STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DOCKET DE 19-057

IN THE MATTER OF: Public Service Company of New Hampshire d/b/a Eversource Energy Petition for Permanent Rates Distribution Service Rate Case

DIRECT TESTIMONY

OF

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Introduction

Q. Please state your full name.

A. Kurt Demmer.

Q. By whom are you employed and what is your business address?

A. I am employed as a Utility Analyst in the Electric Division of the New Hampshire Public Utilities Commission (Commission or PUC). My business address is 21 South Fruit St., Suite 10, Concord, NH, 03301.

Q. Please summarize your education and professional work experience.

A. I graduated from Merrimack College in North Andover, Massachusetts with a Bachelor of Science degree in Electrical Engineering in 1987. In 2002, I received a Master's degree in Electrical Engineering and Power Systems Management from Worcester Polytechnic Institute in Worcester, Massachusetts. Since 1996, I have been a registered professional engineer in the State of New Hampshire.

In June 1988, I joined Massachusetts Electric Company as an Operations Field Engineer. In 1996, I became a Senior Engineer for Massachusetts Electric Company. In 1999, my area of responsibility expanded to include distribution planning engineering. In 2000, I accepted a position as Area Supervisor for the Salem NH area of National Grid USA and was responsible for all distribution engineering, distribution overhead/underground/substation construction, substation operations, and warehousing in the Salem/Pelham area. In 2002, I was promoted to Superintendent of Electric Operations in the Salem/Beverly/Cape Ann Massachusetts area. As Superintendent, I was responsible for distribution engineering immediate oversight, distribution overhead/underground/substation construction, substation operations, and warehousing. From 2003 to 2004, I was a project manager for a 14-mile, $19 million subtransmission 34.5kV underground distribution project consisting of manhole and duct construction housing (1) 34.5kV distribution supply circuit and (1) 34.5kV distribution circuit connecting East Beverly substation to a downtown Gloucester distribution substation. In 2005, as Superintendent of electric overhead distribution operations, I was assigned to the Merrimack Valley district area in Massachusetts. In 2008, I was promoted to Manager of Electric Operations in New Hampshire for National Grid, responsible for the operations, construction, and maintenance functions for the electric distribution organization. In 2010, I was promoted to Acting Director of Electrical Operations in New Hampshire for National Grid. In 2012, I became Director of Electrical Operations in New Hampshire for Liberty Utilities (Liberty). My continued areas of responsibility were to oversee the construction, maintenance, and operation of the electric distribution system. Since 2017, I have been employed as a Utility Analyst in the Electric Division for the Commission.

Q. What is the purpose of your testimony?

A. My testimony in this proceeding will principally address the Eversource Energy (Eversource) proposal for a multiyear Grid Transformation and Enablement Program (GTEP), the Company's existing Reliability Enhancement Program (REP), including vegetation management, and the Company's operational design criteria and procedures.

The first part of my testimony will analyze the GTEP and evaluate the plan based on the Company's current design standards as well as cost effective requirements for Eversource to provide safe and reliable electric service at reasonable rates. In addition to the GTEP operational and cost evaluation, a needs assessment for the program will also be evaluated. In the design and operational assessment, design criteria or strategies that have been adopted by the Company since the 2015 LCIRP filing[1] will be assessed as to the applicability to the New Hampshire service territory in the GTEP proposal.

The second part of my testimony will evaluate Eversource's recent reclassification[2] of vegetation activities and the Company's proposal of vegetation activities going forward. Discontinuation of capital REP investments, a smaller portion of the 2018 and 2019 REP plans, will be discussed as part of the overall base reliability plan.

The third part of my testimony will focus on the Company's reliability indices and performance from 2007 to present as it relates to the reporting of those indices, both internally within the Eversource service territory and externally to entities such as EEI, IEEE, or the NH Commission.

The final part of my testimony address municipal street lighting installation and maintenance.

Q. Have you previously testified before the Commission?

Yes. I have previously testified before the Commission while I was an employee of Liberty, and more recently, I have testified in Docket No. DE 19-111, Annual Stranded Cost Recovery and External Delivery Charge Reconciliation and Rates.

<u>GTEP Analysis</u>

Q. Please provide an overview of Eversource's GTEP plan

[1] Order No. 26,050, Docket No. DE 15-248
[2] Order No. 26,206, Docket No. DE 18-177. Eversource reclassified vegetation management activities as expense for 2019 and future filings.

A. The company's GTEP plan initially filed in DE 19-057 was presented in two parts. The first part includes: a 10 year accelerated replacement plan for 50,000 poles that are 50 years or older; Right of Way (ROW) reconstruction and reconductoring of 10-20 miles of off road circuits per year; and the replacement of substation oil filled circuit breakers (OCB) for an accelerated completion from nine years to seven years.

The second part of the GTEP initially filed included two projects that Eversource included to demonstrate operating and clean energy benefits for customers. The two projects are the Westmoreland Clean Innovation (battery storage) Project and the Oyster River Clean Innovation (microgrid) Project. After the initial Technical Session held on June 21, 2019, the Company learned that Commission Staff, the Office of Consumer Advocate ("OCA"), and other interveners prefer that the Commission's review of the merits of the Projects be conducted in a separate process, outside of the rate case, Docket No. DE 19-057.[3] The Company withdrew the two demonstration projects in Docket DE 19-057 for future submittal and reconsideration.

Q. Please provide in more detail the Company's GTEP proposal for accelerated pole replacement.

A. Presently there are approximately 276,000 distribution wood poles located in Eversource's custodial maintenance service territory.[4] The GTEP targets approximately 50,000-55,000 distribution wood poles, older than 50 years old, for replacement over a 10-year span. There

[3] Attachment KFD-1. Docket No. DE 19-057, Letter from Eversource to PUC Commission dated 7/31/19.
[4] The majority of wood distribution poles are joint owned between Eversource and either Consolidated Communications or TDS Telecommunications Inc. The utility with custodial maintenance performs the interval inspection and replacement of the pole.

are approximately 50,000-55,000 poles, presently located in Eversource's custodial maintenance service territory that meet this age criteria.

Without GTEP, Eversource would replace approximately 1000 poles per year. Annually, through an invasive inspection process, approximately 500 of the 1000 poles are replaced due to failure in providing adequate structural strength that is required for the weight of the pole attachments and the wire tension needed to provide specified clearances for public and lineworker safety. Under GTEP, Eversource would install an additional 4,000 poles per year at an incremental cost of $25,000,000 ($20,000,000 capital, $5,000,000 O&M expense) for 10 years. In order to eliminate the 50,000-55,000 poles older than 50 years, Eversource proposes to spend approximately $200,000,000 in capital and $50,000,000 in O&M expense. This would be in addition to the $50,000,000 in capital to perform typical reject pole replacements, 1000 per year, over the next 10 years.

Q. How does Eversource or other custodial utilities determine that a wood pole needs replacement?

A. This is accomplished through an invasive pole inspection activity that is performed on the 10% of the pole population (approx. 27,000 poles) per year (a 10-year cycle). The requirement for this inspection is based on internal Company procedures, Commission Puc 300 rules, and Intercompany Operating Procedures (IOPs) between the two joint pole owners.[5]

Q. Are there other methods that may be used to determine that a pole should be replaced?

A. Yes. In addition to the invasive pole inspection procedure, there are other methods, such as a field inspection outside the inspection cycle, that may determine the pole is subpar in column

[5] Attachment KFD-2., Eversource Energy TD953 Procedure Rev.7 updated 11/8/2017 " Inspection, Treatment, Restoration, and Replacement Guidelines for Distribution System Wood Poles" ; Puc Rule 306.01; Puc Rule 306.02

strength and requires replacement. These type of assessments are utilized and would add approximately another 500 poles to the 500 poles replaced after invasive inspection. On an annual basis, using these two methods, Eversource typically replaces approximately 1000 poles.

Q. Is Staff aware of the Company procedures and policies when assessing these investments?

A. Initially no. Staff requested, via email on 11/5/18, all operational and design documents for the Company's distribution operational requirements which range from field operations to design criteria. Eversource provided Staff an extensive list of policies, procedures, and documents. All of the documents were received on July 18, 2019. After a DE 19-057 technical session held on September 5 and 6, 2019, Staff requested Eversource's Distribution System Engineering Manual (DSEM) because Staff was unaware that there were additional engineering documents that were utilized in Staff Response 10-25 dated August 27, 2019.[6] The DSEM was sent to Staff on September 11, 2019. Attachment KFD-3 includes the two emails and a list of Eversource policies and procedures that were provided to Staff.

Q. The poles that are targeted in GTEP are older than 50 years, which is greater than their depreciated life. Should those poles be replaced on their age?

A. No. An asset's field lifespan is not dictated by the asset's book value. As part of least cost planning and cost effective pole asset replacement, periodic asset evaluation and maintenance is required to proactively address possible unplanned failure of the asset. In addition, replacement of the asset should reflect either the present need of the asset or a known short-term future need. In this case, 10% of the company's custodial pole population is inspected,

[6] Attachment KFD-3, Docket No. DE 19-057, Email correspondences dated 11/5/18 and 9/11/19, List of Eversource Policies and Procedures provided by Eversource dated 2/13/19.

every 10 years, utilizing an invasive inspection on the pole per the Company's inspection procedure[7]. Moreover, as line crews, supervisors, and engineers interact with these assets during storm restoration, day to day service calls, or periodic line inspections, visual inspections are also being performed. Premature replacement prior to the asset being evaluated as not meeting the threshold as specified in the inspection procedure does not provide any additional benefit.

Q. What are some of the concerns that Staff have with the GTEP pole replacement proposal?

A. Staff is concerned with a number of issues in the accelerated replacement of 50,000-55,000 poles in the Eversource custodial service territory.

The proposal is to replace all poles more than 50 years old, regardless of existing structural condition. As stated earlier in my testimony, age of an asset or the book lifespan is not necessarily a deciding factor in asset replacement. The company stated that "the Company will prioritize poles for replacement based primarily on age, condition, location, and number of customers served by the circuits on the poles."[8]. Although the Company may prioritize the replacement of identified reject poles on location or number of customers served (i.e. reliability impact), the prioritization of replacement based on age conflicts with Eversource's inspection program. An inspection program, by its definition, is an attempt to identify structural defects based on an industry best practice, for example, by boring and sounding poles. This activity is conducted on a 10-year cycle, which is more frequent inspection cycle

[7] Attachment KFD-1
[8] Docket No. DE 19-057. Testimony of Joseph A. Purrington and Lee Lajoie, dated 5/28/19, Bates page 441, lines 3-5.

than what is stated for Connecticut and Western Massachusetts in the Company's TD 953 Procedure Rev.7 updated 11/8/17.

The Company also stated that, "[a]lthough there are reliability benefits from accelerating pole replacement, the biggest impact will be the greater integrity and resiliency of the system through a range of weather events. For example, in recent years it has not been unusual for hundreds of poles to be damaged in a single weather event. The new poles that PSNH is installing are physically larger and stronger and have the potential to withstand more extreme weather conditions as compared to smaller 50-year old poles."[9].

In a recent Technical Session, Staff inquired how many poles were replaced during the October 2019 Wind Storm. This was the most recent storm, and Staff expected that the Company would have a heightened sensitivity to a large event such as this windstorm. In addition, the windstorm would be similar to an event that the Company is referring to in its testimony for GTEP investments for storm resiliency. The company's response[10] stated that 59 poles were broken in the event. Wind, trees, or tree limbs were the causal factors in the broken poles. In addition, in response to a data request, the Company stated that it does not track the type or class of poles that are replaced. If the Company is not tracking the size and class of the pole that it is replacing during a major event, the Company cannot correlate the size of the pole and its age with the damage to the pole during the storm event. Numerous other factors may affect the analysis; if it were a tree, how large was the tree, was the pole in Eversource custodial area, was the pole already identified as a pole inspection reject, etc.

[9] Docket No. DE 19-057. Testimony of Joseph A. Purrington and Lee Lajoie, dated 5/28/19, Bates page 441, lines 10-15.
[10] KFD-4, Docket No. DE 19-57, Eversource Response Staff TS 2-48.

Staff also asked the Company to provide a cost effective analysis, business case, or other means of justifying the increased cost for all of the GTEP investments, including the accelerated pole replacement. Attachment KFD-4 indicates that the Company did not perform a cost effective analysis for any of the GTEP investments, including the accelerated pole replacement proposal. Instead, the Company recited that the GTEP investments are asset condition based and will be prioritized on level of condition and reliability impact. Staff agrees that asset condition such as a typical one for one wood pole replacement does not require a cost benefit analysis to replace; however, the basis for that decision is evidenced based from an inspection result indicating a structural or safety concern.

Q. Are there other items to consider for the accelerated pole replacement proposal in GTEP?

Yes. The additional 4000 poles per year would increase the reject pole replacement to 5,000 poles per year. Unintended consequences for this accelerated replacements include: (1) significantly greater amount of double poles in Eversource's custodial maintenance area; (2) significantly higher costs to either TDS or Consolidated Communications as the telecommunications utility (ILEC) would be responsible for a fixed cost per pole replacement and any cost required to transfer telecommunications assets to the new pole pursuant to the established Intercompany Operating Procedures (IOP);(3) possible significant pushback from the ILEC joint owner because poles are being replaced based on age rather than a prescribed process such as what is established in IOP #7; and (4) third party providers (e.g. Comcast) incurring additional pole transfer costs due to accelerated and premature pole replacements. Although these costs and considerations are separate from electric rate impacts, they demonstrate that additional costs to customers through significantly higher pole capital replacement is not an isolated impact. Consolidated Communications or TDS, as well as third party providers may increase their service rates to offset the increased cost of this accelerated pole replacement over 10 years.

Q. What is staff's recommendation for the accelerated pole replacement proposal in GTEP?

A. The Company has not performed or presented any cost benefit analysis or business case that would provide Staff the reliability or resiliency quantifiable benefit information Staff needs to support the additional costs in this proposal.

Q. Please provide in more detail the Company's GTEP proposal for ROW and roadside reconstruction

A. The Company is proposing an accelerated investment in reconstructing or relocating existing lines that are currently in the Company's ROW. The Company is proposing to increase the annual capital spend by approximately $15,000,000, and the annual O&M expense by approximately $750,000. Without the additional investment proposed in the GTEP, the Company is already investing $10,700,000 on an annual basis for ROW reconstruction and reconductoring in 2020-2024. As a result, total spending for that activity is estimated by the Company to be $26.6M per year.

The objective of the reconstruction and reconductoring is to relocate lines that are presently in the ROW with limited access to the street for better access. Many of these lines are distribution three phase circuits.

Q. What are some of the concerns that Staff have with the GTEP ROW reconstruction and replacement proposal?

A. Two items in the proposal need to be addressed. The first is the present capital investment the Company is proposing to install outside the GTEP initiative. Similar to other reliability initiative projects, the Company bears the burden of proving that the reconstruction and reconductoring of these ROW circuits is necessary and will provide the reliability benefits required to justify the significant capital investment. The second is the acceleration portion of this GTEP initiative. Presently Eversource has one of the lowest SAIDI and SAIFI metrics that the Company has experienced since 2007. The Company has not experienced any significant reliability issues with the existing ROW circuits. The relocation on the street ROW for some of these circuits may not be necessary due to the significant ROW widening and maintaining that the Company has performed over the past 5 years. Moreover, relocation of existing assets to the street could create additional pole assets or space constraints in the public ROW if there are already significant distribution assets already present in the public ROW.

Staff asked about the Company's statement regarding the reconductoring of undersized wire in testimony. "The Company estimates that approximately 80 percent of the 600 miles of off-road lines are constructed with undersized bare wire that will need to be upgraded for resiliency and to prepare the grid for integration of advanced energy solutions." In Attachment KFD-5[11], OCA inquired about the level of resiliency and how the upgraded wire will enable the integration of advanced energy solutions. The Company responded that "[t]here is no in-depth analysis that is needed to demonstrate that the upgraded wire will improve resiliency; and no available, accepted or feasible method for quantifying what that improvement would be."

[11] Attachment KFD-5, Docket No. DE 19-057, Eversource to OCA Response 6-53.

