of 15 feet or less is allowed in this zone.

Legal Right of Way (ROW): The full width of the easement. Maximum height of mature vegetation between the Managed ROW and Legal ROW is dependent upon tree species, tree health, and distance from the wires.



Note: existing poles are shown in gray for reference.

energizeEASTSIDE

PSE PUGET SOUND ENERGY

Vegetation Management Standards

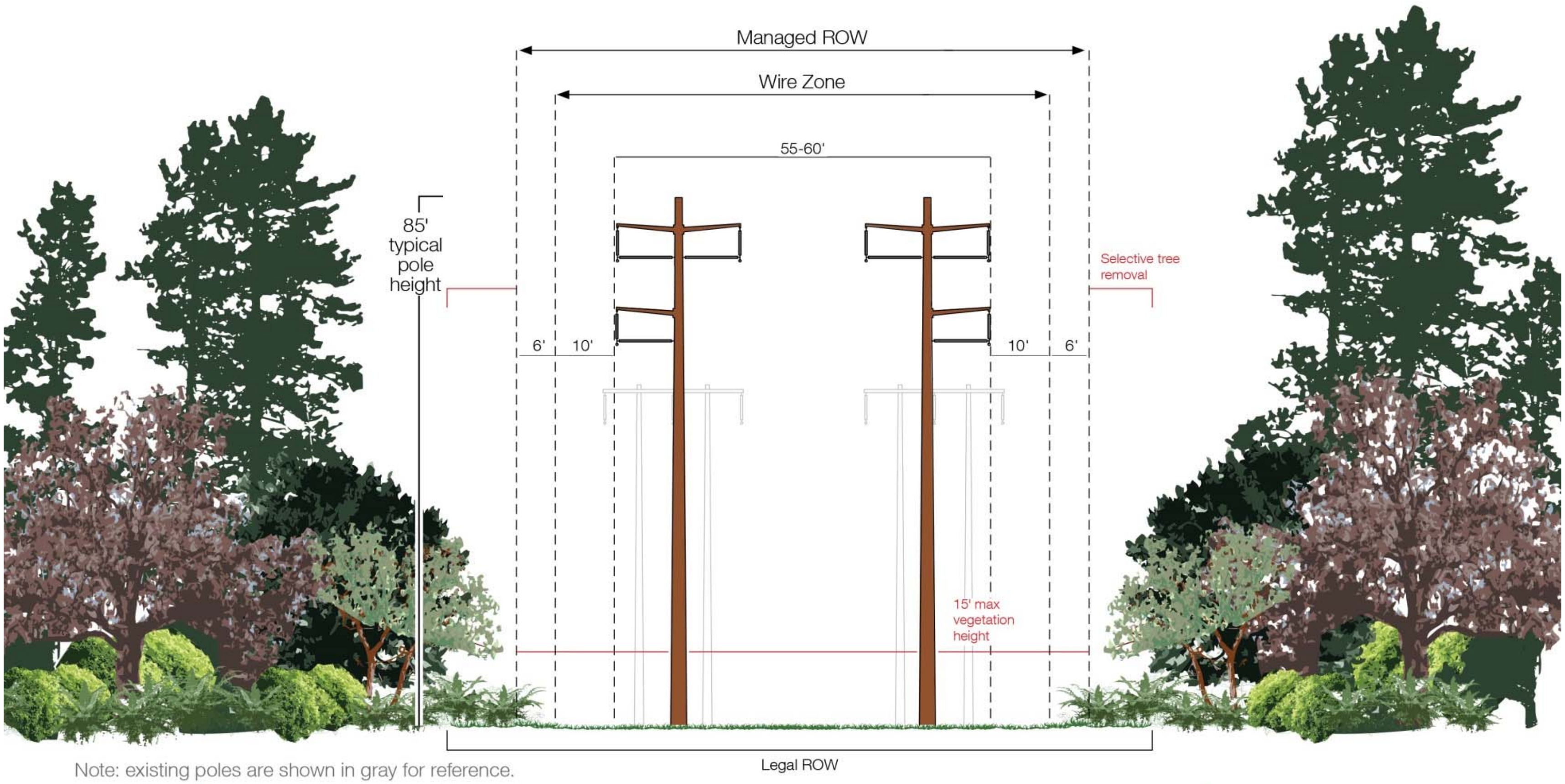
230 kV transmission lines

PSE's 230 kV transmission vegetation management standards generally requires removing trees located in the wire zone that have a mature height of more than 15 feet.

Wire Zone: Section of a utility transmission right of way extending to 10 feet from the outside transmission wire(s). Vegetation with a mature height of 15 feet or less is allowed in this zone.

Managed Right of Way (ROW): The section of a transmission right of way that extends roughly 16 feet from the outside transmission wire(s). Vegetation with a mature height of 15 feet or less is allowed in this zone.

Legal Right of Way (ROW): The full width of the easement. Maximum height of mature vegetation between the Managed ROW and Legal ROW is dependent upon tree species, tree health, and distance from the wires.



Note: existing poles are shown in gray for reference.

energizeEASTSIDE

PSE PUGET SOUND ENERGY

DSD 010909

Vegetation Management Standards

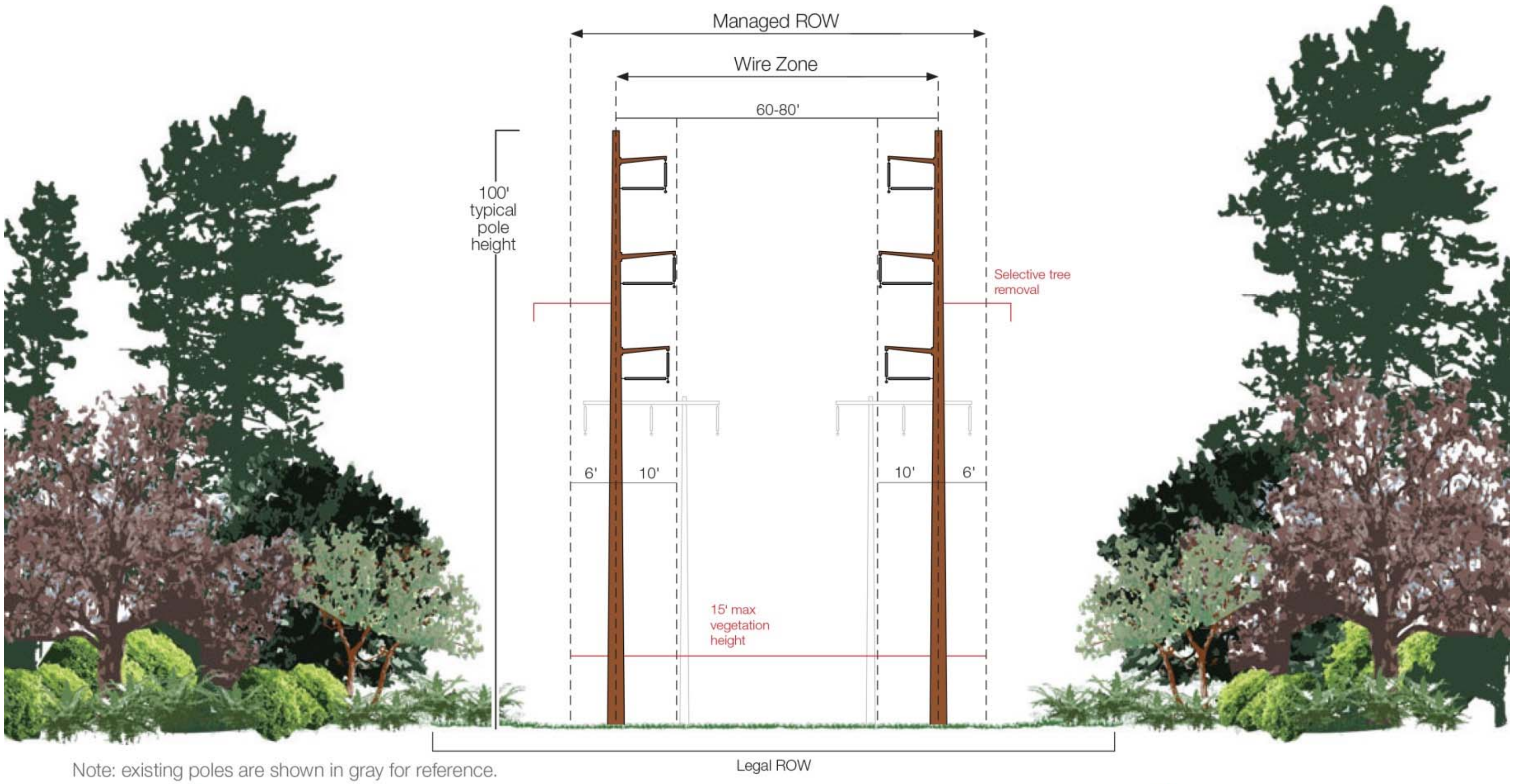
230 kV transmission lines

PSE's 230 kV transmission vegetation management standards generally requires removing trees located in the wire zone that have a mature height of more than 15 feet.

Wire Zone: Section of a utility transmission right of way extending to 10 feet from the outside transmission wire(s). Vegetation with a mature height of 15 feet or less is allowed in this zone.

Managed Right of Way (ROW): The section of a transmission right of way that extends roughly 16 feet from the outside transmission wire(s). Vegetation with a mature height of 15 feet or less is allowed in this zone.

Legal Right of Way (ROW): The full width of the easement. Maximum height of mature vegetation between the Managed ROW and Legal ROW is dependent upon tree species, tree health, and distance from the wires.



Note: existing poles are shown in gray for reference.

energizeEASTSIDE

PSE PUGET SOUND ENERGY

F

Recreation Policies

DSD 010911

APPENDIX F. RECREATION RELATED STUDY AREA POLICIES BY JURISDICTION

Policy Title	Policy Text
City of Redmond	
Utilities Policy: UT-9	Promote the efficiency of utility placement both in cost and timing through methods such as the following: Encourage joint use of utility corridors for utilities, recreation and appropriate non-motorized connections.
City of Bellevue	
Parks & Open Space System Plan Goals	Define and enhance neighborhood character by using open space as visual relief to separate and buffer between uses.
Parks and Open Space Policy: PA-30	Protect and retain, in a natural state, significant trees and vegetation in publicly and privately-dedicated greenbelt areas.
Parks and Open Space Policy: PA-37	Require a public review process for the conversion to non-recreational use of park lands and facilities.
Utilities Policy: UT-68	Encourage the use of utility corridors as non-motorized trails. The city and utility company should coordinate the acquisition, use, and enhancement of utility corridors for pedestrian, bicycle and equestrian trails and for wildlife corridors and habitat.
Utilities Policy: UT-69	Avoid, when reasonably possible, locating overhead lines in greenbelt and open spaces as identified in the Parks and Open Space System Plan.
Richards Valley Sub Area Plan Policy: S-RV-11	Protect and preserve publicly owned land. *Discussion: This policy refers to land set aside for storm drainage and detention, the right-of-way along the Lake Hills Connector, and potential links in the trail and park system.*
Bridle Trails Sub Area Plan Policy: S-BT-20	Work with utility companies to gain public non-motorized trail easements along power line corridors to complete the equestrian trail facilities plan.
City of Newcastle	
Utilities Policy: UT-P7	Where found to be safe, the City of Newcastle shall promote recreational use of utility corridors such as trails, sport courts, and similar facilities.
King County	
Objective 3.2	Invest in planning, design, and construction of new major trail corridors, the Eastside Rail Corridor and the Lake to Sound Trail.

Source: City of Bellevue, 2015; City of Newcastle, 2016a; and City of Redmond, 2015; King County, 2016
Note: City of Renton does not have relevant recreation policies.

G

Supplemental Information: Historic Resources

APPENDIX G. SUPPLEMENTAL INFORMATION: HISTORIC RESOURCES

Table G-1. Historic Register Resources

Map #	Property Name	Address	Year Built	NRHP – Recom. Eligible	NRHP – Determ. Eligible	NRHP - Listed	WHR - Listed	WHB - Listed	Desig. KC Landmark
1	Sammamish-Lakeside-Talbot Hill transmission lines #1 and #2 and the Eastside transmission corridor	Redmond to Renton	1920s	Yes	No	No	No	No	No
2	Safeway Distribution Center Truck Repair Building	1227 124th AVE NE, Bellevue	1958	No	Yes	No	No	No	No
3	Wilburton Trestle	Burlington Northern Railroad spanning Mercer Slough	1904	No	Yes	No	Yes	No	No
4	Twin Valley Dairy	410 130th Place SE	1933	Yes	Yes	No	No	Yes	No
5	Somerset Neighborhood	Bellevue	1960s	Yes	No	No	No	No	No
6	Newcastle Cemetery	SW of 69th Way off 129th Ave SE	c.1870	Yes	No	No	Yes	No	Yes
7	Greenwood Memorial Park	3401 NE 4th Street, Renton	c.1910	No	No	No	No	No	No
8	Mt. Olivet Cemetery	100 Blaine Ave NE, Renton	c.1875	Yes	No	No	No	No	No

KC = King County; NRHP = National Register of Historic Places; WHBR = Washington Heritage Barn Register; WHR = Washington Heritage Register.

Table G-2. Unevaluated Historic Resources

PIN	Year Built	Segment	Option	Pole Type	Applicable Register	Age Threshold
New Corridor						
1524059032	1961	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
1951700010	1968	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
1951700020	1968	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
1951700110	1968	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
1951700120	1968	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
1951700730	1967	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
1951700740	1967	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
1951700750	1967	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
1951700800	1968	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
2206500015	1955	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500020	1957	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500025	1956	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500030	1956	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500035	1957	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500040	1957	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500045	1956	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500185	1955	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500220	1955	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)

PIN	Year Built	Segment	Option	Pole Type	Applicable Register	Age Threshold
2206500225	1955	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500230	1955	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500235	1955	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500240	1955	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500245	1955	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500250	1955	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500255	1955	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500260	1956	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500265	1956	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500280	1956	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500285	1956	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500375	1955	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500380	1955	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500385	1955	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500390	1955	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500395	1956	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500400	1955	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500405	1955	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500410	1955	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500415	1955	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)

PIN	Year Built	Segment	Option	Pole Type	Applicable Register	Age Threshold
2206500420	1955	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500425	1955	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500430	1955	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
2206500435	1955	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
6071800730	1962	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
6071800740	1962	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
6071900130	1962	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
6071900140	1962	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
6071900150	1962	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
6071900160	1963	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
6071900170	1962	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
6071900180	1963	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
6071900190	1962	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
6071900200	1963	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
6071900210	1963	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
6071900220	1962	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
6072200350	1966	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
6072200360	1965	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
6072200410	1965	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
6072200420	1965	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)

PIN	Year Built	Segment	Option	Pole Type	Applicable Register	Age Threshold
6072200430	1965	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
6072200440	1965	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855000010	1962	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855000020	1970	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855000230	1969	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855000250	1970	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855000260	1962	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855000270	1962	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855000280	1961	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
7855000290	1968	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855000300	1967	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855000310	1962	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855000320	1961	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855000325	1961	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855000350	1967	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
7855000360	1961	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
7855000370	1968	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
7855800010	1966	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855800030	1966	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
7855800040	1967	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)

PIN	Year Built	Segment	Option	Pole Type	Applicable Register	Age Threshold
7855800050	1968	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855800060	1970	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855800070	1966	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855800080	1968	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855800090	1968	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
7855800100	1968	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
7855800120	1970	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855800130	1970	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855800140	1968	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855801540	1971	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855801570	1969	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
7855801580	1967	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855801590	1968	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855801600	1967	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855801610	1967	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
7855801660	1967	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
7855801690	1968	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855801700	1968	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7855801710	1968	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
7855801720	1972	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)

PIN	Year Built	Segment	Option	Pole Type	Applicable Register	Age Threshold
7855801730	1968	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (100)	NRHP	45 (1972)
7855801770	1963	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7856410110	1970	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
7856410120	1972	Bellevue South	Willow 1 | Willow 2 | Oak 1 | Oak 2	2 Single-Circuit Monopoles	NRHP	45 (1972)
New Corridor						
2825059066	1969	Bellevue Central	Bypass 1 | Bypass 2	1 Single-Circuit Monopole (100)	NRHP	45 (1972)
2825059085	1962	Bellevue Central	Bypass 1 | Bypass 2	1 Single-Circuit Monopole (100)	NRHP	45 (1972)
0424059039	1960	Bellevue Central	Bypass 2	1 Single-Circuit Monopole	NRHP	45 (1972)
0424059052	1943	Bellevue Central	Bypass 2	1 Single-Circuit Monopole	NRHP	45 (1972)
0424059067	1959	Bellevue Central	Bypass 2	1 Single-Circuit Monopole	NRHP	45 (1972)
0424059132	1960	Bellevue Central	Bypass 2	1 Single-Circuit Monopole	NRHP	45 (1972)
5453300031	1972	Bellevue Central	Bypass 2	1 Single-Circuit Monopole	NRHP	45 (1972)
0672100010	1968	Bellevue Central	Bypass 2	1 Single-Circuit Monopole	NRHP	45 (1972)
0924059088	1963	Bellevue South	Oak 1 | Oak 2	1 Double-Circuit Monopole (80)	NRHP	45 (1972)
0924059182	1972	Bellevue South	Oak 1 | Oak 2	1 Double-Circuit Monopole (80)	NRHP	45 (1972)
0924059228	1964	Bellevue South	Oak 1 | Oak 2	1 Double-Circuit Monopole (80)	NRHP	45 (1972)
5453300166	1969	Bellevue South	Oak 1 | Oak 2	1 Double-Circuit Monopole (80)	NRHP	45 (1972)
5453300180	1970	Bellevue South	Oak 1 | Oak 2	1 Double-Circuit Monopole (80)	NRHP	45 (1972)
1524059027	1951	Bellevue South	Willow 2	1 Single-Circuit Monopole	NRHP	45 (1972)
1524059112	1964	Bellevue South	Willow 2	1 Single-Circuit Monopole	NRHP	45 (1972)

PIN	Year Built	Segment	Option	Pole Type	Applicable Register	Age Threshold
1624059065	1943	Bellevue South	Willow 2	1 Single-Circuit Monopole	NRHP	45 (1972)
1624059104	1959	Bellevue South	Willow 2	1 Single-Circuit Monopole	NRHP	45 (1972)
1624059223	1964	Bellevue South	Willow 2	1 Single-Circuit Monopole	NRHP	45 (1972)
5603500050	1963	Bellevue South	Willow 2	1 Single-Circuit Monopole	NRHP	45 (1972)
5603500070	1959	Bellevue South	Willow 2	1 Single-Circuit Monopole	NRHP	45 (1972)
5603500110	1960	Bellevue South	Willow 2	1 Single-Circuit Monopole	NRHP	45 (1972)
5603500115	1963	Bellevue South	Willow 2	1 Single-Circuit Monopole	NRHP	45 (1972)
1624059079	1961	Bellevue South	Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (80)	NRHP	45 (1972)
1624059093	1949	Bellevue South	Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (80)	NRHP	45 (1972)
1624059168	1960	Bellevue South	Willow 2 | Oak 1 | Oak 2	1 Double-Circuit Monopole (80)	NRHP	45 (1972)

H

Supplemental Information:
EMF (Unique Uses in the Study Area)

energize EASTSIDE EIS

APPENDIX H. SUPPLEMENTAL INFORMATION: ELECTRIC AND MAGNETIC FIELDS

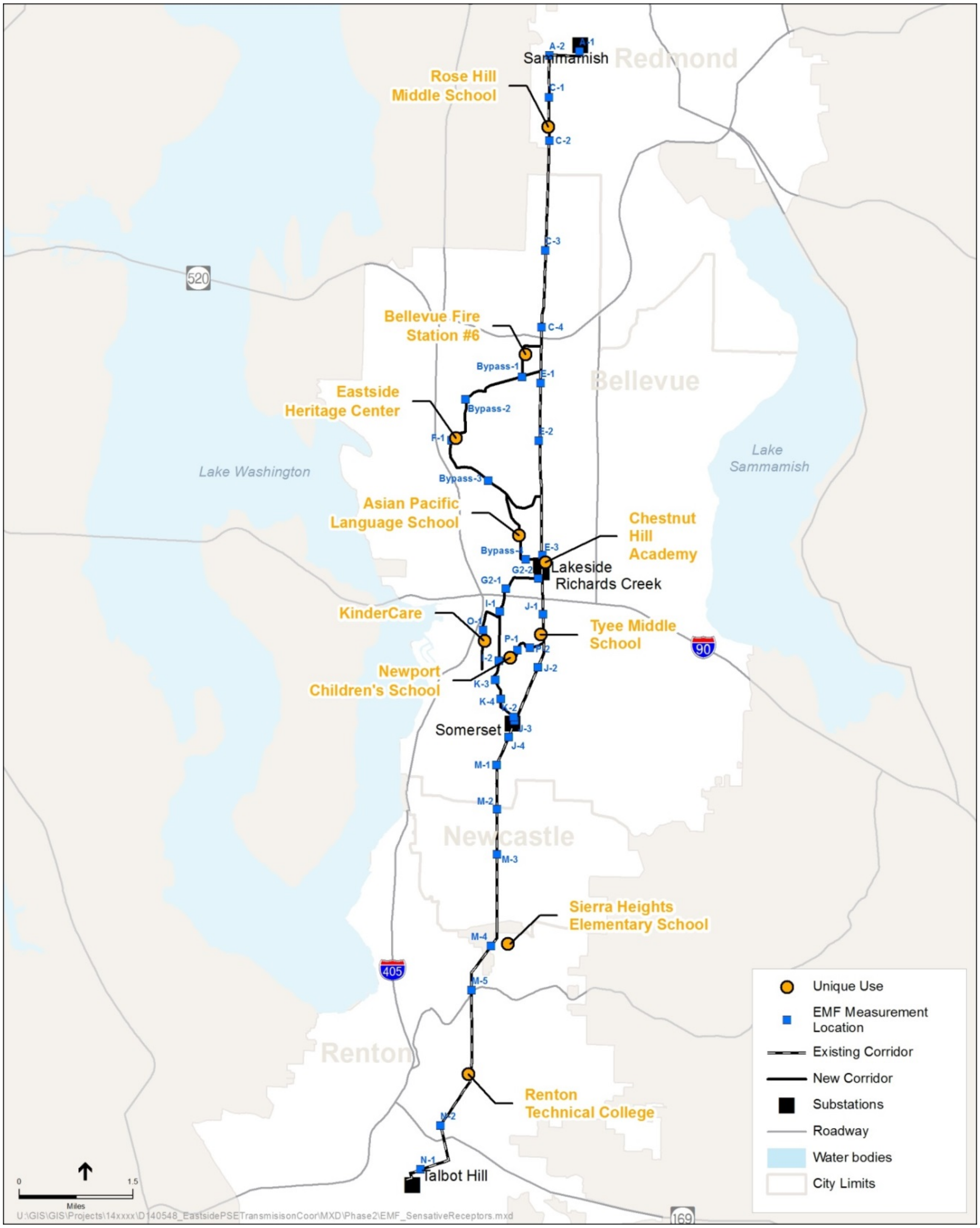


Figure H-1. Unique Uses in the EMF Study Area

Supplemental Information: Pipeline Safety

energize EASTSIDE EIS

DSD 010924

APPENDIX I. SUPPLEMENTAL INFORMATION: PIPELINE SAFETY

APPENDIX I-1: PIPELINE INCIDENTS

The two pipeline incidents that led to the passage of the Pipeline Safety Improvement Act of 2002 and the current pipeline integrity management rules are as follows:

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

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

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

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

References

NTSB (National Transportation Safety Board). 2002. Pipeline Rupture and Subsequent Fire in Bellingham, Washington, June 10, 1999. Pipeline Accident Report NTSB/PAR-02/02. Washington, D.C.

NTSB (National Transportation Safety Board). 2003. Pipeline Rupture and Subsequent Fire near Carlsbad, New Mexico, August 19, 2000. Pipeline Accident Report NTSB/PAR-03/01. Washington, D.C.

APPENDIX I-2: BP PIPELINES CONSTRUCTION REQUIREMENTS

bp

BP Pipelines (North America), Inc.
150 W. Warrenville Road
Naperville, IL 60563

BP PIPELINES (NORTH AMERICA) INC.
GENERAL CONSTRUCTION REQUIREMENTS

ROW File Reference: __________

BP Pipelines (North America) Inc. (hereinafter referred to as "BP") is committed to environmental stewardship and maintaining the safety of its employees, contractors and the general public. The pipelines BP operates transport various liquids and gasses at high pressure, and do so very safely each and every day. There are, however, potential hazards associated with construction or excavation work around pipelines. As a result of these potential hazards, and in compliance with the requirements imposed upon BP as an industry regulated by the U.S. Department of Transportation and Office of Pipeline Safety, the following list of general requirements for working on pipeline rights-of-way has been compiled.

Compliance with BP's General Construction Requirements does not guarantee BP's final approval of your project. These are considered guidelines. Each request will be assessed on a case by case basis and additional requirements specific to your project may apply.

General Safety Requirements

- **811 the national One-Call number, must be contacted at least 48 hours (2 working days)* before any construction and/or excavation activities are initiated within the pipeline right-of-way so that BP may have a representative present to ensure that there are no conflicts with the pipeline. (There is no cost to the third party contractor to use the One-Call Notification service. However, failure to utilize the One-Call service can be quite costly in terms of unnecessary risk for the contractor/excavator, their employees, innocent bystanders, personal property of others and the environment; as well as potential civil penalties and/or fines.)**

- **To have the pipeline physically located and depth verified, please contact BP's local field representative at ___________**

- **It is the responsibility of the requestor to have the pipeline location and depth added to their plans and drawings and submitted to BP for evaluation.**

- **The requestor and/or its' contractor is responsible for taking all necessary safety precautions and will be held responsible for any damages caused to the pipeline or property as a result of their work.**

****Michigan and Tennessee require 72 hours (3 working days) prior notice***

Each proposed project or development in close proximity to the pipeline is of great concern to BP due to potential impact to the operation and integrity of BP's pipelines. To avoid costly and lengthy delays, plans should be submitted to BP during the early planning stages of the project. By working with Owner/Developers, BP strives to ensure the safety of the pipeline while supporting opportunities for property development.

Page 1 of 3

Print Date: 9/16/2014
Revision Date: 8/5/2009

Subdivision Planning

- BP requests all residential and/or commercial lot lines not be placed on the right-of-way. In cases where it is not possible to locate said lot lines off of the right-of-way, lot lines shall under no circumstances be placed on the pipeline.

Excavation Specific Requirements

- No excavation or construction activity will be permitted in the vicinity of a pipeline until all appropriate communications have been made with BP's field operations and the Right-of-Way Department. A formal engineering assessment may be required.

- There shall be no excavation or backfilling within the pipeline right-of-way for any reason without a representative of BP on site giving permission.

- In some instances, excavation and other construction activities around certain pipelines can be conducted safely only when the pipeline operating pressure has been reduced. Contractors are therefore cautioned that excavation which exposes or significantly reduces the cover over a pipeline may have to be delayed until the reduced operating pressures are achieved.

General Construction Activities

- The contractor shall not be permitted to transport construction materials or equipment longitudinally over the pipeline.

- Where it is necessary for construction equipment (*i.e.*, tractors, backhoes, dump trucks, etc.) or equipment transporting construction materials to cross the pipeline, the crossing of the pipeline right-of-way shall be at, or as near to, a 90° angle as is feasible.

- To gain access to the job site, the contractor shall submit a plan indicating where construction equipment will cross the pipeline, along with the depth of the pipe at the crossings, any proposed ramping over the pipeline, together with the following specifications for the equipment: type and weight of equipment; for track equipment – track width and length; for wheeled equipment – number of axles (single or tandem axles). BP will perform a stress factor calculation to determine if the equipment can safely cross the pipeline. If crossing of the pipeline is allowed, special measures may need to be taken to ensure the integrity of the pipeline.

- No track type construction equipment shall be permitted to pivot or turn directly over the top of the pipeline.

- A scraper or pan type tractor shall not be used for removal of soil within ten feet (10') of the centerline of the pipeline. Rubber tire or small track type equipment is an acceptable alternative.

- A sheepsfoot roller shall not be used for compaction purposes within five feet (5') or directly above the centerline of the pipeline.

- No vibratory rollers shall be used within three feet (3') of the centerline of the pipeline until the compacted cover over the pipeline has reached a depth of three and one-half feet (3 ½').

Parking Lots, Roads, Driveways, Fences and Structures

- No permanent structures may be constructed on the pipeline right-of-way (permanent structures shall include, but not be limited to, swimming pools, sheds, fences, earthen berms, bike paths, etc.).

- All permanent structures shall cross the pipeline right-of-way at, or as near to, a 90° angle as is feasible. In no instance shall the angle of the crossing be less than 45°.
- There shall be a minimum vertical separation of two feet (2') between the pipeline and any underground structure.

- For proposed road crossings and driveways BP will perform a stress factor calculation to determine the amount of cover required over the pipeline. Under no circumstances shall cover be less than the following: a) five and one half feet (5.5') for all road crossings and commercial driveways, and b) three feet (3') for residential driveways.

- Proposals for parking lot construction on the pipe line right-of-way are discouraged.

- A minimum of four feet (4') of cover is required for all drainage ditches.

- No utility structures (such as, but not limited to, manholes or catch basins) shall be located over the pipeline. A minimum horizontal clearance of five feet (5') is required between the structure and the pipeline.

Landscape and Vegetation

- No trees are allowed on the pipeline right-of-way. BP may permit the installation of limited landscaping and minor shrubbery plantings with written communication and/or documentation. For a major development, landscaping plans must first be submitted in writing to BP for review and approval. Any plantings that restrict efficient aerial inspection or limit access to the easement area will be considered an interference and will not be allowed.

Foreign Line or Utility Crossings

- All foreign lines shall cross the pipeline right-of-way at, or as near to, a 90° angle as is feasible. In no instance shall the angle of the crossing be less than 45°.

- In no instance shall the foreign line be placed parallel to the pipelines right-of-way.

- The foreign line shall cross under the pipeline with at least two feet (2') of vertical separation unless the pipeline is at a prohibitive depth. If the pipeline is at a prohibitive depth, BP personnel will review and evaluate the proposed crossing location to determine if it will be feasible to allow the foreign line to cross above the pipeline.

- If the foreign line is a telecommunications cable, power cable, or similar in nature, the foreign line shall be placed in a Schedule 40 PVC conduit, or greater, for a linear distance extending ten feet (10') on either side of the centerline of the pipeline. The entire length of carrier pipe shall either be encased in concrete, or shall have a concrete cap placed on top of it.

- If the foreign line is a metallic pipeline, or similar in nature, the foreign line shall be coated with a suitable coating for a distance of at least fifty feet (50') on either side of the centerline of the pipeline. The foreign line owner, operator, or their contractor, shall install cathodic protection bonds and potential test leads to the foreign line at the crossing location and terminate the leads at an above-ground location as identified by BP's on-site representative. BP will install the test leads on BP's pipeline.

- Below-ground precautionary flagging (warning tape) shall be placed in the ditch line above the foreign line. The warning tape shall be placed approximately one foot (1') below the final surface grade/elevation. The warning tape shall extend for a linear distance of ten feet (10') on either side of the centerline of the pipeline.

If, in the exercise of the pipeline easement rights, any "Permitted Facility" is damaged, disturbed or otherwise interfered with, BP and/or the pipeline easement owner shall be held harmless from and against any and all claims of whatsoever kind and nature which might be associated with or derived from such damage, disturbance or interference.

APPENDIX I-3: OLYMPIC DATA REQUEST AND RESPONSES (FOR ENERGIZE EASTSIDE EIS PIPELINE RISK ASSESSMENT)

EDM Services, Inc.

March 29, 2017
Energize Eastside – OPL Data Request

SYSTEM SAFETY AND RISK OF UPSET – OPL DATA REQUEST

LEAK DETECTION, ISOLATION, SHUTDOWN CONTROLS

Please provide a detailed description of the existing leak detection system, automated systems, shut-down system and other controls being proposed. Specifically,

- How does the leak detection system operate and function?
- What is the sensitivity of the leak detection alarms? For example, for a given size release flow rate, how long does it take for the release to be recognized and sound an alarm? How long is the communication and poling cycle to activate shut down via the SCADA system?
- Where are valves located on either side, and within the line segment where the proposed overhead high voltage power lines located? How are these valves actuated (e.g., manual valves, remotely actuated, automatic shut-down, etc.)?
- In the event of a release on this segment, please describe how the release would be identified and how the segment would be isolated.

Olympic Pipe Line Company's ("Olympic's") Pipeline Leak Detection System (PLDS) has been in service in the Olympic control center since the early 1990's making Olympic an early adopter of computerized leak detection. PLDS coverage includes all Olympic meter bound main and lateral pipelines.

PLDS is a real-time pipeline simulation that detects and locates leaks by comparing a modeled packing rate to the measured flow balance in a defined pipeline section. When the difference exceeds a defined loss threshold, the software declares a warning. If the condition persists, an alarm is declared. Alarms are communicated through the SCADA alarm and event system. Olympic's enterprise SCADA System covers 60 sites over its roughly 400 miles of main and lateral pipeline segments. PLDS is a separate software package but is integrated with the SCADA software.

Olympic's PLDS 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").

Specific details regarding the precise type and location of Olympic's valves and related facilities within this segment is treated as confidential information not available for public disclosure due to potential security risks. See Northwest Gas Association v. WUTC, 141 Wn.App. 98, 168 P.3d 443 (2007), rev. denied, 163 Wn.2d 1049 (2008).

PIPELINE DESCRIPTION

Please provide a detailed description of the pipeline components along this corridor. For example,

Please provide a description of the supervisory control and data acquisition system (SCADA).

See above description.

EDM Services, Inc.

March 29, 2017
Energize Eastside – OPL Data Request

Please describe the operating and emergency response procedures for the following situations: electrical power loss, loss of communications, leak response, fire response, explosion response, emergency shutdown, and any other situations deemed critical.

Olympic maintains a 24-hour Emergency Hotline (1-888-271-8880). Olympic is willing to make available for review at its offices its current manual for responding to emergencies involving its pipeline and facilities. The manual is based on the Northwest Area Contingency Plan, as approved by the Washington State Department of Ecology and the federal Pipeline and Hazardous Materials Safety Administration. Olympic also is willing to make available for review at its offices its Damage Prevention Program and Procedures.

Specific details regarding Olympic's emergency response procedures are treated as confidential information not available for public disclosure due to potential security risks. See Northwest Gas Association v. WUTC, 141 Wn.App. 98, 168 P.3d 443 (2007), rev. denied, 163 Wn.2d 1049 (2008).

What, if any, measures are used which exceed the minimum requirements of 49 CFR 195 to minimize the likelihood of leaks from the major causes (e.g., external corrosion, internal corrosion, 3rd party damage, operating error, design flaw, equipment failure, weld failure, etc.)?

Olympic exceeds regulatory requirements, to varying degrees, in the majority of its integrity management programs.

What risks do you foresee during the construction and operation of the proposed high voltage power lines within this pipeline corridor? What mitigation is proposed to address these risks, both during construction and operation?

Pipelines and AC power lines often share the same utility corridor and standard mitigation measures have been developed within the industry to minimize any risks associated with construction and joint operation within the corridor.

In any situation in which construction requires excavation in close proximity to the pipeline there are a number of measures to minimize the risk of physical damage to the pipeline. To address the potential risk of damage caused by third-party excavations the Washington legislature enacted the "one-call" locator service law (RCW ch. 19.122). Under the one-call program, anyone planning to excavate near an underground utility is required to provide advance notice of the excavation by calling a designated central number. The affected utility is then notified and required to monitor the excavation work to ensure no damage is done. Consistent with these requirements, if a project is within 100 feet of Olympic's pipeline, its Damage Prevention Team will meet with the construction team onsite at the start of the project and weekly thereafter to reinforce the importance of following established safety protocols. The Damage Prevention Team also will be on-site to monitor the excavation project any time equipment with the ability to reach within 10 feet of the pipeline is being used. While the relevant federal regulations generally require at least 12 inches of clearance between a pipeline and any underground structures,[1] Olympic's practice is to double the federal standard and ensure at least 24 inches of clearance.

---

[1] The relevant regulation, 49 CFR 195.250 (Clearance between pipe and underground structures) provides that:

DSD 010931

The risk of damage from imposed weight loading during construction can also be reduced through monitoring by Olympic's Damage Prevention Team, as well as engineering review of any planned equipment crossings prior to commencement of work.

There are also a number of proven practices and guidelines used by the industry to successfully mitigate potential AC interference-related-corrosion on pipelines. Olympic has a program to actively monitor and, where necessary, mitigate the impact of AC interference on its pipelines. As part of this program, AC interference is currently monitored in the segment of the pipeline at issue. AC grounding systems are commonly installed in connection with power transmission towers to safely dissipate any energy to ground and, as the project plans evolve, Olympic will undertake an engineering analysis to assess the necessity for installation of similar systems along the pipeline.

