b) A condition assessment of the existing short-circuit adequacy of equipment and bus structures, lightning protection, and conformance to National Electrical Safety Code (NESC) clearance requirements and UI design standards; and
c) A 3D Light Detection and Ranging (LiDAR) survey of the 115-kV yard to evaluate conformance to American National Standards Institute (ANSI), NESC, and UI clearance requirements with a focus on the areas surrounding the 115-kV OCB and associated disconnect switches.

(UI 1, p. 1-6)

48. As a result of its studies, UI determined that Old Town Substation contains the following deficiencies in terms of reliability and physical condition:

a) **Inadequate Lightning Protection** – The substation bus infrastructure does not adequately protect the exposed equipment (such as disconnect switches) from direct stroke lightning strikes. UI's analysis determined that there is a 99.8 percent probability that the exposed equipment would be damaged from lightning strikes;
b) **Insufficient Control Enclosure Space** – The existing control enclosure does not meet NESC criteria for sufficient work room and cannot be expanded due to the small size of the existing substation site. As result, the control enclosure cannot be upgraded to support any needed improvements at the substation;
c) **Single Point of Failure** – Both mains to and feeders from the No. 3 bus enclosure extend though the same manhole in the substation yard. This design is unique to Old Town Substation and is not found elsewhere in UI's system. A catastrophic event in this manhole, such as a cable fault, has the potential to de-energize the entire substation as these sections of cable are covered by the transformer differential protection scheme. Thus, there is a significant risk of interrupting all customer load supplied by the substation for an extended period of time due to the design of this manhole;
d) **Bus No. 3 Enclosure Issues** – Bus No. 3 is essentially a metal enclosed switchgear. It is located on piers rather than a flat slab foundation. The steer bus is buckling from the weight of the circuit breakers, so it is becoming more difficult to "rack in" and "rack out" the circuit breakers. UI has had several incidents of where the breakers do not operate properly because of the shifting of the floor. Thus, remediation is required. While UI has performed maintenance to address the breaker issues, the underlying problem leading to these failures persists, and it requires frequent and more difficult maintenance due to the age of the equipment and the lack of available replacement parts;
e) **OCB Replacement** – The substation's 115-kV OCB is obsolete and poses increased risk of failure. It is the only OCB that UI still has in its system. Other OCBs have already been replaced with gas insulated circuit breakers. This existing OCB is difficult to maintain due to its age and availability of spare parts;
f) **Lack of Mobile Substation Access** – UI owns two 50 MVA 115-kV/13.8-kV mobile substation transformers that can be deployed to substations in the event of a transformer failure in order to maintain service to customers. However, the existing Old Town Substation was designed for a single point of access for mobile substation deployment and has insufficient space to deploy even UI's smallest mobile transformer without violating clearances to the overhead strain bus. In addition, the only available location for a mobile transformer is over the substation's septic system. No other space is available due to the

location of the substation equipment and the small overall size of the existing substation site.

g) **Disconnect Switch Maintenance Issues** – The OCB disconnect switches are outdated and increasingly difficult maintain due to absence of replacement parts and long lead times for specialty fabricated components. In addition, the disconnect switches do not conform to current ANSI standards;
h) **Corroded Capacitor Coupled Voltage Transformers (CCVTs)** – Two CCVTs for the #1710 Line require replacement. These CCVTs are corroded with a high risk of moisture penetration into the internal components.

(UI 1, pp. 1-6 and 1-7; Tr. 1, pp. 17-19)

Contingency Modeling – Old Town Substation

49. A 90/10 load forecast contains load projections based on a plausible worst-case hot weather scenario. It means that there is only a 10 percent chance that the projected peak load would be exceeded in a given year. 90/10 load forecasts are used for utility infrastructure planning. (Council Administrative Notice Item No. 43 – Council 2017/2018 Forecast of Electric Loads and Resources, pp. 9 and 20)

50. The weather-normalized 90/10 loading of the existing Old Town Substation was 64.82 MVA during 2019. Based on UI's 2019 90/10 Ten Year Load Forecast, this loading is projected to grow to 66 MVA by 2030; this results in a compound annual growth rate (CAGR) of approximately 0.164 percent. (UI 2, responses 4, 8 and 9; Council Administrative Notice Item No. 43 – Council 2017/2018 Forecast of Electric Loads and Resources, CAGR Formula, p. 20)

51. The existing Old Town Substation transformers have a total capacity of approximately 85 MVA. Thus, UI's proposed replacement of the Old Town Substation is not due to an existing MVA capacity issue. (UI 2, response 4; Tr. 1, p. 16)

52. The proposed replacement substation would be constructed with two transformers with a top nameplate rating of 75 MVA. The MVA capacity of the proposed replacement substation depends on the emergency load ability of the transformers and would be determined based on a thermal analysis of the as-built transformers. Notwithstanding, the MVA capacity of the proposed replacement substation is expected to be significantly greater than the nameplate rating of 75 MVA. (UI 2, response 8; Tr. 1, p. 16)

53. The proposed replacement substation would also be designed to accommodate a mobile transformer for emergency conditions. (UI 1, p. 2-3; UI 2, response 15)

System Alternatives

54. UI considered three potential system alternatives as noted below:

a) No action;
b) Rebuild the entire substation in place, over the existing footprint; or
c) Full replacement on a different site.