In order to assert that a measure will create improvement, there first needs to a base value by which improvement is measured.. If resiliency cannot be measured, how does the Company know that the investment will be prudent and the benefits outweigh the investment costs?

Q. What is staff's recommendation for the ROW reconstruction and reconductoring proposal in GTEP?

A. The ROW reconstruction and reconductoring proposal in GTEP and outside of GTEP requires a cost benefit analysis and measureable reliability benefits. Replacing existing wire that is sufficient for loading concerns for resiliency and reliability reasons need to be quantified. Since resiliency and reliability improvements for wire considered undersized by the company has not been quantified, Staff cannot support this initiative whether it is part of the GTEP initiative or part of the proposed capital plan for 2020-2024.

Q. How does the Company justify its proposal under the GTEP to accelerate substation renewal through replacement of its Oil Circuit Breakers (OCBs)?

A. The Company has justified accelerated replacement of their OCBs primarily by asserting that they: (1) have failed resulting in widespread outages; (2) are costly to maintain; (3) may result in costly environmental damages upon failure; and (4) are in excess of 40 years old. Each of these assertions is examined below.

The Company has suggested oil circuit breakers require accelerated replacement because they are "[T]he cause of some widespread outages in the past, when the breakers failed to operate as quickly as intended."[12] However, when asked to identify any widespread outages caused by oil circuit breakers in the past five years, the Company acknowledges that over the past 14 years, there have been no widespread outages associated with oil circuit breakers.[13]

[12] Docket No. 19-057 Testimony of Joseph A. Purrington and Lee Lajoie, Bates 400, Lines 10-12.
[13] Attachment KFD-6, Docket No, DE 19-057 Eversource Response to OCA 6-37.

The Company was able to describe two oil circuit breaker failures that occurred at a single substation in Laconia during 2005 where 25,000 customers lost power; however the root cause of the outage was not provided. A single outage caused by an oil circuity breaker in in 15 years does not necessitate the magnitude of accelerated investment described in the GTEP program.

The Company has suggested oil circuit breakers require accelerated replacement because "Some of these older breakers also have bushings containing oil with high levels of polychlorinated biphenyls (PCBs)," and that "[f[ailure of some of these bushings have resulted in extensive and costly cleanup efforts."[14] However, when asked to identify any cleanup efforts and the relevant costs associated with OCB bushing failures, the Company was unable to provide an example specific to OCBs, and instead cited an event relating to a Potential Transformer.[15]

The Company has suggested that one of the benefits of replacing OCBs is that the maintenance costs of vacuum circuit breakers is lower than the maintenance costs associated with OCBs.[16] However, when asked to compare the maintenance costs of the two pieces of equipment, the Company acknowledged that"[a]pproximate costs over the 12-year cycle are over $11,000 for oil circuit breakers and around $3,200 for vacuum breakers."[17] In light of the fact that cost of replacing an OCB is approximately $500,000,[18] the maintenance savings of approximately $650/year does not support accelerated OCB replacement.

[14] Docket No. 19-057 Testimony of Joseph A. Purrington and Lee Lajoie, Bates 400, Lines 13-14
[15] Attachment KFD-7, Docket No. DE 19-057 Eversource Response to OCA 6-38.
[16] Docket No. 19-057 Testimony of Joseph A. Purrington and Lee Lajoie Bates 400, Line 15
[17] Attachment KFD-8, Docket No. DE 19-057 Eversource Response to OCA 6-39.
[18] Attachment KFD-9, Docket No. DE 19-057 Eversource Response to OCA 6-64.

The Company has suggested oil circuit breakers require accelerated replacement because "[a] significant number of the Company's oil circuit breakers (OCBs") are in excess of 40 years old."[19] However, only approximately 30 of the Company's approximately 100 OCBs appear to be beyond the expected useful life of 55 years for items such as the OCBs, which recorded in FERC account 362.[20] Replacement of high cost items before the end of their useful life should only occur when adequate justification is provided. Based on the facts discussed above, such justification has not been provided. Therefore, the Company should not accelerate its OCB replacement beyond that which is already planned within its base capital budget.

Q. What is Staff's conclusion regarding the proposal under the GTEP to accelerate substation renewal through replacement of its OCBs?

A. The Commission should deny recovery of the Company's proposed substation renewal program. This program would accelerate replacement of OCBs which have not been a major cause of outages, have not failed resulting in environmental damage, have minimal maintenance costs, and on average have not yet reached the end of their expected useful life.

Q. Are there other staff concerns surrounding some of the ongoing capital investments `made by the Company on typical distribution construction?

Yes. There are multiple investments that the company has made over the past 3 years as part of their resiliency guidelines which staff was unaware of until the DE 19-057 testimony was presented. These investments appear to be part of Eversource (parent company) adopting a company-wide initiative for distribution resiliency. For example, the storm resiliency guideline relates only to Connecticut and Massachusetts, and originated in an order adopted

[19] Docket No. 19-057 Testimony of Joseph A. Purrington and Lee Lajoie, Bates 400, Lines 3-6
[20] Attachment KFD-10, Docket No. DE 19-057 Eversource Response to OCA 6-36.

by the Connecticut utility regulator. It appears that the proposed use of the Connecticut and Massachusetts standard in New Hampshire is driven not by a business case, but by a desire to have uniform standard across the Eversource system.

Q. **Please explain your concerns as they relate to wood pole replacement.**

A. In the testimony of Messrs. Purington and Lajoie, it states that when the Company replaces poles of any class and height, the standard going forward will be to replace all poles in the public ROW with a minimum Class 2 pole. Prior to this change, the Company standard pole was a 40-ft. Class 4 pole. The reason behind the change is driven by claimed resiliency benefits. The cost difference between a Class 4 pole and a Class 2 pole is approximately $75 more for the Class 2 pole. The Company has stated a 50% increase in pole strength due to the new Class 2 standard; however, since the standard pole was a Class 4 pole and that standard was driven by actual field conditions (weight of the attachments, wire tension, and guying) and calculated by distribution design engineer, the additional strength of the new standard Class 2 pole is excessive and not justifiable.

Q. **Does staff have similar concerns as they relate to other pole top equipment.**

A. Yes. Another pole top equipment standard that is being adopted by Eversource NH is the composite crossarm. This fiberglass crossarm is used in place of a wooden crossarm that was a standard in New Hampshire previous to the new DSEM resiliency and reliability guidelines. The fiberglass crossarm structural strength compared to a wooden crossarm is excessive for a majority of the distribution construction design presently on Eversource's street distribution circuits. The cost difference between a wood crossarm and a composite crossarm is approximately $65 higher for the composite crossarm.

Q. **Does staff have any other pole construction concerns that would apply to other circuit locations?**

A. Yes. For ROW circuit applications, mainly backbone or mainline circuit locations, the Company has changed their standard to light-duty steel poles instead of wood poles in the ROW. The Company has stated that the lighter steel poles have twice the life of a comparable wood pole (90 years compared to 45 years) and are not susceptible to insect or woodpecker damage. The Company has stated increased resiliency benefits with the installation of the light-duty steel poles. Staff is concerned that similar to the Class 2 pole, theCompany is installing an asset that is higher in cost and has increased strength that is redundant and will not be utilized. The cost of a 40-ft. Class 2 pole is $899. A light-duty Class 1 steel pole is $2152, or $1253 additional cost. There are additional costs with a light duty steel pole in the ROW. The basic impulse level (BIL) needs to be raised to 300kV rather than the 200kV on the wooden pole. This higher BIL translates into additional insulators on the structure therefore increasing costs higher for the light-duty steel pole installation.

Q. What is staff's recommendation for the resiliency based investments that are proposed in this docket DE 19-057?

See Attachment KFD-6. Staff had requested the Company for any business case or cost benefit analysis to be provided with the above resiliency proposals. The Company said it had not conducted any cost benefit analysis or business case for these investments. Therefore, staff cannot support the installation of these investments without quantifiable benefits and recommends the Commission deny these future investments as they are presented in this docket. The Company has the burden of justifying the increased expenditure that provides little to no measureable benefits, even if the Company cites a standardization requirement.

Q. In light of Staff's recommendation for the Commission to deny recovery of future plant additions for the aforementioned proposed investments, does Staff have any recommendation regarding plant additions already installed which also may not comply?

A. Yes. Staff recommends that the Commission order the Company to work with Staff to identify any plant additions from years 2018 through 2020 that do not comply with the above, and fully identify additional costs of plant additions for this timeframe. Staff also recommends the Commission order that a Staff recommendation be filed by December 31, 2020 regarding any additional costs for the Commission's consideration.

Vegetation Management

Q. What is Staff's assessment of the company's vegetation management program?

A. The company's approximately 12,200 miles of distribution overhead lines vegetation management presently consists of multiple vegetation activities which fall into different budget classifications. Although there are multiple activities associated with vegetation management, Staff will concentrate on four areas of vegetation management; Scheduled Maintenance Trimming (SMT), Enhanced Tree Trimming (ETT), Full width ROW clearing (ROW), and Enhanced Hazard Tree Removal (ETR).

First, SMT follows an established trim cycle of approximately 4.5 years. The average miles per year for SMT is approximately 2500 miles.

Second, ETT is performed on the backbone or the mainline of the circuit and worse performing feeder based on SAIDI performance are chosen for ETT with a target of approximately 150 miles of circuit backbone trimmed to expanded clearances beyond the typical SMT clearances (8 feet to the side, 15 feet above, and 10 feet below). There are occasions where a poor performing circuit will be scheduled for SMT and will receive ETT within the same timeframe.

Third, full width clearing involves full-width ROW clearing. This clearing includes a clearing of trees and brush up to the full width of the right of way easement or property lines.

Fourth, hazard tree removal involves the identification, and complete removal, of trees determined to be a reliability impact to the distribution lines, both within and outside standard trimming zones.

The Company is requesting the following budget going forward[21]:

Public Service Company of New Hampshire dba Eversource Energy DE 19-057 Staff Data Requests - Set #1; Question 1-3 2009 - 2018 Annual Spending and 2019 Budget					
	2019 Forecast	**2020 Forecast**	**2021 Forecast**	**2022 Forecast**	**2023 Forecast**
O&M - Total	**31,079,577**	**32,732,964**	**33,714,953**	**34,726,402**	**35,768,194**
Base - Total	14,979,577	15,428,964	15,891,833	16,368,588	16,859,646
SMT					
METT					
Hot Spot					
Mid-Cycle					
REP - Total	16,100,000	17,304,000	17,823,120	18,357,814	18,908,548
ETT	5,000,000	5,150,000	5,304,500	5,463,635	5,627,544
ETR	10,000,000	10,300,000	10,609,000	10,927,270	11,255,088
ROW	1,100,000	1,854,000	1,909,620	1,966,909	2,025,916

[21] Attachment KFD-11, Docket No. DE 19-057, Eversource Response to Staff TS 2-31.

Staff has analyzed the reliability data for Eversource using SAIFI[22] data rather than SAIDI[23] data for tree circuit performance. SAIFI is a more common tool for circuit design assessment as it is not time based, but rather impact based. Utilizing or prioritizing tree performance under SAIDI criteria can still be utilized as a second level decision tool or validation for tree based reliability enhancements but unless the resource and geographic parameters are uniform, the SAIDI data can inflate or reduce a circuits tree performance. This is due to crew response which can be largely dictated by time of day, day of the week, number of crews that are on the property that day, or if there are concurrent outages occurring at the same time. The same location may experience different crew restoration times and therefore change the SAIDI of the tree related event month to month or year to year.

Staff analyzed the tree related system SAIFI performance from 2009 to 2018[24].

Docket No. DE 19-057
Data Request TS 2-033
Dated 11/01/19
Attachment TS 2-033

NHPUC Data Request - 2009 - 2018 - NH Tree Related - IEEE Criteria

Year	SAIDI	SAIFI
2009	56.94	0.4826
2010	108.69	0.7518
2011	85.25	0.6482
2012	79.38	0.6024
2013	75.85	0.5524
2014	61.81	0.5822
2015	57.23	0.5517
2016	82.53	0.7297
2017	77.12	0.5994
2018	70.25	0.5197

[22] SAIFI is the System Average Interruption Frequency Index.- the number of outages an average customer experiences.
[23] SAIDI is System Average Interruption Duration Index - the average duration of outage the average customer experiences annually.
[24] Attachment KFD-12, Docket No. DE 19-057. Eversource Response to Staff TS 2-33.

Although there was a change in the OMS system in 2015, a system level of tree related SAIFI and SAIDI was available for analysis for all 10 years.

- The average SAIFI for the 10 years is 0.602.
- The average SAIDI is 75.5 minutes.
- 2018 SAIFI performance is 0.08 less than the 10 year average.
- 2018 SAIDI performance is 5.25 minutes less than the 10-year average.

The average cost per mile for SMT for 2016 through 2018 is $5,235/circuit mile.[25]

The average cost per mile for ETT for 2016 through 2018 is $42,644/circuit mile.[26]

Since 2009, there have been at least two cycles of SMT performed on the Eversource distribution system. The ETT, however has not been completed, only completing approximately 1085 miles of backbone circuit or 67% of the total 1600 miles of backbone on the Eversource distribution system.

Considering that ETT was performed on the worse performing circuits for the past 10 years, there should be an expectation of SAIFI or SAIDI performance as more of the system had ETT performed.

There is little to no evidence of overall SAIFI or SAIDI performance as the ETT activity progressed. Moreover, the expense per mile of ETT, which is approximately 8 times that of SMT, creates a very high cost per SAIFI improvement or $ per ΔCI. The SMT program is designed to provide a maintenance function to the tree contribution in reliability performance. In other words, one would expect that SMT would maintain the system reliability.

[25] Attachment KFD-11, Docket No. DE 19-057, Eversource Response to Staff TS 2-31
[26] Attachment KFD-11, Docket No. DE 19-057, Eversource Response to Staff TS 2-31

The non-discernable performance improvement of ETT for system reliability is part of the issue with continuing to perform ETT on backbone circuits. Another issue is the contribution that Eversource receives from the joint owner, Consolidate Communications or TDS. Per the IOP, Eversource performs all tree trimming activities including SMT and ETR. The ILEC is responsible for reimbursement to Eversource for those activities. Eversource, however cannot be reimbursed for part of the ETT activity as ETT is not defined in the IOP agreement. This presents an issue if the circuit that is scheduled to have SMT performed, has ETT performed on part of the circuit. The portion of the circuit where ETT is displacing SMT , does not receive any contribution from the ILEC. The amount of contribution not collected can be significant. See Attachment KFD-13[27]. The contributions not collected from the ILEC due to ETT is $236,620 since 2015. This demonstrates another reason why ETT should not be performed.

Q. Did Staff assess other activities in the company's vegetation management program?

A. Yes. The ETR activity was also analyzed similar to the ETT program. ETT is presently performed on both three phase and single phase circuits with an internal prioritization applied in order to maximize reliability benefits. The Company has requested $10,000,000 going forward in 2020 for ETR funding. Staff analyzed the cost benefit ratio of performing ETR on single phase vs. three phase ETR. These tables are derived from Eversource response to Staff Data Request TS 2-33.

[27] Attachment KFD-13, Docket No. DE 19-057. Eversource Response to Staff 12-40.