What is the wall thickness(s), pipe grade(s), diameter, etc. of this segment(s)?

The Allen to Renton 16" line typical dimensions are 0.312 wall thickness, API 5L X52 grade, with an outside diameter of 16". There are small sections of re-routes that may have an increased wall thickness or a higher grade.

The Allen to Renton 20" line typical dimensions are 0.250 wall thickness, API 5L X52 grade, with an outside diameter of 20". There are small sections of re-routes that may have an increased wall thickness or a higher grade.

When was the pipeline(s) originally constructed?

The Allen to Renton 16" line was constructed in 1965.

The Allen to Renton 20" line was constructed in 1972 to 1974.

How is this line(s) cathodically protected?

The lines are cathodically protected primarily with overlapping impressed current systems.

What type of external coating(s) is installed?

The majority of the Allen to Renton 16" and 20" pipelines are coated with coal tar enamel.

When was this line(s) last hydrostatically tested? What was the test pressure? When is the next hydrotest scheduled?

Allen to Renton 16" - 2001. Tested to 1806 psi.

Allen to Renton 20" - 1974. Tested to 1157 psi.

Any pipe installed underground must have at least 12 inches (305 millimeters) of clearance between the outside of the pipe and the extremity of any other underground structure, except that for drainage tile the minimum clearance may be less than 12 inches (305 millimeters) but not less than 2 inches (51 millimeters). However, where 12 inches (305 millimeters) of clearance is impracticable, the clearance may be reduced if adequate provisions are made for corrosion control.

There are no scheduled hydrotests since we use internal inspection tools to monitor the integrity of the pipeline.

When was this line(s) last internally inspected? What type of inspection tool(s) was employed? When is the next internal inspection scheduled?

The last inspections of the Allen to Renton 16" and 20" pipelines were in April of 2014 using a high resolution deformation and hi resolution magnetic flux leakage tool. The next planned inspection is in early 2019.

What is the normal (excluding line crossing and special features) depth of cover?

Typical depth of cover is 3' to 4'.

What percentage of the circumferential welds were radiographically inspected during original construction?

Inspections were conducted per industry requirements at the time of original construction. Radiographic inspection of circumferential welds was not industry practice at that time. Both pipeline segments were subjected to post construction hydrotests that were at least 1.25 times MOP.

Does this line segment contain any ERW pipe? If so, please provide year of manufacture and other data?

There is no ERW pipe installed within the segment at issue.

OPERATION

Please describe the normally operating parameters, including:

Please provide a list of the refined petroleum products normally transported through this pipeline(s).

Gasoline, diesel, and jet fuel.

How often is the pipeline(s) operational (e.g., percentage of the time)?

Over 95%

When in operation, what is the normal operating pressure?

Allen to Renton 16" - 500 to 800 psi

Allen to Renton 20" - 300 to 500 psi

What is the maximum operating pressure (MOP)?

Allen to Renton 16" - 1265 psi maximum discharge pressure from Woodinville Station.

Allen to Renton 20" - 928 psi maximum discharge pressure from Allen Station.

When the line is not operational, what is the pressure within this segment?

Allen to Renton 16" - 300 - 500 psi

Allen to Renton 20" - 300 - 500 psi

EMERGENCY RESPONSE

What is the anticipated range of response times to various locations along this pipeline segment?

Response times will vary depending not only on location, but also by type of event and traffic conditions. Access to the pipeline along the relevant segment is quite good, which can significantly reduce response times. Members of Olympic's Damage Prevention Team are located nearby at all times and are able to respond to certain types of events as quickly as traffic permits. During normal working hours, Olympic has qualified personnel located to the North and South of this segment, at its facilities in Woodinville and Renton, respectively. Outside of normal working hours, Olympic has on-call personnel who live in close proximity to this segment. Finally, Olympic has contracted with the National Response Corporation – Environmental Services (NRCES) to respond anywhere along its pipeline system within 2 hours.

Please describe the emergency response measures to be employed should a leak occur where the refined petroleum product could migrate beyond the corridor.

Olympic maintains a 24-hour Emergency Hotline (1-888-271-8880). Olympic is willing to make available for review at its offices its current manual for responding to emergencies involving its pipeline and facilities. The manual is based on the Northwest Area Contingency Plan, as approved by the Washington State Department of Ecology and the federal Pipeline and Hazardous Materials Safety Administration. Olympic also is willing to make available for review at its offices its Damage Prevention Program and Procedures.

Specific details regarding Olympic's emergency response procedures are treated as confidential information not available for public disclosure due to potential security risks. See Northwest Gas Association v. WUTC, 141 Wn.App. 98, 168 P.3d 443 (2007), rev. denied, 163 Wn.2d 1049 (2008).

Please describe the emergency response procedures to be employed should an evacuation become necessary.

In the event of an evacuation on the pipeline right-of-way, local first responders and the Olympic Pipeline team would set up exclusion zones. Door to door notifications would be made to impacted homeowners. Air monitoring would be utilized and documented throughout the entirety of the incident to ensure the exclusion zones are properly identified in accordance with the conditions of the day (wind speed, direction, etc.).

ALIGNMENT SHEETS

May need to request pipeline alignment drawings for the existing OPL pipeline(s) within the overhead power line corridor to support the quantitative risk assessment. If determined needed, we will provide a follow-up request specifying for which segments.

APPENDIX I-4: PSE ENERGIZE EASTSIDE CORRIDOR SAFETY FAQ SHEET

PSE PUGET SOUND ENERGY

energize**EASTSIDE**

corridor safety

September 2016

Safety is PSE's top priority

As the largest natural gas utility in Washington, we understand pipeline safety concerns and employ safe procedures when working near pipelines. PSE approaches every project – from the smallest natural gas service installation to the largest transmission line – with the same priority: the safety of our customers, the communities we work in, and our fellow co-workers.

For Energize Eastside, PSE will continue to follow all safety regulations to maintain safety in the corridor. This includes building and operating the project to meet strict federal standards that govern both pipeline and transmission line infrastructure.

PSE and Olympic's infrastructure have safely coexisted in the corridor for decades

The backbone of our transmission system on the Eastside shares a utility corridor with Olympic Pipe Line Company's (Olympic) underground petroleum pipelines. It's been this way for more than 40 years, and co-locating utilities is encouraged by many Eastside jurisdictions.

PSE and Olympic working together

Both PSE and Olympic have a mutual interest in the continued protection and safe operation of facilities in the shared utility corridor.

We have a long history of working closely together. This close coordination ensures mutual safety of our infrastructure and of neighbors adjacent to and near the corridor.

Focus on safety in design, construction and operations

Safety is critical to Energize Eastside's design. Newer technology and strict safety requirements allow PSE to build to the highest safety standards, which our design will meet or exceed. Our engineers are rigorously

In 2016, we coordinated with Olympic on the work plan and safe construction practices to replace two poles in Newcastle.

analyzing the design for Energize Eastside to ensure safe construction and operation of the line within the shared corridor.

We're working with DNV-GL, a leading national expert in pipeline safety, to assist with developing design parameters to help ensure the safe operation of the co-located utilities. As we get to construction, our engineers will work closely with Olympic to develop a project-specific safe construction plan. Construction will entail installation of new, longer-lasting equipment, and fewer poles that will typically be farther away from the pipeline than the poles are today.

Once construction ends, PSE and Olympic's safety coordination continues through day-to-day operations and ongoing communication.

Frequently Asked Questions

What steps will PSE and Olympic take during and after construction to keep me and my family safe?

Our engineers will work closely with Olympic on a safe construction plan that may include:

- Having an Olympic representative on-site to monitor construction activities near the pipeline

DSD 010935

- Installing temporary fencing or other markers around the pipeline area
- Placing a temporary protective cover (e.g., steel plates) over the pipeline to mitigate excessive load from heavy equipment
- Using specialized equipment or hand-digging within close proximity to the pipeline

Having worked with Olympic for decades, PSE knows firsthand that Olympic employs stringent standard operating practices, including:

- Using a cathodic protection system to suppress corrosion
- Meeting with Olympic's Damage Prevention Team on site at the start of the project and weekly thereafter if a project is within 100 feet of the pipeline to reinforce established safety protocols
- Requiring a Damage Prevention Team to be on site during any excavation within 10 feet of the pipeline

Once construction ends, PSE and Olympic's safety coordination will continue through day-to-day operations. This includes ongoing communication to keep each other informed of activity in the corridor. Additionally, Olympic regularly inspects its pipeline and monitors its operation 24 hours a day.

Who regulates PSE and Olympic to ensure they are implementing safety procedures correctly?

Interstate pipelines, whether they transport natural gas or liquid petroleum products, are held to both state and federal safety regulations administered by the:

- Federal Energy Regulatory Commission
- US Department of Transportation's Pipeline and Hazardous Materials Safety Administration
- Washington State Department of Transportation
- Washington Utilities and Transportation Commission

Are there safeguards in place if extreme weather such as earthquakes or lightning affect the corridor?

As with all of our projects, our design will meet or exceed industry standards and address seismic activity, high winds, ice and lightning. For example, to protect against lightning, our designs call for grounding the poles and using shield wires to disperse current safely and to avoid affecting the pipelines.

Can you give more examples of PSE and Olympic working together?

- In 2007 and 2008, PSE worked with Olympic to replace more than 130 poles and reframe more than 200 poles in this corridor and others.
- In 2015, PSE successfully completed more than 50 geotechnical investigation borings within the existing corridor. Half of these geotechnical borings took place in the vicinity of the Olympic pipeline.
- In June 2016, we replaced two poles adjacent to the pipelines to address an imminent safety concern created by the construction of new apartments in Newcastle. We met onsite with Olympic's Damage Prevention Team to review construction activities to help ensure safe construction practices were followed.

Interested in learning more?

- Learn more about Energize Eastside and pipeline safety at **pse.com/energizeeastside**
- For information about Olympic's safety practices, visit the Pipeline and Community Safety page at **bp.com/en_us/bp-us/what-we-do/bp-pipelines/pipeline-and-community-safety.html**

Thank you for your interest in Energize Eastside.

pse.com/energizeeastside 1-800-548-2614 energizeeastside@pse.com

APPENDIX I-5: ENERGIZE EASTSIDE EIS PIPELINE SAFETY TECHNICAL REPORT (PREPARED BY EDM SERVICES)

Energize Eastside EIS

Pipeline Safety Technical Report

Prepared for

Environmental Science Associates (ESA)

EDM Services, Inc.
4100 Guardian Street, Suite 250
Simi Valley, California 93063
Web Site Address: edmsvc.com
Phone: (805) 527-3300
FAX: (805) 583-1607
EDM Services Job Number 16-136-1982

Table of Contents

DSD 010939

DSD 010940

DSD 010941

ENERGIZE EASTSIDE EIS – PIPELINE SAFETY AND RISK OF UPSET

Introduction and General Approach

The purpose of this report is to present the results of a risk assessment that has been performed to estimate the risks posed to the public from the existing Olympic Pipeline Company (OPL) pipelines. This report also presents and estimate of the potential additional risks that could be posed where the proposed Energize Eastside overhead high voltage alternating current (HVAC) transmission line would be collocated with the OPL pipeline(s). The general approach used to conduct this risk assessment is summarized below:

1. Information was gathered regarding the existing 16-inch and 20-inch diameter OPL pipelines.
2. Historical unintentional release data was obtained from the United States Department of Transportation (USDOT) for similar refined petroleum product transmission pipelines. This included the USDOT database of all hazardous liquid pipeline incidents that have occurred since January 1, 2010. These data are presented in Section 5.0, Baseline Data, of this Report. These data were analyzed to develop the following estimates:
   - Frequency of unintentional releases,
   - Frequency of public injuries and fatalities,
   - Spill size distribution,
   - Causes of the unintentional releases, and the
   - Likelihood of fires or explosions following an unintentional release.
3. Using the above historical and OPL unintentional release data, high level estimates of the likelihood of various size releases, fires, and public fatalities resulting from unintentional releases from OPL's pipelines were developed. This analysis is included in Section 6.0, Qualitative Aggregate Risk Assessment, of this Report.
4. Using the actual pipeline operating parameters, release modeling was performed to evaluate the range of potential impacts to the public from fires, explosions and flash fires. The results of this release modeling are presented in Section 7.0, Release Modeling Results, of this Report.
5. Using the above data, the conditional probabilities for each of the following items were estimated. The development of these estimates is presented in Section 8.0, Conditional Probabilities, of this Report.
   - Probability of the pipelines carrying diesel, jet fuel, or gasoline, since the potential risks to the public differ somewhat for each;
   - Percentage of the time that the OPL pipeline(s) would be operational;
   - Probability of various size unintentional releases from the OPL pipeline(s);
   - Probability of fires or explosions following an unintentional release;
   - Probability of fatal injuries following a fire or explosion.

6. The increased risks of an unintentional release from the OPL pipelines due to the proposed Energize Eastside overhead high voltage alternative current (HVAC) transmission line were estimated by reviewing a number of publications and reports.
7. An individual risk assessment has been conducted. This assessment estimates the likelihood of a public fatality to an individual exposed to the potential hazards 24 hours per day, 365 days per year. The results of this analysis are presented in Section 9.0, Individual Risk Assessment, of this report.
8. A societal risk assessment has been conducted. This assessment estimates the probability that a specified number of people could be fatally injured following an unintentional release. This assessment used three different population densities in order to estimate the number of individuals that could be fatally injured. The results of this analysis are presented in Section 10.0, Societal Risk Assessment, of this Report.
9. Risk reduction measures are presented in Section 11.0 of this Report. These measures could be employed to reduce the likelihood and severity of unintentional releases from the OPL pipelines.

1.0 Environmental Setting

1.1 Existing Olympic Pipeline (OPL) Company Pipelines

Much of the HVAC electrical transmission line corridor contains either one, or two refined petroleum product pipelines. These pipelines transport gasoline, diesel and jet fuel[1] and are owned by OPL. This Technical Report will present the life safety risks posed by these pipelines in three different situations:

- Where the pipeline(s) operate in a corridor without any overhead HVAC electrical transmission line,
- Where the pipeline(s) are collocated within the corridor with the existing overhead HVAC electrical transmission line, and
- Where the pipeline(s) would be collocated within the corridor with the proposed overhead HVAC electrical transmission line.

1.1.1 16-inch outside diameter, OPL Allen to Renton Pipeline

The 16-inch outside diameter, Allen to Renton pipeline has the following parameters (Olympic Pipeline):

- This pipeline is constructed of API 5L X52 grade, 0.312-inch wall thickness[2].
- The length of this line which is collocated with the overhead HVAC line is 62,906-feet.
- This pipeline was originally constructed in 1965. After initial construction, this pipeline was subjected to a hydrostatic test that was at least 1.25 times the maximum operating pressure.
- The majority of this line is externally coated with coal tar enamel and is protected by an impressed current cathodic protection system.
- This line was most recently hydrostatically tested in 2001, to a test pressure of 1,806 psi (89% SMYS)[3].
- The normal operating pressure is 500 to 800 psi within the electrical transmission corridor.
- This pipeline was internally inspected using a high resolution deformation and high resolution magnetic flux leakage tool in April 2014. The next planned internal inspection is early 2019.
- The normal flow rate is approximately 5,400 barrels per hour (228,000 gallons per hour).
- This pipeline ships the following commodities: 18% Diesel, 37% Jet Fuel, and 45% Gasolines.
- The typical depth of cover is three to four feet.
- The pipeline does not contain any electric resistance welded pipe (ERW) within the electrical transmission corridor under analysis.[4]

[1] In this Report, these hazardous liquids are also called refined petroleum products.
[2] Since initial construction, there have been some relatively short pipe replacements (re-routes) which may have an increased wall thickness and/or higher grade pipe.
[3] See Section 12.1 for a list of acronyms used in this Report.
[4] There is significant evidence that inferior electric-resistance welded (ERW) pipe was manufactured and installed, especially before 1970; some of this pipe has yielded increased frequencies of pipeline incidents.

1.1.2 20-inch outside diameter, OPL Allen to Renton Pipeline

The 20-inch outside diameter, Allen to Renton pipeline has the following parameters (Olympic Pipeline):

- This pipeline is constructed of API 5L X52 grade, 0.250-inch wall thickness[5].
- The length of this line which is collocated with the overhead HVAC line is 68,122-feet.
- This pipeline was originally constructed in 1972 to 1974.
- The majority of this line is externally coated with coal tar enamel and is protected by an impressed current cathodic protection system.
- This line was most recently hydrostatically tested in 2001, to a test pressure of 1,157 psi (89% SMYS).
- The normal operating pressure is 300 to 500 psi within the electrical transmission corridor.
- This pipeline was internally inspected using a high resolution deformation and high resolution magnetic flux leakage tool in April 2014. The next planned internal inspection is early 2019.
- The normal flow rate is approximately 7,900 barrels per hour (333,000 gallons per hour).
- This pipeline ships the following commodities: 40% Diesel, 3% Jet Fuel, and 57% Gasolines.
- The typical depth of cover is three to four feet.
- The pipeline does not contain any electric resistance welded pipe (ERW) within the electrical transmission corridor under analysis.

1.1.3 OPL Leak Detection System

Olympic Pipe Line Company's (OPL's) Pipeline Leak Detection System (PLDS) has been in service in the OPL control center since the early 1990's. PLDS is a real-time pipeline simulation that detects and locates leaks by comparing the volume in and the volume out, with volume adjustments based on pressure (compression of the pipe contents) and predicted pressures within a defined pipeline section. When the difference exceeds a defined loss threshold, the software provides a warning to the operator. If the condition persists, an alarm is provided. Alarms are communicated through the SCADA alarm and event system. OPL's enterprise SCADA System covers 60 sites over its roughly 400 miles of main and lateral pipeline segments, including the pipe segments under consideration. PLDS is a separate software package but is integrated with the SCADA software.

OPL's PLDS meets or exceeds State and Federal requirements for pipeline leak detection including WAC 480-75-300[6,7].

---

[5] Since initial construction, there have been some relatively short pipe replacements (re-routes) which may have an increased wall thickness and/or higher grade pipe.

[6] Leak detection systems must be capable of detecting an eight percent (8%) of maximum flow leak within fifteen (15) minutes or less.

[7] OPL pipeline, leak detection system, and emergency response data were provided by OPL in their July 25, 2016 response to our data request.

OPL did not provide specific details regarding the precise type and location of their mainline block valves and related facilities within this segment. OPL treats these data as confidential information which is not available for public disclosure due to potential security risks[8].

1.1.4 OPL Emergency Response

OPL maintains a 24-hour Emergency Hotline (1-888-271-8880). OPL's current manual for responding to emergencies is based on the Northwest Area Contingency Plan, as approved by the Washington State Department of Ecology and the Federal Pipeline and Hazardous Materials Safety Administration (PHMSA). OPL considers specific details regarding OPL's emergency response procedures as confidential information not available for public disclosure due to potential security risks[8].

In the event of an unintentional release, response times would vary depending on the incident location and traffic conditions, among other factors. Access to the pipeline along the relevant segment is relatively good, which can significantly reduce response times. Members of OPL's Damage Prevention Team are located nearby at all times and are able to respond to certain types of events quickly. During normal working hours, OPL has qualified personnel located to the North and South of this segment, at its facilities in Woodinville and Renton, Washington. Outside of normal working hours, OPL has on-call personnel who live in close proximity to this segment. In addition, OPL has contracted with the National Response Corporation – Environmental Services (NRCES) to respond anywhere along its pipeline system within two hours.

In the event of an evacuation along the pipeline right-of-way, local first responders and the OPL employees would set up exclusion zones. Door to door notifications would be made to impacted homeowners. Air monitoring equipment would be utilized and the conditions would be documented throughout the incident to ensure that the exclusion zones are properly identified in accordance with atmospheric conditions (e.g., wind speed, direction, etc.).

1.1.5 OPL Identified Hazards Presented by Proximity to Proposed Overhead High Voltage Transmission Lines

This section describes the existing OPL procedures that address the OPL identified hazards posed by the collocated overhead HVAC transmission lines. In Section 5.4, these and other potential hazards will be discussed further.

Excavation Activities

Any situation in which construction requires excavation in close proximity to a pipeline places the pipeline at risk of damage by the construction equipment. There are a number of mitigation measures which reduce the risk of physical damage to the pipeline. To minimize the likelihood of a pipeline being damaged by excavation activities, the Washington State legislature enacted the

[8] See Northwest Gas Association v. WUTC, 141 Wn. App. 98, 168 P.3d 443 (2007), rev. denied, 163 Wn.2d 1049 (2008).

"one-call" locator service law[9]. Under the one-call program, anyone planning to excavate near an underground utility is required to provide advance notice of the excavation by calling a designated central number. The affected utility is then notified and required to monitor the excavation work to ensure no damage is done.

Consistent with these requirements, if a project is within 100 feet of OPL's pipeline, the OPL Damage Prevention Team meets with the construction team at the construction site at the start of the project and weekly thereafter to reinforce the importance of following established safety protocols. The OPL Damage Prevention Team is also on-site to monitor the excavation project any time equipment with the ability to reach within 10-feet of the pipeline is being used. While the relevant federal regulations generally require at least 12-inches of clearance between a pipeline and any underground structures, OPL's practice is to double the federal standard and ensure there is at least 24-inches of clearance between OPL pipelines and any underground structure. In compliance with the federal regulations, OPL also installs and maintains right-of-way signs along the corridor and conducts regular aerial and/or ground based right-of-way patrols.

Surcharge Loading

There is also some risk of damage to a pipeline from weight of equipment working over an operating pipeline. The OPL Damage Prevention Team mitigates this risk during construction by monitoring construction activities. In addition, OPL conducts an engineering review of any planned equipment crossings prior to commencement of work.

Electrical Interference

Overhead HVAC lines can induce a current which can interfere with cathodic protection systems. This can increase the frequency of external corrosion caused unintentional releases.

There are a number of proven practices and guidelines that can be employed to mitigate the potential for alternating current (AC) interference related corrosion of the pipelines. OPL employs a program to actively monitor and, where necessary, mitigate the impact of AC interference. As part of this program, AC interference is currently monitored along this corridor. AC grounding systems are commonly installed in connection with power transmission towers to safely dissipate any energy to ground. OPL also plans to undertake an engineering analysis to assess the necessity for installation of similar systems along the pipeline.

1.2 Refined Petroleum Products Pipeline Public Risks

Unintentional releases of refined petroleum products from the existing pipelines could pose risks to human health and safety. For example, refined petroleum products could be released from a leak or rupture in one of the pipelines. If an ignition source was present, a fire and/or explosion could occur, resulting in possible injuries and/or deaths.

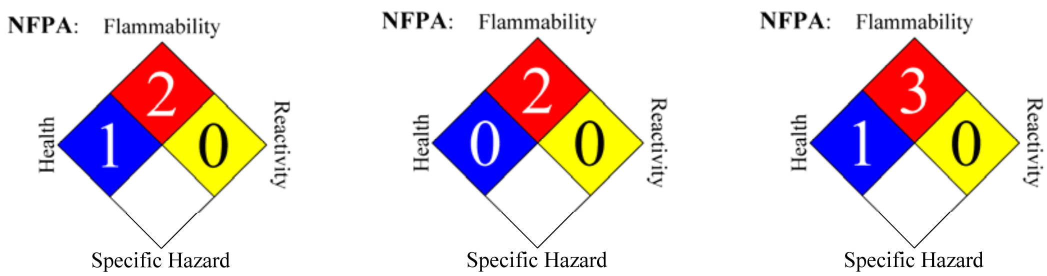
[9] Chapter 19.122, Revised Code of Washington (RCW) – Underground Utilities

Additionally, an unintentional release could present an environmental hazard. For example, soil could be impacted, waterways could be degraded, and wildlife and vegetation could be jeopardized. This Report presents the life safety risks posed to the public.

1.3 Refined Petroleum Products Characteristics

The OPL pipelines transport jet fuel, gasolines, and diesel, the characteristics of which are described in the following sections. The National Fire Protection Association (NFPA) rating sign for each of these fuels is depicted below. For each hazard, the severity ranges from 0 (no hazard) to 4 (health - lethal health hazard, flammability - will vaporize and readily burn at normal temperatures, and reactivity - may explode at normal temperatures and pressures).

Figure 1.3-1 NFPA Rating Sign for Jet, Diesel, and Gasoline Fuels Respectively



1.3.1 Jet Fuel[10]

Jet Fuel (aviation turbine fuel) is comprised primarily of hydrocarbons[11] (e.g., paraffins, naphthenes, olefins, and aromatics). It is colorless to clear light yellow and has a gasoline and/or kerosene-like odor. It may cause eye and skin irritation. Inhalation can produce headaches, dizziness, drowsiness, and nausea, lassitude, weariness, and over excitation. Exposure to very high levels can result in unconsciousness and death.

Kerosene-type jet fuel has thermal stability and a relatively high flashpoint. The flash point[12] is approximately 100°F; the auto-ignition temperature is between 410 - 475°F, depending on fuel type and additives[13]. Its upper explosive limit is 8.0% by volume and the lower explosive limit is 0.7%[14].

[10] See ASTM D1655 for jet fuel specifications.
[11] Organic compounds composed entirely of carbon and hydrogen atoms.
[12] The flash point is the lowest temperature at which the liquid vaporizes and is therefore able to ignite. ASTM D93 is used to determine this threshold.
[13] The auto-ignition temperature is affected by the chemical properties. ASTM E659 defines the standard method for determining the auto-ignition temperature.
[14] Flammable liquid only burns in its gaseous state. If the ratio of jet fuel to air is greater than about 8.0%, the mixture is too rich to burn; if it is less than 0.7%, the mixture is to lean to burn.

1.3.2 Diesel Fuel[15]

Diesel Fuel is similar to Jet Fuel. It is comprised primarily of hydrocarbons. It is colorless to brown and has a kerosene odor. It may cause eye and skin irritation.

Diesel Fuel has a flash point between 100 and 130°F, and an auto-ignition temperature between 351 - 624°F, depending on the type and the additives. Its upper explosive limit is 6.5% by volume and its lower explosive limit is 0.6%.

1.3.3 Gasoline[16]

Gasoline is a complex mixture of hydrocarbons. It is colorless to light yellow and has a strong gasoline and/or kerosene odor. It may cause eye and skin irritation. Inhalation of concentrations over 50 parts per million (ppm) can produce headaches, dizziness, drowsiness, and nausea, lassitude, weariness, over excitation. Exposure to very high levels can result in unconsciousness and death.

Gasoline is more volatile[17] than the other fuels described above, and is described as flammable[18] by the National Fire Protection Association (NFPA).

Unleaded gasoline has a relatively low flash point of -45°F and an auto-ignition temperature of approximately 480°F, depending on the percent ethanol and other additives. The higher the octane number the higher the auto-ignition temperature. Its upper explosive limit is 8.0% by volume and its lower explosive limit is 1.0%.

1.4 Major Pipeline Incident Summaries

Although transportation of hazardous liquids and natural gas has proven to be a very safe mode of transportation[19], there have been a few significant pipeline incidents. Five (5) of these incidents have resulted in changes, and proposed changes, to the Federal pipeline regulations which should further improve pipeline safety.

1.4.1 San Bernardino, California, May 25, 1989

On May 12, 1989, a Southern Pacific Transportation Company freight train derailed in San Bernardino, California. On May 25, 1989, 13 days later, a regulated interstate petroleum products pipeline ruptured. The National Transportation Safety Board summarized this incident in their

[15] See ASTM D975 for diesel fuel specifications.
[16] See ASTM D4814 for gasoline specifications.
[17] A fuel's tendency to vaporize.
[18] According to NFPA 30 a flammable liquid has a flash point lower than 100°F. A liquid with a flashpoint higher than 100°F is described as combustible.
[19] Payne, Brian L. el al. EDM Services, Inc. 1993. California Hazardous Liquid Pipeline Risk Assessment, Prepared for California State Fire Marshal, March.

public information report entitled, Railroad Derailment Incidents Involving Pipelines: 1981 - 1990 as follows:

> *"A Southern Pacific westbound train lost its brakes as it headed down the Cajon grade toward San Bernardino. After reaching a speed of over 100 mph the train derailed at a curve adjacent to a residential section of San Bernardino. Derailing cars and engines left the track and literally tumbled into several houses, killing two children and two train crew members. All sixty-nine of the cars and five of the locomotive units were destroyed and four others sustained extensive damage.*
>
> *During the derailment, and later during the movement of heavy equipment to remove the wreckage, a high-pressured gasoline pipeline adjacent to the tracks was damaged and weakened. Less than two weeks after the wreck, the pipeline ruptured and spewed over 300,000 gallons of flaming gasoline into the neighborhood, resulting in two more deaths, serious burns to three others, and the destruction of eleven more homes and 21 vehicles. Total damage to the train and track alone was estimated to be well over nine million dollars with an additional damage estimate to the neighborhood of over five million dollars."*

The extremity of this incident stimulated a good deal of public concern. As a result, steps were taken to determine that public safety was not being endangered by the proximity of pipelines to rail lines. One of the results was the passage of California Assembly Bill 385 (Elder). California Senate Bill 268 (Rosenthal), which was signed by the Governor at the same time, resulted from chronic leaks from one of the oldest crude oil pipelines in the Los Angeles area. These bills included requirements for the State Fire Marshal to perform certain studies which address the risk levels associated with hazardous liquid pipelines on railroad rights-of-way and other factors. Among other things, they required the State Fire Marshal to:

- Study the spacing of shut-off valves that would limit spillage into standard metropolitan statistical areas and environmentally sensitive areas and, if existing standards were deemed insufficient, to adopt regulations to require the addition of new valves on existing, and new or replacement pipelines.[20]

1.4.2 Bellingham, Washington, June 10, 1999

According to the National Transportation Safety Board (NTSB) accident report,

> *"…about 3:28 p.m., Pacific daylight time, on June 10, 1999, a 16-inch diameter steel pipeline owned by Olympic Pipe Line Company ruptured and released about 237,000 gallons of gasoline into a creek that flowed through Whatcom Falls Park in Bellingham, Washington. About one and one half hours after the rupture, the gasoline ignited and burned approximately and one half miles along the creek. Two 10-year-old boys and an*

[20] Payne, Brian L. el al. EDM Services, Inc. 1993. California Hazardous Liquid Pipeline Risk Assessment, Prepared for California State Fire Marshal, March.

18-year-old young man died as a result of the accident. Eight additional injuries were documented. A single-family residence and the City of Bellingham's water treatment plant were severely damaged. As of January 2002, Olympic estimated that total property damages were at least $45 million.

The major safety issues identified during this investigation are excavations performed by IMCO General Construction, Inc., in the vicinity of Olympic's pipeline during a major construction project and the adequacy of Olympic Pipe Line Company's inspections thereof; the adequacy of Olympic Pipe Line Company's interpretation of the results of in-line inspections of its pipeline and its evaluation of all pipeline data available to it to effectively manage system integrity; the adequacy of Olympic Pipe Line Company's management of the construction and commissioning of the Bayview products terminal; the performance and security of Olympic Pipe Line Company's supervisory control and data acquisition system; and the adequacy of Federal regulations regarding the testing of relief valves used in the protection of pipeline systems.[21]"

1.4.3 Carlsbad, New Mexico, August 19, 2000

According to the NTSB accident report,

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

The major safety issues identified in this investigation are the design and construction of the pipeline, the adequacy of El Paso Natural Gas Company's internal corrosion control program, the adequacy of Federal safety regulations for natural gas pipelines, and the adequacy of Federal oversight of the pipeline operator.[22]"

1.4.4 Walnut Creek, California, November 9, 2004

According to the California State Fire Marshal pipeline failure investigation report:

"At 1322 hours on 9 November 2004, excavation equipment operated by Mountain Cascade, Inc., struck Kinder Morgan's LS-16 pipeline, a 51.4 mile long intrastate products pipeline that travels from Concord to San Jose. The excavator was working on a large-

---

[21] National Transportation Safety Board (NTSB 2002). Pipeline Rupture and Subsequent Fire in Bellingham, Washington, June 10, 1999. Pipeline Accident Report NTSB/PAR-02/02. Washington, D.C.

[22] National Transportation Safety Board (NTSB 2003). Pipeline Rupture and Subsequent Fire near Carlsbad, New Mexico, August 19, 2000. Pipeline Accident Report NTSB/PAR-03/01. Washington, D.C.

> *diameter water supply expansion project in Walnut Creek, CA for the East Bay Municipal Utility District (EBMUD).*
>
> *Upon puncture of the Kinder Morgan pipeline, gasoline under high pressure was immediately released into the surrounding area. Kinder Morgan control center operators in Concord immediately noticed the large pressure drop and started to shut the pipeline down. Several seconds after the line was hit, the gasoline streaming out of the line was ignited by welders employed by Matamoros Pipelines, Inc. who were also working on the new water supply pipeline. The ensuing explosion and fire resulted in the deaths of five workers and significant injury to four others. One nearby two-story structure was burned and other property was damaged.*
>
> *The direct cause of the accident was the excavator's bucket striking the pipeline and puncturing through the wall of the pipe. However, there were several factors that significantly contributed to this accident. These include inadequate line locating, inadequate project safety oversight and communication, and failure to follow the one-call law.[23]"*

This incident demonstrates that even with one-call laws, significant incidents can and do occur due to third party damage. In this case, the Office of the State Fire Marshal (California) found the following:

- The pipeline operator did not properly mark the location of the pipeline in accordance with their damage prevention program and the California Government Code.
- The pipeline operator did not follow the company's line locating procedures.
- Within one minute of the incident, the operator received an alarm indicating a pressure drop in the line. Within four minutes, pump shut down was initiated. Within 38 minutes, the pipeline operator had officials at the accident site.

1.4.5 San Bruno, California, September 9, 2010

According to the NTSB accident report,

> *"On September 9, 2010, about 6:11 p.m. Pacific daylight time, a 30-inch-diameter segment of an intrastate natural gas transmission pipeline known as Line 132, owned and operated by the Pacific Gas and Electric Company (PG&E), ruptured in a residential area in San Bruno, California. The rupture occurred at mile point 39.28 of Line 132, at the intersection of Earl Avenue and Glenview Drive. The rupture produced a crater about 72 feet long by 26 feet wide. The section of pipe that ruptured, which was about 28 feet long and weighed about 3,000 pounds, was found 100 feet south of the crater. PG&E estimated that 47.6 million standard cubic feet of natural gas was released. The released natural gas ignited, resulting in a fire that destroyed 38 homes and damaged 70. Eight people were killed, many were injured, and many more were evacuated from the area.*

[23] Office of the State Fire Marshal, Pipeline Failure Investigation Report, November 9, 2004. California.

Probable Cause

The National Transportation Safety Board determines that the probable cause of the accident was the Pacific Gas and Electric Company's (PG&E) (1) inadequate quality assurance and quality control in 1956 during its Line 132 relocation project, which allowed the installation of a substandard and poorly welded pipe section with a visible seam weld flaw that, over time grew to a critical size, causing the pipeline to rupture during a pressure increase stemming from poorly planned electrical work at the Milpitas Terminal; and (2) inadequate pipeline integrity management program, which failed to detect and repair or remove the defective pipe section.

Contributing to the accident were the California Public Utilities Commission's (CPUC) and the U.S. Department of Transportation's exemptions of existing pipelines from the regulatory requirement for pressure testing, which likely would have detected the installation defects. Also contributing to the accident was the CPUC's failure to detect the inadequacies of PG&E's pipeline integrity management program.

Contributing to the severity of the accident were the lack of either automatic shutoff valves or remote control valves on the line and PG&E's flawed emergency response procedures and delay in isolating the rupture to stop the flow of gas.[24]*"*

As a result of this incident, the NTSB made a number of recommendations that resulted in significant new gas pipeline regulations which require improvements in gas pipeline integrity management.

[24] National Transportation Safety Board (NTSB 2011). Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010. Pipeline Accident Report NTSB/PAR-11/01. Washington, D.C.

2.0 Regulatory Setting

2.1 Regulatory Framework

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

Two statutes provide the framework for the Federal pipeline safety program. The Natural Gas Pipeline Safety Act of 1968 as amended (NGPSA) authorizes the DOT to regulate pipeline transportation of natural (flammable, toxic, or corrosive) gas and other gases as well as the transportation and storage of liquefied natural gas (LNG). Similarly, the Hazardous Liquid Pipeline Safety Act of 1979 as amended (HLPSA) authorizes the DOT to regulate pipeline transportation of hazardous liquids (crude oil, petroleum products, anhydrous ammonia, and carbon dioxide). Both of these Acts have been re-codified as 49 USC Chapter 601.

The Federal Pipeline Safety Act of 2002 (Public Law 107-355 dated December 17, 2002) provided for the sharing of the oversight of hazardous liquid pipelines with authorized State agencies. States must demonstrate to the Secretary of the Department of Transportation that their programs are consistent with the Federal pipeline safety regulations. The Secretary can then authorize that State's hazardous liquid pipeline agency to participate in the oversight of intrastate pipelines and some activities of interstate pipelines.