(UI 1, pp. 9-1 to 9-5)

55. With the "No Action" alternative, the existing Old Town Substation would continue in-service at the present site, and there would be no improvements made to upgrade the substation's transmission and distribution system infrastructure. Thus, the current infrastructure issues would remain including, but not limited to: reliability and operating issues relating to the substation's transmission and distribution infrastructure; obsolete 115-kV OCB and associated disconnect switches; inadequate control enclosure; insufficient access/clearance for emergency mobile transformers; and inadequate lightning protection. Thus, the "No Action" alternative was rejected because it would not resolve the asset condition issues at the Old Town Substation, and it would not improve the reliability of the electric system. The substation would remain outdated and at risk for equipment failures that would lead to extended duration outages affecting customers and the bulk power system. (UI 1, p. 9-2)

56. With the "Rebuild in Place" alternative, the existing Old Town Substation would be upgraded including, but not limited to, replacement of the transformers to conform to UI's current standard; provision of access for a mobile substation transformer; and addition of a new pre-fabricated control enclosure. Such upgrades would cost approximately $47M. (UI 1, p. 9-3; Tr. 1, p. 20)

57. The "Rebuild in Place" alternative was rejected because it would result in various constraints and construction challenges. For example, the existing substation would have to be taken out of service for an extensive length of time, and construction activities would have to be closely coordinated with available outage periods. A mobile substation would be required at the site to maintain reliable service to UI customers; the mobile substation would be unavailable for other uses; and it would further increase the complexity of the substation construction. There would be increased safety risk during construction because substation upgrades would have to be performed in proximity to energized equipment. The "Rebuild in Place" alternative does not include any provisions for the expansion of the substation to serve future customer needs or for the replacement of equipment that may become obsolete in the future. Lastly, the "Rebuild in Place" alterative would be more costly at $47M than the proposed replacement substation which is estimated to cost about $39.1M. (UI 1, p. 9-3; UI 2, response 6)

58. After determining that the asset condition issues at Old Town Substation could not feasibly be addressed by the "Rebuild in Place" alternative, UI conducted a review to identify and assess potential sites for a replacement Old Town Substation. (UI 1, p. 9-4)

Location Alternatives

59. In its search for a substation site, UI considered the following standard criteria below:

a) Minimize the need to acquire residences and viable commercial/industrial uses to accommodate substation development;
b) Maintain consistency/compatibility with existing land uses and land use plans to the extent possible;
c) Minimize adverse effects on sensitive environmental resources;
d) Protect public health and safety; and
e) Demonstrate cost-effectiveness while adhering to good engineering and sound environmental planning practices.

(UI 1, p. 9-4)

60. UI also considered the following site-specific criteria relative to a replacement substation site.

a) Distance to the existing Old Town Substation and the Eversource 115-kV transmission lines that must connect to the substation;
b) Availability of property, e.g. sites that are UI-owned, vacant/undeveloped, for sale, or would not require the removal or relocation of existing commercial or residential uses;
c) Site size of at least 2.75 acres, including undeveloped buffers and setbacks needed for a 115/13.8-kV AIS facility of the type required for the replacement substation;
d) Site topography and subsurface conditions;
e) Environmental and land use characteristics, including present and past property uses, e.g. presence of jurisdictional water resources, cultural resources, threatened/endangered species, and need for environmental remediation;
f) Substation constructability;
g) Availability of property (e.g. via fee ownership or easement) for transmission and distribution line connections to the substation and the required lengths of new transmission and distribution line segments needed to connect the replacement substation;
h) Accessibility;
i) Permit-ability, i.e. the anticipated ability to obtain all required regulatory approvals for construction at the site; and
j) Cost.

(UI 1, pp. 9-4 and 9-5)

61. UI identified seven potential sites to construct a replacement substation. These sites are listed below:

a) 4750 Park Avenue, Bridgeport;
b) 561 Frenchtown Road, Bridgeport;
c) 280, 312, 330 Kaechele Place, Bridgeport (i.e. the proposed site);
d) 2300 Reservoir Avenue, Trumbull;
e) Quarry Road, Trumbull;
f) Rocky Ridge Drive/Quail Trail, Trumbull; and
g) Huntington Turnpike, Trumbull.

(UI 1, p. 9-8)

62. After examining the potential sites, UI selected the proposed site for a replacement substation. None of the remaining six sites are presently owned by UI or dedicated to utility use. As a result, property acquisition would pose challenges and would increase costs. Additionally, none of the six remaining sites are located in the immediate vicinity of the existing Old Town Substation; thus, no efficiencies would be realized via minimizing new transmission and distribution connections. Several of the six remaining sites have land use constraints (e.g. presence of wetlands and recreational uses), and others would require costly distribution system connections. (UI 1, p. 9-7)

Proposed Site Location

63. The proposed replacement substation site includes a 0.9-acre UI-owned parcel located at 282 Kaechele Place that contains UI's existing Old Town Substation and a total of 3 acres of undeveloped UI-owned parcels at 312 and 330 Kaechele Place (collectively, the subject property). (UI 1, p. ES-1)

64. The existing substation parcel is entirely developed for utility use and contains no vegetation other than lawn and ornamental vegetation along Kaechele Place. The undeveloped UI parcels contain upland forest, shrub vegetation, and a wetland. (UI 1, p. ES-1)

65. The subject property is located within the City's Residential (R-A) Zone. (UI 1, p. 4-7)

66. Commercial development exists west of the subject property along Kaechele Place and Main Street. A single commercially-developed property, which fronts on Main Street, and multiple residentially-developed properties located along Sequoia Road abut the subject property to the north. ERWP, a City of Bridgeport park and a large wooded property, abuts the subject property to the east and south. ERWP is undeveloped but does have some blazed hiking trails. The Eversource electrical transmission ROW extends from the east through ERWP and through a portion of the existing substation site before continuing to the west. (UI 1, Appendix D – Visual Assessment and Photo-Simulations, p. 1 and Existing Conditions Photo-simulation)

67. There are approximately 89 residences located within a 1,000-foot radius of the center of the proposed replacement substation. (UI 2, response 2)

68. The nearest residence is located approximately 90 feet southwest of the proposed replacement substation fence line. (UI 1, Appendix G – Electric and Magnetic Field Report, pp. 13-14)

Proposed Replacement Substation Description

69. The proposed replacement substation would have an irregular shape with an interior fenced area totaling 2.25 acres (or approximately 98,000 square feet) which consists of 0.9 acre of the existing substation parcel and 1.35 acre of the 3 acres of additional parcels. (UI 1, Appendix D – Visual Assessment and Photo-Simulations, p.1 and Proposed Conditions Photo-simulation)

70. The proposed replacement substation would be enclosed by a 14-foot high chain link fence with privacy slats and one foot of barbed wire on top. (UI 1, p. ES-2 and 2-4)

71. To accommodate existing topography and minimize grading, a concrete retaining wall approximately 700 feet in length and about two to ten feet in height would be constructed around portions of the substation perimeter, and the chain link fence would be installed on top of the retaining wall. (UI 1, pp. ES-4 and 2-4)

72. Access to the substation would be via a new paved access drive inside the fenced substation from two gates* located off of Kaechele Place.