NHPUC Data Request - September 13 2015 - 2018 - NH Tree Related - IEEE Criteria - Single Phase Devices

Year	Phase_IND	SAIDI	SAIFI
Sep 13 -YE 2015	1_PH	7.25	0.06
2016	1_PH	37.15	0.26
2017	1_PH	36.42	0.25
2018	1_PH	33.98	0.26

a.iv - September 13 2015 - 2018 - Single Phase By Trim Zone - IEEE Criteria

Year	Phase_IND	TRIM_ZONE	SAIDI	SAIFI
Sep 13 -YE 2015	1_PH	Inside Zone	0.14	0.0014
2016	1_PH	Inside Zone	0.28	0.0028
2017	1_PH	Inside Zone	0.42	0.0042
2018	1_PH	Inside Zone	0.58	0.0060
Sep 13 -YE 2015	1_PH	Outside Zone	7.11	0.0569
2016	1_PH	Outside Zone	36.86	0.2577
2017	1_PH	Outside Zone	36.00	0.2491
2018	1_PH	Outside Zone	33.40	0.2507

NHPUC Data Request - September 13 2015 - 2018 - NH Tree Related - IEEE Criteria - Three Phase Devices

Year	Phase_IND	SAIDI	SAIFI
Sep 13 -YE 2015	3_PH	7.21	0.1065
2016	3_PH	42.92	0.4561
2017	3_PH	35.40	0.3270
2018	3_PH	32.89	0.2494

a.iv - September 13 2015 - 2018 - Three Phase By Trim Zone - IEEE Criteria

Year	Phase_IND	TRIM_ZONE	SAIDI	SAIFI
Sep 13 -YE 2015	3_PH	Inside Zone	0.59	0.0084
2016	3_PH	Inside Zone	1.60	0.0441
2017	3_PH	Inside Zone	1.51	0.0140
2018	3_PH	Inside Zone	0.38	0.0053
Sep 13 -YE 2015	3_PH	Outside Zone	6.62	0.0982
2016	3_PH	Outside Zone	41.32	0.4120
2017	3_PH	Outside Zone	33.89	0.3130
2018	3_PH	Outside Zone	32.51	0.2441

Staff made the following high level assumptions in the analysis.

- There is a uniformity of hazard tree occurrence between single phase and three phase.

- Hazard tree locations and density are uniform between single phase and three phase.
- Outages that occur from tree contact that initiated within the tree clearance zone (inside zone) is attributable to normal sideline growth or overhang within the clearance zone. This issue is generally related to SMT efficiency.
- Outages that occur from tree contact that initiated outside the tree clearance zone (outside zone) is attributable to hazard tree contact. Either a piece of the tree or branch failed outside the normal trim zone.
- Approximately 95% of the SAIFI contribution is from the outside zone tree related contact.
- Distribution system lateral vs backbone (mainline) [28]
    - 12,200 miles of overhead distribution circuits
    - 3,000 miles of road-side, three-phase distribution circuits
    - Approximately 17 percent of the distribution system is considered backbone
    - Approximately 83 percent of the system consists of overhead laterals stemming off backbone circuits.

Utilizing the last 4 years of SAIFI, the three phase averaged 0.2668, the single phase averaged 0.2036.

Three phase outside trim contributes to approximately 57% of the total outside trim SAIFI.

The annual spend of 10,000,000 in hazard tree removal will be utilized on the circuits which 17% of the circuits are backbone and contribute to 57% percent of the total outside SAIFI.

[28] Docket No. 19-057 Testimony of Joseph A. Purrington and Lee Lajoie, Bates 397, Lines 4-9

Therefore approximately $1,700,000 of the $10,000,000 budgeted will contribute to over half of the SAIFI metric.

Q. The Company included the $1.2 M ILEC contribution that was unpaid in 2018/2019 as part of the reconciliation and O&M recovery. Does Staff agree with that position?

A. Staff does not. The contributions that have been agreed to per the Intercompany Operating Procedures (IOP) should be reflected in the reconciliation as if the ILEC had paid the Company the full amount owed. The Company has other legal avenues to collect the debt from the ILEC and those avenues should be exhausted prior to requesting the amount from customers. If the Company is made whole without going through the legal options that are available, there is no incentive to the Company to advance further with legal action. If there is an IOP business process issue, the Company should address that issue immediately. Recovery of the debt owed will not incentivize the Company to address the issue in a timely manner.

Q. What is Staff's recommendation for the vegetation management activities going forward?

A. Staff recommends that the Company continue to perform certain base O&M activities as performed pre-2019. These include scheduled maintenance trimming (SMT), scheduled maintenance for previously enhanced tree trimming (METT), mid-cycle trimming, hot spot and trouble trimming, and ROW maintenance mowing and side trim. The Company requested $14.97M for 2019 with an escalating 2-3% increase in budget to 2023. Staff recommends an annual budget of $14.8M for the above vegetation activities. This is derived from the average of the budgeted amount from 2016 thru 2018.[29]

[29] Attachment KFD-14, Docket No. DE 19-057. Eversource Response to OCA 1-51

The Company requested $16.8 annually to be in base O&M for the following vegetation activities: ETT-$5M , ETR - $10M , Full Width ROW Clearing - $1.8M

Staff agrees that there are reliability and operational benefits for a limited ETR and full width ROW clearing, however Staff does not recommend the continuation of ETT. The lack of evidence of reliability benefit to high cost implementation is the primary reason. Secondary was the absence of ILEC contributions that should be in line with ETT claimed benefits.

Staff also recommends the reduction of ETR cost with a focus on three-phase backbone or mainline hazard tree removal. The reliability benefits a significantly greater with mainline hazard tree removal utilizing less $ per ΔCI.

Therefore Staff recommends an annual budget for the following additional vegetation activities: ETT - $0, ETR – $2.5M , Full Width ROW Clearing - $1.8M

In addition, Staff recommends that all billed ILEC contribution should be deducted from the Company's SMT and ETR spend used for calculating annual reconciliation.

Q. The Company has performed ETT since 2009. Why is Staff now recommending a discontinuation of the program?

A. Initially in 2009, Staff was concerned with the Company's vegetation management focus and declining reliability indices. The Company has significant historical tree related data to allow for further analysis on cost effectiveness in each of the vegetation activities. With the increasing cost of the ETT program, Staff has utilized the extensive duration of reliability data to analyze the cost effectiveness of this program and has recommended the discontinuation based on little to no improvement of tree related SAIFI over the past 10 years.

<u>Reliability Indices</u>

Q. What is Staff's concern with the present reliability reporting performed by the Company?

A. During the Staff docket investigation, it was apparent there were two reporting issues in the Company's external reporting to the Commission.

The first issue was a clarification issue. The IEEE critieria presented by the Company in the Puc E-38 filings had an incorrect last page to the report. The page is a definition of reliability indices and terms. Listed were the types of outages that were not included in the reliability data presented to the Commission as IEEE-1366. The IEEE criteria has a smaller set of exclusions which the last page erroneously stated. The Company has corrected the issue reporting going forward will reflect a modified last page.

The second issue arose when Staff inquired about the PUC exclusionary events. The PUC defined reliability metrics differ from the IEEE reliability standard. The PUC reliability metric is Company and NH State specific. It lacks the standardization the regulator needs to compare reliability metrics between utilities in NH and in other states. This standardization is the reason why the Commission decided to report only IEEE in the PUC E-38 reports.

See Attachment KFD-15[30], Staff requested a breakdown of causal factors that are considered miscellaneous or "other" in normal reporting. After reviewing the data, Staff noticed a sharp increase in planned outage reporting from 2015 to 2019. Staff inquired further in Staff request TS 2-41. See Attachment KFD-16[31] . Staff requested the Company explain in further detail the incident that was reported as a planned outage. It was apparent that Staff

[30] Attachment KFD-15, Docket No. DE 19-057. Eversource Response to Staff 15-14
[31] Attachment KFD-16, Docket No. DE 19-057. Eversource Response to Staff TS 2-41

was not following its internal planned outage policy[32] that was provided to Staff in January 2019 in Docket DE 19-017.

Q. What is Staff's recommendation?

A. Staff recommends that this issue be addressed in Docket DE 19-017. The issue of planned outage notification and reliability reporting will need to be investigated further. If the Company is found to have improperly classified the outages , Staff will recommend that the Company address previous E-38, REP related dockets, and any other affected submittals in order to properly classify the outage. Proper analysis relies on an outage classification being correct. Otherwise the planned outage criteria masks the root causal factor to the outage. Once the issue has been investigated in the IR 19-017 docket, Staff will issue a recommendation to the Commission, which will include this issue.

<u>**Municipal Street Lighting Installation and Maintenance**</u>

Q. Does Staff have a recommendation regarding municipal street lighting installation and maintenance?

A. Yes. Staff recommends that Eversource align its policy and tariff to allow its municipalities the opportunities to install and maintain its own streetlights through a private line contractor subject to special agreement with Eversource. This would align Eversource's policy and tariff on municipal street light installation and maintenance with Unitil's existing tariff and Liberty's proposed tariff in its current rate case Docket No. DE 19-064. The Company states it has considered and is amenable to such an arrangement, recognizing a number of conditions and concerns would need to be addressed. Please see Attachment KFD-18[33].

[32] Attachment KFD-17, Docket No. DE 19-017. Eversource Response to Staff 1-1
[33] Attachment KFD-18, Docket No. DE 19-057. Eversource Response to Staff 10-40

Q. Does this conclude your testimony?

A. Yes

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July 31, 2019

NHPUC 31JUL'19PM4:23

Debra Howland
Executive Director
New Hampshire Public Utilities Commission
21 South Fruit Street, Suite 10
Concord, NH 03301-2429

RE: Docket No. DE 19-057
Public Service Company of New Hampshire d/b/a Eversource Energy
Notice of Intent to File Rate Schedules

Dear Director Howland:

On May 28, 2019, Public Service Company of New Hampshire d/b/a Eversource Energy ("PSNH" or the "Company") submitted its request for permanent rates in the above-captioned docket, including among its proposals the Grid Transformation and Enablement Program ("GTEP"). The GTEP encompasses a series of initiatives to raise the condition of the Company's electric distribution system to a level that is necessary to meet the growing expectations of customers for a reliable and resilient system, while at the same time reducing greenhouse gas emissions and promoting advanced technology solutions. The primary elements of the GTEP are presented in the joint testimony of Joseph A. Purington and Lee G. Lajoie, and cost recovery for the program is proposed through a separate rate mechanism, a Distribution Rate Adjustment Mechanism ("DRAM"), presented in the joint testimony of Eric H. Chung and Troy M. Dixon. As part of the GTEP proposal, the Company submitted the joint testimony of Charlotte Ancel and Jennifer Schilling describing two Clean Innovation Projects that would be funded through the cost recovery mechanism established in the rate case (the "Projects").

The Projects include: (1) the Westmoreland Clean Innovation Project, which is a proposal to provide a solution to a reliability-challenged area through the integration of battery storage, distributed energy resources, and enhanced energy efficiency, supported by the testimony and exhibits of Ms. Ancel; and (2) the Oyster River Clean Innovation Project, which is a proposal to construct and operate a microgrid in collaboration with the University of New Hampshire and Town of Durham, supported by the testimony and exhibits of Ms. Schilling. The Company presented the joint testimony of Ms. Ancel and Ms. Schilling in the rate case for the purpose of illustrating the types of advanced technology solutions that would be supported by the GTEP and to obtain preauthorization to move forward on the Projects based on the general parameters as proposed. Recovery of actual costs for the Projects would be subject to further review at a later date, in accordance with the recovery terms approved in the rate case.

On June 21, 2019, the Company and other parties met in a technical session following the pre-hearing conference in this matter. Based upon that session and subsequent discussions among the parties, the Company learned that Commission Staff, the Office of Consumer Advocate ("OCA") and others prefer that the Commission's review of the merits of the Projects be conducted in a separate process, outside of the rate case, Docket No. DE 19-057. PSNH was asked to consider whether it would move its request for the preauthorization of the Projects to separate dockets. The Company is amenable to this approach and will resubmit the Projects for approval in separate dockets, as described below.

Because each of the Projects is in a different stage of development, PSNH intends to resubmit each proposal for preauthorization in a separate docket on a staggered schedule. Specifically, the Company intends to submit the testimony and exhibits of Ms. Ancel on the Westmoreland Clean Innovation Project shortly. For the Oyster River Clean Innovation Project, the Company will file at a later date a petition and the testimony and exhibits of Ms. Schilling, following a planned request for proposals ("RFP") to obtain outside support in developing the project design details. By these submissions, PSNH proposes that review of the merits of these Projects will shift to the new dockets, as will issues regarding the application of the cost recovery mechanism to these Projects. Because the joint testimony of Ms. Ancel and Ms. Schilling is limited to discussion of the two Projects, and all issues related to preauthorization of the Projects will be addressed in the new dockets, PSNH will withdraw consideration of that joint testimony from the rate case docket.[1]

As described in the Company's rate case application, the Projects are examples of the types of initiatives under review by the Company through the GTEP that will require a funding mechanism incremental to base rate recovery. The Company included the Projects with its initial rate case application because these initiatives are moving ahead expeditiously. The Company was concerned that a lag in administrative review could hinder the progress of project implementation. Accordingly, in transferring review of the Projects from the rate case to the new dockets, the Company does so on the understanding that the other parties will support proceeding in an expeditious and efficient manner such that those dockets may be concluded without undue delay and preferably near in time to the conclusion of the rate case.

Furthermore, PSNH notes that this plan does not affect any other elements of the rate case proposals, including, but not limited to, its proposal for implementation of a DRAM that would, if approved, provide the apparatus for reconciling various expenses including those relating to the GTEP (and the Projects).

Because this process for further review of the Projects is based upon the input of other parties, PSNH sought the agreement of the parties to the docket with respect to the approach described above. PSNH reports that the following parties agree with that approach: Commission Staff and The Way Home.

PSNH looks forward to continuing to work with the parties on the important issues in the rate case proceeding in Docket No. DE 19-057. Likewise, PSNH looks forward to working with interested parties in the individual dockets relating to each of the Projects and anticipates that the

[1] The joint testimony will remain on file in Docket No. DE 19-057 because it is referenced in testimony of other Company witnesses, but consideration of all of the issues raised in the joint testimony will shift to the new dockets.

review of the Projects will happen efficiently so that the important development opportunities to be afforded by the Projects may be obtained in the near future.

If you have any questions, please do not hesitate to contact me. Thank you for your assistance with this matter.

Very truly yours,

Matthew J. Fossum
Senior Regulatory Counsel

CC: Service List

EVERSOURCE	TD953 Revision 7	
TD PROCEDURE	**Inspection, Treatment, Restoration and Replacement Guidelines for Distribution System Wood Poles**	

Issue Date:	**Effective Date:**	**Owner Department**: Engineering Services	**Applicability:**
03/16/2015	**03/14/2015**	**Subject Matter Expert:** Howard P. Winslow	CT-NH-Western MA

All changes to TD procedures are controlled by TD 001
"Writing, Revising, and Publishing Transmission and Distribution Procedures."

This procedure replaces and supersedes the following procedures (in whole or in part), as described in Section 3 "Summary of Changes": TD 953 Rev. 6 "Inspection, Treatment, Restoration & Replacement Guidelines for Distribution System Wood Poles," effective 01/22/2014.

Approvals:

Approval Signature: *Michael G. Waggoner*

Michael G. Waggoner
Director, Engineering Services

Approval Signature: *Dominick M. Lauria*

Dominick M. Lauria
Director-Distribution Design

Approval Signature: *James C. Eilenberger*

James C. Eilenberger
Director-System Engineering

Approval Signature: *Robert S. Coates Jr*

Robert S. Coates Jr
Vice President-Electric Field Operations

Procedure applicable only to states for which an approval signature appears above.

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1. INTRODUCTION

1.1 Objective

This procedure establishes a uniform approach for distribution wood pole inspection, treatment, restoration and replacement. It defines the schedule, inspection, and reporting requirements for these facilities.

1.2 Applicability

This procedure pertains to the operations of Eversource CT Electric, Western MA Electric and New Hampshire Electric.

1.3 References

Unless otherwise specified:

- Maintenance procedures:
    - Eversource Maintenance Program on the Standards Bookshelf:
        - EMP Chapter 5.61 - Wood Poles
        - EMP Instructions 6.61 - Wood Poles - Inspections
        - EMP Instructions 6.61A - Wood Poles - Reinforcement
- Procedures are available at the following locations:
    - Lotus Notes Field Documentation Database.
    - Lotus Notes Regulated Businesses Policies & Procedures database.
    - Distribution Engineering Standards Bookshelf.
- Forms are available through Lotus Notes Forms Catalog or Forms Catalog on the intranet.

Development References
Documents used to develop this procedure and the process it controls:

- TD 001 “Writing, Revising, and Publishing Transmission & Distribution Procedures”

Supporting References
Documents that support performance of activities directed by this procedure:

- Program effectiveness reporting

Supporting Programs and Databases
Programs and databases that support performance of activities directed by this procedure:

- WMS System
- Cascade

1.4 Discussion

Questions regarding this procedure will be answered by the Manager – Distribution Standards Engineering.