The Revised Codes of Washington (RCW) Title 81, Chapter 81.88 established the Washington State Utilities & Transportation Commission. As referred to in this regulation, the law's short title is the Washington Pipeline Safety Act of 2000. It established a Commissioner whose duties included, "The development and administration of a comprehensive pipeline safety program for natural gas and hazardous liquid pipelines, and the acquisition of a Federal certification of the pipeline safety program to act as a delegate to OPS". The Washington State Utilities & Transportation Commission developed and demonstrated that the State's pipeline programs were consistent with the Federal program and gained authorization to share oversight of hazardous liquids pipelines.

2.2 Federal Pipeline Regulations

Interstate and intrastate hazardous liquid transportation by pipeline and rail fall under the jurisdiction of the U.S. Department of Transportation. Hazardous liquid pipelines must conform with the design, construction, testing, operation and maintenance regulations contained in Title 49 Code of Federal Regulations (CFR) Part 195, "Transportation of Hazardous Liquids by Pipeline," as authorized by the Hazardous Liquid Pipeline Safety Act of 1979 (HLPSA - 49 USC § 2004). However, the DOT does not issue a construction permit or conduct a plan check for all pipeline projects. Within this study, 49 CFR Parts 195 will be referred to as the "regulations," or the "pipeline regulations." After the HLPSA was originally written, several pipeline safety measures have been passed by Congress to improve pipeline safety and to revise 49 CFR Part 195. Some portions of the laws initiated studies in specific areas that led to subsequent changes in the Regulations.

49 CFR Part 194 prescribes the federal requirements for response plans for onshore oil pipelines. Other relevant federal requirements applicable to the transportation of hazardous liquids by pipeline are contained in 40 CFR Parts 109, 110, 112, 113, and 114, which pertain to the need for "Oil Spill Prevention Control & Countermeasures (SPCC) Plans" and Public Law 101-380 (H.R.), promulgated in response to the Oil Pollution Act (OPA) of 1990.

2.2.1 Overview of 49 CFR Part 190

This part prescribes procedures that are used by the DOT relative to DOT's duties regarding natural gas and hazardous liquid pipeline safety.

2.2.2 Overview of 49 CFR Part 195

2015 PHMSA Notice of Proposed Rulemaking

A number of Congressional Acts have been passed since the initial Pipeline Safety Act of 1979 with the intent of improving hazardous liquid pipeline safety. Recently, The Pipeline Safety, Regulatory Certainty, and Jobs Creation Act of 2011 gave direction to PHMSA to perform a number of studies relating to hazardous liquid pipeline safety and to develop regulations to address the findings of those studies. In October 2015, PHMSA drafted a document outlining proposed rulemaking as a result of the safety studies initiated by the Congressional Act of 2011. The proposed rulemaking includes the following proposed changes to 49 CFR Part 195:

- 195.1 - The regulation will now consider certain gathering lines to be considered jurisdictional to the regulations, specifically those that cross navigable waterways.
- 195.2 - The regulations will now include ethanol, ethanol blends, and other biofuels in the definition of hazardous liquids. This section will also add the definition ``Significant Stress Corrosion Cracking'' and require such damage to be excavated and repaired.
- 195.11 - The regulation will now require certain gathering pipelines to be subject to the pipeline integrity assessment and leak detection requirements of the regulations.
- 195.13 - The regulations will now require hazardous liquid gravity lines to be included in the annual, safety related, and incident reporting requirement of the regulations.
- 195.120 - The regulations will no longer allow operators to petition to not make changes to their systems that would accommodate internal instrumentation tools.
- 195.134 - The regulation will now require all new pipeline designs to include computational pipeline modeling (CPM) leak detection based on API 1130 or other applicable standard(s).
- 195.401 - The regulation will now define the timeframe for all non-integrity management repairs.

- 195.414 - The regulation will now require operators to inspect their pipelines after the cessation of any of the listed events to insure the safe operation of their pipelines.
- 195.416 - The regulations will now include this new section that requires the integrity assessment of current non-integrity management pipelines every 10 years.
- 195.422 - The regulations will now include requirements for the repairs of pipelines outside of HCA's (non-integrity management jurisdictional pipeline segments) analogous to the repair requirements within HCA's to insure the safe operation of the pipelines.
- 195.444 - The regulations will now include requirements that all pipelines have CPM leak detection.
- 195.452 - The regulations will now eliminate obsolete deadlines currently stated within this part. The regulation will now include clarifications on the requirements of newly identified HCA's. The regulations will include the consideration of local environmental factors (including seismicity) that have an effect on pipeline integrity. The regulation will expand the criteria required for integrity analysis. The regulation will include new timeframes for repairs including revised language pertinent to the discovery of a condition and the reporting of that condition to PHMSA. The regulations will also require all pipelines to be able to accommodate an internal inspection tool within 20 years that cross existing HCA's and within 5 years of newly identified HCA's.

If enacted as published, the existing OPL pipelines would be subject to these new requirements, as applicable.

Subpart A – General (Sections 195.0 – 195.12)

This part provides the definition of a jurisdictional hazardous liquid pipeline and the general responsibilities of a hazardous liquid pipeline operator. Section 195.3 of the regulation incorporates, by reference, the applicable national safety standards of the following organizations:

- American Petroleum Institute (API)
- American Society of Mechanical Engineers (ASME)
- American National Standards Institute (ANSI)
- American Society for Testing and Materials (ASTM)
- Manufacturers Standardization Society of the Valve and Fittings Industry (MSS)

Section 195.6 was added to the regulations on December 21, 2000, which defines Unusually Sensitive Areas (USAs). USAs are drinking water or ecological resource areas that are unusually sensitive to environmental damage from a hazardous liquid pipeline release, including the following resources:

- Certain drinking water resources (e.g., community water systems, certain aquifers, sole source aquifers, etc.),
- Certain ecological resources (e.g., critically imperiled species, multi-species assemblage area, threatened or endangered species, etc.), and
- Alternative drinking water sources.

It should be noted that all USAs are High Consequence Areas (HCAs), as discussed later in this report (49 CFR 195, Subpart F). Unfortunately, the USDOT does not publish maps of USAs due to security concerns.

Subpart B – Annual, Accident, and Safety-Related Condition Reporting (Sections 195.48 – 195.64)

This part outlines the various reporting requirements of a hazardous liquid pipeline operator as well as the timing of submission of various incident, accident and safety related conditions discovered by the operator. Sections 195.50 to 195.54 require reporting of the following scenarios caused by unintentional releases:

- An incident which resulted in an explosion or fire not intentionally set by the operator.
- Effective January 1, 2002, the reportable spill volume was reduced to any release of 5 gallons or more of hazardous liquid or carbon dioxide, unless the spill resulted from maintenance activity, in which case the reportable spill volume is 5 barrels (210 gallons) or more. (Prior to January 1, 2002, the reportable spill volume was 2,100 gallons or more of liquid for any unintentional release.)
- Death of a person.
- Effective January 1, 2002, an accident resulting in an injury necessitating hospitalization must be reported. (Prior to January 1, 2002, an accident resulting in serious injury to any person resulting in loss of consciousness, necessity to carry the individual from the scene, medical treatment, or disability which prevents the discharge of normal duties or the pursuit of normal activities beyond the day of the incident was required to be reported.)
- Damage to property of operator, or others, or both, greater than $50,000 (including the cost of clean-up and recovery, property damage, and lost product).

Sections 195.55 and 195.56 require reporting of the following safety related conditions. The pipeline operator is required to file a written report with the DOT within five working days of the time in which the operator first determined that the condition exists.

- General corrosion which has reduced the wall thickness to less than that required for the maximum operating pressure or localized corrosion which could result in a leak;
- Unintended movement or abnormal loading of a pipeline by environmental causes (e.g., earthquake, landslide, flood) that impairs its serviceability;
- Any material defect or physical damage that impairs the serviceability of a pipeline;
- Any malfunction or operating error that causes the pressure of a pipeline to rise above 110 percent of the maximum operating pressure;
- A leak in a pipeline that constitutes an emergency; and
- Any safety related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator) a 20 percent or more reduction in operating pressure or shutdown of pipeline operation.

The following safety related conditions are excluded from the above reporting requirements:

- A safety related condition that is more than 220 yards from a human occupancy or outdoor assembly place. (Please note that reports are required for safety related conditions within railroad rights-of-way, paved roadways, or where an incident could reasonably be expected to pollute any stream, river, lake, reservoir, or other body of water.);
- Is an accident that is required to be reported under 195.50 or results in such an accident before the deadline for filing the safety-related condition report; or
- Any safety related condition that is corrected by repair or replacement in accordance with applicable safety standards before the report deadline. (Please note that reports are required for general corrosion on all lines and localized corrosion on unprotected lines.)

Subpart C – Design Requirements (Sections 195.100 – 195.134)

This part includes the design requirements for new pipelines, relocated pipeline segments, pipe replacements, and other changes to existing systems that use steel pipe. These requirements include:

- Qualification of metallic components other than pipe,
- Design temperature,
- Variations in pressure,
- Internal design pressure,
- External pressure,
- External loads,
- Fracture propagation,
- New pipe,
- Used pipe,
- Valves,
- Fittings,
- Passage of internal inspection devices,
- Fabricated branch connections,
- Closures,
- Flange connections,
- Station piping,
- Fabricated assemblies,
- Design and construction of breakout tanks, and
- Computational pipeline monitoring (CPM) leak detection.

Subpart D – Construction (Sections 195.200 – 195.266)

This part provides the minimum requirements for constructing new pipelines, relocating existing pipelines, replacing pipe segments, or otherwise changing existing pipeline systems that use steel pipe. These requirements include:

- Compliance with written standards and specifications,
- Construction inspection,

- Repair, alteration, and reconstruction of aboveground breakout tanks that have been in service,
- Welding,
- Pipeline location,
- Pipe bending,
- Welding procedure qualification,
- Welder qualification,
- Production welding,
- Welding inspection and nondestructive testing of welds,
- Defective weld repair and removal,
- External corrosion protection and cathodic protection,
- External pipe coating,
- Installing pipe in the ditch,
- Pipe burial depth (cover),
- Clearances between the pipeline and other substructures (49 CFR Part 195.250 requires 12 inches of clearance between a buried pipeline and any other buried structure, with few exceptions)[25],
- Clearances between the pipeline and other substructures,
- Backfilling,
- Rail and highway crossings,
- Valves,
- Valve locations,
- Pumping equipment,
- Breakout tanks, and
- Construction records.

Subpart E – Pressure Testing (Sections 195.300 – 195.310)

This part prescribes the minimum requirements for hydrostatic testing, compliance dates, test pressures and duration, test medium, and records. Basically, this section requires new pipeline segments to be tested at 125% of the maximum allowable operating pressure (MAOP) for a period of four hours and an additional four hours at 110% of the MAOP (if buried) prior to operation. The regulations do not require the periodic re-testing of pipelines after the initial construction test. The regulations do require that any new pipe, installed within an existing pipeline, be pre-tested prior to installation into the pipeline system, or the existing pipeline segment be re-tested after the new pipe is installed. Also, operators do have the option of using hydrostatic pressure testing as a means to establish their baseline integrity assessment as part of their integrity management plans in lieu of using internal electronic inspection tools.

Subpart F – Operation and Maintenance (Sections 195.400 – 195.452)

[25] 49 CFR 195 does not currently contain any specific requirements for pipeline separation from buildings or other structures.

This part specifies the following minimum requirements for operating and maintaining steel pipeline systems. Of special interest to this study is Section 195.402 (c) (10) that requires the development of a written plan for the abandonment of pipelines (permanently removed from service per 195.2 Definitions) and what activities must be performed to properly abandon a pipeline. Other requirements of this part include:

- Correction of unsafe conditions within a reasonable time,
- Procedural manual for operations, maintenance, and emergencies (including abandonment of pipelines),
- Training,
- Maps and record maintenance,
- Maximum operating pressure,
- Communication system,
- Line markers,
- Inspection of right-of-way and navigable water crossings,
- Cathodic protection systems,
- External and internal corrosion control,
- Valve maintenance,
- Pipeline repairs,
- Pipeline movement,
- Scraper and sphere facilities,
- Over pressure safety devices,
- Firefighting equipment,
- Breakout tank inspections,
- Signs around pump stations and breakout tanks,
- Security of facilities,
- Smoking or open flames in pump station and breakout tank areas,
- Public awareness and education program for hazardous liquid pipeline emergencies and reporting,
- Pipeline integrity management in high consequence areas,
- Damage prevention programs,
- Computerized leak detection monitoring, and
- Control room management.

On December 1, 2000, significant operation and maintenance requirements (49 CFR 195.452) were added to this subpart. These are the pipeline integrity management program requirements. These requirements apply to hazardous liquid pipelines that may affect high consequence areas (HCAs). Operators of these pipelines must conduct a baseline assessment within prescribed deadlines. These assessments may include the following tests: internal inspection tools (smart pigs), pressure testing, and other equivalent technologies. For operators of more than 500 miles of pipeline that is subject to 49 CFR Part 195, at least 50% of the pipeline mileage, beginning with the highest risk segment of pipeline, must have been assessed by September 30, 2004; the remaining mileage must be assessed by March 31, 2008. For operators of less than 500 miles of pipe subject to this regulation, the deadlines are August 16, 2005 and February 17, 2009, respectively. The new regulation also requires that certain defects be repaired within prescribed timeframes, depending on their severity. HCA's are defines as follows (49 CFR 195.450):

- (1) A commercially navigable waterway, which means a waterway where a substantial likelihood of commercial navigation exists;
- (2) A high population area, which means an urbanized area, as defined and delineated by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1,000 people per square mile;
- (3) An other populated area, which means a place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area;
- (4) An unusually sensitive area, as defined in §195.6. (See also Subpart A discussion above.)

The OPL pipelines corridor are within a highly populated area. As a result, they are subject to these pipeline integrity management program requirements.

Subpart G – Qualification of Pipeline Personnel (Sections 195.500 – 195.509)

This part of the regulations (effective August 29, 1999) prescribes the minimum qualification requirements for hazardous liquid pipeline operations and maintenance personnel. This involves the development of an operator qualification program and documentation that employees have been qualified to perform their daily tasks.

Subpart H – Corrosion Control (Sections 195.551 – 195.589)

This part prescribes the minimum corrosion control requirements for hazardous liquid pipeline systems. These requirements include:

- Qualification of corrosion control program supervisors,
- Requirements for external corrosion control,
- Inspection of external coatings,
- What pipelines must have cathodic protection in place,
- Installation of cathodic protection on breakout tanks,
- Cathodic protection test leads,
- Examination of exposed portions of buried pipelines,
- Criteria for the evaluation of adequate cathodic protection,
- Monitoring of external corrosion,
- Pipeline electrical isolation, inspection, testing, safeguards, and repairs,
- Alleviation of stray electrical currents on pipelines,
- Atmospheric corrosion protection, control and acceptable coating materials,
- Monitoring of atmospheric corrosion,
- Corrective measures for corroded pipes,
- Methods available to determine the strength of corroded pipes,
- Standards for direct assessment of corrosion, and
- Maintenance and retention of corrosion control maps and records.

Appendix A to Part 195 - Delineation between Federal and State Jurisdiction - Statement of Agency Policy and Interpretation

This appendix describes the jurisdictional relationship between intrastate and interstate pipelines and how the regulations are enforced by DOT and the state agencies.

Appendix B to Part 195—Risk-Based Alternative to Pressure Testing Older Hazardous Liquid and Carbon Dioxide Pipelines

As stated in the appendix, *"This Appendix provides guidance on how a risk-based alternative to pressure testing older hazardous liquid and carbon dioxide pipelines rule allowed by 195.303 will work. This risk-based alternative establishes test priorities for older pipelines, not previously pressure tested, based on the inherent risk of a given pipeline segment. The first step is to determine the classification based on the type of pipe or on the pipeline segment's proximity to populated or environmentally sensitive area. Secondly, the classifications must be adjusted based on the pipeline failure history, product transported, and the release volume potential."*

Appendix C to Part 195—Guidance for Implementation of an Integrity Management Program

As stated in the appendix, *"This Appendix gives guidance to help an operator implement the requirements of the integrity management program rule in 195.450 and 195.452."*

2.2.3 Overview of 49 CFR Part 199, (Drug Testing, Requirements)

Operators of interstate hazardous liquid pipeline systems are required to comply with the drug testing requirements of this regulation. The regulation requires operators to maintain an anti-drug plan, provide pre-employment employee testing, conduct post-accident drug testing, and perform random testing such that half of the employee pool is tested each twelve-month period. All employees that perform operating, maintenance, or emergency response functions are subject to these requirements. Employees who fail or refuse a drug test may not be used in these functions unless they completed a rehabilitation program and have met other requirements.

2.2.4 Overview of 40 CFR Parts 109, 110, 112-114

The Federal Environmental Protection Agency (EPA), as authorized by 40 CFR, to develop regulations to prevent and respond to oil spills onto navigable waters of the United States. The Oil Spill Prevention Control & Countermeasures (SPCC) covered in these regulations apply to oil storage and transportation facilities and terminals, tank farms, bulk plants, oil refineries, and production facilities, as well bulk oil consumers such as apartment houses, office buildings, schools, hospitals, farms, and state and federal facilities.

Part 109 establishes the minimum criteria for developing oil removal contingency plans for certain inland navigable water by state, local, and regional agencies in consultation with the regulated community (e.g., oil facilities).

Part 110 prohibits discharge of oil in such a manner that applicable water quality standards would be violated, or in such a manner that would cause a film or sheen upon or in the water. These regulations were updated in 1987 to adequately reflect the intent of Congress in Section 311(b)(3) and (4) of the Clean Water Act.

Part 112 deals with oil spill prevention and preparation of SPCC Plans. These regulations establish procedures, methods, and equipment requirements to prevent the discharge of oil from onshore and offshore facilities into or upon the navigable waters of the United States. Current wording applies these regulations to facilities that are non-transportation related. However, proposed rules would make the spill emergency planning in these rules applicable to all oil facilities. Part 112 should be used by pipeline operators as additional guidelines for the development of oil spill prevention, control, and emergency response plans.

Part 113 establishes financial liability limits; however, these limits have now been preempted by the Oil Pollution Act of 1990.

Part 114 provides civil penalties for violations of the oil spill regulations. The amount of the penalty is determined considering the gravity of the violation and demonstrated good faith efforts to achieve rapid compliance after notification of a violation. The amount is assessed during the hearing process, or may be assessed by the Regional Administrator if a hearing is not requested.

2.2.5 Oil Pollution Act of 1990 (OPA)

The Oil Pollution Act of 1990 (OPA), together with the Oil Pollution Liability and Compensation Act of 1989, builds upon Section 311 of the Clean Water Act (CWA) to create a single federal law providing cleanup authority, penalties, and liability for oil pollution. The bill creates a single fund to pay for removal of and damages from oil pollution. This new fund replaces those created under the Trans-Alaska Pipeline Act, Deep Water Port Act of 1974, and Outer Continental Shelf Lands Act, and supersedes the contingency fund established under Section 311 of CWA. OPA-90 also authorized the Oil Spill Liability Trust Fund (OSLTF) up to $1 billion to pay for expeditious oil removal and uncompensated damages up to $1 billion per incident. The administration of OSLTF was delegated to the United States Coast Guard by executive order.

The Oil Spill Compensation Fund will be available for all removal costs and compensatory damages (limited to $1 billion per incident). The OPA provides for liability and availability of funds to pay removal costs and compensation in case of discharges of oil. It adopts the standard of liability of dischargers for cleanup costs-strict, several, and joint liability, under Section 311. The OPA establishes financial liability of all oil facility operators, including pipeline operators. The OPA provides for financial liability related to land-based pipelines, but only as they relate to "discharges of oil, unto or upon the navigable waters or adjoining shorelines..."

The OPA affirms the rights of states to protect their own air, water, and land resources by permitting them to establish state standards which are more restrictive than federal standards. More stringent state laws are specifically preserved. Section 106 of the OPA explicitly preserves authority of any state to impose its own requirements or standards with respect to discharges of oil within each state.

As a result of this legislation, 49 CFR Part 194 was codified to require operators to prepare oil spill response plans for onshore oil pipelines (including pipelines transporting petroleum, fuel oil, etc.). The intent of these 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 DOT 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 - NWACP).

2.3 State Pipeline Regulations

The State of Washington's Utilities and Transportation Commission is responsible for the administration and oversight of hazardous liquid pipeline operations in the State as authorized by the USDOT. The State has adopted the Federal hazardous liquids pipeline regulations as a part of their own enhanced regulations. The following section outlines the regulatory framework within the State of Washington that constitutes the State's hazardous liquid pipeline regulations.

2.3.1 Revised Code of Washington (RCW) Title 81

The RCW Title 81, Chapter 81.88 establishes the Washington State Utilities & Transportation Commission. As referred to in this regulation, the law's short title is the Washington Pipeline Safety Act of 2000. It establishes a Commissioner whose duties include:

- The development and administration of a comprehensive pipeline safety program for natural gas and hazardous liquids pipelines,
- The creation of a State 3rd Party Damage Prevention Program,
- The development of a State pipeline mapping program,
- The acquisition of a Federal certification of the pipeline safety program to act as a delegate to OPS,
- The inspections of maps, records, and procedures of hazardous liquid pipeline operators, and
- The establishment of a citizen's committee on pipeline safety.

The RCW Title 81, Chapter 81.88.144 establishes the above-mentioned Citizens Committee on Pipeline Safety. This is a 13-member group, appointed by the Governor, to serve 3 year staggered terms. The members will include 9 voting members that are elected officials, and representatives of the public, and 4 non-voting members that represent owners and operators of hazardous liquids and gas pipelines. As stated in the regulation, "The citizens committee on pipeline safety is established to advise the state agencies and other appropriate federal and local government agencies and officials on matters relating to hazardous liquid and gas pipeline safety, routing, construction, operation, and maintenance."

2.3.2 Washington Administrative Code, Title 480 (WAC-480)

As developed and administered by the Washington Utilities and Transportation Commission, WAC-480 contains two chapters relating to hazardous liquid pipelines within the State that fulfill a portion of the Utilities & Transportation Commissioner's charge.

- Chapter 480-73: Hazardous Liquid Pipeline Companies: This State regulation defines the applicability of the regulations and the administrative guidelines and rules hazardous liquid pipeline companies must follow.
- Chapter 480-75: Hazardous Liquid Pipelines, Safety – This State regulation provides Washington State specific pipeline safety rules. 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 require compliance, by reference, with 49 CFR Part 195.

Of particular interest is this State's adoption of the natural gas class location definitions published in 49 CFR Part 192, Chapter 480-75. The Washington State regulation governing hazardous liquid pipelines adopts design factors, based on population density (area class), that limit the operating pressure in more densely populated areas. It also requires that for station piping, the design factor be 0.50. These requirements are the same as the Federal requirements for gas pipelines; they are more conservative than the Federal requirements for hazardous liquid pipelines.

Unlike the Federal hazardous liquid regulations, WAC 480-75-300, Leak Detection, specifically defines the performance measures of a computerized leak detection system where the 49 CFR Part 195.134 Computational Pipeline Monitoring (CPM) Leak Detection refers compliance to API RP 1130. The State requires a CPM leak detection system to be able to detect a leak equivalent to 8% of maximum flow within 15 minutes. These exact limits are not defined by the API RP because of such variability in pipeline CPM methods, pipeline configurations, pipeline contents, etc.

WAC 480-75-640, Depth-of-Cover Survey also requires an operator to perform a survey of the depth of cover every 5 years. Areas found to have less than the originally required depth of cover, must be lowered back to the regulatory required depth of cover. This requirement is also more conservative than the Federal hazardous liquid pipeline regulation, which only requires the specified depth of cover at the time of construction, although the pipeline must be maintained in a safe manner.

2.3.3 Revised Code of Washington (RCW), Title 19

RCW-19 contains a number of various titles for business operations within the State. Within this Title, Chapter 122 (RCW-19.122) was developed specific to underground utilities.

RCW-19.122 addresses one of the assigned responsibilities of the Utilities and Transportation Commission for administering hazardous liquids pipelines. It establishes a comprehensive one-call excavation damage prevention program for the state.

Underground Utilities, Damage Prevention Law RCW 19.122 addresses public health and safety and prevention of disruption of vital utility services through a comprehensive damage prevention program.

2.3.4 Washington Administrative Code, Title 173 (WAC-173)

WAC-173 empowers the State of Washington Department of Ecology with the protection of the ecological resources of the state. This includes water, air and shoreline protection from pollution. Specific to pipelines are the requirements in Chapter 182 Oil Spill Contingency Plan requirements for the State.

WAC-173-182 empowers the State of Washington Department of Ecology to require pipeline operators, and others (vessel operators), to develop and submit for approval, Oil Spill Contingency Plans to the State. Generally, these are the same plans developed for Federal plan compliance with minor adjustments for State specific requirements. This is the OPA-90 required Oil Spill Contingency Plan. The plan developed by pipeline operators must be consistent with the national and area oil spill contingency plans as required by OPA-90. The area contingency plan is titled the Northwest Area Contingency Plan (NWACP). The United States Coast Guard, 13th District, along with the support of numerous multi-state organizations, develops and administers the NWACP. These organizations assist with developmental input to the plan, assistance with emergency spill response, and incident reporting. The States of Washington, Oregon, and Idaho participate in the NWACP as well as Native American Communities. All spill emergency response activities are initiated by calling the National Response Center (NRC) in Washington, D.C., who in turn, notifies the trustees of the NWACP.

WAC-173-182 has not been revised since 2006. There is a proposed rulemaking by the Washington State Department of Ecology that would involve changes to the regulations that govern hazardous liquids pipelines with the State. Per the Department of Ecology website, the proposed rulemaking would, if enacted as published:

- Update definitions to ensure clarity and consistency with existing federal regulations,
- Clarify the Worst Case Discharge calculation for pipelines,
- Create a new pipeline geographic information planning standard which will use available geo-referenced data to support preparedness planning and initial decision making during pipeline oil spills,
- Enhance the existing air monitoring requirements for pipelines to ensure safety of oil spill responders and the general public,
- Enhance the spills to ground requirements to ensure rapid, aggressive and well-coordinated responses to spills to ground which could impact ground water,
- Update the pipeline planning standard storage requirements to ensure the equipment required is appropriate for the environments pipelines may impact,
- Expand the Best Achievable Protection (BAP) Review Cycle to facilities and pipelines, and
- Other changes to clarify language and make any corrections needed.

3.0 Significance Criteria

3.1 Aggregate Risk

Aggregate risk, or probable loss of life (PLL), is one risk measure used to evaluate projects. Aggregate risk is the total anticipated frequency of a particular consequence, normally fatalities, that could be anticipated over a given time period, for all project components being analyzed. Aggregate risk is a type of risk integral; it is the summation of risk, as expressed by the product of the anticipated consequences and their respective likelihood. The integral is summed over all of the potential events that might occur for all of the project components, over the entire project length. For example, if one were evaluating a ten mile pipeline system, which included a storage tank and pump station, the aggregate risk would be the risk posed by all components – ten miles of pipeline, pumps, station piping, storage tank, etc. There are no known codified *bright line thresholds*[26] for acceptable levels of PLL or aggregate risk. (This risk is presented in Section 6.0, Qualitative Aggregate Risk Assessment of this Report.)

3.2 Individual Risk

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

To our knowledge, the United States federal and Washington state governments have not adopted individual risk thresholds; the acceptable level of risk is left to local decision makers and project proponents. Figure 3.2-1 presents the individual risk thresholds for a number of jurisdictions, where such thresholds have been adopted.

[26] A bright-line rule (or bright-line test) is a clearly defined rule or standard, composed of objective factors, which leaves little or no room for varying interpretation. The purpose of a bright-line rule is to produce predictable and consistent results in its application. The term "bright-line" in this sense generally occurs in a legal context. Bright-line rules are usually standards established by courts in legal precedent or by legislatures in statutory provisions.

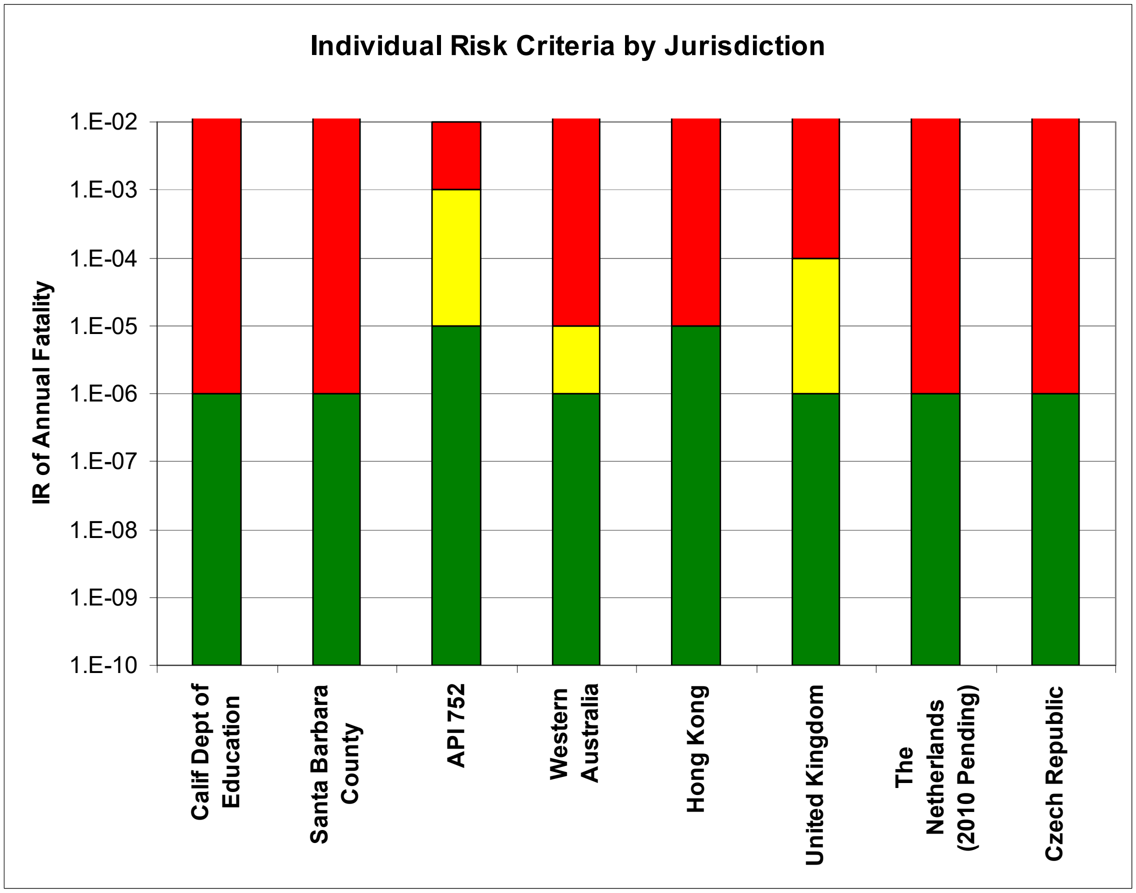


Figure – 3.2-1 Individual Risk Criteria by Jurisdiction[27]

The upper end of the green areas represent the de minimus[28] risk values for each jurisdiction; IR risk levels within the green range are considered broadly acceptable. Risks within this green region are considered so low that no further consideration is warranted. In addition, risks within the green band are generally considered so low that it is unlikely that any risk reduction would be cost effective, since extraordinary measures would normally be required to further reduce the risk. As a result, a benefit – cost analysis of risk reduction is typically not undertaken.

[27] Sources: (CDE 2007, SBCO 2008, API 752, Marszal 2001, Hong Kong

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

The lower end of the red areas represent the de manifestus[29] risk values; IR risk levels within the red range are considered unacceptable and the risks are not normally justified on any grounds.

For example, the California Department of Education and Santa Barbara County use 1.0×10^{-6} as their bright line threshold; this is equivalent to a one in one million (1 : 1,000,000) likelihood that an individual at a specific location, would be fatally injured over a one year period[30].

Some jurisdictions have adopted a “grey area”, where the risk levels may be negotiated or otherwise considered. The United Kingdom developed the ALARP (as low as reasonably practicable) approach. This approach is depicted by the yellow areas in Figure 3.2-1. Generally, risks within the yellow area may be tolerable only if risk reduction is impractical or if its cost is grossly disproportionate to the risk improvement gained. The underlying concept is to maximize the expected utility of an investment, but not expose anyone to an excessive increase in risk.

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

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

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

[29] ALARP (as low as reasonably practical) principle states that there is a level of risk that is intolerable, sometimes called the de manifestus risk level. Above this level risks cannot be justified.
[30] For reference, National Geographic Magazine estimates that the odds of becoming a victim of a lightning strike in the United States is 1 in 700,000 (1 :700,000).

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

3.3 Societal Risk

Societal risk is the probability that a specified number of people will be affected by a given event. The accepted number of casualties is relatively high for lower probability events and much lower for more probable events. As shown in Figure 3.3-1, the acceptable values for societal risk vary greatly by different agencies and jurisdictions. We are not aware of any prescribed societal risk guidelines for the United States, nor the State of Washington. (See also Section 3.2.)

The California Department of Education and The County of Santa Barbara, California have upper and lower bounds for unacceptable and acceptable societal risk levels respectively. The upper bound is represented by the red line in the following figure; risks above this line are deemed intolerable. The lower bound is represented by the green line in the following figure; risks below this line are deemed acceptable. Between these two bounds is a "gray area" similar to that discussed above for individual risks.

Using the Netherlands, as one possible criteria, for a given number of fatalities, if the likelihood is greater than the value represented by the blue line (e.g., above the line), then the societal risk is deemed unacceptable; if the likelihood is less than the value represented by the line (e.g., below the line) then the societal risk that falls below the line is acceptable. For example, for one hundred (100) fatalities, as shown on the "x" axis, the bright line threshold for the Netherlands (blue line) is 1.00E-07 (or 1.0×10^{-7}, or 1 : 10,000,000), as shown on the "y" axis. In other words, if the likelihood of one hundred (100) fatalities is less than one in ten million (1 : 10,000,000), the risk is deemed acceptable; if not, it is unacceptable.

It should be noted that societal risk does not assume that individuals would be exposed one hundred percent (100%) of the time, as with individual risk. For societal risk, the time that individuals would be exposed to the potential risk is considered in the analysis.

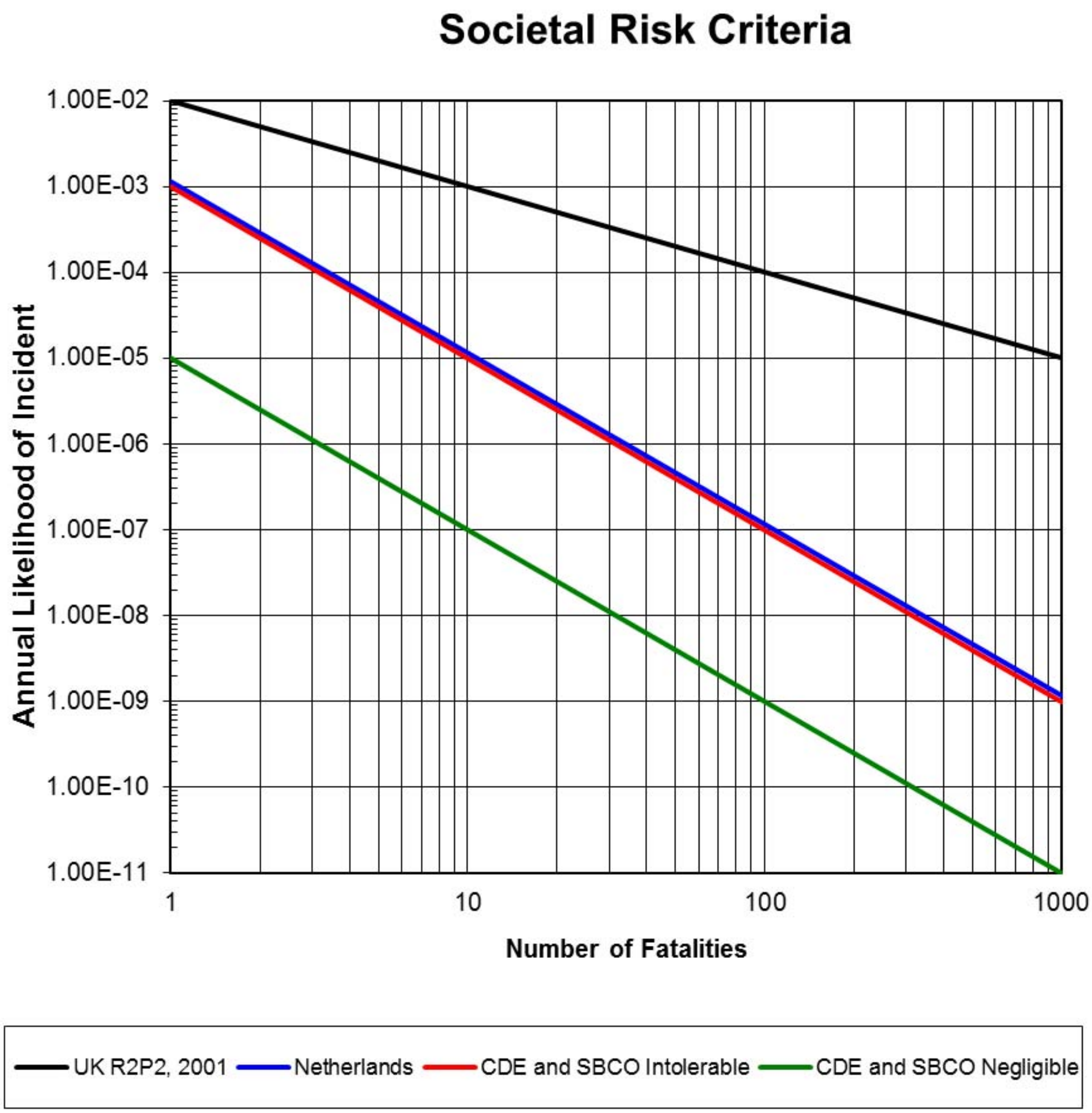


Figure 3.3-1 – Various Societal Risk Criteria[31]

[31] Sources – CDE 2005 and 2007, API 752, SBCO 2008, Marzal 2001, Hong Kong

4.0 Potential Hazards

The proposed project could pose additional risks to the public. For example, if the proposed project were to impact either, or both, of the OPL pipelines, refined petroleum product could be released from a leak or rupture. If the fluid reached a combustible mixture and an ignition source were present, a fire and/or explosion could occur, resulting in possible injuries and/or deaths.