    *A third gate not associated with the access drive will be located within the transmission line ROW. (UI 1, p. 2-1 and Appendix A – Drawing SK-25233-003-001 SH2; Tr. 1, pp. 21-22)

73. The interior surface of the proposed replacement substation would consist of traprock, with the exception of areas occupied by equipment/enclosures and the access drive. The access drive would be paved. (UI 1, pp. 3-2 and 3-5; Tr. 1, pp. 21-22)

74. The primary substation components would include, but not be limited to:

    a) A new approximately 3,840 square foot control enclosure and 13.8-kV switchgear enclosure with dimensions of 120 feet long by 32 feet wide by 16 feet high;
    b) Two 115-kV/13.8-kV 45/60/75 MVA power transformers;
    c) Three 115-kV sulfur hexafluoride (SF_6) dead tank circuit breakers;

d) 115-kV disconnect switches;
e) CCVTs;
f) Associated 115-kV insulators, tubular aluminum bus, surge arrestors, and connectors;
g) Provisions to accommodate a temporary mobile transformer for emergency conditions;
h) Lightning masts; and
i) Associated structural steel to support electrical equipment.

(UI 1, p. 2-3)

75. The proposed control enclosure and switchgear enclosure would contain the following including, but not limited to:

a) Protection and control panels with associated relay and metering equipment;
b) Battery banks and associated chargers;
c) AC/DC distribution panels;
d) Lavatory facility;
e) Communications equipment;
f) Heating, ventilation and air conditioning (HVAC) equipment;
g) The switchgear room would accommodate construction of four new lineups of indoor 13.8-kV gas insulated substation switchgear separated with space for future additions.

(UI 1, p. 2-3)

76. The existing Eversource transmission connections would be relocated to the proposed replacement substation. Specifically, the #1710 Line and the #1222 Line would connect to the line terminals at the proposed replacement substation. The #1714 Line would be re-routed through the proposed substation yard in anticipation of a future connection, but it would not be connected to the substation at this time. (UI 1, p. 2-4)

77. Eversource would replace the two existing steel lattice towers with four new monopoles to accommodate the transmission interconnection. The four new monopoles would be approximately 105 feet above ground level (agl) which is the same height as the two existing self-supporting lattice structures to be replaced. UI would install five monopoles inside the proposed replacement substation, each reaching a height of less than 100 feet agl. All nine proposed monopoles would have a galvanized steel finish. (UI 1, pp. 2-4, 2-5 and Appendix D – Visual Assessment and Photo-Simulations, p. 1; Tr. 1, p. 21; UI 2, response 12)

78. Eversource would own the four monopoles located outside of the proposed replacement substation along with the insulators and hardware attached to the monopoles. UI would own the five monopoles located inside the proposed replacement substation, conductors entering and exiting the substation to reach the Eversource monopoles, and substation equipment. (UI 1, p. 1-10; Tr. 1, p. 42)

79. UI's proposed replacement substation project would require approximately 18 to 24* months to construct. This includes, but is not limited to, the construction of the replacement substation and installation of new line connections, as well as removal of the 115-kV line connections to the existing Old Town Substation. Construction would commence in early 2023, and the replacement substation is projected to be in service by the end of second quarter 2024. The decommissioning work for the existing Old Town Substation could extend beyond this projected schedule window.

*Once the replacement substation is substantially complete by UI, Eversource's line construction work would commence and would require approximately four months to complete. (UI 1, pp. 3-7 and 7-1; Eversource 2, p. 8)

80. Construction hours for UI and Eversource would generally occur from 7:00 a.m. to 7:00 p.m. Monday through Saturday. Some extended hours and Sunday work may be necessary due to circumstances such as inclement weather, outage constraints, and construction work that must occur on a continuous basis such as concrete pours and foundation installations. (UI 1, p. 3-7; Eversource 2, p. 8)

81. After the proposed replacement substation is constructed, the 115-kV transmission lines and 13.8-kV distribution lines are connected, and the facility is commissioned and placed into service, UI will decommission the existing Old Town Substation and associated 115-kV/13.8-kV line connections. This decommission work would include, but not be limited to:

a) Decommission and remove electrical components within the substation e.g. 115-kV 60 MVA transformers, OCB, bus and structures, CCVTs, switchgear and control enclosure;
b) Remove aboveground structural components within the substation; and
c) Eversource would dismantle and remove the existing overhead transmission line connections to the substation e.g. remove conductors, arms and structures.