Technical support shall be provided by the Manager – Distribution Standards Engineering and the Manager Construction Engineering for Eversource CT Electric, Manager System Planning for Western MA, Manager Field Engineering & Operations for NH.

End of Section

2. INSTRUCTIONS

2.1 Planning

CT: Distribution Engineering Managers

Western MA: Manager System Planning

NH: Contract Project Services and Division Field Engineering Manager

2.1.1 DEVELOP annual budgets for distribution wood pole maintenance programs.

- Inspection and Treatment
- Corrective Maintenance

2.1.2 DEVELOP a pole inspection schedule in accordance with EMP chapter 5.61 (4/15/2010: currently 15 year cycle for CT / Western MA and 10 years for NH).

2.1.3 REVIEW & FINALIZE the annual inspection schedule by October 1 of the preceding year and include a list by map grid as required with pole or circuit maps.

2.1.4 IDENTIFY locations where line rebuilds involving pole replacements are planned and communicate to designers.

2.2 Pole Inspection and Treatment

CT: System Projects – Special Projects

Western MA: System Planning

NH: Contract Projects Services

2.2.1 Communicate the annual inspection schedule to Operations Directors and Managers. Review the priority reject email notification groups for accuracy.

2.2.2 ADMINISTER and MONITOR the pole inspection program.

2.2.3 PREPARE the specifications consistent with the requirements contained in EMP Instruction 6.61 – "Wood Poles – Inspection", for inspection supplemental treatment and inspector reporting requirements.

2.2.4 PREPARE bid packages and work with purchasing to request quotes and award contracts.

2.2.5 OBTAIN state highway permits annually (not required in NH) as required for permits to perform pole inspection work along state highways. NH requires a Special Permit for Pole Treatment/Pesticide Application. SEND the report to the following:

- Western MA: Manager System Planning
- CT: Manager Construction Engineering
- NH: Supervisor-Construction & Contract Projects SVCS

2.2.6 Perform inspections in accordance with requirements contained in EMP Instruction "6.61 – Wood Poles – Inspection".

2.2.7 MANAGE pole inspectors and their crews and perform quality assurance audits.

2.2.8 RESOLVE customer and material issues.

2.2.9 REVIEW and APPROVE invoices for pole inspection and treatment.

2.2.10 INITIATE pole replacement priority rejects activities in accordance with step 2.3.

2.2.11 UPDATE Pole Inspection Reports in the Pole Inspection Repository on a bi-weekly basis during the contract term, with inspection results including Rejects and other corrective maintenance work.

2.3 Pole Replacements - Priority Reject

2.3.1 **IMMEDIATELY NOTIFY**:

CT: System Projects – Special Projects

Western MA: System Planning

NH: Contract Project Services

- Telephone the respective Operating Company's Clearing Desk.

The Clearing Desks

2.3.2 INITIATE a STORMS Work Request for a Priority Reject Pole using Job Type "**EMPRP**" (Electrical Maintenance Pole Reject – Priority).

- In the Job Description Field, type the information using the following format:

YYYY Pole Inspection – Priority Reject Pole # XXXX Street, Town, in which "YYYY" is the year of the inspection and "XXXX" is the pole number.

For example:

2011 Pole Inspection – Priority Reject Pole # 1234 Main St., Bloomfield.

Upon creation of the Work Request, automated E-mails will be sent to:

- The Operations Manager and Operations Team
- The Asset Management Group
- Vegetation Management (CT and Western MA) or Contract Project Services NH)

Operations Manager

2.3.3 CHECK the pole within 48 hours to assess the immediate impact on public safety and determine the required make safe methods and replacement and repair requirements.

Distribution Engineering

2.3.1 Immediately PROVIDE Field Engineering Design/Operations with feedback (install same or larger size/class pole) for priority reject poles before work order is written for permanent repairs.

Operations Manager

2.3.2 MAKE the pole SAFE within 10 calendar days using methods based on previous two steps.

2.3.3 Complete STORMS requirement 414 once pole has been MADE SAFE.

Supervisor- Field Engineering Design /Operations Manager

2.3.4 WRITE work order and complete construction for permanent repairs using information from previous three steps (actual pole size, etc.).

CT: System Projects – Special Projects

Western MA: System Planning

NH: Contract Project Services

2.3.5 MONITOR the Work Request until completion to ensure action has been taken to make safe or replace the pole within the specified time.

2.3.6 Monthly, during the inspection period, COMPARE the Priority Rejects identified on the pole inspector's report to the Priority Reject report generated from Work Management data and ENSURE all reported Priority Rejects have been addressed.

2.4 Review of Inspection Results

Distribution Engineering Managers – CT

Manager System Planning – Western MA

Division Operations Manager –NH

NOTE

Refer to Attachments 1 & 2 or EMP Instruction 6.61 – "Wood Pole Inspection" for guidelines in determining whether restoration or replacement should be accomplished, as applicable.

For other joint owners not covered by the above documents, refer to the appropriate intercompany operating procedure for guidance.

2.4.1 REVIEW the list of poles identified for restoration and replacement and provide alternate instructions to Job Designers as required (e.g. - for known/planned projects that will require specific pole size and class or concentrated reject rates that justify additional work such as reconductoring).

2.4.2 Determine the size and class of poles for pole replacements

2.4.3 REVIEW Pole Inspection Repository findings in 2.2.10 and add required corrective maintenance to the patrol database for resolution.

2.4.4 SUBMIT the list of poles identified for restoration and replacement to:

- CT Manager – Construction Engineering
- Western MA Managers – Customer Operations
- NH Customer Operations (Replacements only)
- NH Contract Project Services (Restorations only)

2.5 Corrective Maintenance

Manager – Construction Engineering – CT
Supervisor – Construction & Contract Services – NH
Manager Customer Operations – Western MA

2.5.1 From the list provided by ASSET MANAGEMENT, Create a Work Request under the DQ Annual Project or other project identified for this purpose using the appropriate Job Type.

- EMPRNS - Electrical Maintenance Pole Reject – Normal
- EPPREINFA - Electric Projects Pole Reinforce – Annual
- EPPREINFS - Electric Projects Pole Reinforce – Specific

2.5.2 Check that the work order activity is PREX for pole replacements and PFEX for pole restoration

2.5.3 PREPARE contract bid package.

2.5.4 AWARD contract to pole restoration contractor.

2.5.5 REVIEW and APPROVE invoices for pole restorations and perform audits of restoration contractor.

2.5.6 Complete the work within the calendar year following the inspection year.

2.6 Reporting

CT: System Projects – Special Projects
Western MA: System Planning
NH: Supervisor – Construction & Contract Projects SVCS

2.6.1 PUBLISH an annual report using the format provided in Attachment 3 by the end of January for the preceding year.

a. This report shall contain as a minimum, the following:

1) Number of Poles Inspected:
2) Number of Poles Identified for Restoration:
3) Poles Restored to Date:
4) Number of Poles Identified for Replacement (Normal Reject):
5) Number of Poles Replaced (Normal Reject):
6) Number of Poles Identified for Replacement (Priority Reject):
7) Number of Poles Replaced (Priority Reject):
8) Justification for those poles that could not be restored per NUMM Instruction 6.61A guidelines
9) Summary of Justifications provided for non-restorations.

2.6.2 SEND the report to the process stakeholders for review and appropriate action

a. Stakeholders include as a minimum:

1) Director – Distribution Engineering for CT

2) Director – Engineering Services

3) Director – Field Operations for NH

4) Vice President – Electric Field Operations for CT

5) Vice President – Electric Field Operations for Western MA

2.7 Records

CT: System Projects – Special Projects
Western MA: System Planning
NH: Contract Projects SVCS

2.7.1 MAINTAIN inspection records for the duration of the inspection cycle.

End of Section

3. SUMMARY OF CHANGES

Changes to TD Procedures are controlled by TD 001 "Writing, Revising, and Publishing Transmission & Distribution Procedures".

Revision 1

- Revised to reflect changes in job titles of individuals affected by this procedure
- Revised to reflect changes in the type of wood preservatives used in the treatment and restoration of distribution system wood poles
- Revised as part of TD Procedure Upgrade Project initiated in June 2002.

Revision 2

- DMS-WRES has been change to WMS (Work Management System)
- Section 2.1.2: The scheduling of inspections was changes from requiring that 1/15 of the poles be inspected annually to a schedule that meets the requirements of the National Electric Safety Code and be completed within 15 years.
- Removed all reference to the Pole Inspection Reporting System (PIRS). PIRS was discontinued in 2006. The pole inspection contractors will provide an Excel file with inspection and treatment results.
- The inspection process was revised to require the use of a hand held computer to record data, determine pole strength and measure the wire and attachment load on each pole. All references to the Osmose POLE CIRCUMFERENCE CALCULATOR were removed.
- The data reporting requirements were reduced.
- References to SBC/AT&T was changed to AT&T
- Attachment 7 NESC Requirements was added

Revision 3 - 10/12/2010

- Complete rewrite.
  - ➢ Revised to incorporate NUMM references and to provide consistency with NUMM Chapter 5.61 – Wood Poles as well as NUMM Instructions 6.61 – Wood Pole Inspections and Instruction 6.61A – Wood Pole Restoration.
  - ➢ Removed detailed directions to fielded workers for performance of wood pole inspections and wood pole restoration.
  - ➢ Clarified administrative requirements for the **i**nspection, treatment, restoration and replacement of distribution system wood poles
  - ➢ Updated and clarified responsibilities for the **i**nspection, treatment, restoration and replacement of distribution system wood poles along with the required reporting guidelines.
  - ➢ Updated Approvers
  - ➢ PSNH added

Revision 3 – Editorial Change – 11/10/2010

Engineering Manager-Distribution – PSNH removed from Section 2.5, Corrective Maintenance and added to Section 2.4, Review of Inspection Results, responsible parties.

Revision 4 – Procedure Changes – 05/27/2011

- Changed the Approvers for CL&P and PSNH.
- Under Section 1.3, changed the locations from which procedures are available.
- Under Section 2.2, provided additional steps to the Pole Inspection and Treatment procedure regarding Priority Reject poles.
- Under Section 2.3, changed procedure steps to reflect new communication responsibilities and changed activities regarding Priority Reject poles.
- Under Section 2.4, added responsible person for PSNH.
- Under Section 2.5:
    - Added responsible persons for PSNH and WMECO.
    - Changed procedure steps.
    - Provided new Work Request codes for Corrective Maintenance.
    - Removed existing list of Work Request Estimating Project Selection menus.
- Throughout, changed title of responsible person(s) for PSNH in several locations.
- Referenced NUMM chapter 5.61 for Pole Inspection schedule.

Revision 5 – Responsibility and Notification Changes - 01/17/2014

- Changed all occurrences referring to CL&P Veg Mgmt to "CL&P – System Projects – Special Projects."
- Changed all occurrences referring to: Veg Mgmt ***and*** NU Vegetation Management to "Asset Management."

Revision 6 – Deletion of Duplicate Information – 01/22/2014

- Replaced previous step 2.39 with the following text: "Monthly, during the inspection period, COMPARE the Priority Rejects identified on the pole inspector's report to the Priority Reject report generated from Work Management data and ENSURE all reported Priority Rejects have been addressed."
- Deleted previous step 2.3.10 which had read: "WRITE work order based on feedback from Asset Management regarding pole size requirements and complete construction for permanent repairs."

Revision 7 – Effective Date– 03/15/2015

- Updated Approvers and Titles
- Under section 2.3.5, replace "5 working days" with "10 calendar days. Per request of the NUMM Overhead Lines Working Group.
- Under section 2.6.2, update stakeholders and titles.
- Replaced references from AT&T to Frontier in Attachment 2.
- Added to Eversource template.

Revision 7 – Editorial Change - Effective Date– 11/08/2017

- Updated company names to align with Eversource.
- Changed references to NU Maintenance Manual (NUMM) to Eversource Maintenance Program (EMP).
- Updated department names to align with organizational changes.

Attachment 1

Pole Restoration / Replacement Guideline –Electric Company

(Sheet 1 of 1)

This serves as a guideline to determine whether a reject pole identified for possible restoration should be restored or replaced.

Restore poles when all of the following conditions are met:

- No circuit rebuild requiring taller or larger class poles is planned within the present planning period. Search the WRES system by pole number to determine if other work has been planned for that pole and proceed accordingly.
- No equipment additions (capacitors, reclosers, regulators, switches or transformers) that would require a taller or larger class pole are expected in the near future.
- Telephone Company concurs with pole restoration. (Refer to telephone company guidelines)
- If applicable, State Highway Department concurs with pole restoration for poles along state highways. For the State of Connecticut, written approval must first be obtained from the appointing authority of the local municipality of the state route where pole restoration is planned. A permit by the State of Connecticut Department of Transportation will not be issued unless approval from the municipality is included with the request.

In Connecticut:

- Do not restore poles on scenic highways or in historical areas of towns.
- Replace poles with questionable pole tops (split or rotted) that are estimated will last less than 10 years, or with obvious load or clearance problems or those not selected for reinforcement.
- Restoration is cost justified if the reinforced pole will not require replacement within 5 years for jointly owned poles and within 8 years for solely owned poles.

Attachment 2

Pole Restoration / Replacement Guideline – Frontier (CT)

(Sheet 1 of 1)

This guideline was provided by Frontier - CT for pole restoration and replacement work for jointly owned poles to reduce field visits by NU and Frontier personnel.

Frontier encourages pole restoration in the following cases:

- Poles with Frontier aerial or ground level interface boxes attached.
- Poles with large communication cable risers attached.
- Poles in “Right of Ways”.
- Poles 45 feet and above.

Frontier discourages pole restoration in the following cases:

- 35 foot pole - With power primary, secondary/neutral and communication cables that cross a road.
- 35 foot pole - With power primary, secondary/neutral and more than 3 attachments in the communications gain.
- 40 foot pole - With power primary, secondary/neutral and more than 5 attachments in the communications gain.
- Any pole that is inadequate for planned Frontier construction.
- Any pole with obvious load or clearance problems.
- Any pole not meeting Frontier or State of Connecticut DOT criteria for pole restoration.

NOTE:
Attachments in the communication gain refer to all attachments, roadside and field side, including bare strand. (Frontier, Municipal, State, CATV, other communication companies)

Questionable poles will be reviewed by Frontier Line Construction/ Frontier Engineering upon request.

It is requested that pole maps of the projected pole inspection be supplied to Frontier for review. Frontier will identify areas of planned construction and reply back to NU.

The Frontier Communications contact is:

Joseph Aresco Jr.
Director, Construction & Engineering
1441 North Colony Rd., Meriden, CT
203-238-2640 office
203-317-0281 cell
Joseph.aresco@ftr.com

Attachment 3

Pole Inspection Restoration and Replacement Summary Year End Reports

(Sheet 1 of 2)

The Pole Inspection Restoration and Replacement Program report shall contain, at a minimum, the following information:

DIVISION / COMPANY: ___________________________

POLE INSPECTION YEAR: ___________

REPORT DATE: ___________

INSPECTION AND TREATMENT		**WEEK ENDING** ___/___/___	**YEAR -TO-DATE**
Total number of poles inspected	________	________	
Number of priority rejects		________	________
Number of normal rejects		________	________
Number of visual only inspections		________	________
Number of sound and bore inspections		________	________
Number of groundline treatments		________	________
Number of hollow heart treatments		________	________
Number of WoodFume treatments		________	________
Total cost		________	________
Average cost per pole	________	________	

Monthly, and at the conclusion of the project, the contractor shall provide a computer file containing all of the inspection and treatment data for each pole. This file shall be in a format that can be read and processed by Microsoft Excel and Microsoft Access software.