An unintentional release could also present an environmental hazard. As noted earlier, soil could be impacted, waterways could be degraded, and wildlife and vegetation could be jeopardized. This Report presents the life safety risks posed to the public; an analysis of potential environmental impacts is beyond the scope of this Report.

As will be presented later in this Report, only a small percentage of refined petroleum product releases are ignited, resulting in fire and/or explosion.

4.1 Fire Hazards to Humans

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

Humans in the vicinity of a fire, but not in contact with the flames, would receive heat from the fire in the form of thermal radiation. Radiant heat flux decreases with increasing distance from a fire. Therefore, those close to the fire would receive thermal radiation at a higher rate than those farther away. The ability of a fire to cause skin burns due to radiant heating depends on the radiant heat flux to which the skin is exposed and the duration of the exposure. As a result, short-term exposure to high radiant heat flux levels can be injurious. However, if an individual is far enough from the fire, the radiant heat flux would be lower, likely incapable of causing injury, regardless of the duration of the exposure.

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

- 12,000 Btu/ft^2-hr (37.7 kW/m^2) – 100% mortality after 30 second exposure (CDE 2007).
- 8,000 Btu/ft^2–hr (25.1 kW/m^2) – 50% mortality after 30 second exposure (CDE 2007).
- 5,000 Btu/ft^2-hr (15.7 kW/m^2) – 1% mortality after 30 second exposure (CDE 2007). In many instances, an able bodied person would increase the separation distance or seek cover during this 30 second period.

- 3,500 Btu/ft^2-hr (11.0 kW/m^2) - Second degree skin burns after ten seconds of exposure, 15% probability of fatality (Quest 2003). This assumes that an individual is unprotected or unable to find shelter soon enough to avoid excessive exposure (Quest 2003). Other data sources provide a 10% mortality at 5,500 Btu/hour-square foot and 15% mortality at 5,800 Btu/hour-square foot (CDE 2007).
- 1,600 Btu/ft^2-hr (5.0 kW/m2) - Second degree skin burns after thirty seconds of exposure.
- 440 Btu/ft^2-hr (1.4 kW/m2) - Prolonged skin exposure causes no detrimental effect (CDE 2007, Quest 2003).

4.2 Explosion Hazards to Humans

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

Table 4.2-1 Explosion Over-Pressure Damage Thresholds[32]

Side-On Over-Pressure	Damage Description
0.02 psig	Annoying Noise
0.03 psig	Occasional Breaking of Large Window Panes Under Strain
0.04 psig	Loud Noise; Sonic Boom Glass Failure
0.10 psig	Breakage of Small Windows Under Strain
0.20 psig	Glass Breakage - No Injury to Building Occupants
0.30 psig	Some Damage to House Ceilings, 10% Window Glass Broken
0.50 to 1.00 psig	Large and Small Windows Usually Shattered, Occasional Damage to Window Frames
0.70 psig	Minor Damage to House Structures, Injury, but Very Unlikely to Be Serious
1.00 psig	1% Probability of a Serious Injury or Fatality for Occupants in a Reinforced Concrete or Reinforced Masonry Building from Flying Glass and Debris 10% Probability of a Serious Injury or Fatality for Occupants in a Simple Frame, Unreinforced Building
2.30 psig	0% Mortality to Persons Inside Buildings or Persons Outdoors (CDE 2007)
3.10 psig	10% Mortality to Persons Inside Buildings (CDE 2007)
3.20 psig	<10% Mortality to Persons Outdoors (CDE 2007)
14.5 psig	1% Mortality to Those Persons Outdoors (LEES)

[32] Sources: LEES, CDE 2007, Quest 2003

5.0 Baseline Data

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

- United States Hazardous Liquid Pipelines (USDOT)
- United States Refined Petroleum Project Pipelines (USDOT)

5.1 U.S. Hazardous Liquid Pipeline Releases, January 2010 through December 2015

49 CFR 195.50 requires that the following incidents be reported:

> *"An accident report is required for each failure in a pipeline system subject to this part in which there is a release of the hazardous liquid or carbon dioxide transported resulting in any of the following:*
>
> *(a) Explosion or fire not intentionally set by the operator.*
>
> *(b) Release of 5 gallons (19 liters) or more of hazardous liquid or carbon dioxide, except that no report is required for a release of less than 5 barrels (0.8 cubic meters) resulting from a pipeline maintenance activity if the release is:*
>
> > *(1) Not otherwise reportable under this section;*
> >
> > *(2) Not one described in § 195.52(a)(4);*
> >
> > *(3) Confined to company property or pipeline right-of-way; and*
> >
> > *(4) Cleaned up promptly;*
>
> *(c) Death of any person;*
>
> *(d) Personal injury necessitating hospitalization;*
>
> *(e) Estimated property damage, including cost of clean-up and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000."*

In August 2016, the raw incident data file for hazardous liquid pipeline releases occurring since January 1, 2010 was downloaded. Releases[33] which have occurred since December 31, 2015 were then deleted, since the data set is incomplete for the 2016 calendar year. This left 2,362 reported

[33] As used herein, the terms release, spill, or leak are used interchangeably. They all refer to unintentional releases from the pipeline.

releases which occurred during the six year period between January 1, 2010 and December 31, 2015[34]. These incidents are summarized in the following table.

Table 5.1-1 – Reported U.S. Hazardous Liquid Pipeline Releases and Fatalities, January 2010 through December 2015

Calendar Year	Total Hazardous Liquid Pipeline Mileage	Number of Reported Incidents	Total Fatalities[35]	General Public Fatalities
2015	200,000[36]	454	1	1
2014	199,627	445	0	0
2013	192,417	401	1	0
2012	186,211	366	3	2
2011	183,580	346	1	0
2010	181,986	350	1	1
Totals	1,143,831	2,362	7	4

Using the above data, the following incident rates have been developed:

- Frequency of Reported Incidents – 2.0650 incidents per 1,000 mile years[37]
- Frequency of Fatalities[38] – 0.0061 fatalities per 1,000 mile years
- Frequency of General Public Fatalities – 0.0035 fatalities per 1,000 mile years
- Frequency of General Public Injuries – 0.0035 injuries per 1,000 mile years

It should be noted that during this reporting period, although there were seven (7) fatalities, only four (4) were members of the general public. There were a total of four reported (4) general public injuries.

[34] When there is a new change in operator incident reporting requirements, the USDOT often begins a new database to ensure that all data contained within a given database is consistent. The most recent database began in January 2010. Since 2016 data is incomplete, incidents occurring in 2016 were deleted from the analysis. The resulting data includes a complete six year history of over one million mile-years of pipeline operation.

[35] The total number of fatalities includes fatalities of the pipeline operator's personnel, the pipeline operator's contractor's personnel, and the general public.

[36] The total hazardous liquid pipeline mileage for 2015 is not yet available. This value has been assumed.

[37] This unit provides 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 incidents per 1,000 miles years, one would expect one incident per year on a 1,000 mile pipeline. Using this unit, frequencies of occurrence can be calculated for any combination of pipeline length and time interval.

[38] The total number of fatalities includes fatalities of the pipeline operator's personnel, the pipeline operator's contractor's personnel, and the general public.

5.2 U.S. Refined Petroleum Product Releases, January 2010 through December 2015

Since the OPL pipelines only transport refined petroleum products, the U.S. Hazardous Liquid Pipeline release data summarized above was filtered to include only refined petroleum product pipelines releases. Releases from hazardous liquid pipelines which transport other commodities (e.g., crude oil, highly volatile liquid, carbon dioxide, biofuel, etc.) were excluded. The results for this data subset are summarized below:

Table 5.2-1 – Reported U.S. Refined Petroleum Product Releases and Fatalities, January 2010 through December 2015

Calendar Year	Total Refined Petroleum Product Pipeline Mileage	Number of Reported Incidents	Total Fatalities[39]	General Public Fatalities
2015	61,000[40]	133	0	0
2014	61,763	157	0	0
2013	63,351	134	0	0
2012	64,042	133	0	0
2011	64,130	123	0	0
2010	64,800	125	0	0
Totals	379,086	805	0	0

Using the above data, the following incident rates have been developed:

- Frequency of Reported Incidents – 2.1235 incidents per 1,000 mile years[41]
- Frequency of Fatalities[42] – 0.0000 fatalities per 1,000 mile years
- Frequency of General Public Fatalities – 0.0000 fatalities per 1,000 mile years
- Frequency of General Public Injuries – 0.0000 injuries per 1,000 mile years

It should be noted that during this reporting period, there were zero (0) fatalities. There were a total of two (2) reported injuries, but neither of these were members of the general public; one (1) was the pipeline operator's employee and one (1) was the pipeline operator's contractor's employee.

[39] The total number of fatalities includes fatalities of the pipeline operator's personnel, the pipeline operator's contractor's personnel, and the general public.
[40] The total hazardous liquid pipeline mileage for 2015 is not yet available. This value has been assumed.
[41] This unit provides 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 incidents per 1,000 miles years, one would expect one incident per year on a 1,000 mile pipeline. Using this unit, frequencies of occurrence can be calculated for any combination of pipeline length and time interval.
[42] The total number of fatalities includes fatalities of the pipeline operator's personnel, the pipeline operator's contractor's personnel, and the general public.

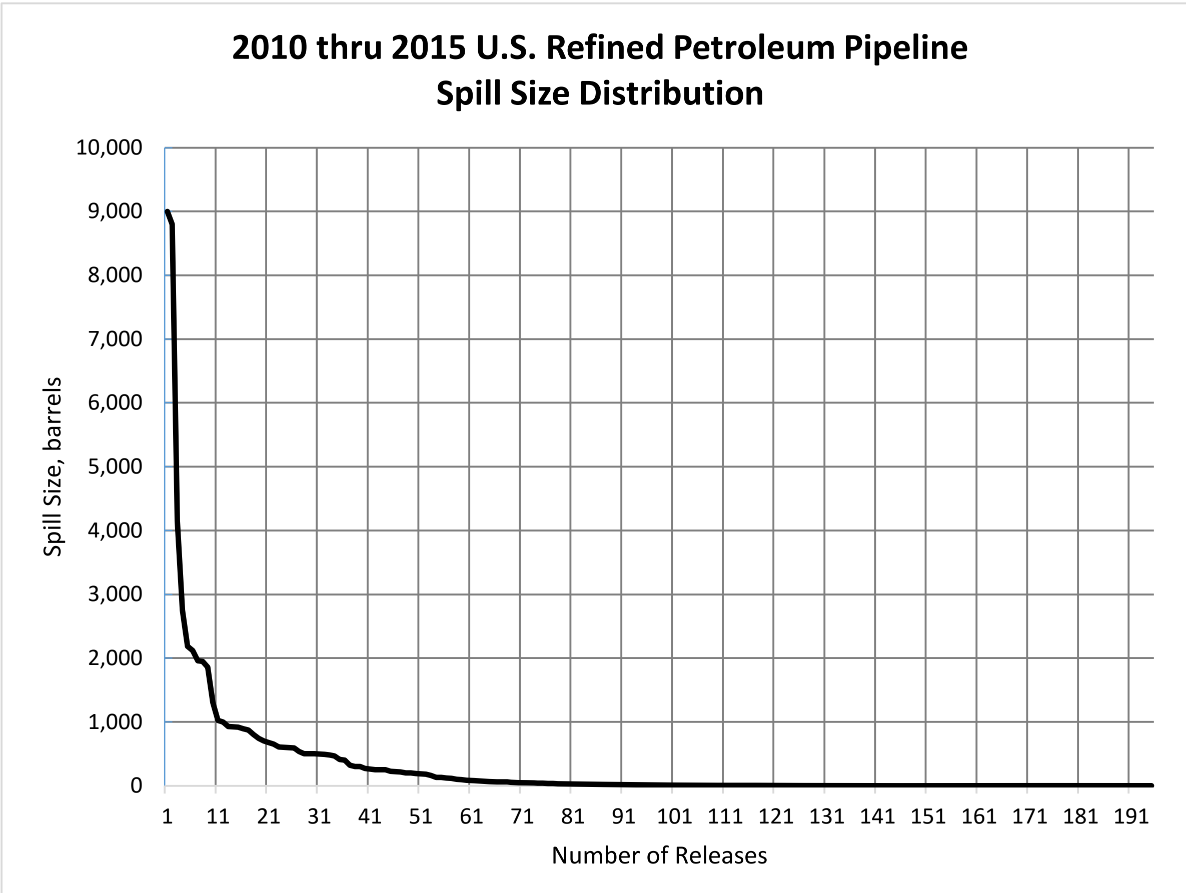
The releases presented in Table 5.2-1 fall into three categories, as identified on PHMSA Form F 7000-1, Accident Report – Hazardous Liquid Pipeline Systems.

- Contained on Pipeline Operator Property – 610 of the 805 (76%) releases occurred on pipeline operator controlled property and were entirely contained within the property boundary. These releases were identified as occurring at the following types of facilities: valve stations, terminals, tank farms, junctions, pump stations, meter stations, etc. The "system part" identified on the accident reports included: onshore pipeline, including valve sites (41 releases, 6%); onshore terminal or tank farm equipment and piping (242 releases, 40%); onshore pump or meter station equipment and piping (237 releases, 39%); and onshore breakout tank or storage vessel, including attached appurtenances (90 releases, 15%).
- Extended Beyond Operator Property - 38 of the 805 (5%) releases occurred on pipeline operator controlled property, but the release migrated beyond the parcel boundary.
- Pipeline Right-of-Way - 157 of the 805 (19%) releases were identified as occurring along the pipeline right-of-way. These included releases which occurred at valve sites.

The proposed collocated OPL pipeline and overhead HVAC line corridor does not include any of the types of facilities identified on the accident reports as "pipeline operator controlled property" (e.g., valve stations, terminals, tank farms, junctions, pump stations, meter stations, etc.). Further, the releases that occurred on the pipeline operator's controlled property which did not extend beyond the operator controlled property boundary would not normally affect the public. As a result, these 610 releases (first bullet above) were not included in the data set used to evaluate the risks posed to the public from the OPL pipeline(s).

The average spill size from the remaining 195 releases (157 releases which occurred along the pipeline right of way plus 38 releases which occurred on the pipeline operator controlled property, but the release migrated beyond the parcel boundary) was 306 barrels (12,900 gallons). The largest reported unintentional release was 9,000 barrels (378,000 gallons). These data are presented in the Figure 5.2-1.

Figure 5.2-1 – Spill Size Distribution, 2010 thru 2015 U.S. Refined Petroleum Product Pipeline Releases[43]



The resulting frequency of unintentional releases which affect property beyond that of the pipeline operator was 0.5144 incidents per 1,000 mile years. The distribution of these incidents by cause is shown in Table 5.2-2 below.

[43] This includes all releases which occurred along the pipeline right-of way and all releases which occurred on the pipeline operator controlled property, which migrated beyond the property boundary. Releases which occurred on the pipeline operator controlled property and totally contained on the operator's property, have not been included.

Table 5.2-2 – Reported U.S. Refined Petroleum Product Pipeline Releases by Cause, January 2010 through December 2015

Cause	Number of Reported Incidents	Percentage	Frequency (incidents per 1,000 mile years)	Average Spill Size (Barrels[44])
Equipment Failure[45]	48	24.6%	0.1266	246
Incorrect Operation[46]	15	7.7%	0.0396	704
External Corrosion	43	22.1%	0.1134	269
Outside Force/Excavation	38	19.5%	0.1002	473
Material Failure	33	16.9%	0.0871	194
Internal Corrosion	4	2.0%	0.0106	21
Natural Force[47]	8	4.1%	0.0211	154
Other	6	3.1%	0.0158	18

5.2.1 Spill Size Distribution, U.S. Refined Petroleum Product Pipelines, Normalized to 18-inch Diameter Pipe

For large releases (e.g., pipe rupture), pipe diameter can have a direct impact on the volume that may be released during a major incident. As a result, for larger releases (e.g., full bore ruptures), using the spill size distribution presented in Figure 5.2-1 above, for the relatively large diameter OPL pipelines, would not be appropriate. For large releases, the volume and flow rate are generally proportional to the pipe diameter squared. For example, the pipe volume and flow rate for a 16-inch diameter pipe is generally four times greater than for an 8-inch diameter pipe [e.g., $(16 / 8)^2 = 4$].

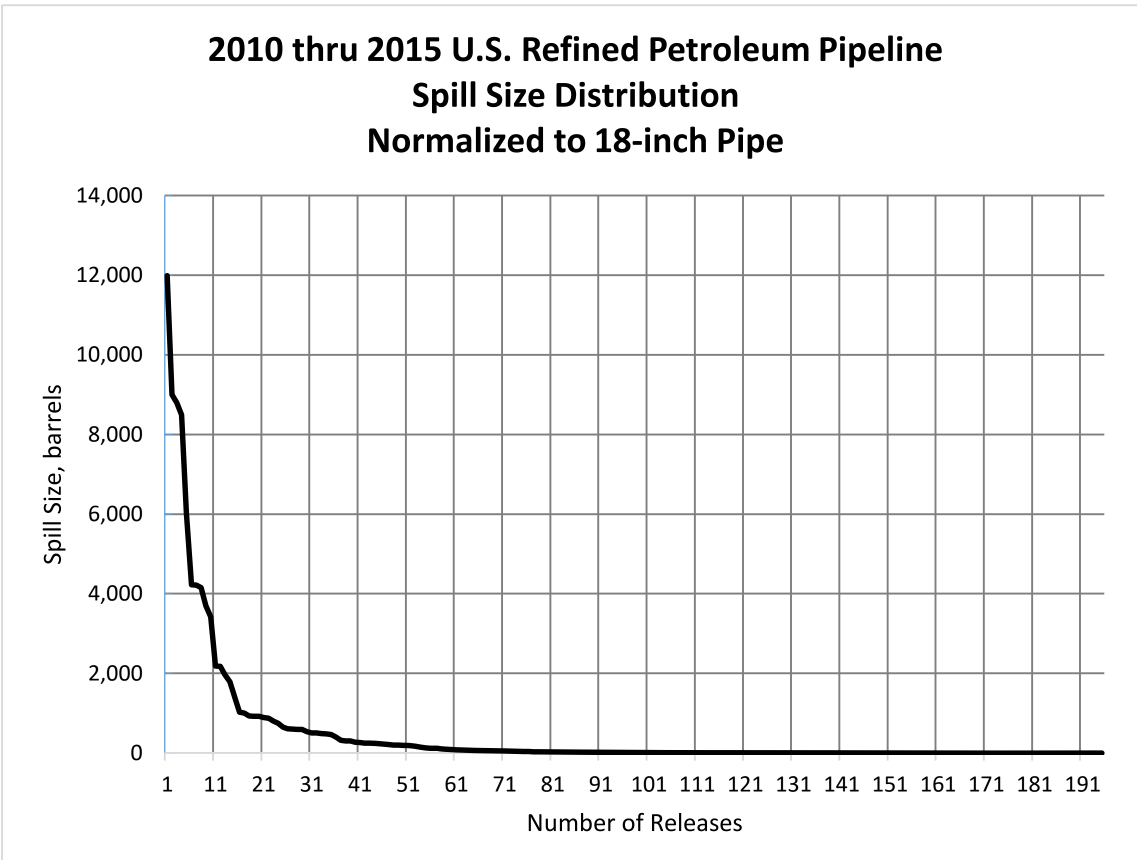
On the other hand, for a relatively slow corrosion caused release, one would expect a similar spill volume regardless of pipe diameter, since the release volume would generally depend on the size of the pipe defect, not the pipe diameter. For example, for a ¼-inch diameter hole in the pipe wall, the release volume from a 6-inch diameter pipe would be similar to that from a 20-inch diameter line, assuming similar operating pressures.

Figure 5.2.1-1 and Table 5.2.1-1 present a "normalized" spill size distribution; for releases that were identified on the incident report as "ruptures" (12 incidents), the unintentional release

[44] Barrels is a measure of volume equal to 42 U.S. gallons.
[45] Includes items such as: defective or loose tubing, malfunction of control or relief equipment, non-threaded equipment failure, pump, threaded connection, or coupling failure.
[46] Includes items such as: incorrectly installed equipment, over-pressure, overfill tank or vessel, valve left in wrong position, wrong equipment installed, etc.
[47] Includes items such as: earth movement, floods, lightning, temperature, etc.

volumes presented in Figure 5.2-1 have been multiplied by (18.0[48] / Pipe Diameter)^2. For ruptures of pipes larger than 18-inches in diameter, the spill volume was reduced. For releases from lines smaller than 18-inches, the spill volume was increased. For all other releases (e.g., mechanical puncture, leak, or other), no changes to the reported spill volume have been made.

Figure 5.2.1-1 – Spill Size Distribution, U.S. Refined Petroleum Product Pipeline Releases, Normalized to 18-inch Diameter Pipe, January 2010 through December 2015[49]



The normalized average spill size from these releases was 484 barrels (20,300 gallons). The largest normalized reported unintentional release was 12,000 barrels (504,000 gallons). As noted,

[48] One of the OPL pipelines under study is 16-inches in outside diameter, the other is 20-inches in outside diameter. An average 18-inch diameter has been used for both lines in this study.

[49] For this Report, we have used an average pipe diameter of 18-inches for both the OPL 16-inch and 20-inch diameter pipelines. This includes all releases which occurred along the pipeline right-of way and all releases which occurred on the pipeline operator controlled property, which migrated beyond the property boundary. Releases which occurred on the pipeline operator controlled property and totally contained on the operator's property, have not been included.

the majority of these releases were relatively small, with a small portion having rather significant spill volumes.

These data are also summarized in tabular form in Table 5.2.1-1. These data will be used later in the individual and societal risk assessments.

Table 5.2.1-1– Spill Size Distribution, U.S. Refined Petroleum Product Pipeline Releases, Normalized to 18-inch Diameter Pipe, January 2010 through December 2015[50]

Spill Size Range Barrels	Average Spill Size	Distribution
1 Barrel or Less	0.5 Barrels	27 Percent
2 to 9 Barrels	4.3 Barrels	21 Percent
10 to 99 Barrels	36 Barrels	22 Percent
100 to 999 Barrels	416 Barrels	21 Percent
1,000 to 5,000 Barrels	2,603 Barrels	6 Percent
6,000 to 12,000 Barrels	8,861 Barrels	3 Percent

5.2.2 Olympic Pipeline Leak History

The PHMSA incident data file for hazardous liquid pipeline releases was reviewed to identify the frequency of releases from OPL's two pipelines that share the HVAC overhead power line corridor. Between January 1, 2010 and December 31, 2015, there were five (5) reported releases on the OPL system. These releases varied in size from 0.2 to 7.5 barrels. All of the releases occurred at valve stations and the releases were entirely contained within OPL property; there were no reported releases along the pipeline right-of-way.

Three (3) of the releases occurred on the 20-inch diameter Allen to Renton pipe segment, at Allen Station, near Mount Vernon. One (1) release occurred at Renton Station on the Renton to Seattle pipe segment. One (1) release occurred at Ferndale on the Ferndale to Allen segment. There were no reported injuries, fires, or explosions. These releases are summarized in the table below.

[50] This includes all releases which occurred along the pipeline right-of way and all releases which occurred on the pipeline operator controlled property, which migrated beyond the property boundary. Releases which occurred on the pipeline operator controlled property and totally contained on the operator's property, have not been included.

Table 5.2.2-1– OPL Reported Releases, January 1010 through December 2015

Date	Release Volume (barrels)	Location	Item Involved
9/19/2011	0.29	MP 7 Block Valve	Instrumentation Connection Failure
3/31/2012	1.96	Allen Station	Threaded Connection/Coupling Failure
4/1/2012	0.97	Allen Station	Instrumentation (Pressure Gauge) on Pig Launcher
7/20/2014	0.19	Renton Station	Scraper Trap O-Ring Connection Failure on Pig Trap Door
11/10/2014	7.49	Allen Station	Threaded Connection Failure

Assuming a four hundred (400) mile OPL pipeline system, the resulting frequency of unintentional release was 2.0833 incidents per 1,000 mile years over this six (6) year period; this is essentially the same frequency of unintentional release (2.1235 incidents per 1,000 miles years) for the roughly 60,000 miles of U.S. refined petroleum product pipelines over this same period. The average spill size was 2.2 barrels, significantly less than the national overage of 94.5 barrels. It should also be noted that all of the released refined petroleum product was entirely contained on OPL controlled property; there were no reported releases during this period that occurred along the pipeline right-of-way or were not entirely contained on OPL controlled property.

5.3 Population Density

Societal risk is dependent on the number of exposed individuals. In the societal risk analysis presented later in this Report, population densities were used to determine the number of exposed individuals. These data were obtained by analyzing census data; the following data were provided by Environmental Science Associates for the HVAC overhead power line corridor which would be shared with the OPL pipeline(s).

- Minimum Population Density – 568 persons per square mile
- Average Population Density - 3,228 persons per square mile
- Maximum Population Density - 23,169 persons per square mile

The societal risk analysis will present the likelihood of various release scenarios for each of these population densities.

5.4 Potential Hazards of Collocated Overhead HVAC Lines and Hazardous Liquid Pipelines

Previously, in Section 1.1.5, the existing OPL procedures that address the OPL identified hazards posed by the collocation of overhead HVAC transmission lines and hazardous liquid pipelines, were presented. In this section, these, and other risks which will be used in the analysis will be discussed.

When overhead HVAC lines are collocated with a hazardous liquid pipeline(s), the following potential hazards can be presented.

- **Fault Conditions** – When a ground fault occurs on a HVAC transmission line, it can cause high electrical current to travel through the soil and onto a pipeline. Under fault conditions, elevated potentials can lead to coating damage or direct arcing to the pipeline.[51] These situations can cause pipe external corrosion coating damage, damage to the pipe wall, and through wall pipe failures.

- **Touch and Step Potential** – Touch potential is the voltage a person may be exposed to when contacting a pipe or electrically continuous appurtenance (e.g., cathodic protection test station, access stile, valve, etc.); this can be a concern during both normal steady state inductive and fault conductive/inductive conditions. High touch or step potentials can pose a safety hazard to a person in contact with the pipeline, or pipeline appurtenance. The current industry threshold is 15 volts. At touch potentials greater than this value, personnel may be subject to safety risks posed by electrical shock.

- **Pipeline Integrity** – During steady state operation, an overhead HVAC line can induce interference that can contribute to accelerated external corrosion damage to a pipeline. According to the A.C. Corrosion State of the Art: Corrosion Rate, Mechanism, and Mitigation Requirements, published by the National Association of Corrosion Engineers (NACE),

  "In 1986, a corrosion failure on a high-pressure gas pipeline in Germany was attributed to AC corrosion. This failure initiated field and laboratory investigations that indicated induced AC-enhanced corrosion can occur on coated steel pipelines, even when protection criteria are met. In addition, the investigations ascertained that above a minimum AC density, typically accepted levels of cathodic protection would not control AC-enhanced corrosion. The German AC corrosion investigators' conclusions can be summarized as follows:

  a. AC-induced corrosion does not occur at AC densities less than 20 amp/meter^2 (1.9 amps/foot^2).
  b. AC corrosion may or may not occur (is unpredictable) for AC densities between 20 to 100 amp/meter^2 (1.9 to 9.3 amps/foot^2).
  c. AC corrosion occurs at current densities greater than 100 amp/meter^2 (9.3 amps/foot^2)."

- **Encroachment and Construction Hazards** – The construction of facilities near an active hazardous liquid pipeline can increase the risk that the line will be hit or damaged by the construction activity. Increased pipe stresses due to surcharge loading can also be imposed by equipment operating over, or near, the pipeline.

[51] Det Norske Veritas, Criteria for Pipelines Co-Existing with Electric Power Lines, October 2015. Prepared for INGAA Foundation, Inc.

5.5 Pipeline Incidents Caused By Close Proximity to Electrical Utilities

Unfortunately, national data, similar to that presented earlier from the PHMSA database is not available to directly quantify the increased risk of unintentional release that may be posed by the collocation of overhead HVAC lines and hazardous liquid pipeline(s). In order to estimate the increased risk, the following data would be required:

- Total length of collocated hazardous liquid pipelines and overhead HVAC lines.
- Total number of unintentional releases, injuries, and fatalities, by cause, for all such collocated facilities.

These data, combined with that presented in Section 5.2, would enable a comparison of pipelines which are collocated with overhead HVAC lines and those which were not collocated.

In the absence of any such data, the PHMSA incident report database for the period from January 2010 through December 2015 has been reviewed. We attempted to identify all releases that may have been caused by a pipeline's close proximity to electrical utility facilities. Unfortunately, the external corrosion caused releases do not include data to identify releases caused by A.C. interference with cathodic protection systems; nor do the excavation damage caused releases identify construction related specifically to overhead power line or other electrical utility construction. However, the following observations are noteworthy; they help put the additional pipeline risk posed by ground faults due to the collocation of overhead HVAC lines and hazardous liquid pipelines into perspective.

- Of the 2,362 reported hazardous liquid pipeline incidents from January 2010 through December 2015. Fifteen (15, or 0.6 percent) were reported as being caused by an indication of "stray current" on the incident report.
- Based on the incident reports, it does not appear that any of the seven (7) fatalities were a result of collocated pipelines and overhead HVAC lines.
- Based on a review of the OPL incident reports, there do not appear to be any OPL releases that were caused by the pipelines being collocated with the existing overhead HVAC lines.
- There were six (6), or 0.25 percent of the 2,363 hazardous liquid pipeline incidents from January 2010 through December 2015 that may have been caused due to their close proximity to electrical utilities. These incidents were identified by reviewing all incidents caused by "other outside force damage", where "electrical arcing from other equipment or facility" was marked on the PHMSA Form F 7000 Accident Report. (These six incidents are summarized in the following subsections of this Report.)

5.5.1 Chevron Pipe Line Company June 11, 2010 Incident

According to the PHMSA Failure Investigation Report, "A large electrical charge was introduced to a fence directly over Chevron's pipeline. The charge jumped from a metal fence post to Chevron's pipeline causing an ~ 1" hole in the fence post and an ~1/2" hole near the 12:00 position on the pipe. The leak occurred near a small creek that runs through a high density populated area. The crude followed the creek to a pond where most of it was captured."

This event caused a reported 800 barrel (33,600 gallon) crude oil spill (778 barrels, or 32,700 gallons, were reported as recovered) and $32 million in clean-up costs, repairs, remediation, lost product, private property damage, emergency response, and settlements. The site was located adjacent to a Rocky Mountain Power Electrical Transition Station (ETS), near Red Butte Creek, near Salt Lake City, Utah. An ETS is where a high voltage above grade transmission line transitions to below grade buried cable.

According to the PHMSA report, the bottom of the fence post was within three (3) inches of the top of the pipeline. (There were no one-call laws in place at the time of fence construction, around 1980.) The cause of the "large electrical charge" was determined to be a ground fault that sent a very large surge of electricity through the fence. (It was later discovered that the fence was connected to the ETS station grounding grid.)

Figure 5.5.1-1 Photograph from PHMSA report showing hole in pipe wall caused by electrical fault.

5.5.2 Oneok NGL Pipeline August 8, 2011 Incident

The accident report filed by the pipeline operator reported the incident cause as, "A 34 kV electrical wire came down off the utility pole struck the ground and the 106E pipeline cased crossing vent pipe initiating a small grass fire. The downed powerline arced a hole in the 106E pipeline, casing for road crossing and vent stack on casing. The 14# natural gasoline product releasing from the pipeline made its way to the surface and became ignited by the grass fire." Electrical arcing was noted on the incident report. This incident resulted in a 3.26 barrel (137 gallon) natural gas liquid spill. The total estimated damage from this incident was $411,000.

5.5.3 Crimson Pipeline September 8, 2013 Incident

The accident report filed by the pipeline operator reported the incident cause as, "the cause appears to be third party damage related to a nearby power pole grounding rod." Electrical arcing was noted on the incident report. This incident resulted in a 100 barrel (420 gallon) crude oil spill. The total estimated damage from this incident was $3.1 million.

5.5.4 Buckeye Partners LP March 14, 2014 Incident

The accident report filed by the pipeline operator reported the incident cause as, "A power line was reported down to the Kankakee, Illinois fire department by a passing motorist on Route 113 in Kankakee, Illinois. The power line fell directly on top of where the Buckeye 162 pipeline crosses Route 113… draft report of metallurgical analysis by same third party has stated the cause to be local melting of the pipe walls. The energy source for the melting was a high current arc that originated from a downed electrical power distribution line..." This incident resulted in a 25 barrel (1,020 gallon) refined petroleum product (transmix) spill. 16.6 barrels (697 gallons) were recovered. The total estimated damage from this incident was $2.0 million.

5.5.5 Marathon Pipeline (MPL) February 17, 2015 Incident

The accident report filed by the pipeline operator reported the incident cause as, "The leak was caused by an electrical arc from a grounding rod in the electric company's grounding system to MPL's jet fuel pipeline, resulting in an electrical arc burn breach to the pipe and release of jet fuel." This incident resulted in a 160 barrel (6,720 gallon) refined petroleum product spill. 112 barrels (4,700 gallons) were recovered. The total estimated damage from this incident was $2.5 million.

5.5.6 Kinder Morgan September 9, 2015 Incident

The accident report filed by the pipeline operator reported the incident cause as, "severe weather caused a center point high voltage line cross member to fall, draping lines over a high voltage 12.47 kV three phase distribution line. The electrical energy from the lightning was transferred through the poles steel guide wire and into the ground where it arced to the LCRC 12" pipeline. This arc caused a small hole in the pipe that caused the leak." 180 barrels (7,560 gallons) was recovered. The total estimated damage from this incident was $80,000.

5.6 A.C. Interference Analysis, Proposed 115/230 kV Project (Willow 2)

Puget Sound Energy, the project proponent, retained Det Norske Veritas to perform an analysis of potential A.C. interference with the existing OPL 16-inch and 20-inch pipelines. Their findings are presented in the final report, entitled, A.C. Interference Analysis – 230 kV Transmission Line Collocated with Olympic Pipelines OPL16 and OPL 20, (A.C. Interference Study) dated December 13, 2016. The A.C. Interference Study utilized the Elsyca Inductive and Resistive Interference Simulator (IRIS) software to predict the steady state electrical interference and resistive fault effects of the proposed overhead HVAC transmission lines on the existing 16-inch and 20-inch diameter OPL refined petroleum product pipelines.

In the evaluation of the proposed project and project alternatives, the study conservatively used the winter peak electrical loads. The study evaluated both the proposed 115/230 kV circuit voltage and the future 230/230kV circuit voltage.

5.6.1 Soil Resistivity

Det Norske Veritas collected soil resistivity measurements at 32 locations along the right-of-way. The results are summarized below at a depth of 5-feet.

- Minimum Resistivity – 66 ohm-meters
- Average Resistivity – 1,005 (OPL 20-inch) and 1,013 (OPL 16-inch) ohm-meters
- Maximum Resistivity – 4,021 ohm-meters

5.6.2 Model and Simulation Validation

The A.C. Interference Study included a comparison of modeled to actual A.C. interference for the existing 115 kV transmission line (Willow 1). In general, the measured A.C. potentials were fairly low – a maximum of 4.08 volts for the 16-inch line and 5.63 volts for the 20-inch line. (The common industry threshold is 15 volts, which can pose a safety threat to personnel.)