(UI 1, p. 2-6)

Environmental Considerations

Coastal Area Resources

82. The proposed site is not located within a Coastal Boundary. (UI 2, response 19)

Agricultural Resources

83. There are no Prime Farmland Soils located on the proposed site. (UI 2, response 20)

Historic and Archaeological Resources

84. No previously identified archaeological sites or properties listed or eligible for listing on the National Register of Historic Places are located within 0.5 mile of the proposed project area. (UI 1, Appendix B – SHPO Letter dated January 16, 2020)

85. No historic properties would be affected by the proposed project. (UI 1, Appendix B - SHPO Letter dated January 16, 2020)

Forest

86. On the subject property, UI would clear shrub vegetation and remove approximately 60 trees of six inches diameter or greater to construct the project. In addition, within the easement in the ERWP, approximately 10 additional trees of six inches diameter or greater would be removed to accommodate the relocated overhead 115-kV transmission line connections to the proposed replacement substation. (UI 1, p. 3-3)

87. No tree clearing or widening of the ROW would be necessary for the installation of Eversource's monopole structures. (Eversource 2, p. 5)

88. No tree clearing within core forest is proposed for this project. (UI 2, response 21)

Wildlife

89. By letter dated October 18, 2019, DEEP reviewed the Natural Diversity Database (NDDB) and found that the eastern box turtle (EBT), a state-listed Species of Species Concern, occurs in the area of the proposed site. DEEP included protective measures for the EBT including, but not limited to, performing work during the active season of April through October; hiring a qualified herpetologist; use of exclusion fencing; contractor training; protection of wetland habitat; and reporting requirements. UI would implement the protective measures for the EBT. (UI 1, Appendix B.2.2 – DEEP NDDB Letter dated October 18, 2019; UI 1, pp. 5-5 and 5-6; Tr. 1, p. 53)

90. UI consulted with the U.S. Fish and Wildlife Service (USFWS) regarding the northern long-eared bat (NLEB), a federally-listed Threatened Species and state-listed Endangered Species. USFWS indicated that no NLEB habitat occurs at the site. However, based on UI's ecological assessment of the site, three to five viable NLEB roosting trees were identified at the proposed site. In the unlikely event that NLEB utilizes such trees as roosting or nursery habitat, UI would limit clearing to outside of the June through July pup season. (UI 1, p. 4-5; UI 1, Appendix C – Ecological Assessment Report, p. 1; Council Administrative Notice Item No. 54 – 2015 DEEP Endangered, Threatened and Special Concern Species)

91. Depending upon the type of species identified, Eversource would employ appropriate wildlife protection measures including time of year construction. (Tr. 1, p. 81)

Wetlands and Watercourses

92. The Inland Wetlands and Watercourses Act (IWWA), CGS §22a-36, *et seq.*, contains a specific legislative finding that the inland wetlands and watercourses of the state are an indispensable and irreplaceable but fragile natural resource with which the citizens of the state have been endowed, and the preservation and protection of the wetlands and watercourses from random, unnecessary, undesirable and unregulated uses, disturbance or destruction is in the public interest and is essential to the health, welfare and safety of the citizens of the state. (CGS §22a-36, et seq.)

93. The IWWA grants regulatory agencies with the authority to regulate upland review areas in its discretion if it finds such regulations necessary to protect wetlands or watercourses from activity that will likely affect those areas. (CGS §22a-42a)

94. The IWWA forbids regulatory agencies from issuing a permit for a regulated activity unless it finds on the basis of the record that a feasible and prudent alternative does not exist. (CGS §22a-41)

95. UI performed an on-site wetland and watercourse investigation of the proposed site on April 23, 2018. (UI 1, Appendix C – Ecological Assessment Report, p. 1)

96. Wetland A is an on-site 0.49 acre wetland and unnamed intermittent stream identified in the northern portion of the site. (UI 1, Appendix C – Ecological Assessment Report, pp. 2, 4 and Wetland Delineation, Figure 3)

97. Wetland B is an off-site wetland and unnamed intermittent stream identified southeast of the proposed site within the ERWP as well as within the Eversource ROW. (UI 1, Appendix C – Ecological Assessment Report, pp. 3, 4 and Wetland Delineation, Figure 3)

98. As a result of construction, UI does not anticipate any permanent impacts to Wetland A, e.g. fill being placed within Wetland A. However, as the design of the substation is finalized, it is possible that some vegetation may need to be cut in this wetland, and some construction activities (including the installation of the retaining wall) may necessitate the use of temporary construction matting in the western portion of the wetland. (UI 1, p. 5-3; Tr. 1, pp. 60, 72)

99. If any temporary wetland impacts are required, UI would consult with and provide necessary submittals to DEEP and the U.S. Army Corps of Engineers (ACOE). If any portion of Wetland A must be filled to develop the substation, UI would also consult with and secure appropriate permitting from DEEP and ACOE. (UI 1, p. 5-3)

100. During the April 2018 wetland and watercourse delineation, Wetland B was initially identified as potential habitat for breeding amphibians. Wetland A was not identified as potential habitat for breeding amphibians due to inadequate hydrology. On April 5, 2019, a follow-up survey was performed, and no obligate vernal pool species were identified in Wetland B. Thus, Wetland B is not considered viable vernal pool habitat. (UI 1, Appendix C – Ecological Assessment Report, p. 10)

101. During construction of the project, UI would implement measures to minimize the potential for runoff into municipal sewers and to protect water resources (e.g. wetland and streams) and would utilize erosion and sedimentation control measures in accordance with its Stormwater Pollution Control Plan (SWPCP) and DEEP Stormwater Permit. (UI 1, p. 5-3)

Groundwater

102. The proposed substation site is not located within a DEEP-designated Aquifer Protection Area (APA). (Council Administrative Notice Item No. 85 – DEEP statewide APA Map; UI 1, p. 4-3)

103. Groundwater in the project area is classified by DEEP as GB. Water with a GB classification includes industrial process and cooling waters and base flows for hydraulically connected water bodies. Such water is presumed not suitable for human consumption without treatment. (UI 1, p. 4-3)

104. The depth to groundwater in project area is estimated at approximately 10 feet below grade. (UI 1, p. 4-3)

105. UI would prepare a SWPCP in accordance with the DEEP Stormwater Permit. (UI 1, pp. 3-6 and 3-7)

106. The proposed project would comply with the 2004 Connecticut Stormwater Quality Manual. (Tr. 1, pp. 23-24)

107. Dewatering protocols would be implemented as necessary consistent with the SWPCP and the DEEP Stormwater Permit. (UI 1, p. 5-2)