Attachment 3

Pole Inspection Restoration and Replacement Summary Year End Reports

(Sheet 2 of 2)

The Pole Inspection Restoration and Replacement Summary report indicates the numbers of pole restorations and replacements relate to the year the poles were inspected. Much of the restoration and replacement work may take place in years subsequent to the year that the inspection was performed. This report shall comprise a running history and at a minimum contain the following information:

REPORT SUMMARY BY INSPECTION YEAR
Number of Poles Identified for Replacement (Priority Reject):
Number of Poles Replaced (Priority Reject):
Number of Poles Identified for Replacement (Normal Reject):
Number of Poles Replaced (Normal Reject):
Number of Poles Identified for Restoration:
Number of Poles Restored:

DIVISION / COMPANY: ___________________________

POLE INSPECTION YEAR: ___________

REPORT DATE: ___________

Year	Poles Identified for Replacement (Priority Reject)	Poles Replaced (Priority Reject)	Poles Identified for Replacement (Normal Reject)	Poles Replaced (Normal Reject)	Poles Identified for Restoration	Poles Restored
2010						
2011						
2012						
2013						
2014						
2015						
2016						
2017						
2018						
2019						

The report file shall be in a format that can be read and processed by Microsoft Excel and Microsoft Access software.

EVERSOURCE MAINTENANCE PROGRAM	Document Number: **5.61 Rev. 3** Document Name: **Wood Poles**
Owner Name:	Henry J. Matuszak
SME Name:	Howard Winslow
Effective Date:	July 1, 2015

Approvals: **Connecticut**:

Name: Charles E. Fontenault
Title: Director – Division Operations
Date Signed: 5-17-2015

Eastern Massachusetts:
Name: Donald M. Boudreau
Title: Director, Electric Operations
Date Signed: 5-15-2015

New Hampshire:
Name: Marc Geaumont
Title: Director – Customer Operations
Date Signed: 5-14-2015

Western Massachusetts
Name: Bliss A. Young
Title: Director – Operations
Date Signed: 5-11-2014

Transmission:
Name: Michael B. M^cKinnon
Title: Directors – Transmission Construction Test & Maintenance
Date Signed: 5-12-2015

Operations Services:
Name: Michael G. Waggoner
Title: Director – Engineering Services
Date Signed: 5-11-2015

Ensure you are using the current revision by verifying it against the controlled electronic copy located on the Distribution Engineering Standards Bookshelf or the Regulated Businesses Policies and Procedures Lotus Notes Database.

5.61 Wood Poles

General Description

This procedure establishes a uniform approach for distribution wood pole inspection, treatment, restoration and replacement. It defines the schedule, inspection, and reporting requirements for these facilities.

This applies to all wood distribution poles within the custodianship or the maintenance responsibility of Eversource. It shall include push braces and guying stub poles as well as line poles scheduled for the given year.

Facilities/Equipment

- Wood Poles

5.61.1 Inspection and Maintenance Activity Schedules

5.61.1.1 Table 1 – Wood Poles Maintenance Intervals

Wood Poles **Maintenance Schedule**	**All**
PM Task	
Condition Monitoring	N/A
Time-Directed	
Routine Inspection	15Y (**Notes 1 & 2**)
Condition-Based	
Priority Reject	**(Note 3)**
Schedule repairs or replacement.	A/R **(Note 4)**
Failure Finding	
Corrective Maintenance	A/R

In **Table 1**, the intersection of the row and column indicate the age-based inspection or maintenance interval for wood poles based on the preservation treatment listed in the column heading. For example, the age requirement for a Routine Inspection is 15Y (or 15 Years). The abbreviations used for the intervals are:

Y = Year, i.e. 2Y = 2 Years

A/R = As Required

N/A = Not Applicable

Note 1 = 15 years is the minimum requirement for pole inspection. This interval may be changed due to contractual requirements with joint owners.

Note 2 = The type of inspection performed shall be determined by the age of the pole and its type of treatment, as shown in the following table:

Inspection Type	Creosote, Penta, all others	CCA
Visual	0 to 9 years old	0 to 19 years old
Sound & Bore	10 to 14 years old	20 years old and older
Ground Line Excavate	15 years old and older	If decay is indicated by Sound & Bore

Note 3 = Field supervision shall check the pole within forty eight (48) hours from identification as a “priority reject” to assess the conditions and verify there is no immediate danger to the public. The pole must be made safe within 10 calendar days or less from its identification as a “priority reject” wood pole..

Note 4 = Complete the repair or replacement within one year of determination of need following inspection

5.61.2 Maintenance Categories

5.61.2.1 Routine Inspection – Time Directed

1. Routine inspection activities are detailed in EMP Instruction 6.61.

5.61.2.2 Priority Reject Poles

1. Priority reject pole activities are detailed in EMP Instruction 6.61.

5.61.2.3 Normal Reject Poles

1. Normal reject pole activities are detailed in EMP Instruction 6.61.

5.61.3 Evaluation of Restorable Poles

1. The evaluation activities for restorable poles are detailed in EMP Instruction 6.61A.

5.61.4 Failure Finding

1. Failure finding activities are detailed in EMP Instructions 6.61 and 6.61A.

5.61.5 Research/Background

Publications and other reference materials from these organizations were used in the development of this program.

- National Electric Safety Code, as directed by section DER 07-01 “Wood Poles – Aging Infrastructure”
- TD 953 – “Inspection, Treatment, Restoration and Replacement Guidelines for Dist Sys Wood Poles”

5.61.6 Wood Poles - Maintenance Basis Documentation

The maintenance activities and their schedules are based on industry experience, manufacturer's recommendations, feedback from the service technicians, and the subject matter expert, who in this case, is a Senior Engineering Technologist for Distribution Engineering Design.

Requirement	Basis
Routine Inspection at 15Y Interval	**Inspection required by the NESC -** The National Electrical Safety Code requires that poles are inspected as often as experience shows it necessary to maintain the strength required for the pole to remain in service. According to charts developed by Osmose on National averages, the percentage of reject poles starts to rise between ten and fifteen years. However, because Eversource is mostly in a "Moderate Deterioration" zone (National Wood Preservers Association Book of Standards) we could expect better than average results from an inspection program. Eversource's experience finds that a fifteen year inspection and treating program keeps the reject rate reasonable. NOTE: Eversource's line mechanics are taught to visually inspect and sound any pole before climbing it. The 15 year inspection is required, but it is acknowledged that New Hampshire has an existing contract to perform their inspections at a 10 year interval.

5.61.7 Summary of Changes

Revision 1 – Effective Date: **July 15, 2011**

Referenced Feedback – MS-0022

	Description of Changes
1.	Moved inspection activities to Instructions 6.61. Moved Restoration activities to Instructions 6.61A. Added references to TD 953, and Instructions 6.61.

Revision 2 – Effective Date: **January 2, 2015**

Referenced Feedback – MS-0402

	Description of Changes
1.	Increased the period from 5 days to 10 days in which a priority reject pole must be made safe.

Revision 3 – Effective Date: **July 1, 2015**

Related Feedback – N/A

1.	Changed names of the Owner, SME, and Approvers on the Signature page, as required.
2.	Incorporated the following global replacements: • NU Maintenance Manual replaced by Eversource Maintenance Program. • CL&P replaced by Eversource Connecticut. • WMECO replaced by Eversource Western Massachusetts. • PSNH replaced by Eversource New Hampshire. • NSTAR replaced by Eversource Eastern Massachusetts. • NUMM replaced by EMP.
3.	Incorporated the following global replacements: • NU Safety Manual replaced by Eversource Employee Safety Manual

(e) Each utility shall have available the types and quantities of working instruments necessary to determine compliance with these rules for:

(1) Recording and indicating customer voltage; and

(2) Testing any other electrical quantities which may be necessary to comply with the measurement and reporting requirements of this chapter.

(f) Each utility shall check the working instruments required by (e) with the reference instruments at least once each year.

(g) If reference instruments are not available within the utility, the utility shall have field instruments checked in an independent standards laboratory meeting specifications recommended by the meter manufacturer in intervals not to exceed one year.

(h) A utility may certify its indicating standards in a standards laboratory which it maintains provided that the instruments and methods meet specifications recommended by the meter manufacturer.

(i) Pursuant to RSA 365:6, each utility shall, upon request, provide the commission access to its meter testing facilities and any and all meter test results.

Source. #6605, eff 10-21-97; ss by #8448, eff 10-18-05; ss by #10603, eff 5-21-14

PART Puc 306 EQUIPMENT AND FACILITIES

Puc 306.01 Standard Practice in Construction, Operation and Maintenance.

(a) Each utility shall construct, install, operate and maintain its plant, structures and equipment and lines, as follows:

(1) In accordance with good utility practice;

(2) After weighing all factors, including potential delay, cost and safety issues, in such a manner to best accommodate the public; and

(3) To prevent interference with other underground and above ground facilities, including facilities furnishing communications, gas, water, sewer or steam service.

(b) For purposes of this section, "good utility practice" means in accordance with the standards established by:

(1) The National Electrical Safety Code C2-2012, available as noted in Appendix B;

(2) When applicable, the International Energy Conservation Code 2009 as adopted pursuant to RSA 155-A:1,IV; and

(3) The ISO-NE.

Source. #2011, eff 5-4-82; ss by #2912, eff 11-26-84; ss by #4999, eff 11-26-90; ss by #6381, INTERIM, eff 11-27-97, EXPIRED: 3-27-97

New. #6605, eff 10-21-97; ss by #8448, eff 10-18-05; ss by #10603, eff 5-21-14

Puc 306.02 Joint Pole Construction. Each utility involved in any installation which makes use of poles either for single or joint occupancy shall conform its construction, installation, operation and maintenance to the requirements of Puc 306.01.

Source. #2011, eff 5-4-82; ss by #2912, eff 11-26-84; ss by #4999, eff 11-26-90; ss by #6381, INTERIM, eff 11-27-97, EXPIRED: 3-27-97

New. #6605, eff 10-21-97; ss by #8448, eff 10-18-05; ss by #10603, eff 5-21-14

Puc 306.03 Electrical Interference.

(a) Each utility shall make a full and prompt investigation of complaints made by the utility's customers or by the general public involving electrical interference with reception by communications equipment in the proximity of the utility's transmission and service areas, including but not limited to interference with television and radio reception.

(b) Each utility shall maintain a record of complaints which it receives pursuant to (a) above.

(c) Each utility shall report to the commission all complaints, as described in (a) above, that it receives that are not resolved to the satisfaction of the complaining party within 30 days of receipt or notification of the complaint.

(d) The report referred to in (c) above shall include the location of the complaint, the circuit number of the line, and a brief description of the interference.

Source. #2011, eff 5-4-82; ss by #2912, eff 11-26-84; ss by #4999, eff 11-26-90; ss by #6381, INTERIM, eff 11-27-97, EXPIRED: 3-27-97

New. #6605, eff 10-21-97; ss by #8448, eff 10-18-05; ss by #10603, eff 5-21-14

Puc 306.04 Safety Instructions.

(a) Each utility, in the operation, construction or maintenance of its plant and facilities, shall:

(1) Develop and implement a safety and health program to ensure that its employees have been:

a. Properly informed of safety practices and procedures; and

b. Protected from hazards associated with the work environment;

(2) Adopt comprehensive written instructions for the safety of its employees; and

(3) Distribute a copy of the written instructions required by (2) above to each of its employees before assignment to duty in any assignment which requires handling any energized electrical plant.

Source. #2011, eff 5-4-82; ss by #2912, eff 11-26-84; ss by #4999, eff 11-26-90; ss by #6381, INTERIM, eff 11-27-97, EXPIRED: 3-27-97

New. #6605, eff 10-21-97; ss by #8448, eff 10-18-05; ss by #10603, eff 5-21-14

Demmer, Kurt

From: Mackey Karen <karen.mackey@eversource.com>
Sent: Tuesday, November 6, 2018 1:34 PM
To: Demmer, Kurt
Subject: RE: Operational Documents

Hi Kurt,
This request will take some time to pull together, but I have requested the documents. As soon as I have the information, I'll forward to you.
Thanks,

Karen

Karen T. Mackey | Senior Engineer – Technical Compliance & Reporting | Eversource
EP-2 | 780 No. Commercial St | Manchester, NH 03101 | ☎ : 603.634.2519 | ✉ : Karen.Mackey@eversource.com

---

From: Demmer, Kurt
Sent: Monday, November 5, 2018 10:56 AM
To: Mackey Karen ; letourneau (unitil.com) ; Leo Cody
Cc: paul.kasper@puc.nh.gov; richard.chagnon@puc.nh.gov
Subject: Operational Documents

In order for Staff to be current with your utility's safety, operational practices, construction procedures, and construction standards, PUC staff is requesting the current documents that your utility uses in its Distribution Operations. I have included a brief description of the documents requested since each utility may not have the same naming convention for its documents. If there are additional documents that your utility utilizes in its operation or maintenance of electric distribution system, please include those documents. Preference for media is electronic unless electronic versions are not available or format is not available in a typical Windows Office based software package.

Please note, distribution personnel includes all personnel that conduct business in the Distribution Utility side of the business. Distribution Operations includes, design; planning; work management and scheduling; field construction and maintenance; field or office protection installing, maintenance and testing; or any other functions that align with distribution grid functionality. Any transmission procedures, standards, or construction that have a direct impact on Distribution operations should also be included.

Safety Manual: Corporate (if applicable) and Jurisdictional, The safety manual for Distribution employees ; Electric and Gas (if applicable)

Electric Operating Procedures : Electric procedures for distribution personnel for substation, underground, overhead, and protection applications e.g. Tagging and Grounding, Rubber Glove applicability, URD Testing standards and procedures, etc.

Electric Distribution Construction Standards: Construction manuals for the installation of overhead, underground, and substation applications.

Substation Maintenance Procedures or Standards: If Different from above. These would include procedures and standards that are specifically scoped for Substation work.

Misc. Bulletins or Notices: Bulletins, Notices or Memorandum that have been issued by Operations, Safety, Engineering, Corporate, or Compliance that have not be incorporated into the above aforementioned documents, however are considered a requirement for distribution personnel to follow.

If I have the wrong point person in this email to request this information, please forward as appropriate and indicate who is the correct person for future document requests or updates.

Thank you, in advance, for the fulfillment of this request.

Kurt Demmer P.E.
Utility Analyst-NH Public Utilities Commission
Electric Division
21 S. Fruit Street
Concord, NH 03301-2429
Office: 603-271-6077 | E-mail: kurt.demmer@puc.nh.gov

From: Mackey, Karen <karen.mackey@eversource.com>
Sent: Wednesday, September 11, 2019 4:04 PM
To: Demmer, Kurt <Kurt.Demmer@puc.nh.gov>
Cc: Chagnon, Richard <Richard.Chagnon@puc.nh.gov>; Kasper, Paul <Paul.Kasper@puc.nh.gov>; Desbiens, Allen M <allen.desbiens@eversource.com>; Lajoie, Lee G <lee.lajoie@eversource.com>
Subject: Eversource's Distribution System Engineering Manual (DSEM)

EXTERNAL: Do not open attachments or click on links unless you recognize and trust the sender.

Good afternoon, Kurt

I talked with Lee Lajoie and he shared that you didn't have a copy of Eversource's Distribution System Engineering Manual. I have attached an electronic copy for you.
Please confirm that you've received it. Even compressing the document, it's still a very large file.

Note, too, that this manual applies to all of Eversource and certain sections apply only to certain jurisdictions. Each page that does not apply to all areas is marked with the areas that is subject to that information.