It should be noted that these measurements were not taken at the winter peak electrical loads; the operating parameters of the transmission line (e.g., phase conductor load and phase balance) have a significant impact on the induced A.C. potentials. Other factors that affect the measured values include: geometry of transmission lines, pipeline proximity, soil resistivity, external pipe corrosion coating type and condition, depth of cover, pipe diameter, angle between the pipeline and overhead HVAC transmission line, phase conductor spacing and distance above the ground, etc.

These field measurements were compared to modeled results to validate the model. The modeled results were in general conformance with the actual measured results, considering the range in values for the various factors noted above. The actual field measurements and the simulated results are presented graphically on the following figures for the 16-inch and 20-inch OPL pipelines.

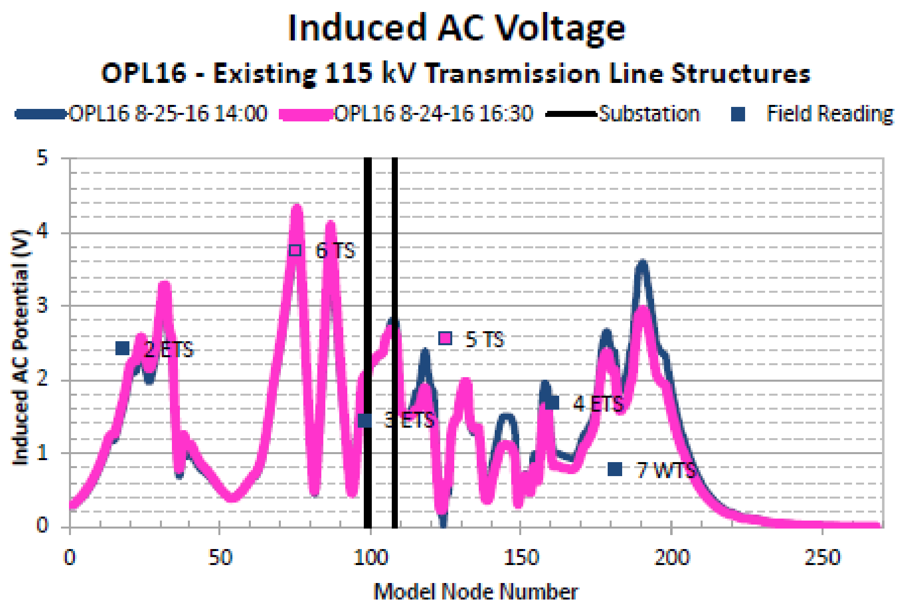


Figure 5.6.2-1 OPL 16-inch Modeled versus Actual A.C. Potentials

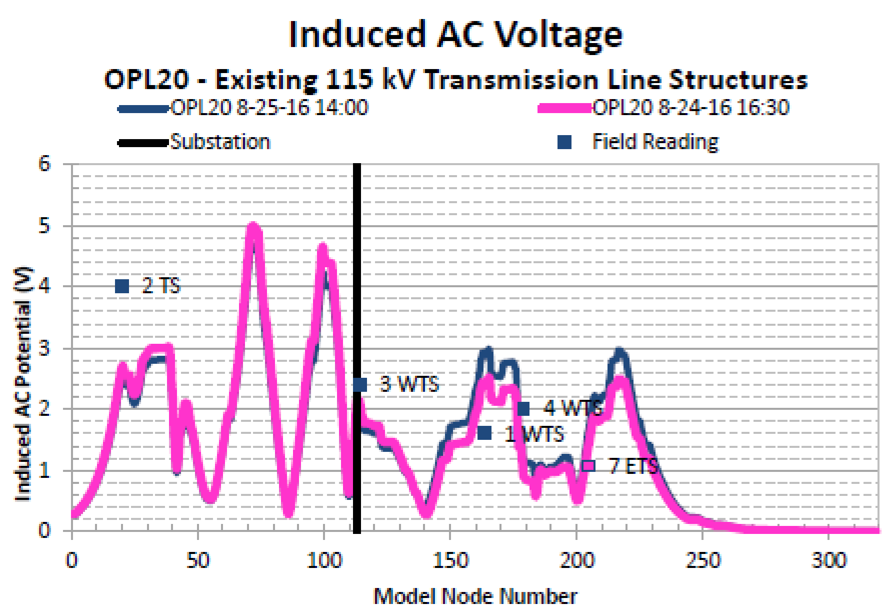


Figure 5.6.2-2 OPL 20-inch Modeled versus Actual A.C. Potentials

5.6.3 Predicted Results for Proposed 115/230 kV Project (Willow 2)

Structure (Pole) Type Sensitivity Study

A sensitivity study was performed to analyze various pole configurations. For the Willow 2 route, the C2 structure was modeled along the corridor, except for a short segment, where low profile structures are proposed. The location of where the low profile poles were analyzed is depicted in Figure 5.6.3-1. (It should be noted that the low profile poles would normally result in higher levels of A.C. interference on the pipelines due to the low pole configuration; as a result, their proposed use was limited.) The sensitivity study results are presented in Table 5.6.3-1 below for winter peak loading.

Table 5.6.3-1 Willow 2 Sensitivity Study Results, Winter Peak Loading

Structure Type	Load Scenario	Maximum Induced A.C. Potential[52] (volts)		Maximum Theoretical A.C. Current Density[53] (amps per square meter)	
		OPL 16-inch	OPL 20-inch[54]	OPL 16-inch	OPL 20-inch
Low Profile	115/230 kV	10	-	47	-
Low Profile	230/230 kV	11	-	52	-
C2	115/230 kV	22	24	74	47
C2	230/230 kV	18	18	83	71

Optimized Structure (Pole) Configuration

Due to the complexities along the right-of-way, the same pole configuration cannot be used along the entire corridor. The A.C. Interference Study analyzed an optimized configuration of transmission structures along the corridor. This configuration is presented in Figure 5.6.3-1.

[52] The common industry threshold is 15 volts, which can pose a safety threat to personnel.

[53] As noted previously, A.C. induced corrosion does not occur at AC densities less than 20 amp/meter^2. A.C. corrosion may or may not occur (is unpredictable) for AC densities between 20 to 100 amp/meter^2. AC corrosion occurs at current densities greater than 100 amp/meter^2.

[54] The OPL 20-inch line is not located within the corridor where the low profile structures are proposed.

DSD 010989

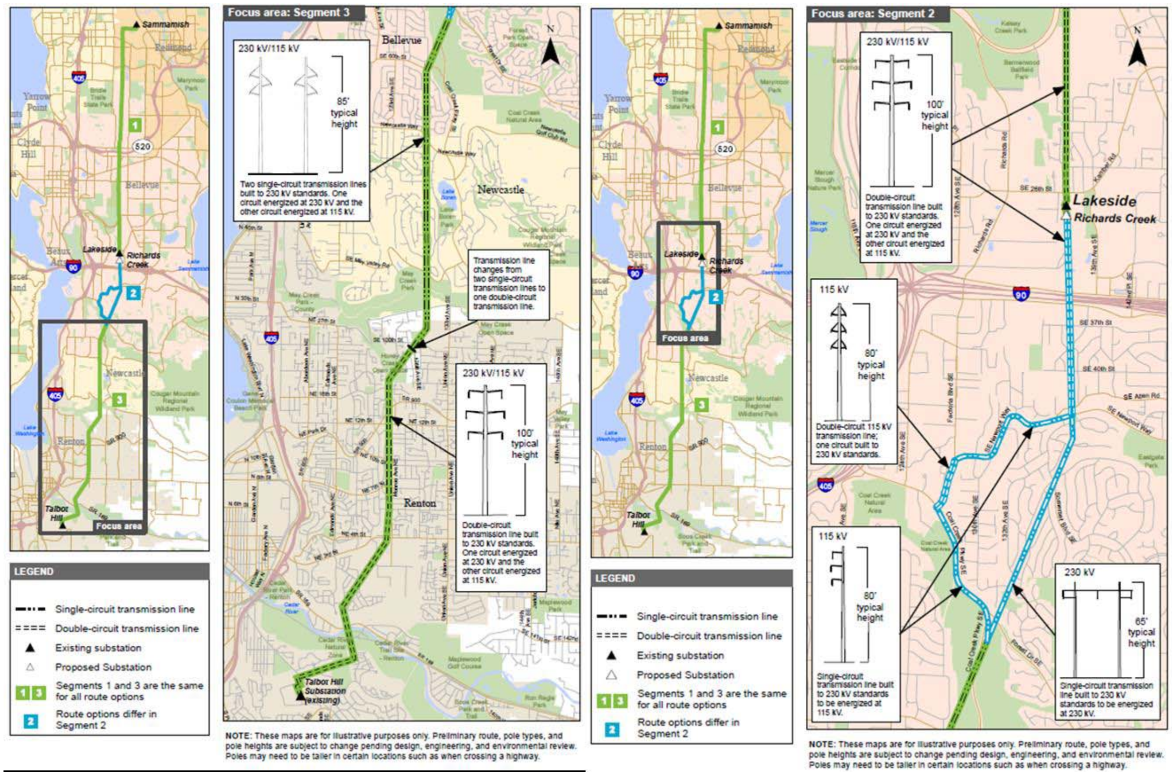


Figure 5.6.3-1 Willow 2 Transmission Line Route Depicting Modeled Structures (C1, C2, Low Profile, and C16)[55]

[55] This Figure has been taken from A.C. Interference Analysis – 230 kV Transmission line Collocated with Olympic Pipelines OLP16 and OPL20, dated December 13, 2016, prepared by Det Norske Veritas, Inc.

Estimated Induced A.C. Voltage (Touch Potential)

The simulated induced A.C. voltage results for the OPL 16-inch line are presented in the figure which follows for the proposed 115/230 kV and potential future 230/230 kV installations. This figure depicts the results for the optimized pole structure configurations, presented above. As noted, at peak winter loads, the predicted induced A.C. voltage would slightly exceed the 15 volt threshold for potential personal injury near the substation (node 100 to 110) for the proposed 115/230 kV installation.

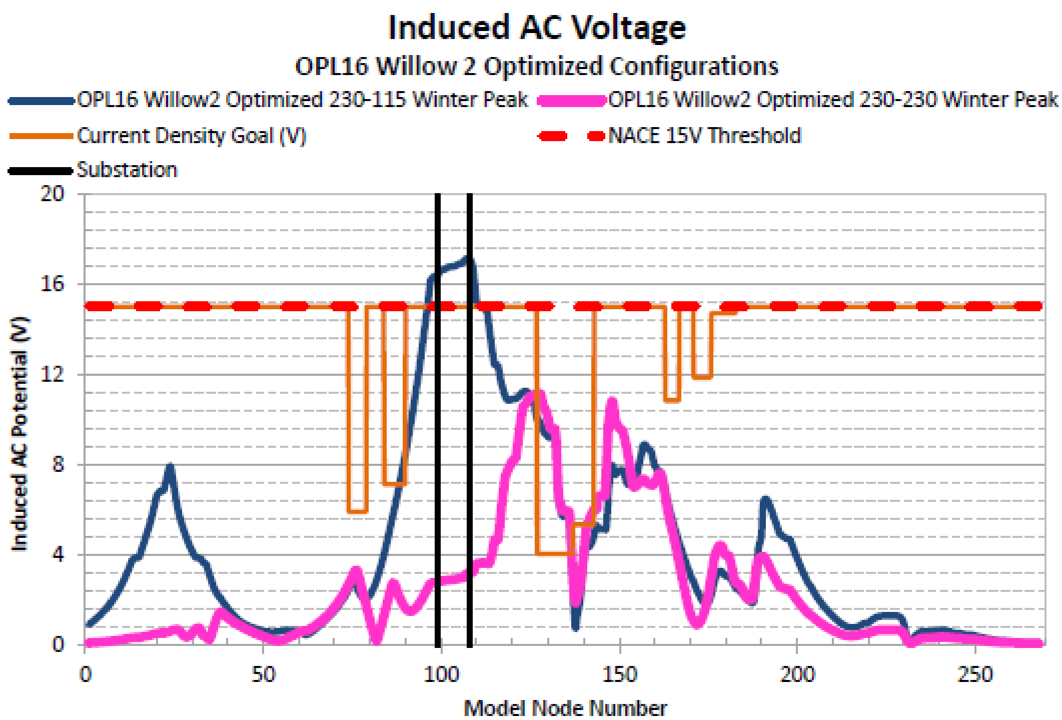


Figure 5.6.3-2 Induced A.C. Voltage, OPL 16-inch, Willow 2 Transmission Line Route[56]

[56] This Figure has been taken from A.C. Interference Analysis – 230 kV Transmission line Collocated with Olympic Pipelines OLP16 and OPL20, dated December 13, 2016, prepared by Det Norske Veritas, Inc.

The simulated induced A.C. voltage results for the OPL 20-inch line are presented in the figure which follows for the proposed 115/230 kV and potential future 230/230 kV installations. This figure depicts the results for the optimized pole structure configurations. As noted, at peak winter loads, the predicted induced A.C. voltage would slightly exceed the 15 volt threshold for personal injury near the node 150; the touch voltage threshold would be exceeded for both the proposed 115/230 kV and future 230/230 kV installations.

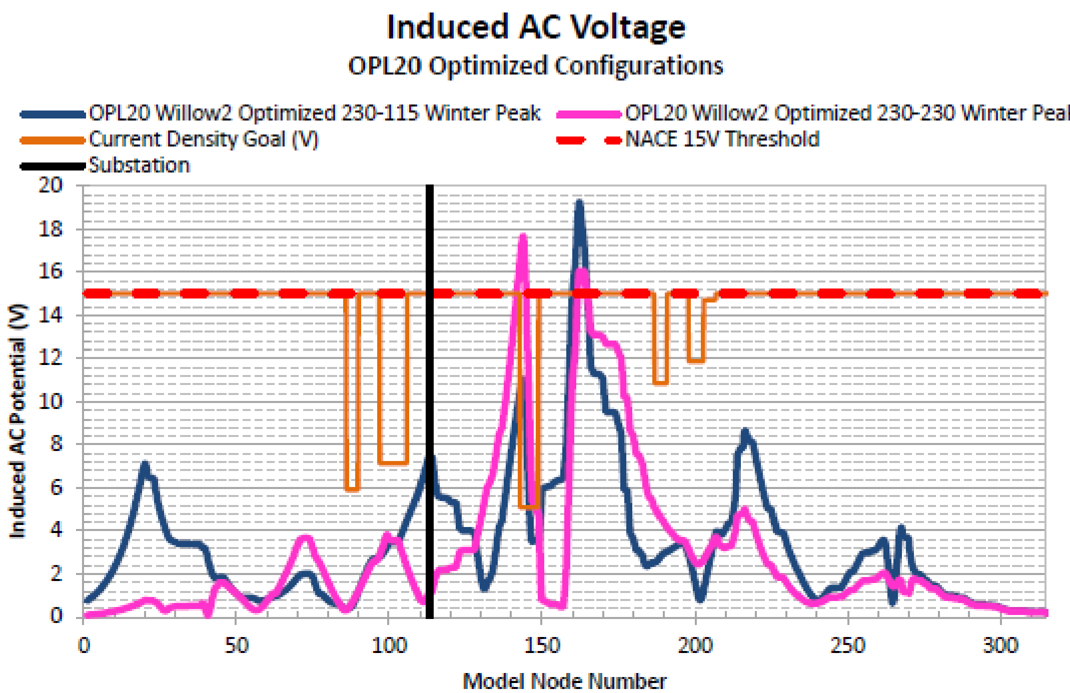


Figure 5.6.3-3 Induced A.C. Voltage, OPL 20-inch, Willow 2 Transmission Line Route[57]

[57] This Figure has been taken from <u>A.C. Interference Analysis – 230 kV Transmission line Collocated with Olympic Pipelines OLP16 and OPL20</u>, dated December 13, 2016, prepared by Det Norske Veritas, Inc.

Estimated A.C. Current Density

The simulated A.C. current densities for the OPL 16-inch line are presented in the figure which follows for the proposed 115/230 kV and future 230/230 kV installations. This figure depicts the results for the optimized pole structure configurations. As noted, at peak winter loads, the predicted A.C. current for the proposed 115/230 kV installation exceeds the 20 amps per square meter threshold near node 90. Both the proposed 115/230 kV and future 230/230 kV installations exceed this threshold from about not 130 to node 140. (Between A.C. current densities of 20 and 100 amps per square meter, A.C. corrosion may or may not occur; A.C. corrosion does occur above 100 amps per square meter.)

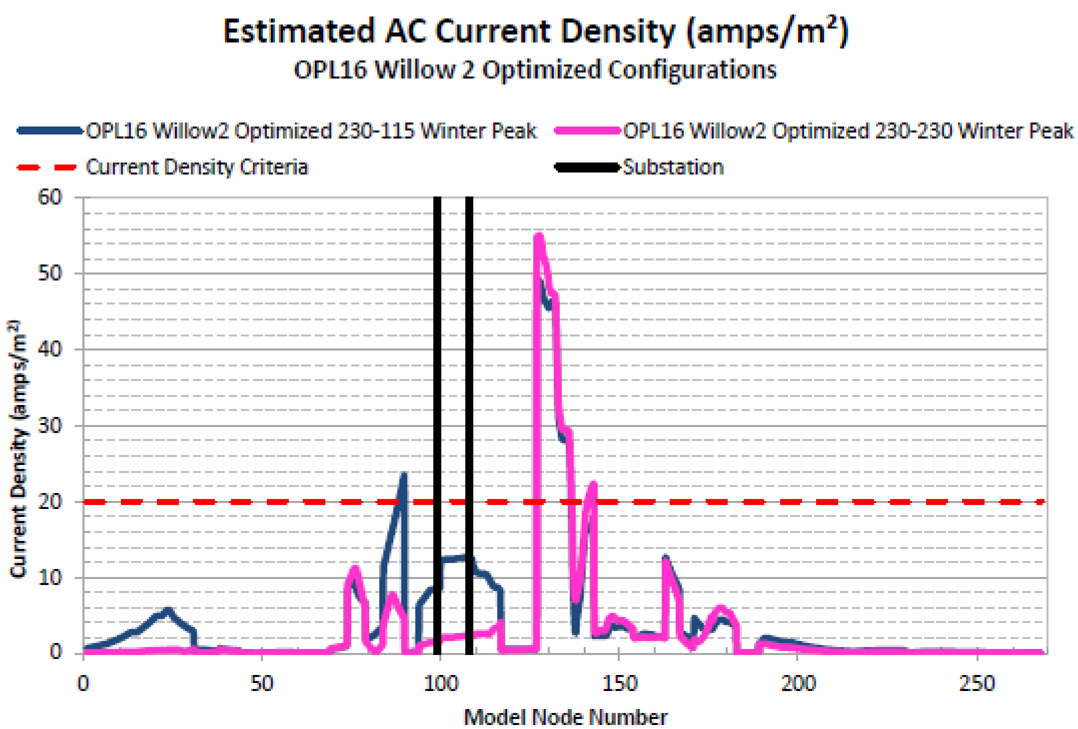


Figure 5.6.3-4 Induced A.C. Voltage, OPL 16-inch, Willow 2 Transmission Line Route[58]

[58] This Figure has been taken from A.C. Interference Analysis – 230 kV Transmission line Collocated with Olympic Pipelines OLP16 and OPL20, dated December 13, 2016, prepared by Det Norske Veritas, Inc.

The simulated A.C. current densities for the OPL 20-inch line are presented in the figure which follows for the proposed 115/230 kV and future 230/230 kV installations. This figure depicts the results for the optimized pole structure configurations. As noted, at peak winter loads, the predicted A.C. current density for the proposed 115/230 kV installation and the future 230/230 kV installation exceed the 10 amps per square meter threshold near node 140. (Between A.C. current densities of 20 and 100 amps per square meter, A.C. corrosion may or may not occur; A.C. corrosion does occur above 100 amps per square meter.)

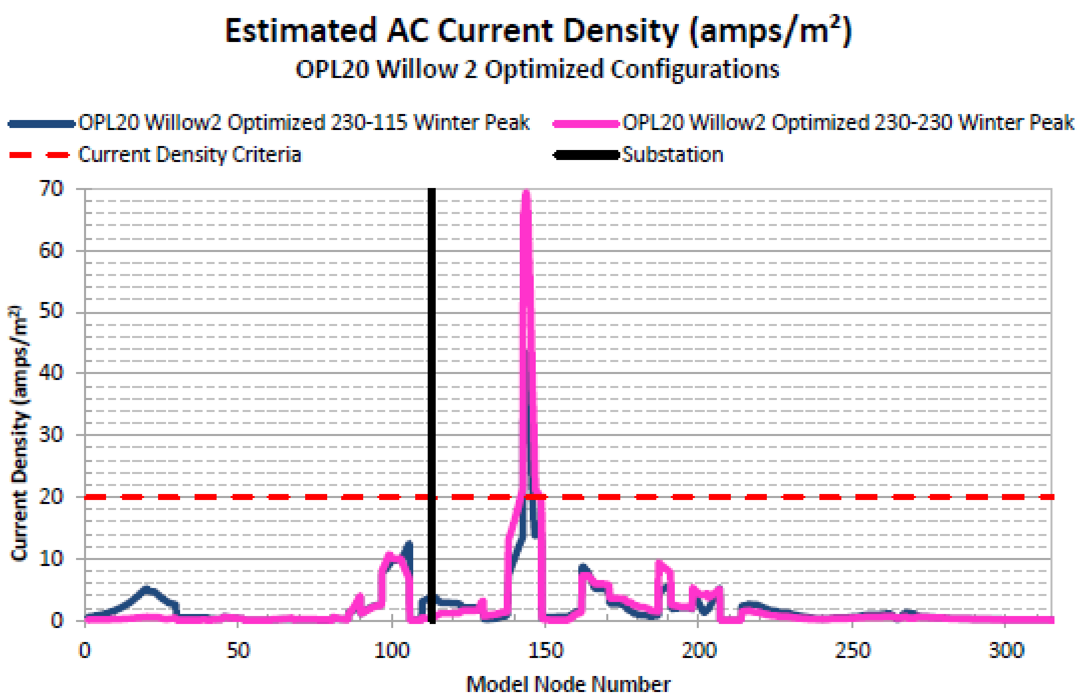


Figure 5.6.3-5 Induced A.C. Voltage, OPL 20-inch, Willow 2 Transmission Line Route[59]

Estimated Coating Stress Voltage – Structure (Pole) and Shield Wire Sensitivity

The A.C. Interference Analysis report noted that, "*several sensitivity studies were performed with regards to the fault analysis whereby the effects of fault currents, shield wire configurations, and pole configurations were evaluated to determine the pipelines' susceptibility to damage, resulting from a fault incident. For each fault sensitivity study, a single line-to-ground fault was considered at multiple locations south along the collocation. The resulting coating stress voltage (voltage across the coating) on the pipeline was compared for the C1, C2, C3, and Low Profile pole configurations, which showed for the same magnitude of fault current, the C2 and C3 pole configurations resulted in the same coating stress voltages. Thus for the resistive fault simulation, as the C2 and C3 poles were both single pole configurations, the coating stress voltage was the*

[59] This Figure has been taken from A.C. Interference Analysis – 230 kV Transmission line Collocated with Olympic Pipelines OLP16 and OPL20, dated December 13, 2016, prepared by Det Norske Veritas, Inc.

same in each case. Based upon these results, a separate fault sensitivity study was not performed for the C16 structures, as the coating stress voltages were expected to be similar to the C2 and C3 structures. For the Low profile structures, as they are comprised of two poles, the resulting coating stress voltage is different, considering the same fault current.

A fault current value of 25 kA was used in this study, which is based on the maximum transmission system fault current that could be experienced in the portions of the corridor where the pipelines are collocated. The scenarios that were analyzed to arrive at 25 kA include a bus fault at the Sammamish, the proposed Richards Creek, and Talbot Hill substations. The Olympic Pipelines first enter the PSE transmission corridor approximately 3 miles north of the Talbot Hill substation, which was accounted for in the calculation of fault current present at that location. Using a fault current of 25 kA the sensitivity studies were analyzed with no shield wire, an Alumoweld shield wire, and an Optical Ground Wire (OPGW). The same four poles were considered for the C1, C2, and C3 studies where the two closest poles north and south of the substation were faulted in the analysis. For each case, the maximum coating stress voltage and maximum arcing distance were calculated…"

As noted in the following table, when a shield wire is used, the coating stress voltages decrease dramatically, as the primary function of the shield wire is to provide a low resistance path to carry the majority of the fault current to ground. In the absence of a shield wire, the total fault current returns to ground at a single location, possibly at one of the OPL pipelines.

Table 5.6.3-2 Coating Stress Voltages Resulting from 25 kA Fault Current

Fault Scenario	Pole Number	Structure (Pole) Type	Coating Stress Voltage (volts)		
			No Shield Wire	Alumoweld	OPGW
FC1	16	C1	18,840	3,219	2,833
FC2	48	C1	55,170	7,902	5,970
FC3	179	C2/C3	44,850	6,297	3,447
FC4	46	C2/C3	20,010	2,826	1,517
FC5	100	Low Profile	-	2,595	1,637
FC6	106	Low Profile	-	1,931	2,097
FC7	108	Low Profile	-	2,560	2,428

Based on the type and thickness of the exterior corrosion coating on the OPL pipelines, the Report estimated the coating breakdown voltage at 10,825 volts. As noted above, provided a shield wire is used, the predicted coating stress voltage is less than the coating breakdown voltage. The applicant has committed to using an OPGW shield wire.

Estimated Arcing Distance – Structure (Pole) Type and Shield Wire Sensitivity

As noted previously, a phase to ground fault on a HVAC transmission line can result in large currents in the soil. These faults are typically caused by lightning, phase insulator failure, conductor failure, other failure which allows the conductor to touch the ground, or transformer failure. These high currents can cause arc damage to the pipe, resulting in pipe wall damage or through wall pipe containment failures.

The A.C. Interference Study analyzed potential faults and developed predicted maximum return to ground currents and resulting arcing distances for a variety of pole configurations and shield wires. The maximum soil resistivity values were used in the analysis, as they result in the maximum arcing distance (worst case). As noted previously, the actual soil resistivity along the corridor ranged from 66 to 4,021 ohm-meters, with an average of 1,012 meters; a soil resistivity of 4,021 ohm-meters was used in the analysis with a fault current of 25 kV.

Table 5.6.3-3 Arc Distances

Structure (Pole) Type	Shield Wire	Maximum Return Current to Ground (amps)	Maximum Arcing Distance (feet)
C1 and C2/C3	None	25,000	42
C1 and C2/C3	Alumoweld	3,805	17
C1 and C2/C3	OPGW	2,207	13
Low Profile	Alumoweld	1,109	10
Low Profile	OPGW	602	7

As noted in the above table, the OPGW shield wire provides the lowest return current to ground values and shortest arcing distances. The applicant has committed to the installation of an OPGW shield wire.

The A.C. Interference Study also analyzed the arc distances using the actual range of soil resistivity. Assuming a fault current of 25 kV and an OPGW shield wire, the resulting arc distances ranged from 4 to 13-feet. Due to the variation is soil resistivity and imprecision in pipe location, the A.C. Interference Study recommended the following:

- Distances between the pipeline and transmission line pole grounds should be field verified by the transmission line and pipeline operators.

- If the transmission line pole grounds are found to be within 13 feet of the pipeline, arc shielding protection should be installed, consisting of a single zinc ribbon extending a minimum of 25 feet past the transmission line pole grounds in both directions. The zinc ribbon should be connected to the pipeline through a single direct-current decoupler (DCD).

5.7 A.C. Interference Analysis, Existing 115 kV Corridor

Puget Sound Energy retained Det Norske Veritas (U.S.A.), Inc. to perform an analysis of potential A.C. Interference for the existing 115 kV corridor. The results of this analysis are presented in a MS PowerPoint Slide Deck entitled, Puget Sound Energy A.C. Interference Analysis Existing Corridor. (The soil resistivity data and model validation were presented earlier, in Sections 5.6.1 and 5.6.2 of this report.)

In the evaluation of the existing corridor, the study conservatively used the peak winter electrical loads presented below.

Table 5.7-1 Loading Scenarios (Peak Winter Loads)

Loading Scenario	South		North	
	Talbot Hill – Lakeside #2	Talbot Hill – Lakeside #1	Sammamish-Lakeside Creek #2	Sammamish – Lakeside #1
115 kV Actual Winter 2013-14	618	618	402	161
115 kV Predicted Winter 2027-28	884	889	136	110

5.7.1 Estimated Induced A.C. Voltage (Touch Potential)

The simulated induced A.C. voltage results for the OPL 16-inch and 20-inch lines are presented in the figures which follow for the existing corridor. As noted, at peak winter loads, the predicted induced A.C. voltage would be less than the 15 volt threshold. As a result, a touch potential hazard will not be posed to personnel.

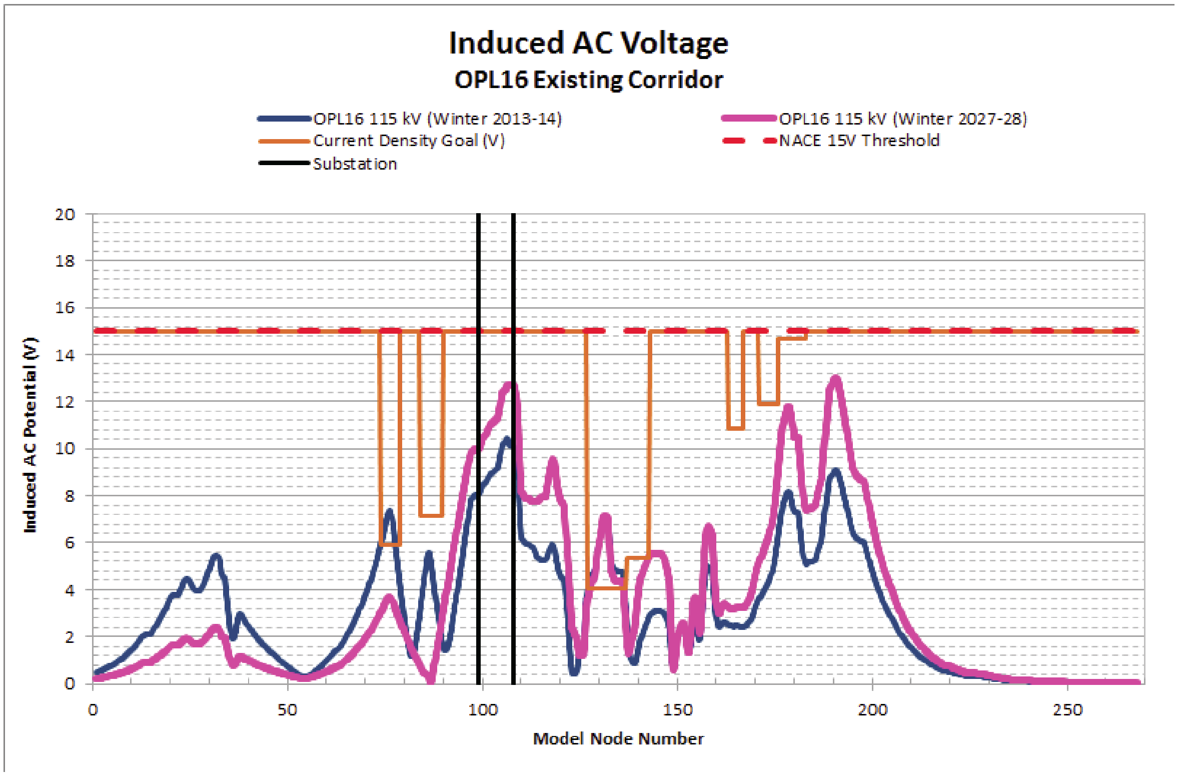


Figure 5.7.1-1 Induced A.C. Voltage, OPL 16-inch, Existing Corridor[60]

[60] This Figure has been taken from Puget Sound Energy, A.C. Interference Analysis, Existing Corridor, dated February 2, 2017, prepared by Det Norske Veritas, Inc.

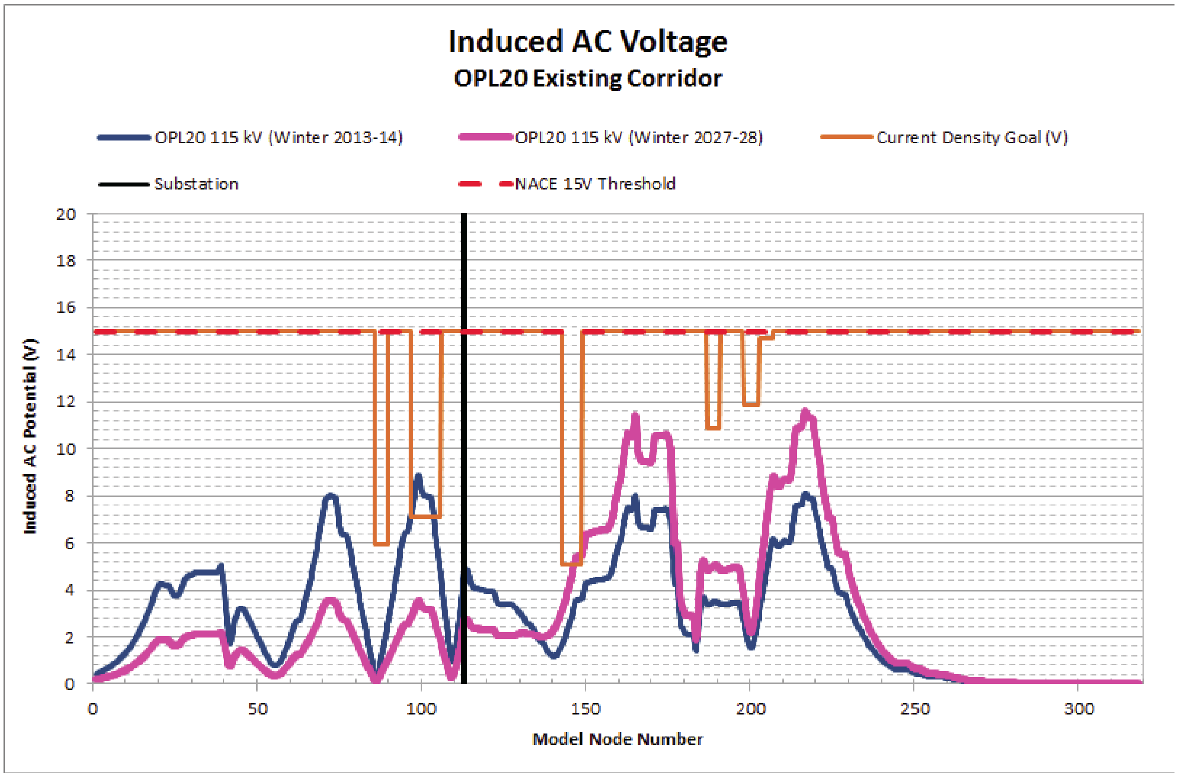


Figure 5.7.1-2 Induced A.C. Voltage, OPL 20-inch, Existing Corridor[61]

5.7.2 Estimated A.C. Current Density

The simulated A.C. current densities for the OPL 16-inch line are presented in the figure which follows for the existing 115 kV installation. As noted, at peak winter loads, the predicted A.C. current density would exceed the 20 amps per square meter threshold near nodes 75 and 135. The highest anticipated current density would be 35 amps per square meter. (Between A.C. current densities of 20 and 100 amps per square meter, A.C. corrosion may or may not occur. A.C. corrosion does occur above 100 amps per square meter; it does not occur below 20 amps per square meter.)

[61] This Figure has been taken from Puget Sound Energy, A.C. Interference Analysis, Existing Corridor, dated February 2, 2017, prepared by Det Norske Veritas, Inc.