108. If any contaminated groundwater is encountered, it would be managed in accordance with DEEP requirements. (UI 1, pp. 5-2 and 5-3)

109. Each of the proposed transformers would have a secondary containment system designed to hold 110 percent of a transformer's insulating (mineral) oil capacity and would include accidental spill prevention measures. UI would also have a Spill Prevention Control and Countermeasures Plan. (UI 1, pp. 3-5 and 5-4; Tr. 1, pp. 64, 73)

Soil and Earthwork

110. UI's and Eversource's erosion and sedimentation controls would be consistent with the 2002 Connecticut Guidelines for Erosion and Sediment Control. Eversource would also comply Eversource Best Management Practices (BMPs). (UI 1, p. 3-6; Tr. 1, pp. 80-81)

111. Approximately 9,300 cubic yards of cut and 8,800 cubic yards of fill would be required to grade the site for construction. Any spoils generated during the project construction would be managed in accordance with UI procedures and applicable regulatory requirements. (UI 2, response 13; UI 1, p. 3-7; Tr. 1, p. 23)

Flood Design

112. The proposed site is not located within any mapped 100-year or 500-year Federal Emergency Management Agency flood zones. (UI 1, p. 4-3; Tr. 1, p. 52)

Visibility

113. The tallest features of the proposed project would be Eversource's four new monopoles that would reach a height of 105 feet agl which is the same height as the two existing self-supporting lattice structures to be replaced. UI's five monopoles to be constructed inside the proposed replacement substation would each reach a height of less than 100 feet agl.

*Lightning masts on top of the structures are not expected to be necessary.

(UI 1, pp. 2-4, 2-5 and Appendix D – Visual Assessment and Photo-Simulations, p. 1; Tr. 1, p. 21)

114. The most prominent views of the proposed replacement substation would from nearby locations along Kaechele Place and Main Street immediately west of the subject property. During leaf-off conditions, portions of the substation's infrastructure would also be visible from locations on Sequoia Road north of the subject property. (UI 1, Appendix D – Visual Assessment and Photo-Simulations, p. 2)

115. In general, views of the proposed replacement substation from Main Street would be screened by existing intervening commercial buildings. Many nearby views of the substation would be mitigated seasonally by foliage (which includes new plantings) and screening elements incorporated into the facility design. (UI 1, Appendix D – Visual Assessment and Photo-Simulations, p. 2)

116. The Merritt Parkway (Route 15), a National Scenic Byway, is located approximately 0.4 mile north of the proposed project. No views of the proposed project would be expected from the Merritt Parkway. No other state or locally designated scenic roads are located within the vicinity of the proposed project. (UI 2, response 3)

117. The nearest publicly accessible recreational resource is ERWP which is located directly east of the proposed site and contains a portion of the existing Eversource transmission ROW. ERWP contains hiking trails, but not other recreational facilities. No views of the proposed project would be expected from the blazed hiking trails within ERWP. (UI 1, pp. 4-9 to 4-11 and Appendix D – Visual Assessment and Photo-Simulations, p. 2)

118. The nearest school to the proposed replacement substation site is Valley Medical Institute located approximately 0.11 mile to the southwest. The nearest daycare facility to the proposed replacement substation site is Cheyenne's Early Learning Center located approximately 0.15 mile to the southwest. (UI 1, pp. 4-10 and 4-11)

119. The proposed project would be located immediately east of a developed urban area that is well lit due to existing commercial facilities and a nearby transportation network. As a result, the construction and operation of the proposed project would result in only localized and minor modifications to the lighting environment. (UI 1, p. 5-11)

120. The proposed replacement substation would include general task lighting that would only be turned on during maintenance or switching operations. UI would also install an entry lighting which may be controlled by a photocell so it would operate at night. Security lighting is also required. UI would work closely with its security department as well as neighbors in the direct vicinity with respect to security lighting. (UI 1, p. 3-5; Tr. 1, pp. 71-72)

Public Safety

121. UI's proposed replacement substation would comply with the standards of the NESC, ANSI, the Institute of Electrical and Electronic Engineers (IEEE), good utility practices, and UI specifications. (UI 1, p. 3-1)

122. For fire protection, the proposed replacement substation would meet the requirements of IEEE/ANSI as well as the National Fire Protection Association. (UI 1, p. 3-8)

123. UI trains its employees and the local fire department on safe methods to address a substation fire. (UI 1, p. 3-8)

124. UI would secure the control house and equip it with fire extinguishers and remotely monitored smoke detectors. Smoke detection would automatically activate an alarm at the UI System Operations Center, and the system operators would then take appropriate action. (UI 1, p. 3-9)

125. The proposed replacement substation yard would be gated and locked. Security devices would constantly monitor the substation to alert UI of any abnormal or emergency situations. (UI 1, p. 3-9)

126. Appropriate signs would be posted at the proposed replacement substation fence and gates in order to alert the general public of the presence of high-voltage facilities. (UI 1, p. 3-9)

127. The three proposed 115-kV circuit breakers would contain SF_6, a greenhouse gas, and each would be pressurized to approximately 80 pounds per square inch. No leakage of SF_6 is anticipated; however, as a precaution, the breakers would be alarmed and monitored by UI on a 24/7 basis. (Tr. 1, pp. 25-26, 69)

128. Notice to the Federal Aviation Administration (FAA) is not required for UI's proposed replacement substation or Eversource's four proposed permanent transmission structures. UI and Eversource would check on the need for submitting notice to FAA for temporary structures such as cranes to be used during construction. (UI 2, response 16)

129. By letter dated September 9, 2014, the ISO-NE Reliability Committee (ISO-NE RC) determined that the proposed project would not have a significant adverse effect on the reliability or operating characteristics of the transmission system. (UI 2, response 18)