If you have any questions, please let me know.
Thanks,
Karen

Account Executives

CO-1006 - Account Executive Coverage Procedure

CO-1007 - Managed Accounts Survey

CO-1084 - Electric Service Agreement Preparation

Administrative Procedures

CO-1134 - Customer Operations Vacation Policy

CO-1156 - Statement of Expected and Prohibited Behaviors

Community Relations

CO-1001 - Key Event Participation

CO-1011 - Temporary Decorative Pole Attachment Policy

CO-1111 - Municipal Decorative Pole Attachment

Design Build

CO-1049 - Design Build Process - Section I Receive the Information

CO-1050 - Design Build Process - Section II Assigning the Job

CO-1051 - Design Build Process - Section III Project Assessment

CO-1052 - Design Build Process - Section IV Final Design

CO-1053 - Design Build Process - Section V Select Construction Resource

CO-1054 - Design Build Process - Section VI Allocate Crews, Schedule Materials & Equipment

CO-1055 - Design Build Process - Section VII Pre-Construction/Re-Confirmation Activities

CO-1057 - Design Build Process - Section IX Performance Management

CO-1058 - Design Build Process - Section X Closing the Work Package

CO-1059 - Build It First (No Design) Procedure

CO-1128 - Third Party Application and Pole Attachment License Process

CO-1165 - Distribution Pole Height

Designers/Writers

CO-1005 - Access Requirements for New Service Locations

CO-1026 - Design Study for Replacing Distribution Facilities

CO-1029 - Serving Non-Franchised Customers

CO-1117 - NHDOT Force Account Lighting, Estimating, and Billing

CO-1141 - NHDOT Projects Communications Process

CO-1157 - Field Technician - Competency Requirements Evaluation Procedure

CO-1161 - Designing Service to Residential Customers

CO-1169 - Determining Franchise Area Locations

CO-1173 - Petition and Pole License Job Design Guidelines - PSNH Pole Installations and/or Pole Replacements

CO-1175 - Construction Tree Trimming and Joint Owner Exchange of Notice Guidelines

Emergency Response

CO-1027 - Information Access by Unregulated Affiliates During Emergency Restoration Activities

CO-1044 - Establishing Key Box Access for Emergency Response

CO-1079 - Hours of Work During Emergency Response Events

CO-1092 - Tree Trimming Documentation and Billing - Heavy Storm Events

CO-1095 - Emergency Restoration Response - On Call Supervisor

CO-1096 - Mutual Aid and Deployment - PSNH

CO-1099 - Detailed Damage Assessment - Heavy Storm Events

CO-1100 - Wires Down

CO-1101 - Initial Damage Assessment and Outage Assessment Report

CO-1104 - Crew Guide

CO-1105 - Outage Status Reporting and Estimated Time of Restoration (ETR)

CO-1110 - Standardized Restoration Team - Heavy Storm Events

CO-1112 - Customer Operations Responsibilities During OP-0007 Actions in an Emergency

CO-1135 - Meal Guidelines During Storm Restoration

CO-1139 - Alternate Work Location Due to Emergencies - Mileage and Travel Time Pay Practices

CO-1170 - Major Storm Event- Lessons Learned

Operate & Restore

CO-1009 - Climbing Wood Poles

CO-1012 - Guidelines for the Disposal of Wood Products

CO-1013 - Keeping Job Information Updated

CO-1018 - Model T-150 Cable Reel Dolly Operation

CO-1020 - Transformer Ratio and Polarity Testing

CO-1021 - Step Transformer Installation

CO-1023 - Large Power Customer Oil Spill Procedure

CO-1024 - Area Work Center Billing Guidelines

CO-1031 - Primary Circuit Map Underground Plan & Miles of Line Updates

CO-1038 - Dispatching Crews to Respond to Trouble Calls During Normal Working Hours

CO-1040 - Voltage Regulators

CO-1041 - Inclement Weather Utilization

CO-1042 - Billing Customer for Final Inspections

CO-1043 - Job Ready - No Final Inspection

CO-1045 - Standby Take Home Vehicle Policy

CO-1046 - Outage and Non-Outage TR/UPER Reporting Procedure

CO-1047 - Covering Conductor For Private Contractors

CO-1060 - Rubber Glove Failure Notification Process

CO-1063 - Pole Transfer & Removal Procedure

CO-1068 - Meter Inspection Approvals and Line Department Meter Sets

CO-1077 - Issuing Specific Service Cable and Conduit Using a Clearing Work Order

CO-1078 - Inventory Cable Accuracy

CO-1081 - Streetlight/Rental Light Repairs

CO-1086 - Division Level Analysis of Work Management System Issues

CO-1097 - Municipal Street Lighting Rate Conversions

CO-1098 - Installations and Removals of Municipal Street Lights

CO-1114 - Municipal Street Light Audit

CO-1136 - Rubber Gloving 600 Volts to 35,000 Volts

CO-1137 - Skylift Ranger 40 Utilization

CO-1138 - ATV Utilization

CO-1150 - Approved Tools

CO-1151 - Private Contractors in Close Proximity to Energized Pad Mounted Equipment

CO-1152 - Boom Cleaning Schedule - Bucket Truck

CO-1153 - Lineworker Evaluation Process

CO-1154 - Non-Slip Footwear

CO-1158 - Candidate Selection Process - Working Foreman-Line

CO-1159 - Contractor Resource Procurement and Release

CO-1160 - Working on Customer Roofs

CO-1167 - Contractor Invoicing Guidelines

CO-1171 - Voltage Conversion

CO-1172 - Customer-Built Line Extensions

CO-1177 - Scada-Mate Installation

CO-1179 - Automated On Call Lineworker Dispatch (AOD)

CO-1180 - Primary By-Pass Trailer Procedure

CO-1181 - Distribution ROW Line Patrols

CO-1182 - Reporting Hazards or Unsafe Conditions

Plant Records

CO-1121 - Balance Sheet Account Reconciliation - Telephone Company Joint Line Billing

CO-1162 - Pole Renumbering

CO-1164 - Distribution Easements

Resource Planning

CO-1036 - Resource Planning & Crew Movement

CO-1064 - Bidding Jobs to Outside Contractors

CO-1089 - iScheduler - Scheduling & Reporting

Safety & Methods

CO-1004 - Load-Break Elbow Procedure

CO-1010 - Utilization of Puller-Tensioner

CO-1066 - Tailboard Job Briefings

CO-1069 - Overhead Distribution System Emergencies

CO-1070 - Working Beyond Reclosers

CO-1072 - Distribution Transformers

CO-1073 - Emergency Tree Trimming - Distribution System

CO-1075 - Conductor Stringing With Puller Tensioner

CO-1076 - Overhead Wire

CO-1088 - Unmanned Pole Support

CO-1102 - Sauber Pole Trailer Use

CO-1133 - Bucket/Digger Truck Compliance Review

CO-1143 - Inspection of Lever Operated Hoists

CO-1155 - Isolation of Capacitor Banks on Distribution Circuits

Training & Methods

CO-1030 - Lineworker Progression

Eversource System Operating Procedures (ESOPs)

ESOP-100 - Operating and Control of the Eversource Transmission & Distribution Electric System

ESOP-15 - Real-time Data and Analysis Quality, and Alarm Processor Monitoring

ESOP-33 - Human Error Reduction

ESOP-9 - Communications

NH ESCC Control Center SOPs

OP-0001 - Responsibility and Authority of the ISOC

OP-0002 - Support Equipment Maintenance

OP-0003 - Outage Application Requests

OP-0004 - Capacity Deficiency Actions

OP-0005 - Voltage Reduction

OP-0006 - System Restoration

OP-0007 - Actions in an Emergency

OP-0008 - HEATSMART

OP-0009 - Communications

OP-0010 - Power System Emergency Reporting

OP-0011 - ESCC Actions for M/LCC 2

OP-0012 - Voltage and Reactive Control

OP-0013 - NHEC Outage Coordination

OP-0018 - ISOC Information Policy

OP-0019 - Transmission Operations

OP-0020 - Geomagnetic Disturbance

OP-0021 - ISOC Emergency Response Plan

OP-0022 - ESCC Records Policy

OP-0023 - ESCC Enhancement Procedure

OP-0024 - Dispatcher Print Standards and Revisions

OP-0025 - UF Relay Description and Restoration Procedure

OP-0026 - ISOC Building Evacuation Procedures

OP-0027 - Contract Tree Trimmer Location Tracking

OP-0028 - Do Not Reclose Policy

OP-0030 - Emergency Patrols and Actions for Line Faults

OP-0031 - Underground System Tracking

OP-0032 - ISOC Emergency Staffing Plan

OP-0033 - Tower Warning Lights

OP-0034 - ISOC Reference Documents Policy

OP-0035 - ISOC Training Manual

OP-0036 - Policy for ESCC Tours

OP-0038 - Load Flow and RTNET/RTCA Instruction

OP-0040 - ISOC Shift Responsibilities and Turnover

OP-0042 - Switching Orders

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OP-0046 - Dam Failure Emergency Action Plan Response

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EVERSOURCE	TD953 Revision 7 **Inspection, Treatment, Restoration and Replacement Guidelines for Distribution System Wood Poles**	
TD PROCEDURE		

Issue Date:	**Effective Date:**	**Owner Department**: Engineering Services	**Applicability:**
03/16/2015	**03/14/2015**	**Subject Matter Expert:** Howard P. Winslow	CT-NH-Western MA

All changes to TD procedures are controlled by TD 001
"Writing, Revising, and Publishing Transmission and Distribution Procedures."

This procedure replaces and supersedes the following procedures (in whole or in part), as described in Section 3 "Summary of Changes": TD 953 Rev. 6 "Inspection, Treatment, Restoration & Replacement Guidelines for Distribution System Wood Poles," effective 01/22/2014.

Approvals:

Approval Signature: *Michael G. Waggoner*

Michael G. Waggoner
Director, Engineering Services

Approval Signature: *Dominick M. Lauria*

Dominick M. Lauria
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Approval Signature: *James C. Eilenberger*

James C. Eilenberger
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Robert S. Coates Jr
Vice President-Electric Field Operations

Procedure applicable only to states for which an approval signature appears above.

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1. INTRODUCTION

1.1 Objective

This procedure establishes a uniform approach for distribution wood pole inspection, treatment, restoration and replacement. It defines the schedule, inspection, and reporting requirements for these facilities.

1.2 Applicability

This procedure pertains to the operations of Eversource CT Electric, Western MA Electric and New Hampshire Electric.

1.3 References

Unless otherwise specified:

- Maintenance procedures:
    - Eversource Maintenance Program on the Standards Bookshelf:
        - EMP Chapter 5.61 - Wood Poles
        - EMP Instructions 6.61 - Wood Poles - Inspections
        - EMP Instructions 6.61A - Wood Poles - Reinforcement
- Procedures are available at the following locations:
    - Lotus Notes Field Documentation Database.
    - Lotus Notes Regulated Businesses Policies & Procedures database.
    - Distribution Engineering Standards Bookshelf.
- Forms are available through Lotus Notes Forms Catalog or Forms Catalog on the intranet.

Development References
Documents used to develop this procedure and the process it controls:

- TD 001 “Writing, Revising, and Publishing Transmission & Distribution Procedures”

Supporting References
Documents that support performance of activities directed by this procedure:

- Program effectiveness reporting

Supporting Programs and Databases
Programs and databases that support performance of activities directed by this procedure:

- WMS System
- Cascade

1.4 Discussion

Questions regarding this procedure will be answered by the Manager – Distribution Standards Engineering.

Technical support shall be provided by the Manager – Distribution Standards Engineering and the Manager Construction Engineering for Eversource CT Electric, Manager System Planning for Western MA, Manager Field Engineering & Operations for NH.

End of Section

2. INSTRUCTIONS

2.1 Planning

CT: Distribution Engineering Managers

Western MA: Manager System Planning

NH: Contract Project Services and Division Field Engineering Manager

2.1.1 DEVELOP annual budgets for distribution wood pole maintenance programs.

- Inspection and Treatment
- Corrective Maintenance

2.1.2 DEVELOP a pole inspection schedule in accordance with EMP chapter 5.61 (4/15/2010: currently 15 year cycle for CT / Western MA and 10 years for NH).

2.1.3 REVIEW & FINALIZE the annual inspection schedule by October 1 of the preceding year and include a list by map grid as required with pole or circuit maps.

2.1.4 IDENTIFY locations where line rebuilds involving pole replacements are planned and communicate to designers.

2.2 Pole Inspection and Treatment

CT: System Projects – Special Projects

Western MA: System Planning

NH: Contract Projects Services

2.2.1 Communicate the annual inspection schedule to Operations Directors and Managers. Review the priority reject email notification groups for accuracy.

2.2.2 ADMINISTER and MONITOR the pole inspection program.

2.2.3 PREPARE the specifications consistent with the requirements contained in EMP Instruction 6.61 – “Wood Poles – Inspection”, for inspection supplemental treatment and inspector reporting requirements.

2.2.4 PREPARE bid packages and work with purchasing to request quotes and award contracts.

2.2.5 OBTAIN state highway permits annually (not required in NH) as required for permits to perform pole inspection work along state highways. NH requires a Special Permit for Pole Treatment/Pesticide Application. SEND the report to the following:

- Western MA: Manager System Planning
- CT: Manager Construction Engineering
- NH: Supervisor-Construction & Contract Projects SVCS

2.2.6 Perform inspections in accordance with requirements contained in EMP Instruction “6.61 – Wood Poles – Inspection”.

2.2.7 MANAGE pole inspectors and their crews and perform quality assurance audits.

2.2.8 RESOLVE customer and material issues.

2.2.9 REVIEW and APPROVE invoices for pole inspection and treatment.

2.2.10 INITIATE pole replacement priority rejects activities in accordance with step 2.3.

2.2.11 UPDATE Pole Inspection Reports in the Pole Inspection Repository on a bi-weekly basis during the contract term, with inspection results including Rejects and other corrective maintenance work.

2.3 Pole Replacements - Priority Reject

2.3.1 **IMMEDIATELY NOTIFY**:

CT: System Projects – Special Projects

Western MA: System Planning

NH: Contract Project Services

- Telephone the respective Operating Company's Clearing Desk.

The Clearing Desks

2.3.2 INITIATE a STORMS Work Request for a Priority Reject Pole using Job Type "**EMPRP**" (Electrical Maintenance Pole Reject – Priority).

- In the Job Description Field, type the information using the following format:

YYYY Pole Inspection – Priority Reject Pole # XXXX Street, Town, in which "YYYY" is the year of the inspection and "XXXX" is the pole number.

For example:

2011 Pole Inspection – Priority Reject Pole # 1234 Main St., Bloomfield.

Upon creation of the Work Request, automated E-mails will be sent to:

- The Operations Manager and Operations Team
- The Asset Management Group
- Vegetation Management (CT and Western MA) or Contract Project Services NH)

Operations Manager

2.3.3 CHECK the pole within 48 hours to assess the immediate impact on public safety and determine the required make safe methods and replacement and repair requirements.

Distribution Engineering

2.3.1 Immediately PROVIDE Field Engineering Design/Operations with feedback (install same or larger size/class pole) for priority reject poles before work order is written for permanent repairs.

Operations Manager

2.3.2 MAKE the pole SAFE within 10 calendar days using methods based on previous two steps.

2.3.3 Complete STORMS requirement 414 once pole has been MADE SAFE.

Supervisor- Field Engineering Design /Operations Manager

2.3.4 WRITE work order and complete construction for permanent repairs using information from previous three steps (actual pole size, etc.).

CT: System Projects – Special Projects

Western MA: System Planning

NH: Contract Project Services

2.3.5 MONITOR the Work Request until completion to ensure action has been taken to make safe or replace the pole within the specified time.

2.3.6 Monthly, during the inspection period, COMPARE the Priority Rejects identified on the pole inspector's report to the Priority Reject report generated from Work Management data and ENSURE all reported Priority Rejects have been addressed.

2.4 Review of Inspection Results

Distribution Engineering Managers – CT

Manager System Planning – Western MA

Division Operations Manager –NH

NOTE

Refer to Attachments 1 & 2 or EMP Instruction 6.61 – "Wood Pole Inspection" for guidelines in determining whether restoration or replacement should be accomplished, as applicable.

For other joint owners not covered by the above documents, refer to the appropriate intercompany operating procedure for guidance.

2.4.1 REVIEW the list of poles identified for restoration and replacement and provide alternate instructions to Job Designers as required (e.g. - for known/planned projects that will require specific pole size and class or concentrated reject rates that justify additional work such as reconductoring).

2.4.2 Determine the size and class of poles for pole replacements

2.4.3 REVIEW Pole Inspection Repository findings in 2.2.10 and add required corrective maintenance to the patrol database for resolution.