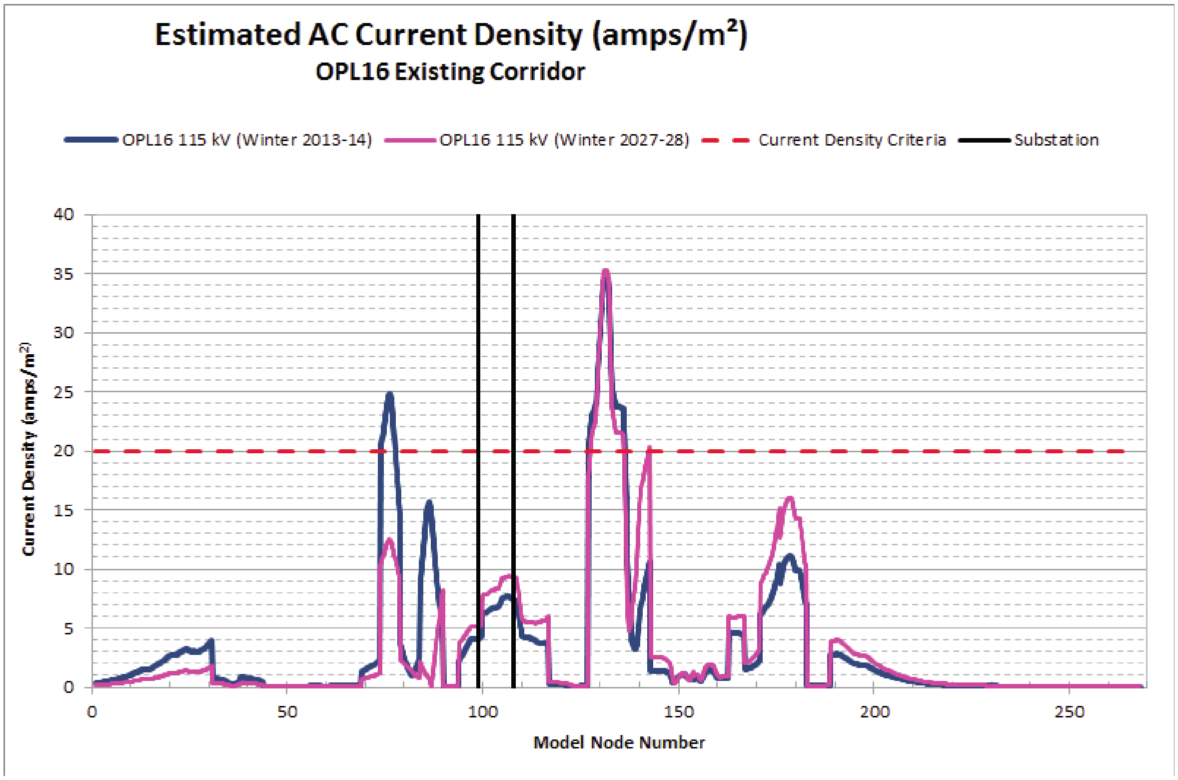


Figure 5.7.2-1 Induced A.C. Voltage, OPL 16-inch, Existing Corridor[62]

The simulated A.C. current densities for the OPL 20-inch line are presented in the figure which follows for the existing 115 kV installation. As noted, at peak winter loads, the predicted A.C. current density would slightly exceed the 20 amps per square meter threshold near nodes 100 and 145. The highest anticipated current density would be 25 amps per square meter. (Between A.C. current densities of 20 and 100 amps per square meter, A.C. corrosion may or may not occur. A.C. corrosion does occur above 100 amps per square meter; it does not occur below 20 amps per square meter.)

[62] This Figure has been taken from Puget Sound Energy, A.C. Interference Analysis, Existing Corridor, dated February 2, 2017, prepared by Det Norske Veritas, Inc.

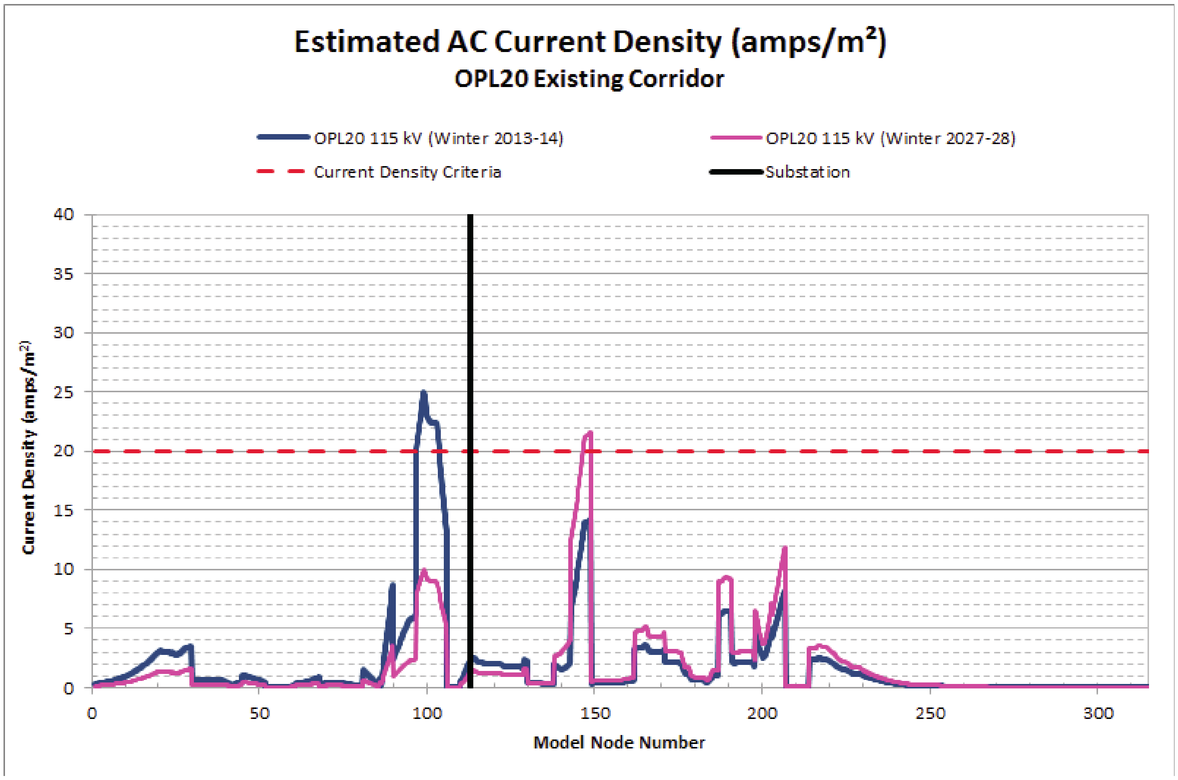


Figure 5.7.2-2 Induced A.C. Voltage, OPL 20-inch, Existing Corridor[63]

5.7.3 Estimated Coating Stress Voltage

OPL did not provided data to the applicant regarding the estimated coating stress voltage for the existing 115 kV corridor.

5.7.4 Estimated Arcing Distance

OPL did not provided data to the applicant regarding the estimated arcing distances the existing 115 kV corridor.

[63] This Figure has been taken from Puget Sound Energy, A.C. Interference Analysis, Existing Corridor, dated February 2, 2017, prepared by Det Norske Veritas, Inc.

6.0 Qualitative Aggregate Risk Assessment

Unfortunately, the baseline data presented in the prior section does not include an inventory of pipelines that are collocated with overhead HVAC line(s), nor do the incident data reports identify incidents which occurred where the pipeline was collocated with overhead HVAC line(s). As a result, using these baseline data, it is impossible to directly develop and quantify the difference in risk which may exist between the subject collocated OPL pipeline segments and those that are not collocated with HVAC overhead transmission line(s).

It is difficult to estimate the potential extent of human injury because there are so many variables affecting the size of a fire or explosion that could result from an unintentional release of refined petroleum product: rate of infiltration into the soil, rate of vapor cloud formation, size of the vapor cloud within the combustible range (controlled by weather, including wind and temperature, release rate, product spilled, etc.), concentration of vapors (varying with wind and topographic conditions), degree of vapor cloud confinement, etc. (These conditions will be evaluated later in the Report, when Individual and Societal Risks are presented.)

As noted in the Baseline Data presented previously, refined petroleum product pipeline releases seldom cause personal injuries or death. In fact, there were no fatalities on the U.S. regulated refined petroleum product pipeline systems from 2010 through 2015. However, such incidents can and do occur (e.g., Bellingham, Washington incident of June 10, 1999 and San Bernardino incident of May 25, 1989). In this section, the likelihood of fatalities will be estimated using these historical baseline data presented in the preceding section. The results provide a means of framing the risk posed by the OPL pipelines.

Using the U.S. hazardous liquid and refined petroleum product pipeline baseline data compiled in the previous section, the anticipated frequencies of unintentional releases, fires and fatalities from the existing OPL 16-inch and 20-inch diameter pipelines have been estimated. The qualitative aggregate risk estimates are based on the following criteria:

- 24.8 total miles of 16-inch and 20-inch OPL Pipeline[64]
- Baseline Incident Rate for Releases from Refined Petroleum Product Pipeline Systems – 0.5144 incidents per 1,000 mile years
- Conditional Probability of Ignition – 2.5 percent

[64] The length of pipeline that is collocated with the transmission line between Sammamish Substation and Talbot Hill Substation is 68,122 linear feet for one pipeline (20-inch diameter pipeline) and 62,906 linear feet (16-inch diameter pipeline).

DSD 011002

Table 6.0-1 Qualitative Aggregate Risk Assessment Results – 24.8 Miles of OPL Pipelines

Unintentional Release Resulting In	Anticipated Frequency Incidents per 1,000 mile years	Anticipated Number of Incidents per Year[65]	Likelihood of Annual Occurrence
Spill Volume Distribution, Normalized to 18-inch Diameter			
Reportable Release of Any Volume	0.5144	0.0128	1 in 78
Pipeline Release of 1 Barrel or Less	0.1389	0.0034	1 in 290
Pipeline Release of 2 to 9 Barrels	0.1080	0.0027	1 in 373
Pipeline Release of 10 to 99 Barrels	0.1132	0.0028	1 in 356
Pipeline Release of 100 to 999 Barrels	0.1080	0.0027	1 in 373
Pipeline Release of 1,000 to 5,000 Barrels	0.0309	0.0008	1 in 1,300
Pipeline Release of 6,000 to 12,000 Barrels	0.0154	0.0004	1 in 2,620
Fire and Fatality			
Fire	0.0129	0.0003	1 in 3,135
General Public Fatality[66]	0.0035	0.0001	1 in 11,520

It should be noted that these historical data do not differentiate between various population densities. For example, a release in an urban area is likely to cause more significant impacts to humans than a release in a rural, undeveloped area. For the more sparsely populated areas of the OPL pipeline, the fatality figures shown above likely overstate the risk to the public; while in the more densely populated areas, they likely understate the risk, due to the more likely public exposure resulting from the greater population density. In Sections 9.0 (Individual Risk Assessment) and 10.0 (Societal Risk Assessment) of this Report, the actual environment will be considered; these analyses will consider population density, pipe contents, pipe diameter, actual operating conditions and the proximity to the public[67].

[65] Assumes 28.4 miles of collocated pipelines with the overhead high voltage alternating current (HVAC) electrical transmission line between Sammamish Substation and Talbot Hill.
[66] This value is based on the total number of fatalities that occurred on U.S. Regulated Hazardous Liquid Pipelines from January 2010 through December 2015.
[67] It should be noted that the Individual Risk assessment will not consider population density due to the definition of Individual Risk.

7.0 Release Modeling Results

In this section, various pipeline release scenarios are presented. The releases were modeled using CANARY, by Quest, version 4.4 software. For vapor cloud explosion modeling, this software uses the Baker-Strehlow model to determine peak side-on over-pressures as a function of distance from a release. The CANARY software also provides a means for evaluating pool fires. Thousands of possible data combinations could be used to evaluate individual releases. However, in order to make a reasonable determination of likely releases, the following assumptions and data inputs were used.

Table 7.0-1 Release Modeling Input

Parameter	Model Input
Pipe Diameter	18-inches[68]
Normal Operating Pressure	650 psig[69]
Average Flow Rate	6,650 Barrels per Hour[70] (BPH)
Pipe Contents Temperature	70 degrees F
Wind Speed	2 meters per second (4.5 miles per hour)
Stability Class	D - Pasquill-Gifford atmospheric stability is classified by the letters A through F. Stability can be determined by three main factors: wind speed, solar insulation, and general cloudiness. In general, the most unstable (turbulent) atmosphere is characterized by stability class A. Stability A occurs during strong solar radiation and moderate winds. This combination allows for rapid fluctuations in the air and thus greater mixing of the released gas with time. Stability D is characterized by fully overcast or partial cloud cover during daytime or nighttime, and covers all wind speeds. The atmospheric turbulence is not as great during D conditions, so the gas will not mix as quickly with the surrounding atmosphere. Stability F generally occurs during the early morning hours before sunrise (no solar radiation) and under low winds. This combination allows for an atmosphere which appears calm or still and thus restricts the ability to actively mix with the released gas. A stability classification of "D" is generally considered to represent average conditions.
Relative Humidity	70%
Air and Surface Temperature	70 degrees F
Spill Surface	Soil

[68] One of the OPL pipelines is 16-inches in diameter; the other is 20-inches in diameter. An average 18-inch pipe diameter has been used to model both of these lines.
[69] As presented in Section 1.1, the normal operating pressure of the 16-inch OPL line is 500 to 800 psig; the normal operating pressure of the 20-inch OPL line is 300 to 500 psig.
[70] As presented in Section 1.1, the normal flow rate of the 16-inch OPL line is 5,400 BPH; the normal flow rate of the 20-inch OPS line is 7,900 BPH.

Parameter	Model Input
Fuel Reactivity	Medium - Most hydrocarbons have medium reactivity, as defined by the Baker-Strehlow method. Low reactivity fluids include methane, natural gas (98+% methane), and carbon monoxide. High reactivity fluids include hydrogen, acetylene, ethylene oxide, and propylene oxide.
Obstacle Density	Low This parameter describes the general level of obstruction in the area including and surrounding the confined (or semi-confined) volume. Low density occurs in open areas or in areas containing widely spaced obstacles. High density occurs in areas of many obstacles, such as tightly-packed process areas or multi-layered pipe racks. Low obstacle density is appropriate due to the low building density and open space within the pipeline corridor. Normally, the vapor cloud would be located at ground level, near the release; these surroundings are relatively open along the entire pipeline alignment (low obstacle density).
Flame Expansion	3 D - This parameter defines the number of dimensions available for flame expansion. Open areas are 3-D, and produce the smallest levels of overpressure. 2.5-D expansions are used to describe areas that quickly transition from 2-D to 3-D. Examples include compressor sheds and the volume under elevated fan-type heat exchangers. 2-D expansions occur within areas bounded on top and bottom, such as pipe racks, offshore platforms, and some process units. 1-D expansion may occur within long confined volumes such as hallways or drainage pipes, and produce the highest overpressures.
Reflection Factor	2 - This factor is used to include the effects of ground reflection when an explosion is located near grade. A value of 2 is recommended for ground level explosions.

7.1 Pool Fires

For a buried refined petroleum product pipeline, 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, ground water 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, creating a public safety risk.

For this corridor, the majority of the alignment is within relatively open area, with a soil surface. The CANARY software contains an algorithm that predicts the size of the pool for a given spill volume. This model is a shallow inverted cone. The cone is filled as the fluid flows into the pool, and mass is lost as it evaporates, seeps into the soil, etc. The pool fire model assumes that the depth of fluid is sufficient to sustain burning long enough to establish a flame and result in the impacts being modeled. Naturally, there are literally thousands of possible scenarios based on the actual local site conditions. In this study, we have used the CANARY software algorithm to predict the pool size. The resulting pool fire impacts are presented in Tables 7.1-1, 7.1-2 and 7.1-3 below. These data are presented separately for gasoline, jet fuel and diesel fuel.

The following radiant heat flux mortality endpoints were used in the individual and societal risk analyses:

- 12,000 Btu/ft^2-hr (37.7 kW/m^2) – 100% mortality after 30 second exposure.
- 8,000 Btu/ft^2-hr (25.1 kW/m^2) – 50% mortality after 30 second exposure.
- 5,000 Btu/ft^2-hr (15.7 kW/m^2) – 1% mortality after 30 second exposure.

Table 7.1-1 Pool Fire Impacts - Gasoline

Release Volume (barrels)	Distance from Center of Pool Fire (feet)						Pool Diameter (feet)
	12,000 Btu/ ft^2-hr		8,000 Btu/ ft^2-hr		5,000 Btu/ ft^2-hr		
	Downwind	Crosswind	Downwind	Crosswind	Downwind	Crosswind	
0.5	4.4	1.4	6.2	2.0	8.5	3.0	2
4.3	12.2	5.6	16.4	8.2	21.6	12.2	6
36	24.3	15.1	31.1	21.0	40.2	29.4	16
416	38.5	29.2	45.8	36.3	58.0	48.0	37
2,603	61.9	50.0	69.9	57.7	86.2	73.3	81
8,861	83.4	70.4	91.5	77.7	112.7	98.0	124

Table 7.1-2 Pool Fire Impacts – Jet Fuel

Release Volume (barrels)	Distance from Center of Pool Fire (feet)						Pool Diameter (feet)
	12,000 Btu/ ft^2-hr		8,000 Btu/ ft^2-hr		5,000 Btu/ ft^2-hr		
	Downwind	Crosswind	Downwind	Crosswind	Downwind	Crosswind	
0.5	4.0	1.4	5.5	1.9	7.5	2.9	2
4.3	9.9	4.8	13.3	6.9	17.8	10.4	6
36	20.0	12.6	25.8	17.6	33.2	24.6	16
416	34.5	25.1	40.1	31.0	48.0	39.4	37
2,603	57.2	45.4	61.4	49.6	69.8	58.1	81
8,861	79.0	72.0	82.9	70.0	91.5	78.2	124

Table 7.1-3 Pool Fire Impacts – Diesel Fuel

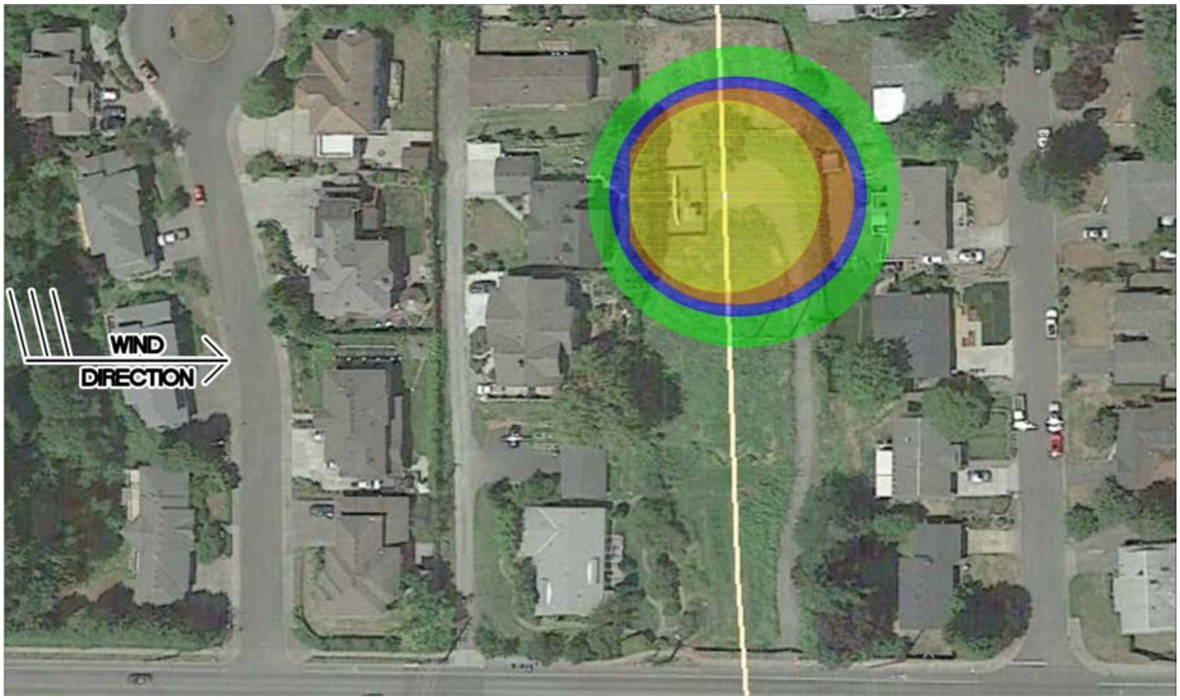
Release Volume (barrels)	Distance from Center of Pool Fire (feet)						Pool Diameter (feet)
	12,000 Btu/ ft^2-hr		8,000 Btu/ ft^2-hr		5,000 Btu/ ft^2-hr		
	Downwind	Crosswind	Downwind	Crosswind	Downwind	Crosswind	
0.5	3.4	1.2	4.7	1.8	6.4	2.7	2
4.3	8.1	4.0	10.8	5.8	14.6	8.8	6
36	16.6	10.4	20.3	14.0	25.2	18.9	16
416	29.9	21.4	33.4	25.0	38.6	30.4	37
2,603	53.0	45.0	55.3	29.2	60.0	47.9	81
8,861	N/A[71]	N/A	80	73	86.0	73.5	124

Figure 7.1-1 presents an aerial depiction of a typical pool fire and the resulting isopleths. The inner, yellow circle is the pool of fluid. The orange oval outer perimeter represents the outer boundary of the 12,000 Btu/ ft^2-hr isopleth. The blue oval outer perimeter represents the outer boundary of the 8,000 Btu/ ft^2-hr isopleth. And the green oval outer perimeter represents the boundary of the 5,000 Btu/ ft^2-hr.

For the societal risk analysis (Section 10.0), the combined yellow and orange shaded areas represent the area subjected to the 12,000 Btu/ ft^2-hr heat flux. The blue shaded area depicts the area subjected to the 8,000 Btu/ ft^2-hr heat flux. And the green shaded area comprises the area subjected to the 5,000 Btu/ ft^2-hr heat flux.

[71] This diesel fuel pool fire does not produce a 12,000 Btu/ ft^2-hr isopleth. The flame drag allows it to radiate downward in the area just downwind of the pool. The smoke from a diesel fire is also heavier, and the fire is very smoky; as a result, the average surface heat flux is smaller, resulting in a “cooler” fire and this heat flux level is not reached.

Figure 7.1-1 Typical Pool Fire Radiant Heat Flux



LEGEND	12,000 Btu/ft²−hr	8,000 Btu/ft²−hr	5,000 Btu/ft²−hr

7.2 Explosions

The potential impacts to humans as a result of explosions was presented earlier in Section 4.2 of this Report. Gasoline, jet fuel, and diesel fuel generally do not explode, unless the vapor cloud is confined in some manner. In this case, the pipeline is located in relatively open areas.

The potential releases from each of the refined petroleum products was modeled using CANARY software. The resulting peak overpressure level was 0.38 psi, due to the relatively open environment (medium fuel reactivity and low obstacle density). This overpressure level is not high enough to pose potentially fatal risks to the public. However, it could cause glass breakage. For reference, the explosion modeling endpoints often used are presented in the following table.

Table 7.2-1– Explosion Modeling Endpoints (CDE 2007)

Mortality Rate	Outdoor Exposure (psi)	Indoor Exposure[72] (psi)
99% Mortality	72	13
50% Mortality	13	5.7
1% Mortality	2.4	2.4

As noted in the California Department of Education, Guidance Protocol for School Site Pipeline Risk Assessment, "Under uncommon circumstances a vapor cloud explosion (VCE) could occur when a flammable vapor cloud ignites. These events are unlikely, based on historical experience, with the petroleum liquids covered here (LEES 1996). Impacts for VCEs are expressed in terms of a shock wave, overpressure (pounds per square inch or psi) above atmospheric pressure. Because the density of crude oil and petroleum product vapors is greater than air, the ALOHA VCE module for evaporating pools (puddles) was used to examine various pool sizes of the gasoline surrogate, n-hexane, for VCE explosion impacts. For an uncongested setting, an overpressure of 1.45 psi (1% mortality) was not encountered for pool sizes between 0 and 600 feet for the conditions modeled." (CDE 2007)

It should also be noted that between January 2010 and December 2015 there were no reported explosions in the PHMSA incident database for refined petroleum product pipelines.

7.3 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. In a flash fire, the portion of the vapor cloud within the combustible range burns very quickly, reducing the potential impact to humans. For gasoline, diesel fuel, and jet fuel, the potential for extensive vapor migration is limited somewhat by the relatively low evaporation rates from the liquid pools.

The California Department of Education, Guidance Protocol for School Site Pipeline Risk Assessment, includes an analysis of various size circular hexane pools. In all cases, the diameter of the vapor cloud within the combustible range is smaller than the diameter of the pool. (The diameter of the vapor cloud within the combustible range varies from 60 to 80% of the pool diameter.)[73]

Since the duration of a refined petroleum flash fire is relatively short and the size of the fire is smaller than the pool diameter, we have assumed that one hundred percent (100%) of the fires

[72] An indoor exposure would be applicable to those individuals located indoors (e.g., inside their home, business, school, etc.). An outdoor exposure applies to those located outdoors.
[73] Since the 100% mortality impacts are larger than the pool size for pool fires, while the portion of the vapor cloud within the combustible range is smaller than the pool size, it is conservative to assume that one hundred percent (100%) of the fires are pool fires.

are pool fires. This is conservative since in all pool fire cases, the 12,000 Btu/ ft^2-hr isopleth extends beyond the pool boundary, whereas the flash fire boundary is smaller than the pool.

8.0 Conditional Probabilities

8.1 Pipeline Contents

We have averaged the OPL reported shipment percentages of the various commodities for each pipeline presented in Section 1.1. The resulting conditional probabilities of pipe contents at the time of an unintentional release have been used in the individual and societal risk assessments.

- Diesel – 29 percent
- Jet Fuel – 20 percent
- Gasoline – 51 percent

8.2 Pipeline Operability

We have conservatively assumed that the pipelines would be operational one-hundred percent (100%) of the time.

8.3 Pool Fire Spill Volumes

In order to create a hydraulic model and analyze the potential release volumes from the two existing OPL pipelines, the following minimum data would be required:

- Pipeline profile,
- Location and means of actuation of block valves,
- Pipeline supervisory control and data acquisition system performance parameters,
- Leak detection system performance parameters, etc.

OPL did not provide these data for security reasons. As a result, for pool fire consequence analysis, the actual reported refined petroleum product pipeline unintentional release volumes which occurred from January 2010 through 2015 have been used. These data were then normalized to an 18-inch diameter pipeline, as discussed in Section 5.2.1. The resulting conditional probabilities for various spill sizes resulting from an unintentional release have been used in the individual and societal risk assessments.

Figure 8.3-1 Pool Fire Conditional Spill Volumes[74]

Spill Size	Conditional Probability
0.5 Barrels	27 Percent
4.3 Barrels	21 Percent
36 Barrels	22 Percent
416 Barrels	21 Percent
2,603 Barrels	6 Percent
8,861 Barrels	3 Percent

8.4 Fire and Explosion

The 2010 through 2015 U.S. Hazardous Liquid Pipeline release data have been analyzed to develop the following data points.

- Of the 2,362 releases from the U.S. Hazardous Liquid Pipeline database are considered, from all components (e.g., crude oil, highly volatile liquid, refined petroleum products, etc.), including those which occurred within, and were entirely contained on, the pipeline operator's controller property, and those which occurred along the right-of-way, from January 2010 through December 2015, 79 (3.3 percent, 3.3%) ignited after release.
- Of the 805 refined petroleum product pipeline releases, 20 (2.5 percent, 2.5%) ignited after release.
- Of the 195 refined petroleum product pipeline system releases which occurred along the pipeline right-of-way, or occurred on pipeline operator controlled property and extended beyond the property boundary, 4 (2.1 percent, 2.1%) ignited after release.
- Of all 195 refined petroleum product pipeline releases which occurred along the pipeline right-of-way, or occurred on pipeline operator controlled property and extended beyond the property boundary, none resulted in an explosion.

Based on the data outlined above, the following conditional probabilities have been used in the individual and societal risk assessments:

- Percentage of OPL pipeline releases which would be ignited – 2.5 percent (2.5 %)
- Percentage of OPL pipeline ignited releases that would result in a fire – 100 percent (100%)
- Percentage of OPL pipeline ignited releases that would result in an explosion – 0.0 percent (0.0 %)

Since the duration of a refined petroleum flash fire is relatively short and the size of the fire is smaller than the pool diameter (CDE 2007), we have assumed that one hundred percent (100%) of the fires are pool fires.

[74] These data were presented previously, in Section 5.2.1 of this Report.

8.5 Likelihood of Fatal Injuries

The following radiant heat flux exposure mortality end points have been used in the individual and societal risk assessments:

- 12,000 Btu/f^{2}t-hr (37.7 kW/m^2) – 100% mortality
- 8,000 Btu/ft^2-hr (25.1 kW/m^2) – 50% mortality
- 5,000 Btu/ft^2-hr (15.7 kW/m^2) – 1% mortality

8.6 Other Primary Assumptions

The following primary assumptions have been made in performing the analyses.

<u>Assumptions Common to Individual and Societal Risk Analyses</u>

- The pool fire modeling assumed that the depth of fluid is sufficient to sustain burning long enough to establish a flame and result in fatalities.
- Pool fires were assumed to be created after every release, one hundred percent (100%) of the time.
- The pool was assumed to form directly over the release, including one hundred percent (100%) of the unintentional release spill volumes. This results in the largest volume of fluid within the pool. (Refined petroleum product would normally evaporate, be diluted, infiltrate into the ground, cling to vegetation, etc. as it flows away from the release site, reducing the pool volume.)

<u>Individual Risk Analysis Assumptions</u>

- The risk level has been determined for the maximally exposed individual; in other words, it assumes that a person is present continuously – 24 hours per day, 365 days per year.
- The risk analysis assumed that the wind direction was perpendicular to the pipeline, resulting in the greatest downwind distance to potentially harmful impacts.

<u>Societal Risk Analysis Assumptions</u>

- The risk level has been determined for a maximally exposed population, exposed 100% of the time. If the exposure was less, the likelihood of each scenario would be reduced proportionately. For example, in residential areas, the population density is normally reduced during work hours; in commercial areas, the population density is reduced during the night. Individuals are also protected from radiant heat flux when inside structures, unless the structures themselves should catch fire; but in these situations, there is often time for individuals to seek safety. For reference, the California Department of Education uses 0.16 (16%) as the conditional probability of occupancy and 0.25 (25% for outdoor exposures) for public school site citing.

- Population density was used to determine the number of individuals exposed to each release. The individuals were assumed to be spread uniformly throughout the area. (See Section 5.3 of this Report.)

9.0 Individual Risk Assessment

As discussed previously, individual risk (IR) is most commonly defined as the frequency that an individual may be expected to sustain a given level of harm from the realization of specific hazards, at a specific location, within a specified time interval. Individual risk is typically measured as the probability of a fatality per year. The risk level is typically determined for the maximally exposed individual; in other words, it assumes that a person is present continuously – 24 hours per day, 365 days per year. The likelihood is most often expressed numerically, using one of the values shown in Table 9.0-1 below. The values shown on each row may be used interchangeably.

Table 9.0-1 Individual Risk Numerical Values

Annual Likelihood of Fatality	Numerical Equivalent	Scientific Notation	Shorthand
1 in 100	1.0×10^{-2}	1.0 E-2	10^{-2}
1 in 1,000	1.0×10^{-3}	1.0 E-3	10^{-3}
1 in 10,000	1.0×10^{-4}	1.0 E-4	10^{-4}
1 in 100,000	1.0×10^{-5}	1.0 E-5	10^{-5}
1 in 1,000,000	1.0×10^{-6}	1.0 E-6	10^{-6}
1 in 10,000,000	1.0×10^{-7}	1.0 E-7	10^{-7}

In the following subsections, the individual risk will be presented for the two (2) OPL pipelines:

- Where they are not collocated with an overhead HVAC line,
- Where they are collocated within the existing overhead HVAC corridor (No Action Alternative), and
- Where they would be collocated within the proposed overhead HVAC corridor (Alternative 1).

Where only one pipeline is present, the likelihood of a release would be one-half the stated values.

The individual risks are presented graphically. These figures present risk transects, which show the annual risk of fatality resulting from a pipeline release as a function of the distance from the center of the pool which could form after an unintentional release; the location of this pool would depend on local terrain and other factors. It should also be noted that the highest risks are posed directly over the center of the pool fire.

9.1 Two OPL Pipelines Not Collocated within Overhead HVAC Corridor

In this section, the individual risk posed along the pipeline corridor will be presented. These results are useful for evaluating the risk to the public only; this excludes the risks posed to OPL personnel and OPL's contractors.

The baseline incident rate of 0.5144 incidents per 1,000 mile years was developed in Section 5.2 of this report. As discussed previously, the PHMSA pipeline incident database includes releases from all hazardous liquid pipelines; it does not distinguish between pipelines collocated or not collocated with overhead HVAC transmission line facilities. As a result, it was not possible to determine separate incident rates for collocated and non-collocated facilities from these data.

For the two pipelines, the resulting baseline incident rate is 1.0288 incidents per 1,000 mile years (2 pipelines x 0.5144 incidents per 1,000 mile years = 1.0288 incidents per 1,000 mile years).

The individual risk maximum annual probability of fatality from two (2) OPL pipelines is 1.77×10^{-7} (1 in 5.7 million). The estimated maximum downwind distance to potentially fatal impacts, measured from the center of the pool fire is 113 feet. The maximum individual risk is presented in the figure below, as a function of the distance from the middle of the pool fire. Where only one line is present, the individual risk would be one-half (1/2) these values.

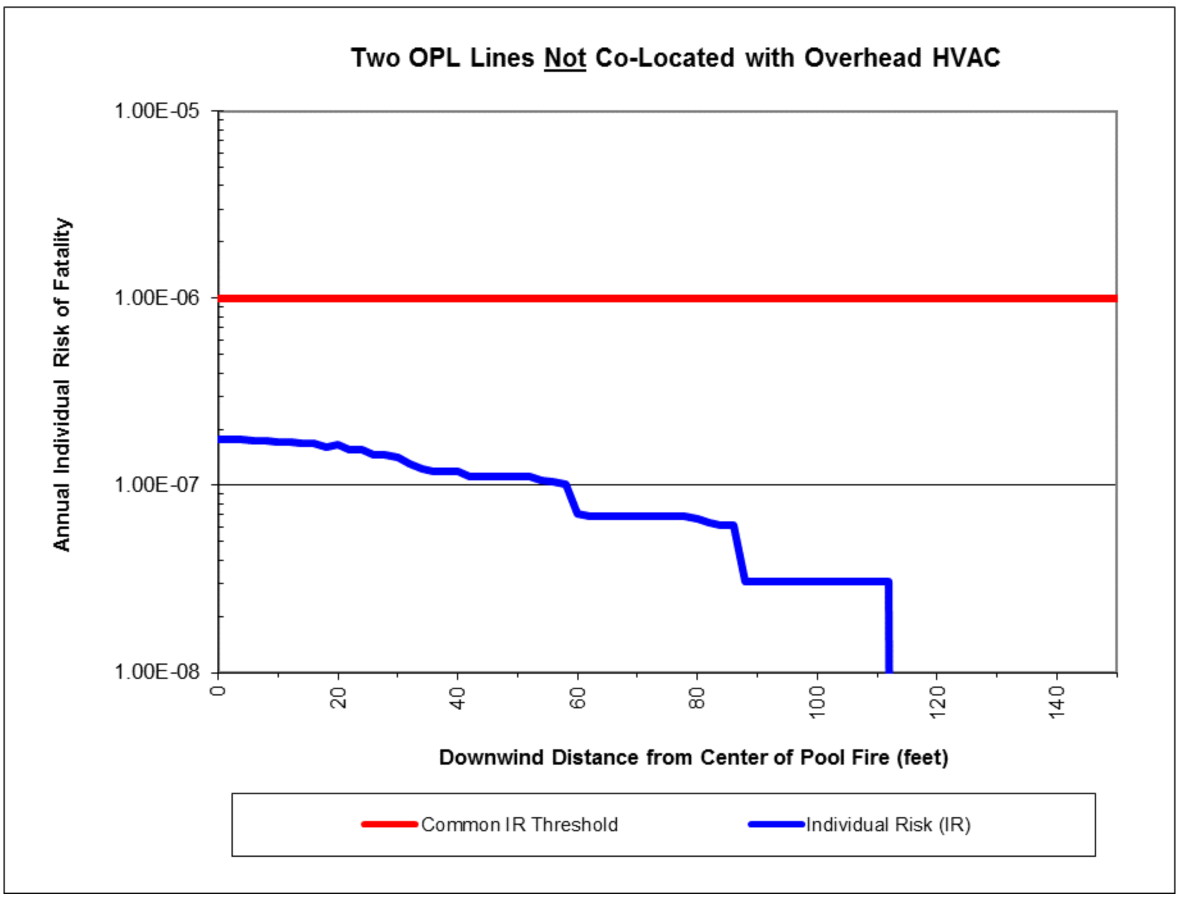


Figure 9.2-1 Individual Risk Transect, Two OPL Pipelines Not Collocated within Overhead HVAC Corridor

It should be noted that the individual risk results are below the threshold of 1.0×10^{-6} (1 in 1.0 million.)[75]

9.2 Two OPL pipelines Collocated with Existing 115 kV Line (No Action Alternative)

Puget Sound Energy retained Det Norske Veritas (U.S.A.), Inc. to perform an analysis of potential A.C. Interference for the existing 115 kV corridor. The results of this analysis are presented in a MS PowerPoint Slide Deck entitled, Puget Sound Energy A.C. Interference Analysis Existing Corridor. The baseline data used in this analysis were presented previously, in Section 5.7 of this Report. In this section, the individual risk posed by the two (2) pipelines where they are collocated within the existing 115 kV corridor will be presented.