130. UI would equip the proposed replacement substation with measures designed to ensure continued service in the event of outages of faults in transmission or substation equipment. If an energized line or piece of equipment fails, protective relaying equipment would immediately remove the failed line or equipment from service, thereby protecting the public and the remaining equipment within the substation. (UI 1, p. 3-8)

131. The project design would include protective relaying equipment to automatically detect abnormal system conditions (e.g. a faulted overhead transmission line) and to send a protective trip signal to circuit breakers to isolate the faulted section of the transmission system. The protective relaying schemes would have redundant primary and backup equipment so that a failure of one scheme would not require the portion of the system monitored by that equipment to be removed from service. (UI 1, p. 3-8)

132. The protective relaying and associated equipment, along with a SCADA system for 24/7 remote control and equipment monitoring, would be housed at UI's System Operations Center. (UI 1, p. 3-8)

133. Corona noise generated by the 115-kV system is too weak and too low a frequency to interfere with communications in the very high frequency (VHF) and ultra-high frequency (UHF) bands in radio, wireless, telecommunications, or cable or satellite television. (UI 2, response 17)

134. In December 2009, President Obama proclaimed power grids as critical infrastructure vital to the United States. The Department of Homeland Security, in collaboration with other federal stakeholders, state, local, and tribal governments, and private sector partners, has developed the National Infrastructure Protection Plan (NIPP) to establish a framework for securing our resources and maintaining their resilience from all hazards during an event or emergency. (Council Administrative Notice Item No. 4)

135. On February 12, 2013, President Obama signed Executive Order 13636 on Improving Cyber Security for Critical Infrastructure, along with an accompanying Presidential Policy Directive on Critical Infrastructure Security and Resilience. The order established the U.S. policy to "enhance the security and resilience of the nation's critical infrastructure." The Secretary of Homeland Security has been given the overall responsibility for critical infrastructure protection and identifies the Department of Energy as the sector-specific agency responsible for the energy sector. The Department of Energy may draw upon the North American Electric Reliability Corporation's (NERC) expertise. (Council Administrative Notice Item No. 5; Council Administrative Notice Item No. 65)

136. NERC developed Physical Security Reliability Standard CIP-014-1 to address threats and vulnerability to the physical security of critical infrastructure on the bulk power system. CIP-014-1 consists of standards and requirements related to security of electronic perimeters, protection of critical cyber assets including personnel, training, security management and disaster recovery planning. CIP-014-1 requires transmission owners to deploy systems for monitoring security events and to have comprehensive contingency plans for cyberattacks, natural disasters and other unplanned events. (Council Administrative Notice Item No. 10; Council Administrative Notice Item No. 65)

Noise

137. The sources of noise for the proposed replacement substation facility would include the two proposed transformers. (UI 1, Appendix F – Environmental Noise Assessment, p. 1)

138. The proposed project is considered a Class C (industrial) noise emitter, and abutting properties are either Class A (residential) or Class B (commercial) receptors. The DEEP noise limit for a Class C emitter to a Class A receptor is 61 dBA during the day and 51 dBA at night. (UI 1, Appendix F – Environmental Noise Assessment, p. 3)

139. UI's noise consultant performed ambient level noise measurements in the vicinity of the proposed site. Short-term and long-term noise monitoring locations are listed below.

Receptor/ Meas. Site ID	Description	Predicted Facility Noise Level (dBA)	Land Use	Applicable Sound Level Limit (dBA)
LT-1	Property line; backyard of 60/76 Sequoia Rd.	43	Residential	61 day / 51 night
ST-1 AM	60 Sequoia Rd.	37	Residential	61 day / 51 night
ST-1 PM	25/61 Sequoia Rd.	37	Residential	61 day / 51 night
ST-2	Greentree townhomes on Frenchtown Rd.	29	Residential	61 day / 51 night
ST-3	Behind 2 Hillview St. on Kaechele Pl.	44	Residential	61 day / 51 night
ST-4	Corner of Main St./Minturn Rd.	33	Residential	61 day / 51 night

(UI 1, Appendix F – Environmental Noise Assessment, p. 8)

140. UI's projected overall noise levels from the proposed replacement substation during the daytime and nighttime are listed below.

Receptor / Measurement Site ID	Allowable Daytime Limit (dBA)	Predicted Facility Noise Level (dBA)	Daytime Ambient L_{eq} (dBA)*	Daytime Total Sound Level (dBA)**	Increase in Daytime Sound Level (dB)***
LT-1	61	43	49	50	1
ST-1 AM	61	37	49‡	49	0
ST-1 PM	61	37	49‡	49	0
ST-2	61	29	46	46	0
ST-3	61	44	53	54	1
ST-4	61	33	64	64	0

Receptor / Measurement Site ID	Allowable Nighttime Limit (dBA)	Predicted Facility Noise Level (dBA)	Nighttime Ambient L_{eq} (dBA)*	Nighttime Total Sound Level (dBA)**	Increase in Nighttime Sound Level (dBA)***
LT-1	51	43	42	46	4
ST-1 AM	51	37	42‡	43	1
ST-1 PM	51	37	42‡	43	1
ST-2	51	29	44	44	0
ST-3	51	44	44	47	3
ST-4	51	33	58	58	0

(UI 1, Appendix F – Environmental Noise Assessment, p. 9)

141. While location ST-4 has a projected total sound level (i.e. proposed facility noise level plus ambient noise level) of 64 dBA during the daytime and 58 dBA during the nighttime and this exceeds the 61 dBA/51 dBA daytime/nighttime DEEP noise control limits, this does not represent a violation of the noise limits because the sound levels due to the proposed project (i.e. 33 dBA for daytime and nighttime) are less than the background/ambient noise levels. Thus, the proposed project is expected to comply with DEEP noise control standards. (UI 1, Appendix F – Environmental Noise Assessment, pp. 1 to 10; Tr. 1, p. 38)