2.4.4 SUBMIT the list of poles identified for restoration and replacement to:

- CT Manager – Construction Engineering
- Western MA Managers – Customer Operations
- NH Customer Operations (Replacements only)
- NH Contract Project Services (Restorations only)

2.5 Corrective Maintenance

Manager – Construction Engineering – CT
Supervisor – Construction & Contract Services – NH
Manager Customer Operations – Western MA

2.5.1 From the list provided by ASSET MANAGEMENT, Create a Work Request under the DQ Annual Project or other project identified for this purpose using the appropriate Job Type.

- EMPRNS - Electrical Maintenance Pole Reject – Normal
- EPPREINFA - Electric Projects Pole Reinforce – Annual
- EPPREINFS - Electric Projects Pole Reinforce – Specific

2.5.2 Check that the work order activity is PREX for pole replacements and PFEX for pole restoration

2.5.3 PREPARE contract bid package.

2.5.4 AWARD contract to pole restoration contractor.

2.5.5 REVIEW and APPROVE invoices for pole restorations and perform audits of restoration contractor.

2.5.6 Complete the work within the calendar year following the inspection year.

2.6 Reporting

CT: System Projects – Special Projects
Western MA: System Planning
NH: Supervisor – Construction & Contract Projects SVCS

2.6.1 PUBLISH an annual report using the format provided in Attachment 3 by the end of January for the preceding year.

a. This report shall contain as a minimum, the following:

1) Number of Poles Inspected:
2) Number of Poles Identified for Restoration:
3) Poles Restored to Date:
4) Number of Poles Identified for Replacement (Normal Reject):
5) Number of Poles Replaced (Normal Reject):
6) Number of Poles Identified for Replacement (Priority Reject):
7) Number of Poles Replaced (Priority Reject):
8) Justification for those poles that could not be restored per NUMM Instruction 6.61A guidelines
9) Summary of Justifications provided for non-restorations.

2.6.2 SEND the report to the process stakeholders for review and appropriate action

a. Stakeholders include as a minimum:

1) Director – Distribution Engineering for CT

2) Director – Engineering Services

3) Director – Field Operations for NH

4) Vice President – Electric Field Operations for CT

5) Vice President – Electric Field Operations for Western MA

2.7 Records

CT: System Projects – Special Projects
Western MA: System Planning
NH: Contract Projects SVCS

2.7.1 MAINTAIN inspection records for the duration of the inspection cycle.

End of Section

3. SUMMARY OF CHANGES

Changes to TD Procedures are controlled by TD 001 “Writing, Revising, and Publishing Transmission & Distribution Procedures”.

Revision 1

- Revised to reflect changes in job titles of individuals affected by this procedure
- Revised to reflect changes in the type of wood preservatives used in the treatment and restoration of distribution system wood poles
- Revised as part of TD Procedure Upgrade Project initiated in June 2002.

Revision 2

- DMS-WRES has been change to WMS (Work Management System)
- Section 2.1.2: The scheduling of inspections was changes from requiring that 1/15 of the poles be inspected annually to a schedule that meets the requirements of the National Electric Safety Code and be completed within 15 years.
- Removed all reference to the Pole Inspection Reporting System (PIRS). PIRS was discontinued in 2006. The pole inspection contractors will provide an Excel file with inspection and treatment results.
- The inspection process was revised to require the use of a hand held computer to record data, determine pole strength and measure the wire and attachment load on each pole. All references to the Osmose POLE CIRCUMFERENCE CALCULATOR were removed.
- The data reporting requirements were reduced.
- References to SBC/AT&T was changed to AT&T
- Attachment 7 NESC Requirements was added

Revision 3 - 10/12/2010

- Complete rewrite.
  - Revised to incorporate NUMM references and to provide consistency with NUMM Chapter 5.61 – Wood Poles as well as NUMM Instructions 6.61 – Wood Pole Inspections and Instruction 6.61A – Wood Pole Restoration.
  - Removed detailed directions to fielded workers for performance of wood pole inspections and wood pole restoration.
  - Clarified administrative requirements for the **i**nspection, treatment, restoration and replacement of distribution system wood poles
  - Updated and clarified responsibilities for the **i**nspection, treatment, restoration and replacement of distribution system wood poles along with the required reporting guidelines.
  - Updated Approvers
  - PSNH added

Revision 3 – Editorial Change – 11/10/2010

Engineering Manager-Distribution – PSNH removed from Section 2.5, Corrective Maintenance and added to Section 2.4, Review of Inspection Results, responsible parties.

Revision 4 – Procedure Changes – 05/27/2011

- Changed the Approvers for CL&P and PSNH.
- Under Section 1.3, changed the locations from which procedures are available.
- Under Section 2.2, provided additional steps to the Pole Inspection and Treatment procedure regarding Priority Reject poles.
- Under Section 2.3, changed procedure steps to reflect new communication responsibilities and changed activities regarding Priority Reject poles.
- Under Section 2.4, added responsible person for PSNH.
- Under Section 2.5:
    - Added responsible persons for PSNH and WMECO.
    - Changed procedure steps.
    - Provided new Work Request codes for Corrective Maintenance.
    - Removed existing list of Work Request Estimating Project Selection menus.
- Throughout, changed title of responsible person(s) for PSNH in several locations.
- Referenced NUMM chapter 5.61 for Pole Inspection schedule.

Revision 5 – Responsibility and Notification Changes - 01/17/2014

- Changed all occurrences referring to CL&P Veg Mgmt to "CL&P – System Projects – Special Projects."
- Changed all occurrences referring to: Veg Mgmt ***and*** NU Vegetation Management to "Asset Management."

Revision 6 – Deletion of Duplicate Information – 01/22/2014

- Replaced previous step 2.39 with the following text: "Monthly, during the inspection period, COMPARE the Priority Rejects identified on the pole inspector's report to the Priority Reject report generated from Work Management data and ENSURE all reported Priority Rejects have been addressed."
- Deleted previous step 2.3.10 which had read: "WRITE work order based on feedback from Asset Management regarding pole size requirements and complete construction for permanent repairs."

Revision 7 – Effective Date– 03/15/2015

- Updated Approvers and Titles
- Under section 2.3.5, replace “5 working days” with “10 calendar days. Per request of the NUMM Overhead Lines Working Group.
- Under section 2.6.2, update stakeholders and titles.
- Replaced references from AT&T to Frontier in Attachment 2.
- Added to Eversource template.

Revision 7 – Editorial Change - Effective Date– 11/08/2017

- Updated company names to align with Eversource.
- Changed references to NU Maintenance Manual (NUMM) to Eversource Maintenance Program (EMP).
- Updated department names to align with organizational changes.

Attachment 1

Pole Restoration / Replacement Guideline –Electric Company

(Sheet 1 of 1)

This serves as a guideline to determine whether a reject pole identified for possible restoration should be restored or replaced.

Restore poles when all of the following conditions are met:

- No circuit rebuild requiring taller or larger class poles is planned within the present planning period. Search the WRES system by pole number to determine if other work has been planned for that pole and proceed accordingly.
- No equipment additions (capacitors, reclosers, regulators, switches or transformers) that would require a taller or larger class pole are expected in the near future.
- Telephone Company concurs with pole restoration. (Refer to telephone company guidelines)
- If applicable, State Highway Department concurs with pole restoration for poles along state highways. For the State of Connecticut, written approval must first be obtained from the appointing authority of the local municipality of the state route where pole restoration is planned. A permit by the State of Connecticut Department of Transportation will not be issued unless approval from the municipality is included with the request.

In Connecticut:

- Do not restore poles on scenic highways or in historical areas of towns.
- Replace poles with questionable pole tops (split or rotted) that are estimated will last less than 10 years, or with obvious load or clearance problems or those not selected for reinforcement.
- Restoration is cost justified if the reinforced pole will not require replacement within 5 years for jointly owned poles and within 8 years for solely owned poles.

Attachment 2
Pole Restoration / Replacement Guideline – Frontier (CT)
(Sheet 1 of 1)

This guideline was provided by Frontier - CT for pole restoration and replacement work for jointly owned poles to reduce field visits by NU and Frontier personnel.

Frontier encourages pole restoration in the following cases:

- Poles with Frontier aerial or ground level interface boxes attached.
- Poles with large communication cable risers attached.
- Poles in "Right of Ways".
- Poles 45 feet and above.

Frontier discourages pole restoration in the following cases:

- 35 foot pole - With power primary, secondary/neutral and communication cables that cross a road.
- 35 foot pole - With power primary, secondary/neutral and more than 3 attachments in the communications gain.
- 40 foot pole - With power primary, secondary/neutral and more than 5 attachments in the communications gain.
- Any pole that is inadequate for planned Frontier construction.
- Any pole with obvious load or clearance problems.
- Any pole not meeting Frontier or State of Connecticut DOT criteria for pole restoration.

NOTE:
Attachments in the communication gain refer to all attachments, roadside and field side, including bare strand. (Frontier, Municipal, State, CATV, other communication companies)

Questionable poles will be reviewed by Frontier Line Construction/ Frontier Engineering upon request.

It is requested that pole maps of the projected pole inspection be supplied to Frontier for review. Frontier will identify areas of planned construction and reply back to NU.

The Frontier Communications contact is:

Joseph Aresco Jr.
Director, Construction & Engineering
1441 North Colony Rd., Meriden, CT
203-238-2640 office
203-317-0281 cell
Joseph.aresco@ftr.com

Attachment 3

Pole Inspection Restoration and Replacement Summary Year End Reports

(Sheet 1 of 2)

The Pole Inspection Restoration and Replacement Program report shall contain, at a minimum, the following information:

DIVISION / COMPANY: ___________________________

POLE INSPECTION YEAR: ___________

REPORT DATE: ___________

		WEEK ENDING	
INSPECTION AND TREATMENT		___/___/___	**YEAR -TO-DATE**
Total number of poles inspected	________	________	
Number of priority rejects		________	________
Number of normal rejects		________	________
Number of visual only inspections		________	________
Number of sound and bore inspections		________	________
Number of groundline treatments		________	________
Number of hollow heart treatments		________	________
Number of WoodFume treatments		________	________
Total cost		________	________
Average cost per pole	________	________	

Monthly, and at the conclusion of the project, the contractor shall provide a computer file containing all of the inspection and treatment data for each pole. This file shall be in a format that can be read and processed by Microsoft Excel and Microsoft Access software.

Attachment 3

Pole Inspection Restoration and Replacement Summary Year End Reports

(Sheet 2 of 2)

The Pole Inspection Restoration and Replacement Summary report indicates the numbers of pole restorations and replacements relate to the year the poles were inspected. Much of the restoration and replacement work may take place in years subsequent to the year that the inspection was performed. This report shall comprise a running history and at a minimum contain the following information:

REPORT SUMMARY BY INSPECTION YEAR
Number of Poles Identified for Replacement (Priority Reject):
Number of Poles Replaced (Priority Reject):
Number of Poles Identified for Replacement (Normal Reject):
Number of Poles Replaced (Normal Reject):
Number of Poles Identified for Restoration:
Number of Poles Restored:

DIVISION / COMPANY: ___________________________

POLE INSPECTION YEAR: ___________

REPORT DATE: ___________

Year	Poles Identified for Replacement (Priority Reject)	Poles Replaced (Priority Reject)	Poles Identified for Replacement (Normal Reject)	Poles Replaced (Normal Reject)	Poles Identified for Restoration	Poles Restored
2010						
2011						
2012						
2013						
2014						
2015						
2016						
2017						
2018						
2019						

The report file shall be in a format that can be read and processed by Microsoft Excel and Microsoft Access software.

EVERSOURCE MAINTENANCE PROGRAM	Document Number: **5.61 Rev. 3** Document Name: **Wood Poles**
Owner Name:	Henry J. Matuszak
SME Name:	Howard Winslow
Effective Date:	July 1, 2015

Approvals: **Connecticut**:
Name: Charles E. Fontenault
Title: Director – Division Operations
Date Signed: 5-17-2015

Eastern Massachusetts:
Name: Donald M. Boudreau
Title: Director, Electric Operations
Date Signed: 5-15-2015

New Hampshire:
Name: Marc Geaumont
Title: Director – Customer Operations
Date Signed: 5-14-2015

Western Massachusetts
Name: Bliss A. Young
Title: Director – Operations
Date Signed: 5-11-2014

Transmission:
Name: Michael B. McKinnon
Title: Directors – Transmission Construction Test & Maintenance
Date Signed: 5-12-2015

Operations Services:
Name: Michael G. Waggoner
Title: Director – Engineering Services
Date Signed: 5-11-2015

Ensure you are using the current revision by verifying it against the controlled electronic copy located on the Distribution Engineering Standards Bookshelf or the Regulated Businesses Policies and Procedures Lotus Notes Database.

5.61 Wood Poles

General Description

This procedure establishes a uniform approach for distribution wood pole inspection, treatment, restoration and replacement. It defines the schedule, inspection, and reporting requirements for these facilities.

This applies to all wood distribution poles within the custodianship or the maintenance responsibility of Eversource. It shall include push braces and guying stub poles as well as line poles scheduled for the given year.

Facilities/Equipment

- Wood Poles

5.61.1 Inspection and Maintenance Activity Schedules

5.61.1.1 Table 1 – Wood Poles Maintenance Intervals

Wood Poles **Maintenance Schedule**	**All**
PM Task	
Condition Monitoring	N/A
Time-Directed	
Routine Inspection	15Y (**Notes 1 & 2**)
Condition-Based	
Priority Reject	**(Note 3)**
Schedule repairs or replacement.	A/R **(Note 4)**
Failure Finding	
Corrective Maintenance	A/R

In **Table 1**, the intersection of the row and column indicate the age-based inspection or maintenance interval for wood poles based on the preservation treatment listed in the column heading. For example, the age requirement for a Routine Inspection is 15Y (or 15 Years). The abbreviations used for the intervals are:

Y = Year, i.e. 2Y = 2 Years

A/R = As Required

N/A = Not Applicable

Note 1 = 15 years is the minimum requirement for pole inspection. This interval may be changed due to contractual requirements with joint owners.

Note 2 = The type of inspection performed shall be determined by the age of the pole and its type of treatment, as shown in the following table:

Inspection Type	Creosote, Penta, all others	CCA
Visual	0 to 9 years old	0 to 19 years old
Sound & Bore	10 to 14 years old	20 years old and older
Ground Line Excavate	15 years old and older	If decay is indicated by Sound & Bore

Note 3 = Field supervision shall check the pole within forty eight (48) hours from identification as a “priority reject” to assess the conditions and verify there is no immediate danger to the public. The pole must be made safe within 10 calendar days or less from its identification as a “priority reject” wood pole..

Note 4 = Complete the repair or replacement within one year of determination of need following inspection

5.61.2 Maintenance Categories

5.61.2.1 Routine Inspection – Time Directed

1. Routine inspection activities are detailed in EMP Instruction 6.61.

5.61.2.2 Priority Reject Poles

1. Priority reject pole activities are detailed in EMP Instruction 6.61.

5.61.2.3 Normal Reject Poles

1. Normal reject pole activities are detailed in EMP Instruction 6.61.

5.61.3 Evaluation of Restorable Poles

1. The evaluation activities for restorable poles are detailed in EMP Instruction 6.61A.

5.61.4 Failure Finding

1. Failure finding activities are detailed in EMP Instructions 6.61 and 6.61A.

5.61.5 Research/Background

Publications and other reference materials from these organizations were used in the development of this program.

- National Electric Safety Code, as directed by section DER 07-01 “Wood Poles – Aging Infrastructure”
- TD 953 – “Inspection, Treatment, Restoration and Replacement Guidelines for Dist Sys Wood Poles”

5.61.6 Wood Poles - Maintenance Basis Documentation

The maintenance activities and their schedules are based on industry experience, manufacturer's recommendations, feedback from the service technicians, and the subject matter expert, who in this case, is a Senior Engineering Technologist for Distribution Engineering Design.

Requirement	Basis
Routine Inspection at 15Y Interval	**Inspection required by the NESC -** The National Electrical Safety Code requires that poles are inspected as often as experience shows it necessary to maintain the strength required for the pole to remain in service. According to charts developed by Osmose on National averages, the percentage of reject poles starts to rise between ten and fifteen years. However, because Eversource is mostly in a "Moderate Deterioration" zone (National Wood Preservers Association Book of Standards) we could expect better than average results from an inspection program. Eversource's experience finds that a fifteen year inspection and treating program keeps the reject rate reasonable. NOTE: Eversource's line mechanics are taught to visually inspect and sound any pole before climbing it. The 15 year inspection is required, but it is acknowledged that New Hampshire has an existing contract to perform their inspections at a 10 year interval.