9.2.1 Induced A.C. Voltage

There are no segments of the existing corridor which are anticipated to yield induced A.C. voltages that exceed the 15 volt threshold. As a result, there is not a touch potential (electrical shock) posed to personnel that may touch the pipeline or pipeline appurtenances (e.g., cathodic protection test leads, etc.) This would not result in an increased frequency of unintentional pipeline releases. (See Figures 5.7.1-1 and 5.7.1-2, presented earlier.)

9.2.2 A.C. Current Density

There are two (2) short segments where the estimated A.C. current density would exceed the 20 amps per square meter de minimus value. (A.C. current densities below 20 amps per square meter do not cause A.C. corrosion.) The estimated current densities for the OPL 16-inch pipeline, during peak winter voltages are expected to be 34 amps per square meter for the actual 2013-14 peak winter load and 35 amps per square meter at the anticipated 2027-28 peak winter load. For the OPL 20-inch pipeline, the estimated current densities are expected to be 25 amps per square meter for the actual 2013-14 peak winter load and 22 amps per square meter for the anticipated 2027-28 peak winter load. (When A.C. current densities are between 20 and 100 amps per square meter, A.C. corrosion may or may not occur.)

For this analysis, we have made the following assumptions:

- The likelihood of an external corrosion caused leak would increase fifty percent (50%) for the anticipated A.C. current densities of 22 to 35 amps per square meter.
- Based on the data presented in Figures 5.7.2-1 and 5.7.2-2, we have conservatively estimated that the A.C. current density may exceed 20 amps per square meter for ten percent (10%) of the length of the OPL 16-inch line and five percent (5%) of the OPL 20-inch line; we have used an average 7.5% of the length for the societal risk analysis. For the individual risk analysis, we have assumed that the individual was located at the maximally exposed location (e.g., highest A.C. current density).

[75] See Section 3.2 of this Report for a discussion of individual risk criteria.

- We have conservatively assumed that the system would operate at peak winter voltages one hundred percent (100%) of the time.

Using these assumptions for the maximum exposed individual (individual risk), the predicted frequency of external corrosion caused releases for the No Action Alternative would be 0.1701 incidents per 1,000 mile years for each pipeline, compared to the baseline of 0.1134 incidents per 1,000 mile years, as calculated below.

0.1134 + [0.1134 x 0.5 x 1.00 (100% at peak winter)] = 0.1701

Using these assumptions for societal risk, based on the average over a given area, the predicted frequency of external corrosion caused releases for the No Action Alternative would be 0.1177 incidents per 1,000 mile years for each pipeline, compared to the baseline of 0.1134 incidents per 1,000 mile years to, as calculated below.

0.1134 + [0.1134 x 0.5 x 0.075 (percentage of length) x 1.00 (100% at peak winter)] = 0.1177

It should be noted that 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." This is a Federal regulatory requirement imposed on OPL.

9.2.3 Coating Stress Voltage Resulting from Fault

We do not have data available for the estimated coating stress voltages for the OPL pipelines within the existing 115 kV corridor. The Applicant has stated that the coating stress voltages for the proposed 115/230 kV corridor will be less than or equal to the existing 115 kV corridor coating stress voltages.

In order to estimate the most conservative incremental risk from the proposed 115/230 kV project, we have assumed that the coating stress voltages and resulting coating stress voltage caused pipeline releases for the existing 115 kV corridor are the same as those for the proposed 115/230 kV project. However, the proposed project may actually reduce the likelihood of unintentional pipeline releases caused by coating stress voltage due to the proposed installation of a shield wire.

9.2.4 Arc Distance Resulting from Fault

We do not have data available for the estimated arc distances for the OPL pipelines within the existing 115 kV corridor. The Applicant has stated that the arc distances for the proposed 115/230 kV corridor will be less than or equal to the existing 115 kV corridor arc distances.

In order to estimate the most conservative incremental risk from the proposed 115/230 kV project, we have assumed that the ground fault arc distances and ground fault arc caused frequency of unintentional releases for the existing 115 kV corridor are the same those for the proposed 115/230 kV project. However, the proposed project may actually reduce the likelihood of unintentional pipeline releases due to electrical arcs; any risk reduction has not been included in our findings.

9.2.5 Estimated Frequency of Unintentional Releases

Using the data summarized above, the estimated frequency of unintentional releases from the OPL pipelines where they are collocated with the existing 115 kV line are as follows:

- Individual Risk Maximum Exposure - is 0.5869 incidents per 1,000 mile years per pipeline, or 1.1738 incidents per 1,000 mile years for the two OPL pipelines.
- Societal Risk Average Exposure - is 0.5193 incidents per 1,000 mile years per pipeline, or 1.0386 incidents per 1,000 mile years for the two OPL pipelines.

Figure 9.2.5-1 Frequency of Unintentional Releases Existing 115 KV Corridor

Cause	Individual Risk Frequency (incidents per 1,000 mile years)	Societal Risk Frequency (incidents per 1,000 mile years)
Equipment Failure	0.1266	0.1266
Incorrect Operation	0.0396	0.0396
External Corrosion	0.1701	0.1177
Outside Force/Excavation	0.1002	0.1002
Material Failure	0.0871	0.0871
Internal Corrosion	0.0106	0.0106
Natural Force	0.0211	0.0211
Other	0.0316	0.0164
Total	0.5869	0.5193

9.3 Two OPL Pipelines Collocated with 115/230 kV Lines (Alternative 1)

The results of the A.C. Interference Analysis – 230 kV Transmission Line Collocated with Olympic Pipelines OPL 16 and OPL 20 are summarized in Section 5.6 of this Report. In this section, the individual risk posed by the 2 pipelines where they would be collocated within the 115/230 kV corridor will be presented.

9.3.1 Induced A.C. Voltage

There are short segments of the corridor which could yield induced A.C. voltages that exceed the 15 volt threshold; these areas would result in potential safety (electrical shock) hazards to personnel that may touch the pipeline or pipeline appurtenances (e.g., cathodic protection test leads, etc.). They would not result in an increased frequency of unintentional pipeline releases. (See Figures 5.6.3-2 and 5.6.3-3, presented earlier.)

9.3.2 A.C. Current Density

There are two areas where the estimated A.C. current density would exceed the 20 amps per square meter de minimus value. (A.C. current densities below 20 amps per square meter do not cause A.C. corrosion.) The estimated A.C. current densities at these locations range from 25 to 70 amps per square meter. When A.C. current densities are between 20 and 100 amps per square meter, A.C. corrosion may or may not occur.

For this analysis, we have made the following assumptions:

- The likelihood of an external corrosion caused leak would increase one hundred percent (100%) when A.C. current densities are between 25 and 70 amps per square meter. (This current density is higher than that presented in Section 9.2.2 for the existing 115 kV corridor.)
- Based on the data presented in Figures 5.6.3-4 and 5.6.3-5, we have conservatively estimated that the A.C. current density may exceed 20 amps per square meter for ten percent (10%) of the length of the OPL 16-inch line and five percent (5%) of the OPL 20-inch line; we have used an average 7.5% of the length for the societal risk analysis[76]. For the individual risk analysis, we have assumed that the individual was located at the maximally exposed location (e.g., highest A.C. current density).
- We have conservatively assumed that the system would operate at peak winter voltages one hundred percent (100%) of the time.

Using these assumptions for the maximum exposed individual, for individual risk, the predicted frequency of external corrosion caused releases for Alternative 1 would be 0.2268 incidents per 1,000 mile years for each pipeline, compared to the baseline of 0.1134 incidents per 1,000 mile years, as calculated below.

$$0.1134 + [0.1134 \times 1.00 \text{ (100\% at peak winter)}] = 0.2268$$

Using these assumptions for societal risk, the predicted frequency of external corrosion caused releases for Alternative 1 would be 0.1219 incidents per 1,000 mile years for each pipeline, compared to the baseline of 0.1134 incidents per 1,000 mile years, as calculated below.

$$0.1134 + [0.1134 \times 0.075 \text{ (percentage of length)} \times 1.00 \text{ (100\% at peak winter)}] = 0.1219$$

It should be noted that 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.” This is a Federal regulatory requirement imposed on OPL.

[76] Societal risk is based on the area exposed to the potential risk and the number of exposed individuals.

9.3.3 Coating Stress Voltage Resulting from Fault

The applicant has committed to the use of an OPGW shield wire. Using this shield wire, at the maximum 25 kA fault current, the estimated coating stress voltage would range from 1,517 to 5,970 volts. The estimated coating breakdown voltage of the pipeline external coating is 10,825 volts. As a result, coating degradation is not anticipated along the corridor provided an OPGW shield wire is used.

9.3.4 Arc Distance Resulting from Fault[77]

The applicant has committed to the use of an OPGW shield wire. Using this shield wire, at the maximum 25 kA fault current, the estimated arc distance ranges from 4 to 13-feet. This would pose a potential pipeline risk at transmission structure ground locations, where the electrical ground might be located less than 13-feet from the pipeline. It should be noted that this risk is not posed along the entire length of the corridor. In other words, the only affected segments of the pipeline would be that portion within the arc distance of the grounding rod (4 to 13-feet).

The existing 115 kV line structures (poles) are spaced at 450 to 725-foot intervals. In general, the proposed 230 kV structures (poles) would be spaced at generally the same spacing as the existing structures, except in some cases where the spacing will be slightly greater. If one conservatively assumes that the OPL 16-inch line is 5-feet from all of the grounding rods and that the OPL 20-inch line is 5-feet from the 16-inch line, then at each grounding rod there would be 24-feet of the 16-inch and 17- feet of the 20-inch pipeline within 13-feet of the grounding rod. This condition is depicted in Figure 9.3.4-1 below.

[77] 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."

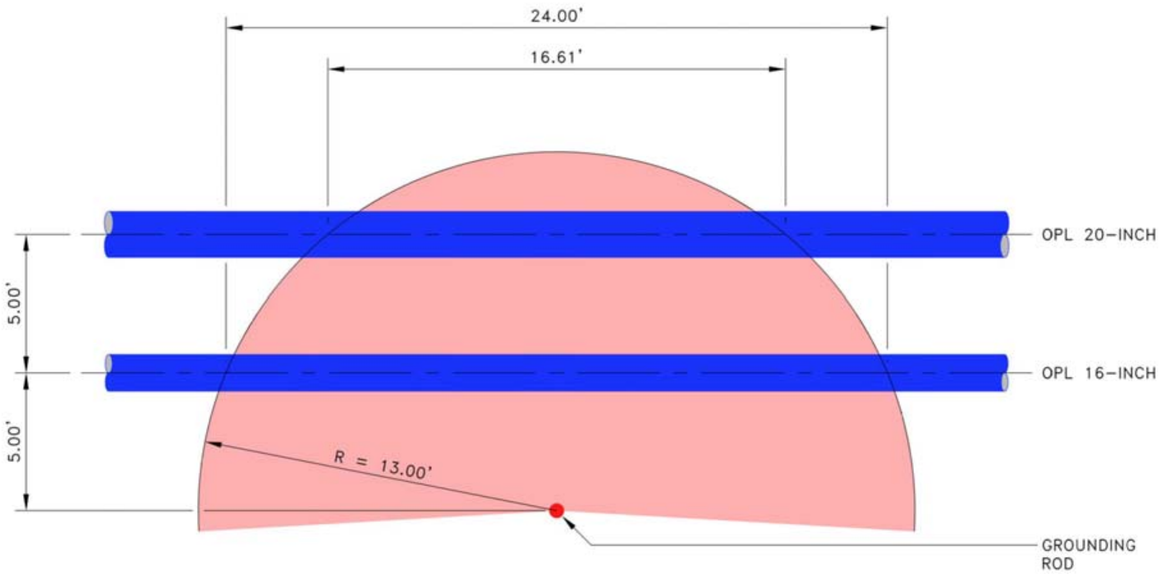


Figure 9.3.4-1 Assumed Pipe Configuration at All Grounding Rods

Assuming an average 500 foot pole spacing, 4.1 percent (4.1 %) of the pipelines would be located within 13-feet of a grounding rod.

(24 - feet + 17 - feet) ÷ (2 × 500 - feet) = 0.041 x 100 = 4.1 percent

Of the 2,362 hazardous liquid pipeline incidents between January 2010 and December 2015, there were 129 (5.5%) that were noted as being caused by "other". Of these 129 incidents, there were only 6 (4.7%) that may have been caused by arcing relating to high voltage electrical facilities.

For the purposes of this analysis, we have conservatively assumed that the frequency of "other" caused releases would increase one hundred percent (100%) for the portion of the pipeline within the worst case arc distance to a grounding rod.

Using these assumptions for the maximum individual risk exposure, the predicted frequency of "other" caused releases for Alternative 1 would be 0.0316 incidents per 1,000 mile years for each pipeline, compared to the baseline of 0.0158 incidents per 1,000 mile years, as calculated below.

0.0158 + [0.0158 x 1.00 (100% at peak winter)] = 0.0316

Using these data and assumptions for societal risk, the predicted frequency of "other" caused releases for Alternative 1 would be 0.0164 incidents per 1,000 mile years for each pipeline, compared to the baseline of 0.0158 incidents per 1,000 mile years, as calculated below:

0.0158 + [0.0158 x 0.041 (percentage of length) x 1.00 (100% at peak winter)] = 0.0164

We believe that this result is conservative, for the following reasons:

- The assumed pipeline distances from the grounding rods is likely conservative.
- The assumed one hundred percent (100%) increase of "other" caused incidents is likely conservative.
- The worst case arc distance of 13-feet has been conservatively used.
- The results for the worst case peak winter loading have been used, for 100% of the time.
- A ground fault condition only occurs when there is a fault on the electrical transmission system; it is a very infrequent hazard.
- As noted previously, there were only six (6) hazardous liquid pipeline incidents between January 2010 and December 2015 that may have been caused by electrical arcing. These incidents represent only 0.25 percent (0.25%) of the total 2,363 hazardous liquid pipeline releases during this time period.
- These results do not reflect the implementation of measures to mitigate potential arc damage to the pipeline. The A.C. Interference Study recommended mitigation to address potential ground fault issues where the pipeline(s) is within the arc distance to a pole structure grounding rod. OPL has verbally committed to mitigating any potential impacts. However, they have not committed to implementing the specific measures included in the A.C. Interference Study; OPL committed to implementing mitigation on a case by case basis in order to maximize the effectiveness of the mitigation.
- There is a Federal regulation requiring OPL to address any known potential unsafe condition (49 CFR 195.401).

9.3.5 Frequency of Unintentional Releases

Using the data summarized above, the resulting estimated frequency of unintentional releases are as follows:

- Individual Risk Maximum Exposure - is 0.6436 incidents per 1,000 mile years per pipeline, or 1.2872 incidents per 1,000 mile years for the two OPL pipelines.
- Societal Risk Average Exposure - is 0.5235 incidents per 1,000 mile years per pipeline, or 1.0470 incidents per 1,000 mile years for the two OPL pipelines.

The frequency of unintentional releases by cause are presented below for a single pipeline where it would be collocated with the proposed 115/230 kV lines.

Figure 9.3.5-1 Frequency of Unintentional Releases Proposed 115/230 kV Corridor

Cause	Individual Risk Frequency (incidents per 1,000 mile years)	Societal Risk Frequency (incidents per 1,000 mile years)
Equipment Failure	0.1266	0.1266
Incorrect Operation	0.0396	0.0396
External Corrosion	0.2268	0.1219
Outside Force/Excavation	0.1002	0.1002
Material Failure	0.0871	0.0871
Internal Corrosion	0.0106	0.0106
Natural Force	0.0211	0.0211
Other	0.0316	0.0164
Total	0.6436	0.5235

9.3.6 Operational Individual Risk

The individual risk maximum annual probability of fatality from two (2) OPL pipelines is 2.21 x 10^{-7} (1 in 4.5 million). The estimated maximum downwind distance to potentially fatal impacts, measured from the center of the pool fire is 113 feet. The maximum individual risk is presented in the figure below, as a function of the distance from the middle of the pool fire. Where only one line is present, the individual risk would be one-half (1/2) these values. These results are useful for evaluating the risk to the public only; this excludes the risks posed to OPL personnel and OPL's contractors.

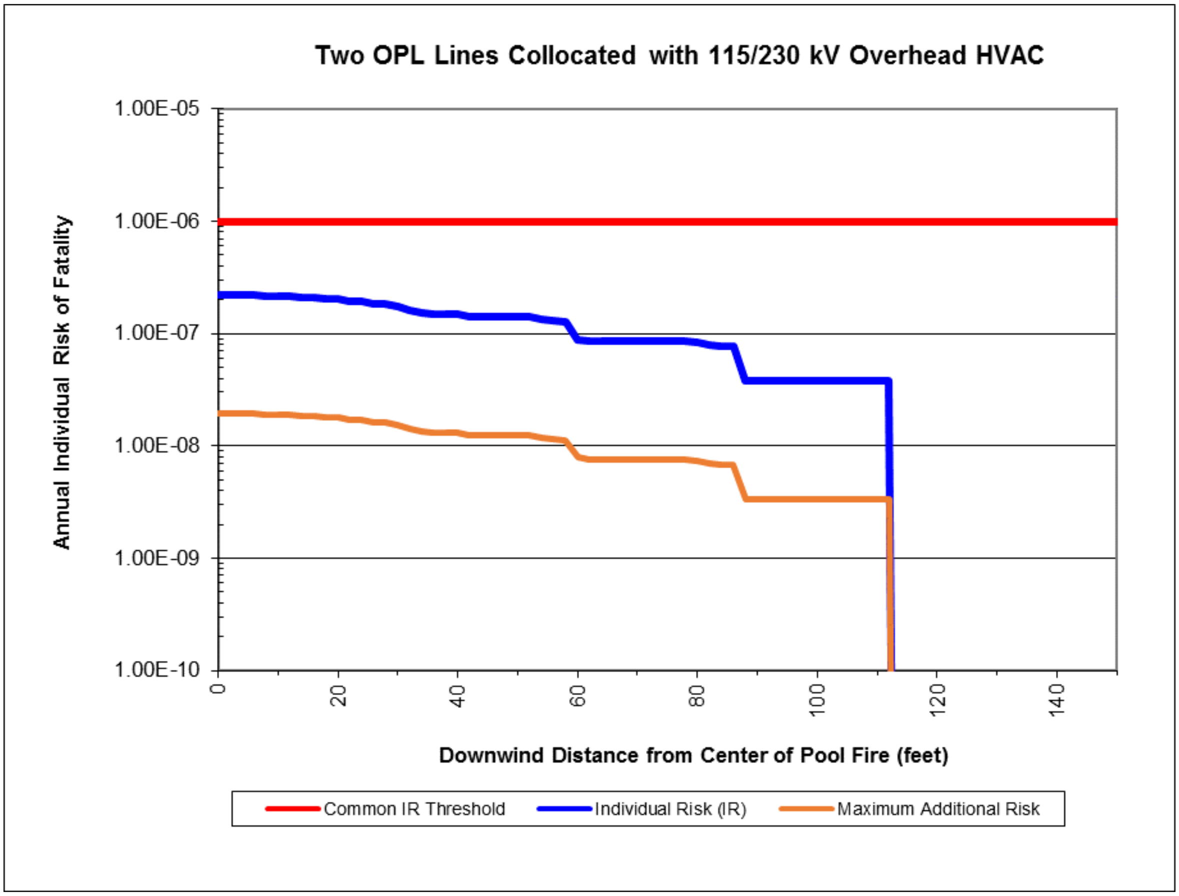


Figure 9.3.6-1 Individual Risk Transect, Maximum Exposure, Two OPL Pipelines Collocated within Proposed 115/230 kV Overhead HVAC Corridor

The increased individual risk for the proposed 115/230 kV project over that posed by the existing 115 kV system is presented by the orange line in the figure above. The maximum additional individual risk annual probability of fatality from two (2) OPL pipelines is 1.95 x 10^{-8} (1 in 51 million).

It is important to note that we did not have coating stress voltage and ground fault arc data available for the OPL pipelines where they are collocated with the existing 115 kV lines. In order to estimate the most conservative incremental risk from the proposed 115/230 kV project, we have assumed that the likelihood or coating stress voltage and ground fault arc caused unintentional releases for the existing 115 kV corridor are the same those for the proposed 115/230 kV project. However, the proposed project may actually reduce the risk of these unintentional pipeline releases.

9.3.7 Construction Individual Risk

As discussed previously, during construction of the proposed facilities, the existing OPL 16-inch and 20-inch pipelines will be exposed to an increased risk of being damaged by construction activities (e.g., excavation) and/or overstressed by surcharge loading from construction equipment. The existing OPL procedures to prevent third party damage have been presented in Section 1.1.5 of this Report. Risk mitigation measures have been presented in Section 11.0.

As presented in Table 5.2-2, outside force/excavation caused 20% of the refined petroleum product releases from January 2010 through December 2015. With the current OPL procedures and the proposed spacing of the structures (poles), the increased risk posed to the pipeline during construction is relatively low. For the purposes of this Study, we have made the following assumptions:

- Average structure (pole) spacing of 500-feet,
- Potential impact radius of 25-feet for each structure (5% of corridor), and
- Fifty percent (50%) increase in outside force/excavation risk during construction of the 230 kV facilities.

Using these assumptions for the maximum individual risk exposure, the predicted frequency of "outside force/excavation" caused releases during construction of Alternative 1 would be 0.1503 incidents per 1,000 mile years for each pipeline, compared to the baseline of 0.1002 incidents per 1,000 mile years, as calculated below.

0.1002 + [0.1002 x 0.50 (50% risk increase)] = 0.1503

Using these data and assumptions for societal risk, the predicted frequency of "outside force/excavation" caused releases during construction of Alternative 1 would be 0.1027 incidents per 1,000 mile years for each pipeline, compared to the baseline of 0.1002 incidents per 1,000 mile years, as calculated below:

0.1002 + [0.1002 x 0.05 (percentage of length) x 0.50 (50% risk increase)] = 0.1027

Figure 9.3.7-1 Frequency of Unintentional Releases Existing 115 KV Corridor during Construction of Proposed 115/230 kV Project

Cause	Individual Risk Frequency (incidents per 1,000 mile years)	Societal Risk Frequency (incidents per 1,000 mile years)
Equipment Failure	0.1266	0.1266
Incorrect Operation	0.0396	0.0396
External Corrosion	0.1701	0.1177
Outside Force/Excavation	0.1503	0.1027
Material Failure	0.0871	0.0871
Internal Corrosion	0.0106	0.0106
Natural Force	0.0211	0.0211
Other[78]	0.0316	0.0164
Total	0.6370	0.5218

Using the data summarized above, the resulting estimated frequency of unintentional releases from the OPL pipelines where they are collocated with the existing 115 kV line are as follows:

- Individual Risk Maximum Exposure - 0.6370 incidents per 1,000 mile years per pipeline, or 1.2740 incidents per 1,000 mile years for the two OPL pipelines.
- Societal Risk Average Exposure - 0.5218 incidents per 1,000 mile years per pipeline, or 1.0436 incidents per 1,000 mile years for the two OPL pipelines.

During construction of the proposed project, the individual risk maximum annual probability of fatality from two (2) OPL pipelines is 2.19×10^{-7} (1 in 4.6 million). The estimated maximum downwind distance to potentially fatal impacts, measured from the center of the pool fire is 113 feet. The maximum individual risk is presented in the figure below, as a function of the distance from the middle of the pool fire. Where only one line is present, the individual risk would be one-half (1/2) these values.

[78] Coating stress voltage and arc distance data is not available for the existing 115 kV corridor. The "other" incident cause data depicted has been taken from the 115/230 kV proposed project.

DSD 011027

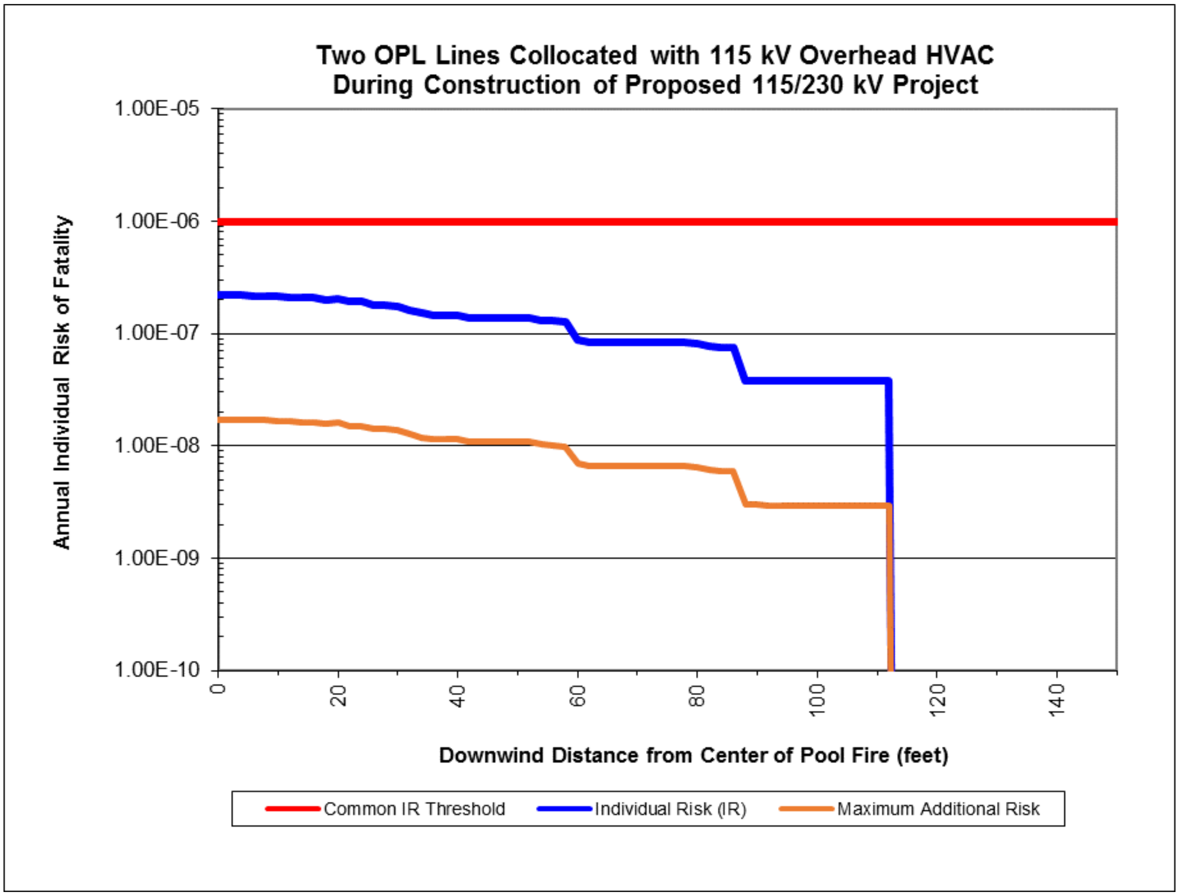


Figure 9.3.7-1 Individual Risk Transect, Maximum Exposure, Two OPL Pipelines Collocated within Proposed 115 kV Overhead HVAC Corridor during Construction of Proposed 115/230 kV Project

The maximum increased individual risk during the construction of the proposed 115/230 kV project over that posed by the existing 115 kV system is presented by the orange line in the figure above. The maximum additional individual risk annual probability of fatality from two (2) OPL pipelines is 1.72 x 10^{-8} (1 in 58 million).

10.0 Societal Risk Assessment

As noted previously, societal risk is the probability that a specified number of people would be affected by a given event. The generally accepted number of casualties is higher for lower probability events and much lower for more probable events, as discussed previously in Section 3.3 of this document.

In order to determine the number of persons exposed to the potential hazard, population density has been used. The individuals were assumed to be spread uniformly throughout the area. The analysis also conservatively assumed that the population would be exposed one hundred percent (100%) of the time. If one assumed that the population were exposed fifty percent (50%) of the time, then the likelihood would be one-half (1/2) the values presented for each scenario.

All of the societal results presented herein are based on one (1) mile of the two (2) OPL pipelines (two miles total pipeline length). If the length were increased, the change in probability for each scenario would be proportional. In other words, if one were considering a two (2) mile length of the two (2) pipelines (four miles total pipeline length), then the likelihood of each scenario would be two (2) times as likely. On the other hand, if one were considering a one (1) mile length of only one (1) pipeline (one mile total pipeline length), then the likelihood of each scenario would be one-half (1/2) as likely.

It is important to note that we did not have coating stress voltage and ground fault arc data available for the OPL pipelines where they are collocated with the existing 115 kV lines. In order to estimate the most conservative incremental risk from the proposed 115/230 kV project, we have assumed that the likelihood of coating stress voltage and ground fault arc caused unintentional releases for the existing 115 kV corridor are the same as those for the proposed 115/230 kV project. However, the proposed project may actually reduce the risk of these unintentional pipeline releases.

10.1 Two OPL Pipelines Not Collocated within Overhead HVAC Corridor

10.1.1 Maximum Population Density

The societal risk results are presented in Figure 10.1.1-1 for the maximum population density of 23,169 persons per square mile, for a one (1) mile length of the two (2) OPL pipelines (two miles total pipeline length), over a one (1) year time period.

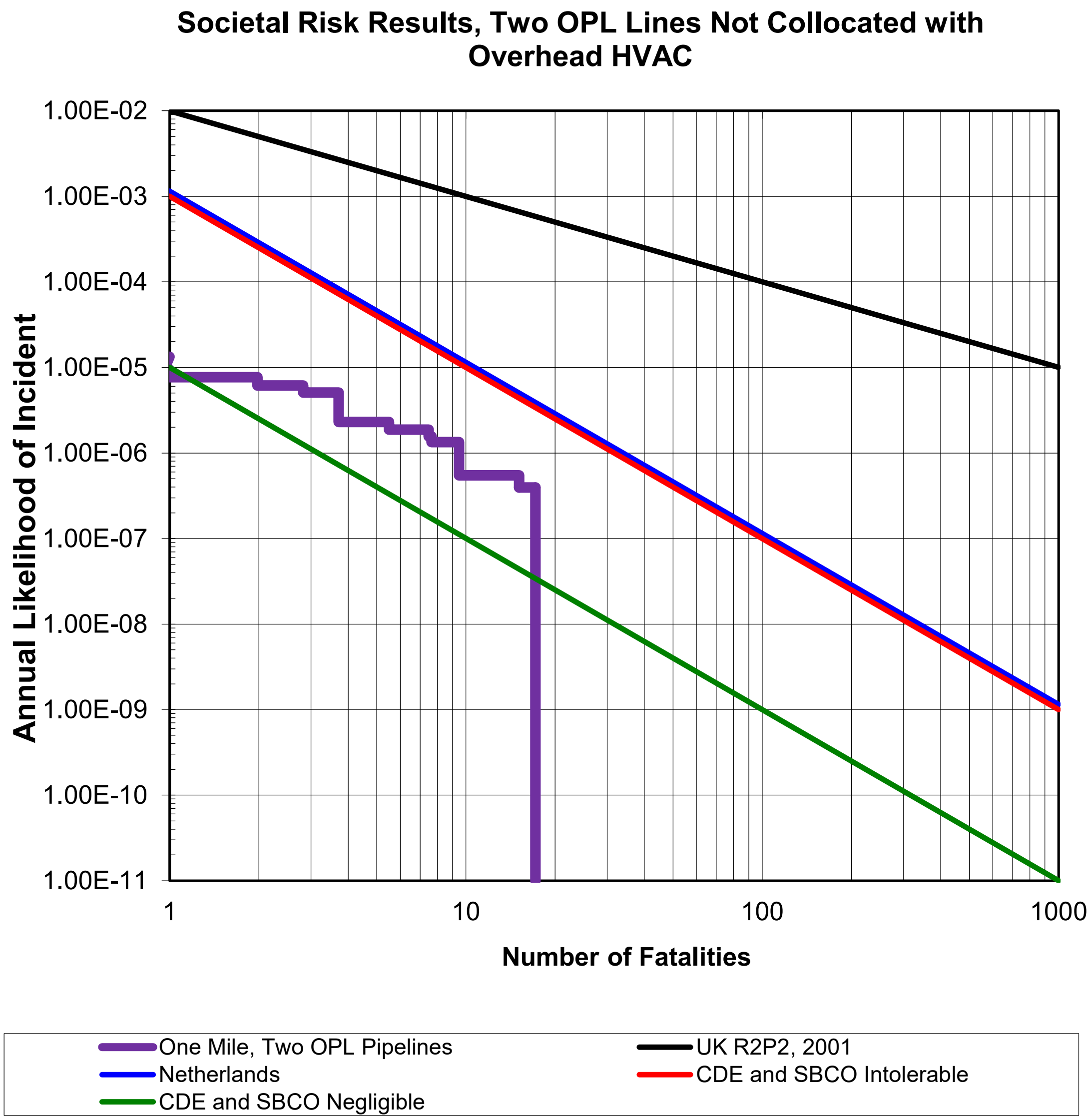


Figure 10.1.1-1 – Societal Risk Results, One Mile of Two OPL Lines Not Collocated with Overhead HVAC, Maximum Population Density

As depicted in Figure 10.1.1-1, there are scenarios that could result in multiple fatalities. The annual probability of these incidents are presented in the following table.

Table 10.1.1-2 Societal Risk Results, One Mile of Two OPL Lines Not Collocates with Overhead HVAC, Maximum Population Density

Number of Fatalities	Probability	Annual Likelihood
17	3.94×10^{-7}	1 in 2.54 million
15	5.48×10^{-7}	1 in 1.83 million
9	1.33×10^{-6}	1 in 749,000
8	1.56×10^{-6}	1 in 642,000
7	1.87×10^{-6}	1 in 536,000
5	2.31×10^{-6}	1 in 432,000
4	5.07×10^{-6}	1 in 197,000
3	6.15×10^{-6}	1 in 163,000
2	7.72×10^{-6}	1 in 130,000
1	1.34×10^{-5}	1 in 74,800

These results are above the thresholds for negligible impacts which are used by Santa Barbara County and the California Department of Education for public school siting. But they are approximately one order of magnitude below (roughly one tenth of) these entities' intolerable level. It should be noted however, that there are no known societal risk criteria for the proposed project. (See also Sections 3.2 and 3.3 of this Report.)

10.1.2 Average Population Density

The societal risk results are presented in Figure 10.1.2-1 for the average population density of 3,228 persons per square mile, for a one (1) mile length of the two (2) OPL pipelines (two miles total pipeline length), over a one (1) year time period.

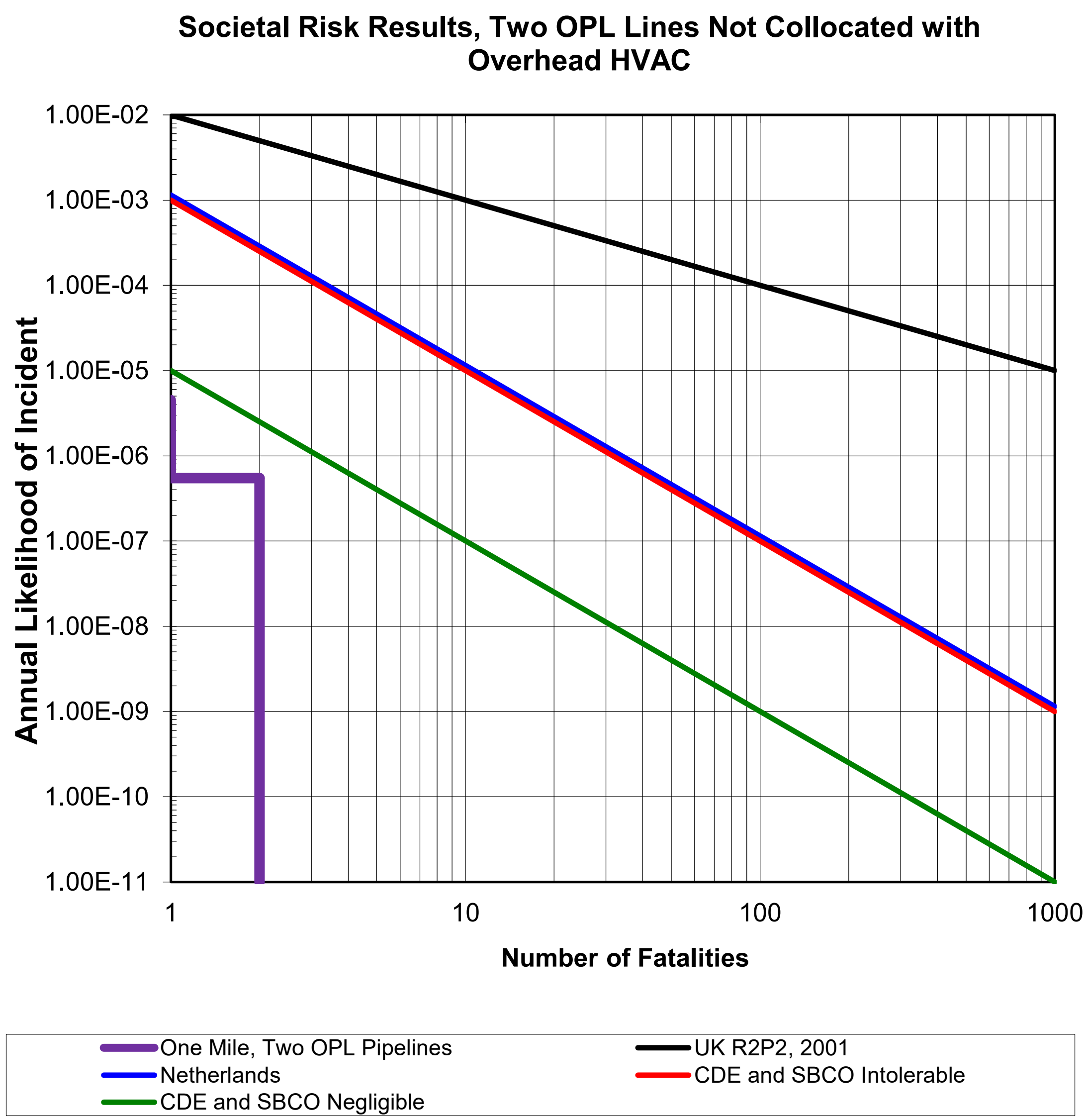


Figure 10.1.2-1 – Societal Risk Results, One Mile of Two OPL Lines Not Collocated with Overhead HVAC, Average Population Density

As depicted in Figure 10.1.2-1, there were incidents where either one (1) or two (2) individuals could be fatally injured. The probability is as follows:

- Two (2) fatalities - The societal risk annual probability is 5.48×10^{-7} (1 in 1.83 million).
- One (1) or more fatalities[79] - The societal risk annual probability is 4.52×10^{-6} (1 in 221,000).