Electric and Magnetic Field Levels

142. Electric fields (EF) and magnetic fields (MF) are two forms of energy that surround an electrical device. Transmission lines are a source of both EF and MF. (Council Administrative Notice Item No. 41)

143. EF is produced whenever voltage is applied to electrical conductors and equipment. Electric fields are typically measured in units of kilovolts/meter. As the weight of scientific evidence indicates that exposure to electric fields, beyond levels traditionally established for safety, does not cause adverse health effects, and as safety concerns for electric fields are sufficiently addressed by adherence to the NESC, as amended, health concerns regarding Electric and Magnetic Fields (EMF) focus on MF rather than EF. (Council Administrative Notice Item No. 41)

144. MF is produced by the flow of electric currents. The magnetic field at any point depends on the characteristics of the source, including the arrangement of conductors, the amount of current flow through the source, and the distance between the source and the point of measurement. Magnetic fields are typically measured in units of milligauss (mG). (Council Administrative Notice Item No. 41)

145. International health and safety agencies, including the World Health Organization, the International Agency for Research on Cancer (IARC), and the International Commission on Non-Ionizing Radiation Protection (ICNIRP), have studied the scientific evidence regarding possible health effects from MF produced by non-ionizing, low-frequency 60-Hertz alternating currents in transmission lines. Two of these agencies attempted to advise on quantitative guidelines for mG limits protective of health, but were able to do so only by extrapolation from research not directly related to health: by this method, the maximum exposure advised by the International Committee on Electromagnetic Safety (ICES, part of IARC) is 9,040 mG, and the maximum exposure advise by the ICNIRP is 2,000 mG. Otherwise, no quantitative exposure standards based on demonstrated health effects have been set world-wide for 60-Hertz MF, nor are there any such state or federal standards in the U.S. The existing and calculated MF levels for this project are well below these recommended exposure levels. (Council Administrative Notice Item No. 41)

146. ICNIRP limits for general public exposure to 60 Hz electric fields is 4.2 kV/m. ICES limits for general public exposure to 60 Hz electric fields is 5 kV/m.*

*Within power line ROWs, the guideline is 10 kV/m.

(UI 1, Tab G – Electric and Magnetic Field Report, p. 8)

147. Although substations are not the subject of the Council's EMF Best Management Practices (BMPs) for the Construction of Electric Transmission Lines in Connecticut, UI applied certain design/analysis elements that comport with the Council's BMPs as follows:

a) The project is not sited adjacent to any statutory facilities with the exception of ERWP;
b) The proposed replacement substation would be located adjacent to and would encompass the existing substation property, and the proposed relocations of the optimally phased overhead transmission lines within the subject property would have essentially no effect on the calculated magnetic field at the closest residences;
c) The replacement substation would avoid the construction of a new substation in a new location with transmission line connections that would be a new source of EMF;
d) The project includes new structures only on UI property within the substation and within Eversource ROW adjacent to the substation on the east side; and
e) The two transmission lines supported by double-circuit lattice structures are optimally phased and are not proposed to be altered as a result of the project.

(UI 1, Tab G – Electric and Magnetic Field Report, pp. 9-10; UI 1, p. 6-6)

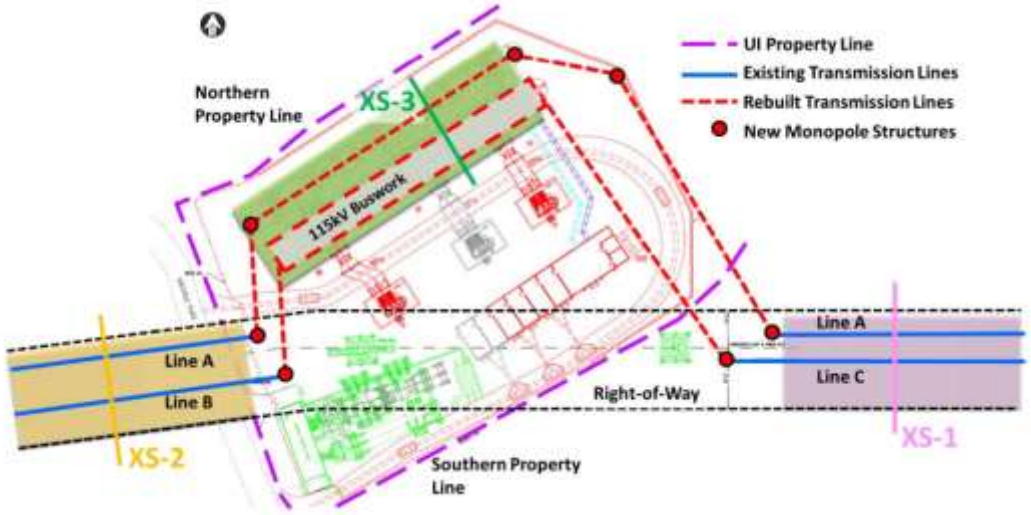
148. In UI's EMF analysis, "existing" or "Pre-Project" conditions assume that the transmission lines are in their existing alignment, and the existing Old Town Substation is in service. "Post-Project" conditions assume that the proposed replacement substation is in service, the existing substation is de-energized, and the existing transmission lines are connected to the proposed replacement substation.*

*The #1714 Line would "pass through" the proposed replacement substation, but it would not be connected to the substation.