These results are below the thresholds for negligible impacts which are used by Santa Barbara County and the California Department of Education for public school siting; they are more than two orders of magnitude below (less than one-one-hundredth of) these entities' intolerable level.

[79] The predicted maximum is two (2) fatalities for this scenario.

However, there are no known societal risk criteria for the proposed project. (See also Sections 3.2 and 3.3 of this Report.)

10.1.3 Minimum Population Density

When the minimum population density of 568 persons per square mile was considered, the number of persons exposed to each incident was below that which resulted in a single fatality. The highest mortality for any of the releases scenarios was 0.4; there were two scenarios which resulted in 0.4 fatalities:

- 8,863 barrel jet fuel pool fire, annual probability of 1.54×10^{-7} (1 in 6.5 million)
- 8,863 barrel gasoline pool fire, annual probability of 3.94×10^{-7} (1 in 2.5 million)

10.2 Two OPL Pipelines Collocated with 115/230 kV Lines (Alternative 1)

10.2.1 Maximum Population Density

The societal risk results are presented in Figure 10.2.1-1 for the maximum population density of 23,169 persons per square mile, for a one (1) mile length of the two (2) OPL pipelines (two miles total pipeline length), over a one (1) year time period for the proposed 115/230 kV project.

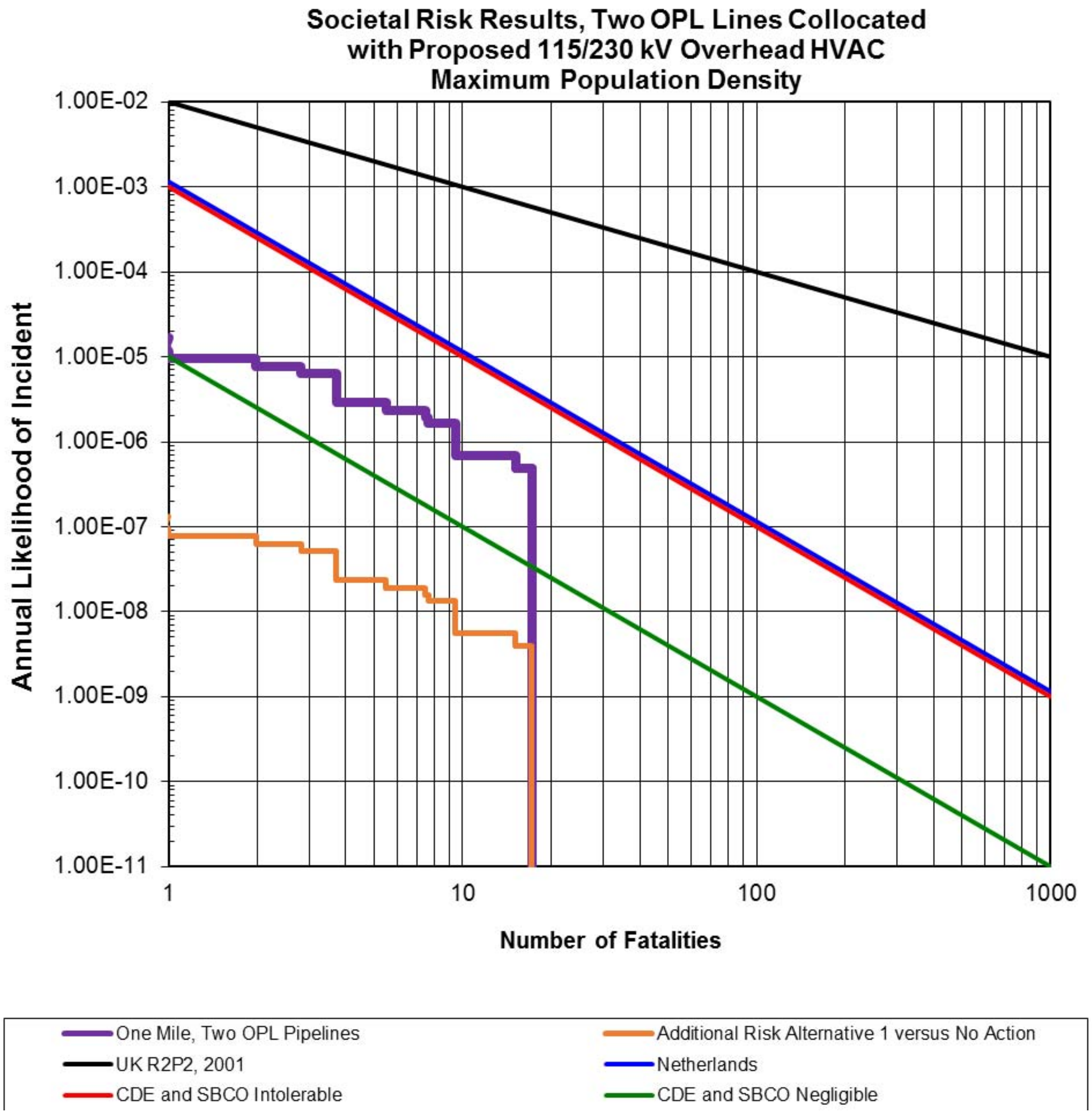


Figure 10.2.1-1 – Societal Risk Results, One Mile of Two OPL Lines Collocated with 115/230 kV Overhead HVAC, Maximum Population Density

As depicted in Figure 10.2.1-1, there are scenarios that could result in multiple fatalities. The annual probability of these incidents are presented in the following table.

Table 10.2.1-1 Societal Risk Results, One Mile of Two OPL Lines Collocated with 115/230 kV Overhead HVAC, Maximum Population Density

Number of Fatalities	Two OPL Lines Collocated with Proposed 115/230 kV Overhead HVAC Annual Likelihood	Additional Risk of Proposed Project versus No Action Alternative Annual Likelihood
17	4.92×10^{-7} 1 in 2.03 million	3.95×10^{-9} 1 in 253 million
15	6.85×10^{-7} 1 in 1.46 million	5.50×10^{-9} 1 in 182 million
9	1.67×10^{-6} 1 in 599,000	1.34×10^{-8} 1 in 74.6 million
8	1.95×10^{-6} 1 in 513,000	1.56×10^{-8} 1 in 63.9 million
7	2.34×10^{-6} 1 in 428,000	1.87×10^{-8} 1 in 53.4 million
5	2.90×10^{-6} 1 in 345,000	2.32×10^{-8} 1 in 43.0 million
4	6.34×10^{-6} 1 in 158,000	5.09×10^{-8} 1 in 19.7 million
3	7.69×10^{-6} 1 in 130,000	6.17×10^{-8} 1 in 16.2 million
2	9.65×10^{-6} 1 in 104,000	7.75×10^{-8} 1 in 12.9 million
1	1.67×10^{-5} 1 in 60,000	1.34×10^{-7} 1 in 7.45 million

These additional risk posed by the proposed 115/230 kV project are less than the thresholds for negligible impacts which are used by Santa Barbara County and the California Department of Education for public school siting. It should be noted however, that there are no known societal risk criteria for the proposed project. (See also Sections 3.2 and 3.3 of this Report.)

10.2.2 Average Population Density

The societal risk results for the proposed 115/230 kV project are presented in Figure 10.2.2-1 for the average population density of 3,228 persons per square mile, for a one (1) mile length of the two (2) OPL pipelines (two miles total pipeline length), over a one (1) year time period.

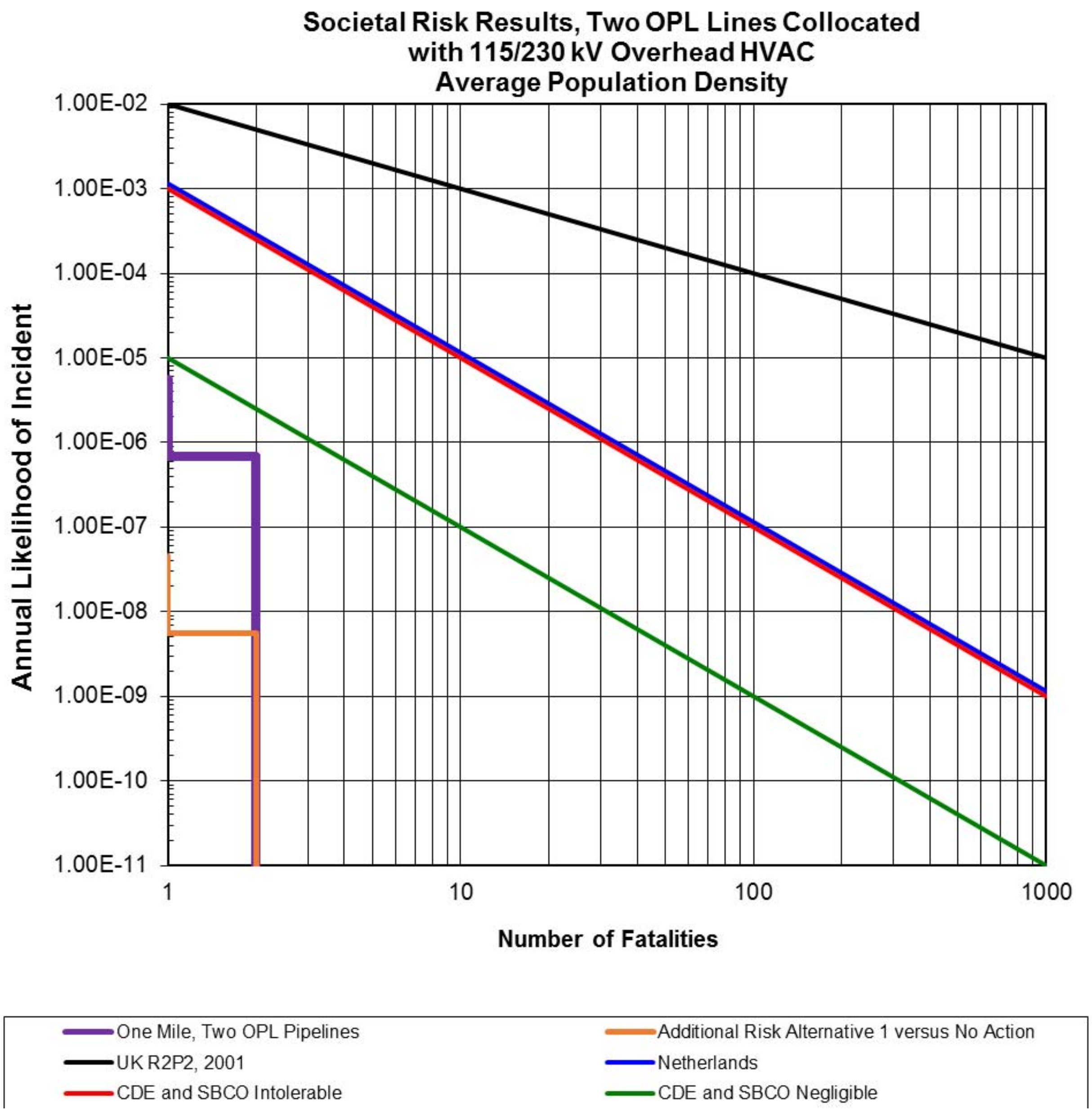


Figure 10.2.2-1 – Societal Risk Results, One Mile of Two OPL Lines Collocated with 115/230 kV Overhead HVAC, Average Population Density

As depicted in Figure 10.2.2-1, there were incidents where either one (1) or two (2) individuals could be fatally injured.

Table 10.2.2-1 Societal Risk Results, One Mile of Two OPL Lines Collocated with 115/230 kV Overhead HVAC, Average Population Density

Number of Fatalities	Two OPL Lines Collocated with Proposed 115/230 kV Overhead HVAC Annual Likelihood	Additional Risk of Proposed Project versus No Action Alternative Annual Likelihood
2	6.85×10^{-7} 1 in 1.46 million	5.50×10^{-9} 1 in 182 million
1	5.66×10^{-6} 1 in 177,000	4.54×10^{-8} 1 in 22.0 million

These results are below the thresholds for negligible impacts which are used by Santa Barbara County and the California Department of Education for public school siting; they are more than two orders of magnitude below (less than one-one-hundredth of) these entities' intolerable level. However, there are no known societal risk criteria for the proposed project. (See also Sections 3.2 and 3.3 of this Report.)

10.2.3 Minimum Population Density

When the minimum population density of 568 persons per square mile was considered, the number of persons exposed to each incident was below that which resulted in a single fatality. The highest mortality for any of the releases scenarios was 0.4; there were two scenarios which resulted in 0.4 fatalities:

- 8,863 barrel jet fuel pool fire, annual probability of 1.93×10^{-7} (1 in 5.18 million)
- 8,863 barrel gasoline pool fire, annual probability of 4.92×10^{-7} (1 in 2.03 million

10.2.4 Construction Societal Risk

Maximum Population Density

The societal risk results during construction of the proposed 115/230 kV project are presented in Figure 10.3.1-1 for the maximum population density of 23,169 persons per square mile, for a one (1) mile length of the two (2) OPL pipelines (two miles total pipeline length), over a one (1) year time period[80].

[80] Coating stress voltage and arc distance data is not available for the existing 115 kV corridor. The "other" incident cause data has been taken from the 115/230 kV proposed project.

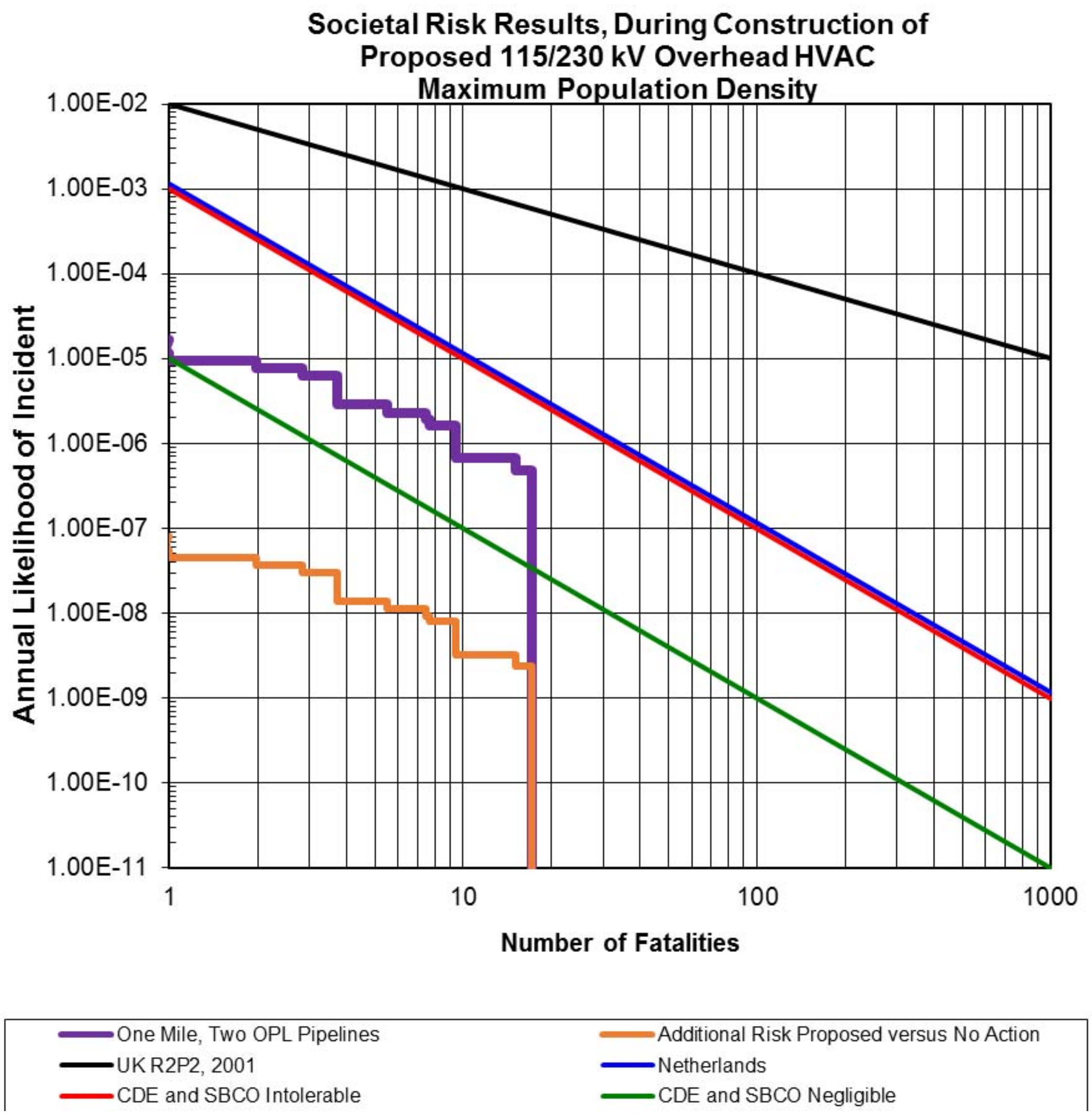


Figure 10.3.1-1 – Societal Risk Results during Construction of Proposed 115/230 kV Project, One Mile of Two OPL Lines Collocated with 115/230 kV Overhead HVAC, Maximum Population Density

As depicted in Figure 10.3.1-1, there are scenarios that could result in multiple fatalities. The annual probability of these incidents are presented in the following table:

Table 10.3.1-1 Societal Risk Results During Construction of Proposed 115/230 kV Project, One Mile of Two OPL Lines Collocated with 115/230 kV Overhead HVAC, Maximum Population Density

Number of Fatalities	Two OPL Lines In Existing 115 kV Overhead HVAC During Construction of Proposed 115/230 kV Project Annual Likelihood	Additional Risk During Construction versus No Action Alternative Annual Likelihood
17	4.87×10^{-7} 1 in 2.05 million	2.33×10^{-9} 1 in 428 million
15	6.78×10^{-7} 1 in 1.47 million	3.25×10^{-9} 1 in 308 million
9	1.65×10^{-6} 1 in 605,000	7.92×10^{-9} 1 in 126 million
8	1.93×10^{-6} 1 in 518,000	9.25×10^{-9} 1 in 108 million
7	2.31×10^{-6} 1 in 432,000	1.11×10^{-8} 1 in 90.3 million
5	2.87×10^{-6} 1 in 349,000	1.37×10^{-8} 1 in 72.8 million
4	6.28×10^{-6} 1 in 159,000	3.01×10^{-8} 1 in 33.2 million
3	7.62×10^{-6} 1 in 131,000	3.65×10^{-8} 1 in 27.4 million
2	9.56×10^{-6} 1 in 105,000	4.58×10^{-8} 1 in 21.8 million
1	1.66×10^{-5} 1 in 60,000	7.94×10^{-8} 1 in 12.6 million

These additional risk posed during construction of the proposed 115/230 kV project are less than the thresholds for negligible impacts which are used by Santa Barbara County and the California Department of Education for public school siting. It should be noted however, that there are no known societal risk criteria for the proposed project. (See also Sections 3.2 and 3.3 of this Report.)

Average Population Density

The societal risks during construction of the proposed 115/230 kV project are presented in Figure 10.3.2-1 for the average population density of 3,228 persons per square mile, for a one (1) mile length of the two (2) OPL pipelines (two miles total pipeline length), over a one (1) year time period.

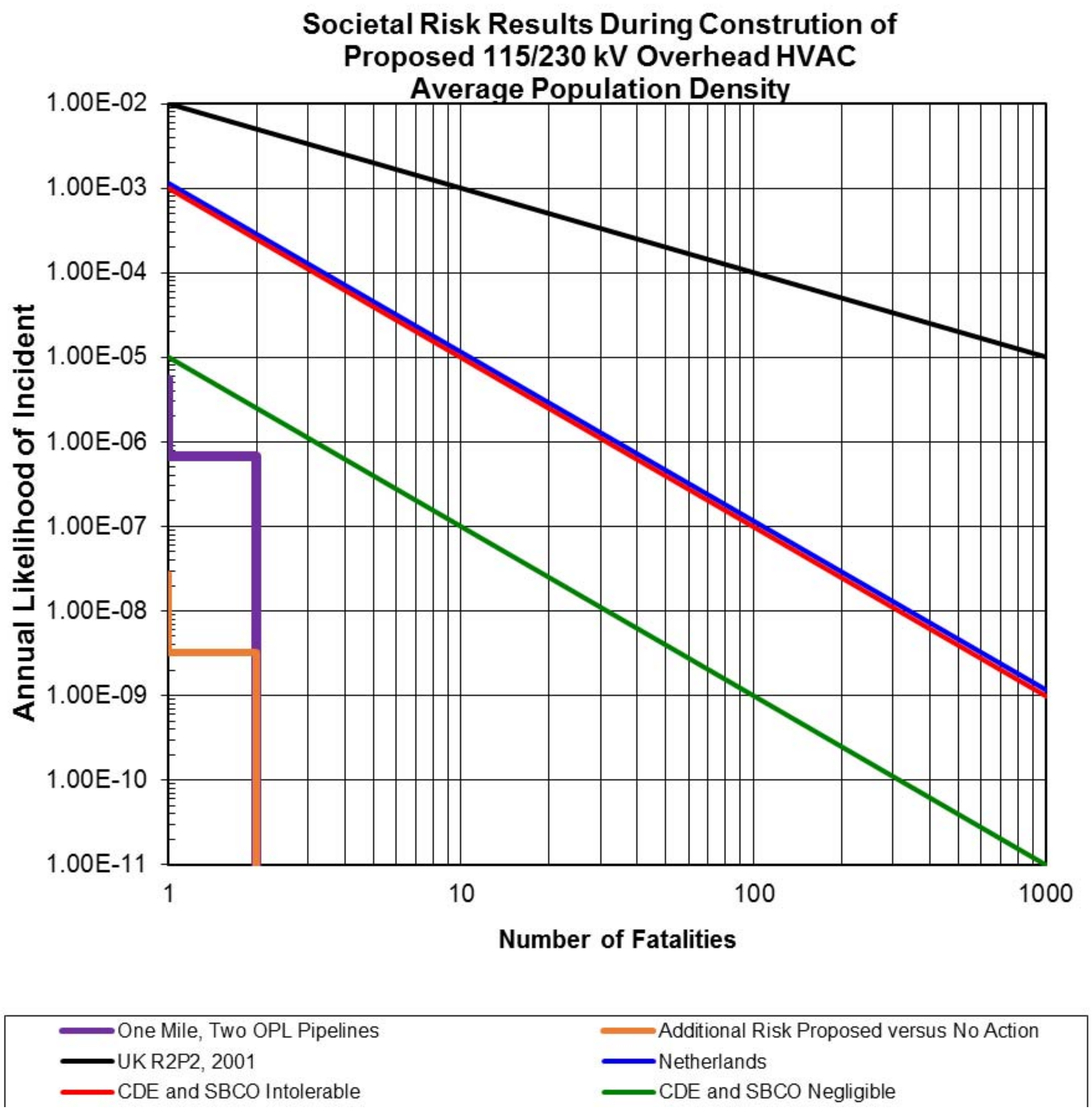


Figure 10.3.2-1 – Societal Risk Results during Construction of Proposed 115/230 kV Project, One Mile of Two OPL Lines Collocated with 115/230 kV Overhead HVAC, Average Population Density

As depicted in Figure 10.3.2-1, there were incidents where either one (1) or two (2) individuals could be fatally injured.

Table 10.3.2-1 Societal Risk Results, One Mile of Two OPL Lines Collocated with 115/230 kV Overhead HVAC, Average Population Density

Number of Fatalities	Two OPL Lines Collocated with Proposed 115/230 kV Overhead HVAC Annual Likelihood	Additional Risk of Proposed Project versus No Action Alternative Annual Likelihood
2	6.78×10^{-7} 1 in 1.47 million	3.25×10^{-9} 1 in 308 million
1	5.60×10^{-6} 1 in 179,000	2.68×10^{-8} 1 in 37.3 million

These results are below the thresholds for negligible impacts which are used by Santa Barbara County and the California Department of Education for public school siting; they are more than two orders of magnitude below (less than one-one-hundredth of) these entities' intolerable level. However, there are no known societal risk criteria for the proposed project. (See also Sections 3.2 and 3.3 of this Report.)

Minimum Population Density

When the minimum population density of 568 persons per square mile was considered, the number of persons exposed to each incident was below that which resulted in a single fatality. The highest mortality for any of the releases scenarios was 0.4; there were two scenarios which resulted in 0.4 fatalities.

11.0 Risk Reduction Measures

The proposed project could increase the likelihood and possibly the severity of unintentional releases from the OPL pipelines. In this section, several measures are presented which could be implemented to reduce this increased risk.

11.1 Surcharge Loading

The application of loads to the soil surface (surcharge loads) can induce stresses on the underlying substructures, including pipelines. These stresses can over-stress the pipe, causing ovality, through wall bending, pipe wall buckling, side wall crushing, fatigue, etc. which can result in an unintentional release.

During the construction of the proposed project, surcharge loads will be imposed on the existing OPL pipelines. In order to reduce the increased risk of unintentional release, the following measure could be imposed on the applicant.

Surcharge Loading Risk Reduction Measure – The Applicant shall analyze, or cause to be analyzed, all surcharge loads which will be imposed on the existing OPL pipeline(s) from heavy equipment, crane matts, etc. in accordance with the following:

- 49 CFR 195, Transportation of Hazardous Liquid by Pipeline,
- American Petroleum Institute Recommended Practice 1102, Steel Pipelines Crossing Railroads and Highways, and
- American Lifelines Alliance, Guidelines for the Design of Buried Steel Pipe.

11.2 Third Party Damage

During construction of the proposed project, excavations and soil disturbance will be required around and near the existing OPL pipeline(s). During these activities, the OPL pipeline(s) could be damaged. This damage could result in an immediate, or subsequent release, similar to those which occurred in Bellingham, Washington, Walnut Creek, California, and San Bernardino, California. (See Section 1.4 of this Report for a summary of these incidents.) In order to reduce the increased risk of unintentional release, the following measure could be imposed on the applicant.

Third Party Damage Risk Reduction Measure – The Applicant shall implement the following measures during construction of the proposed project. These measures are in addition to those required by State and Federal regulations and those included in OPL's operations and maintenance procedures.

- The Applicant shall insure that OPL line marking personnel mark the entire length of any pipeline that is within 50-feet of any excavation or ground disturbance below original grade. It is not acceptable to mark only the location of angle points (points of intersection).

- The Applicant shall excavate, expose, and positively identify the existing OPL pipeline(s) using soft dig methods (e.g., hand excavation, vacuum excavation, etc.) whenever the pipeline(s) are within 25-feet of any proposed excavation or ground disturbance below original grade.
- An OPL employee, trained in the observation of excavations and pipeline locating, shall be on-site at all times an excavation being made, or the ground is being disturbed below the original grade.

11.3 Electrical Interference

The A.C. Interference Study presented an analysis of the potential hazards which could impact the existing OPL pipeline(s). Based on the results of this study, we recommend the following risk reduction measures.

Induced A.C. Voltage Risk Reduction Measure – After the proposed 230 kV system has been commissioned, touch voltage testing should be conducted to insure that touch voltage potentials at all above grade facilities are less than 15 volts. The tests should be conducted during periods when the electrical system is operating at, or near, winter peak loading. Mitigation should be implemented should touch voltages exceed 15 volts. This will help insure that pipeline operators are not injured.

A.C. Current Density Risk Reduction Measure – In areas where the predicted A.C. current density will exceed 20 amps per square meter, testing should be conducted to insure that A.C. current densities do not exceed 20 amps per square meter. The tests should be conducted during periods when the electrical system is operating at, or near, winter peak loading. Where A.C. current densities exceed the 20 amps per square meter threshold, mitigation measures should be implemented to insure that A.C. corrosion does not occur.

Fault Arcing Risk Reduction Measure – In areas where the pipeline is within 13-feet of a grounding rod, mitigation measures should be implemented to prevent ground fault arcing to the pipeline.

12.0 References

12.1 Acronyms

AC – Alternating Current

ALARP - As Low as Reasonably Practicable

ANSI - American National Standards Institute

API - American Petroleum Institute

API 5L X52 – Pipe manufactured in accordance with API Standard 5L, Specification for Line Pipe, with a specified minimum yield strength of 52,000 psi

ASME - American Society of Mechanical Engineers

ASTM - American Society for Testing and Materials

BPH – Barrels per Hour

CFR - Code of Federal Regulations

CWA - Clean Water Act

EIS – Environmental Empact Statement

ERW – Electric Resistance Welded

HLPSA - Hazardous Liquid Pipeline Safety Act

HVAC – High Voltage Alternative Current

IR – Individual Risk

MSS - Manufacturers Standardization Society of the Valve and Fittings Industry

NFPA – National Fire Protection Association

NTSB – National Transportation Safety Board

OPL – Olympic Pipeline Company

OPS – Office of Pipeline Safety

PHMSA - The Pipeline and Hazardous Materials Safety Administration

PLDS - Pipeline Leak Detection System

PLL - Probable Loss of Life

PPM – Parts per Million

PSI – Pounds per Square Inch

RCW – Revised Code of Washington

RSPA - Research and Special Programs Administration

SMYS – Specified Minimum Yield Strength

SPCC - Oil Spill Prevention Control & Countermeasures

USA - Unusually Sensitive Areas

USC – United States Code

USDOT - United States Department of Transportation

WAC – Washington Administrative Code

12.2 Definitions

Aggregate Risk - Aggregate risk, or probable loss of life (PLL), is one risk measure used to evaluate projects. Aggregate risk is the total anticipated frequency of a particular consequence, normally fatalities, that could be anticipated over a given time period, for all project components being analyzed. Aggregate risk is a type of risk integral; it is the summation of risk, as expressed by the product of the anticipated consequences and their respective likelihood. The integral is summed over all of the potential events that might occur for all of the project components, over the entire project length.

ALARP approach. Generally, risks within a band of risk levels are considered tolerable only if risk reduction is impractical or if its cost is grossly disproportionate to the risk improvement gained. The underlying concept is to maximize the expected utility of an investment, but not expose anyone to an excessive increase in risk.

Barrels – A measure of volume equal to 42 U.S. gallons.

Bright Line Threshold - A bright-line rule (or bright-line test) is a clearly defined rule or standard, composed of objective factors, which leaves little or no room for varying interpretation. The purpose of a bright-line rule is to produce predictable and consistent results in its application. The term "bright-line" in this sense generally occurs in a legal context.

Bright-line rules are usually standards established by courts in legal precedent or by legislatures in statutory provisions.

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

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

Flammability Limit - Flammable liquid only burns in its gaseous state. If the ratio of fuel to air is greater than the upper flammability limit, the mixture is too rich to burn; if it is less than the lower flammability limit, the mixture is to lean to burn. (The mixture will only burn in gaseous state, between the upper and lower flammability limit.)

Flash Fire – A flash fire is a rapidly burning gas or vapor cloud of short duration. The duration lasts until all vapor and oxygen in the cloud is consumed. The duration of the flash fire at any point in the space depends on the concentration of the flammable vapor in air and the specific vapor substance involved. (CDE 2005)

Incidents per 1,000 mile years - This unit provides 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 incidents per 1,000 miles years, one would expect one incident per year on a 1,000 mile pipeline. Using this unit, frequencies of occurrence can be calculated for any combination of pipeline length and time interval.

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

Isopleth – A line connecting points at which a given variable has a specified value. In this context, the line connections points of a specified heat flux value.

Pasquill-Gifford Atmospheric Stability – This is classified by the letters A through F. Stability can be determined by three main factors: wind speed, solar insulation, and general cloudiness. In general, the most unstable (turbulent) atmosphere is characterized by stability class A. Stability A occurs during strong solar radiation and moderate winds. This combination allows for rapid fluctuations in the air and thus greater mixing of the released gas with time. Stability D is characterized by fully overcast or partial cloud cover during daytime or nighttime, and covers all wind speeds. The atmospheric turbulence is not as great during D conditions, so the gas will not mix as quickly with the surrounding atmosphere. Stability F generally occurs during the early morning hours before sunrise (no solar radiation) and under low winds. This combination allows for an atmosphere which appears calm or still and thus restricts the ability to actively mix with the released gas. A stability classification of "D" is generally considered to represent average conditions.

Pool Fire – A pool fire would typically follow a vapor flash fire for a liquid product release. If ignition occurs early, the main impact if from the pool fire. The fire burns the evaporated vapor from the pool surface. The fire would continue until all the liquid in the pool was consumed or the fire was extinguished. (CDE 2005)

Refined Petroleum Products – For the purposes of this Report, these products include: gasolines, diesel, and jet fuel.

Societal Risk - Societal risk is the probability that a specified number of people will be affected by a given event. The accepted number of casualties is relatively high for lower probability events and much lower for more probable events.

12.3 Reference Documents

American Petroleum Institute (API 752). Management of Hazards Associated with Location of Process Plant Buildings.

California Department of Education (CDE 2007 and CDE 2005). February 2007. Guidance Protocol for School Site Pipeline Risk Analysis.

Det Norske Veritas (Veritas 2017). Puget Sound Energy A.C. Interference Analysis, Existing Corridor.

Det Norske Veritas (Veritas 2016). A.C. Interference Analysis – 230 kV Transmission line Collocated with Olympic Pipelines OLP16 and OPL20.

Health and Safety Executive (HSE 2000). Report on a Study of International Pipeline Accidents, Contract Research Report 294/2000. United Kingdom.

Mannan, Dr. Sam. (LEES). Lee's Loss Prevention in the Process Industries. Third Edition.

Marszal, Edward M. (Marszal 2001). 2001. Tolerable Risk Guidelines.

National Transportation Safety Board (NTSB 2002). Pipeline Rupture and Subsequent Fire in Bellingham, Washington, June 10, 1999. Pipeline Accident Report NTSB/PAR-02/02. Washington, D.C.

National Transportation Safety Board (NTSB 2003). Pipeline Rupture and Subsequent Fire near Carlsbad, New Mexico, August 19, 2000. Pipeline Accident Report NTSB/PAR-03/01. Washington, D.C.

National Transportation Safety Board (NTSB 2011). Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010. Pipeline Accident Report NTSB/PAR-11/01. Washington, D.C.

Northwest Gas Association v. WUTC, 141 Wn. App. 98, 168 P.3d 443, 2007. Rev. denied, 163 Wn.2d 1049, 2008.

Office of the State Fire Marshal, Pipeline Failure Investigation Report, November 9, 2004. California.

Payne, Brian L. el al. EDM Services, Inc. 1993. California Hazardous Liquid Pipeline Risk Assessment, Prepared for California State Fire Marshal, March.

Presidential/Congressional Commission on Risk Assessment and Risk Management (Commission 1997). 1997. Framework for Environmental Health Risk Management.

Quest Consultants, CANARY. (QUEST 2003) CANARY by Quest User's Manual. 2003.

Santa Barbara County Planning and Development (SBCO 2008). October 2008. Environmental Thresholds and Guidelines Manual.

United States Department of Transportation (USDOT), Bureau of Transportation Statistics. Various Years. National Transportation Statistics.

West, Kim. 2016. Personal communication. Email from Kim West, Project Engineer (Olympic Pipeline) to Karmen Martin (ESA). August 5, 2016 at 4:32 PM with attachment.