(UI 1, p. 1-3 and Tab G – Electric and Magnetic Field Report, p. iii)

149. Average daily peak load conditions are referred to as "average load conditions" in UI's EMF analysis. (UI 1, Tab G – Electric and Magnetic Field Report, p. 1)

150. The existing and post-construction magnetic field levels based on average load conditions are indicated below.



Section	Configuration	100 feet from South ROW edge	South edge of ROW	Max on profile	North edge of ROW	100 feet from North ROW edge
XS-1	Pre-Project	1.3	10	22	15	1.5
	Post-Project	1.3	10	22	15	1.5
XS-2	Pre-Project	4.0	22	47	37	5.5
	Post-Project	3.9	21	47	37	5.4

Section	Configuration	100 feet from Southern Property Line	Southern Property Line	Max on profile	Northern Property Line	100 feet from Northern Property Line
XS-3	Post-Project	0.7	1.4	216	18	3.0

(UI 1, Tab G – Electric and Magnetic Field Report, pp. 6 and B-1)

Project Cost and Cost Allocation

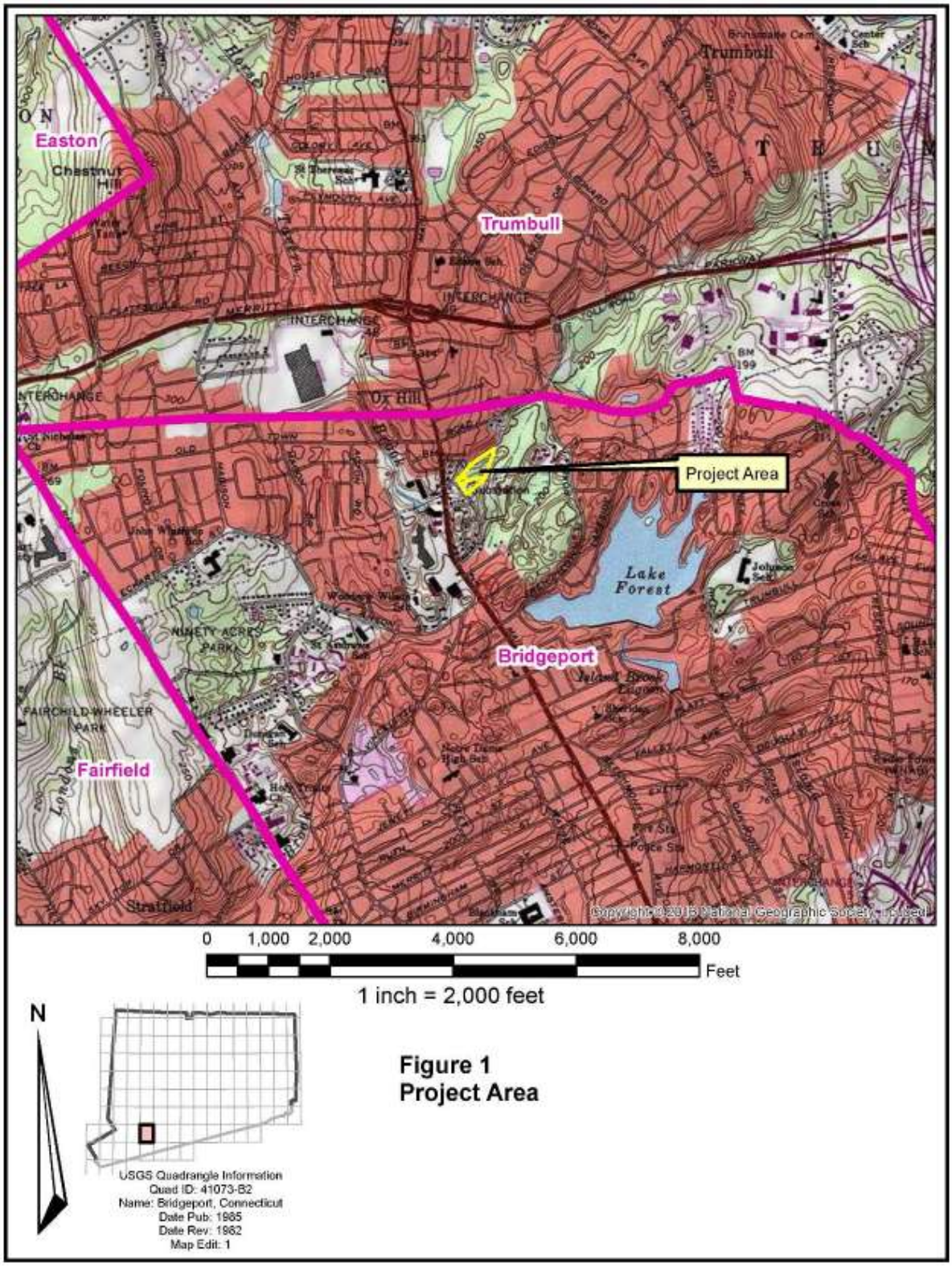
151. Costs of the Project would be recovered through regionalized and localized cost allocation. In general, distribution costs are localized, and most transmission costs are regionalized provided that ISO-NE determines the transmission project provides a regional reliability benefit and it is in accordance with good utility practices. (UI 2, response 6)

152. UI's estimated project cost is approximately $39.1M*. Approximately $23.4M of the project's costs would be regionalized across all New England ratepayers based on load share which is approximately 75 percent New England (or $17.5M) and 25 percent Connecticut (or $5.9M). The remaining $15.6 of project costs are related to distribution and non-Pool Transmission Facilities costs which are typically borne by UI customers.

*The approximately $3M cost for Eversource's portion of the project is not included in this total, and Eversource expects that the entire $3M cost would be regionalized. (UI 2, response 6; Tr. 1, p. 30; Tr. 1, pp. 30, 81-82, 85)

153. Pool transmission facilities (PTF) are the facilities rated 69-kV or higher owned by the participating transmission owners, over which ISO-NE has operating authority in accordance with the terms of the Transmission Operating Agreements. (Council Administrative Notice Item No. 21 – 2019 Regional System Plan)

Figure 1 – Site Location



(UI 1, p. 1-2)

Figure 2 – General Site Plan

(UI 1, Appendix A)

Figure 3 – Proposed Replacement Substation Site Plan

(UI 1, Appendix A)

Figure 4 – Aerial View and Simulation of Proposed Project

(UI 1, Appendix D – Visual Assessment and Photo-Simulations, Proposed Conditions)