5.61.7 Summary of Changes

Revision 1 – Effective Date: **July 15, 2011**

Referenced Feedback – MS-0022

	Description of Changes
1.	Moved inspection activities to Instructions 6.61. Moved Restoration activities to Instructions 6.61A. Added references to TD 953, and Instructions 6.61.

Revision 2 – Effective Date: **January 2, 2015**

Referenced Feedback – MS-0402

	Description of Changes
1.	Increased the period from 5 days to 10 days in which a priority reject pole must be made safe.

Revision 3 – Effective Date: **July 1, 2015**

Related Feedback – N/A

1.	Changed names of the Owner, SME, and Approvers on the Signature page, as required.
2.	Incorporated the following global replacements: • NU Maintenance Manual replaced by Eversource Maintenance Program. • CL&P replaced by Eversource Connecticut. • WMECO replaced by Eversource Western Massachusetts. • PSNH replaced by Eversource New Hampshire. • NSTAR replaced by Eversource Eastern Massachusetts. • NUMM replaced by EMP.
3.	Incorporated the following global replacements: • NU Safety Manual replaced by Eversource Employee Safety Manual

(e) Each utility shall have available the types and quantities of working instruments necessary to determine compliance with these rules for:

(1) Recording and indicating customer voltage; and

(2) Testing any other electrical quantities which may be necessary to comply with the measurement and reporting requirements of this chapter.

(f) Each utility shall check the working instruments required by (e) with the reference instruments at least once each year.

(g) If reference instruments are not available within the utility, the utility shall have field instruments checked in an independent standards laboratory meeting specifications recommended by the meter manufacturer in intervals not to exceed one year.

(h) A utility may certify its indicating standards in a standards laboratory which it maintains provided that the instruments and methods meet specifications recommended by the meter manufacturer.

(i) Pursuant to RSA 365:6, each utility shall, upon request, provide the commission access to its meter testing facilities and any and all meter test results.

Source. #6605, eff 10-21-97; ss by #8448, eff 10-18-05; ss by #10603, eff 5-21-14

PART Puc 306 EQUIPMENT AND FACILITIES

Puc 306.01 Standard Practice in Construction, Operation and Maintenance.

(a) Each utility shall construct, install, operate and maintain its plant, structures and equipment and lines, as follows:

(1) In accordance with good utility practice;

(2) After weighing all factors, including potential delay, cost and safety issues, in such a manner to best accommodate the public; and

(3) To prevent interference with other underground and above ground facilities, including facilities furnishing communications, gas, water, sewer or steam service.

(b) For purposes of this section, “good utility practice” means in accordance with the standards established by:

(1) The National Electrical Safety Code C2-2012, available as noted in Appendix B;

(2) When applicable, the International Energy Conservation Code 2009 as adopted pursuant to RSA 155-A:1,IV; and

(3) The ISO-NE.

Source. #2011, eff 5-4-82; ss by #2912, eff 11-26-84; ss by #4999, eff 11-26-90; ss by #6381, INTERIM, eff 11-27-97, EXPIRED: 3-27-97

New. #6605, eff 10-21-97; ss by #8448, eff 10-18-05; ss by #10603, eff 5-21-14

Puc 306.02 Joint Pole Construction. Each utility involved in any installation which makes use of poles either for single or joint occupancy shall conform its construction, installation, operation and maintenance to the requirements of Puc 306.01.

Source. #2011, eff 5-4-82; ss by #2912, eff 11-26-84; ss by #4999, eff 11-26-90; ss by #6381, INTERIM, eff 11-27-97, EXPIRED: 3-27-97

New. #6605, eff 10-21-97; ss by #8448, eff 10-18-05; ss by #10603, eff 5-21-14

Puc 306.03 Electrical Interference.

(a) Each utility shall make a full and prompt investigation of complaints made by the utility's customers or by the general public involving electrical interference with reception by communications equipment in the proximity of the utility's transmission and service areas, including but not limited to interference with television and radio reception.

(b) Each utility shall maintain a record of complaints which it receives pursuant to (a) above.

(c) Each utility shall report to the commission all complaints, as described in (a) above, that it receives that are not resolved to the satisfaction of the complaining party within 30 days of receipt or notification of the complaint.

(d) The report referred to in (c) above shall include the location of the complaint, the circuit number of the line, and a brief description of the interference.

Source. #2011, eff 5-4-82; ss by #2912, eff 11-26-84; ss by #4999, eff 11-26-90; ss by #6381, INTERIM, eff 11-27-97, EXPIRED: 3-27-97

New. #6605, eff 10-21-97; ss by #8448, eff 10-18-05; ss by #10603, eff 5-21-14

Puc 306.04 Safety Instructions.

(a) Each utility, in the operation, construction or maintenance of its plant and facilities, shall:

(1) Develop and implement a safety and health program to ensure that its employees have been:

a. Properly informed of safety practices and procedures; and

b. Protected from hazards associated with the work environment;

(2) Adopt comprehensive written instructions for the safety of its employees; and

(3) Distribute a copy of the written instructions required by (2) above to each of its employees before assignment to duty in any assignment which requires handling any energized electrical plant.

Source. #2011, eff 5-4-82; ss by #2912, eff 11-26-84; ss by #4999, eff 11-26-90; ss by #6381, INTERIM, eff 11-27-97, EXPIRED: 3-27-97

New. #6605, eff 10-21-97; ss by #8448, eff 10-18-05; ss by #10603, eff 5-21-14

Demmer, Kurt

From: Mackey Karen <karen.mackey@eversource.com>
Sent: Tuesday, November 6, 2018 1:34 PM
To: Demmer, Kurt
Subject: RE: Operational Documents

Hi Kurt,
This request will take some time to pull together, but I have requested the documents. As soon as I have the information, I'll forward to you.
Thanks,

Karen

Karen T. Mackey | Senior Engineer – Technical Compliance & Reporting | Eversource
EP-2 | 780 No. Commercial St | Manchester, NH 03101 | ☎ : 603.634.2519 | ✉ : Karen.Mackey@eversource.com

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From: Demmer, Kurt
Sent: Monday, November 5, 2018 10:56 AM
To: Mackey Karen ; letourneau (unitil.com) ; Leo Cody
Cc: paul.kasper@puc.nh.gov; richard.chagnon@puc.nh.gov
Subject: Operational Documents

In order for Staff to be current with your utility's safety, operational practices, construction procedures, and construction standards, PUC staff is requesting the current documents that your utility uses in its Distribution Operations. I have included a brief description of the documents requested since each utility may not have the same naming convention for its documents. If there are additional documents that your utility utilizes in its operation or maintenance of electric distribution system, please include those documents. Preference for media is electronic unless electronic versions are not available or format is not available in a typical Windows Office based software package.

Please note, distribution personnel includes all personnel that conduct business in the Distribution Utility side of the business. Distribution Operations includes, design; planning; work management and scheduling; field construction and maintenance; field or office protection installing, maintenance and testing; or any other functions that align with distribution grid functionality. Any transmission procedures, standards, or construction that have a direct impact on Distribution operations should also be included.

Safety Manual: Corporate (if applicable) and Jurisdictional, The safety manual for Distribution employees ; Electric and Gas (if applicable)

Electric Operating Procedures : Electric procedures for distribution personnel for substation, underground, overhead, and protection applications e.g. Tagging and Grounding, Rubber Glove applicability, URD Testing standards and procedures, etc.

Electric Distribution Construction Standards: Construction manuals for the installation of overhead, underground, and substation applications.

Substation Maintenance Procedures or Standards: If Different from above. These would include procedures and standards that are specifically scoped for Substation work.

Misc. Bulletins or Notices: Bulletins, Notices or Memorandum that have been issued by Operations, Safety, Engineering, Corporate, or Compliance that have not be incorporated into the above aforementioned documents, however are considered a requirement for distribution personnel to follow.

If I have the wrong point person in this email to request this information, please forward as appropriate and indicate who is the correct person for future document requests or updates.

Thank you, in advance, for the fulfillment of this request.

Kurt Demmer P.E.
Utility Analyst-NH Public Utilities Commission
Electric Division
21 S. Fruit Street
Concord, NH 03301-2429
Office: 603-271-6077 | E-mail: kurt.demmer@puc.nh.gov

From: Mackey, Karen <karen.mackey@eversource.com>
Sent: Wednesday, September 11, 2019 4:04 PM
To: Demmer, Kurt <Kurt.Demmer@puc.nh.gov>
Cc: Chagnon, Richard <Richard.Chagnon@puc.nh.gov>; Kasper, Paul <Paul.Kasper@puc.nh.gov>; Desbiens, Allen M <allen.desbiens@eversource.com>; Lajoie, Lee G <lee.lajoie@eversource.com>
Subject: Eversource's Distribution System Engineering Manual (DSEM)

EXTERNAL: Do not open attachments or click on links unless you recognize and trust the sender.

Good afternoon, Kurt

I talked with Lee Lajoie and he shared that you didn't have a copy of Eversource's Distribution System Engineering Manual. I have attached an electronic copy for you.
Please confirm that you've received it. Even compressing the document, it's still a very large file.

Note, too, that this manual applies to all of Eversource and certain sections apply only to certain jurisdictions. Each page that does not apply to all areas is marked with the areas that is subject to that information.

If you have any questions, please let me know.
Thanks,
Karen

Account Executives

CO-1006 - Account Executive Coverage Procedure

CO-1007 - Managed Accounts Survey

CO-1084 - Electric Service Agreement Preparation

Administrative Procedures

CO-1134 - Customer Operations Vacation Policy

CO-1156 - Statement of Expected and Prohibited Behaviors

Community Relations

CO-1001 - Key Event Participation

CO-1011 - Temporary Decorative Pole Attachment Policy

CO-1111 - Municipal Decorative Pole Attachment

Design Build

CO-1049 - Design Build Process - Section I Receive the Information

CO-1050 - Design Build Process - Section II Assigning the Job

CO-1051 - Design Build Process - Section III Project Assessment

CO-1052 - Design Build Process - Section IV Final Design

CO-1053 - Design Build Process - Section V Select Construction Resource

CO-1054 - Design Build Process - Section VI Allocate Crews, Schedule Materials & Equipment

CO-1055 - Design Build Process - Section VII Pre-Construction/Re-Confirmation Activities

CO-1057 - Design Build Process - Section IX Performance Management

CO-1058 - Design Build Process - Section X Closing the Work Package

CO-1059 - Build It First (No Design) Procedure

CO-1128 - Third Party Application and Pole Attachment License Process

CO-1165 - Distribution Pole Height

Designers/Writers

CO-1005 - Access Requirements for New Service Locations

CO-1026 - Design Study for Replacing Distribution Facilities

CO-1029 - Serving Non-Franchised Customers

CO-1117 - NHDOT Force Account Lighting, Estimating, and Billing

CO-1141 - NHDOT Projects Communications Process

CO-1157 - Field Technician - Competency Requirements Evaluation Procedure

CO-1161 - Designing Service to Residential Customers

CO-1169 - Determining Franchise Area Locations

CO-1173 - Petition and Pole License Job Design Guidelines - PSNH Pole Installations and/or Pole Replacements

CO-1175 - Construction Tree Trimming and Joint Owner Exchange of Notice Guidelines

Emergency Response

CO-1027 - Information Access by Unregulated Affiliates During Emergency Restoration Activities

CO-1044 - Establishing Key Box Access for Emergency Response

CO-1079 - Hours of Work During Emergency Response Events

CO-1092 - Tree Trimming Documentation and Billing - Heavy Storm Events

CO-1095 - Emergency Restoration Response - On Call Supervisor

CO-1096 - Mutual Aid and Deployment - PSNH

CO-1099 - Detailed Damage Assessment - Heavy Storm Events

CO-1100 - Wires Down

CO-1101 - Initial Damage Assessment and Outage Assessment Report

CO-1104 - Crew Guide

CO-1105 - Outage Status Reporting and Estimated Time of Restoration (ETR)

CO-1110 - Standardized Restoration Team - Heavy Storm Events

CO-1112 - Customer Operations Responsibilities During OP-0007 Actions in an Emergency

CO-1135 - Meal Guidelines During Storm Restoration

CO-1139 - Alternate Work Location Due to Emergencies - Mileage and Travel Time Pay Practices

CO-1170 - Major Storm Event- Lessons Learned

Operate & Restore

CO-1009 - Climbing Wood Poles

CO-1012 - Guidelines for the Disposal of Wood Products

CO-1013 - Keeping Job Information Updated

CO-1018 - Model T-150 Cable Reel Dolly Operation

CO-1020 - Transformer Ratio and Polarity Testing

CO-1021 - Step Transformer Installation

CO-1023 - Large Power Customer Oil Spill Procedure

CO-1024 - Area Work Center Billing Guidelines

CO-1031 - Primary Circuit Map Underground Plan & Miles of Line Updates

CO-1038 - Dispatching Crews to Respond to Trouble Calls During Normal Working Hours

CO-1040 - Voltage Regulators

CO-1041 - Inclement Weather Utilization

CO-1042 - Billing Customer for Final Inspections

CO-1043 - Job Ready - No Final Inspection

CO-1045 - Standby Take Home Vehicle Policy

CO-1046 - Outage and Non-Outage TR/UPER Reporting Procedure

CO-1047 - Covering Conductor For Private Contractors

CO-1060 - Rubber Glove Failure Notification Process

CO-1063 - Pole Transfer & Removal Procedure

CO-1068 - Meter Inspection Approvals and Line Department Meter Sets

CO-1077 - Issuing Specific Service Cable and Conduit Using a Clearing Work Order

CO-1078 - Inventory Cable Accuracy

CO-1081 - Streetlight/Rental Light Repairs

CO-1086 - Division Level Analysis of Work Management System Issues

CO-1097 - Municipal Street Lighting Rate Conversions

CO-1098 - Installations and Removals of Municipal Street Lights

CO-1114 - Municipal Street Light Audit

CO-1136 - Rubber Gloving 600 Volts to 35,000 Volts

CO-1137 - Skylift Ranger 40 Utilization

CO-1138 - ATV Utilization

CO-1150 - Approved Tools

CO-1151 - Private Contractors in Close Proximity to Energized Pad Mounted Equipment

CO-1152 - Boom Cleaning Schedule - Bucket Truck

CO-1153 - Lineworker Evaluation Process

CO-1154 - Non-Slip Footwear

CO-1158 - Candidate Selection Process - Working Foreman-Line

CO-1159 - Contractor Resource Procurement and Release

CO-1160 - Working on Customer Roofs

CO-1167 - Contractor Invoicing Guidelines

CO-1171 - Voltage Conversion

CO-1172 - Customer-Built Line Extensions

CO-1177 - Scada-Mate Installation

CO-1179 - Automated On Call Lineworker Dispatch (AOD)

CO-1180 - Primary By-Pass Trailer Procedure

CO-1181 - Distribution ROW Line Patrols

CO-1182 - Reporting Hazards or Unsafe Conditions

Plant Records

CO-1121 - Balance Sheet Account Reconciliation - Telephone Company Joint Line Billing

CO-1162 - Pole Renumbering

CO-1164 - Distribution Easements

Resource Planning

CO-1036 - Resource Planning & Crew Movement

CO-1064 - Bidding Jobs to Outside Contractors

CO-1089 - iScheduler - Scheduling & Reporting

Safety & Methods

CO-1004 - Load-Break Elbow Procedure

CO-1010 - Utilization of Puller-Tensioner

CO-1066 - Tailboard Job Briefings

CO-1069 - Overhead Distribution System Emergencies

CO-1070 - Working Beyond Reclosers

CO-1072 - Distribution Transformers

CO-1073 - Emergency Tree Trimming - Distribution System

CO-1075 - Conductor Stringing With Puller Tensioner

CO-1076 - Overhead Wire

CO-1088 - Unmanned Pole Support

CO-1102 - Sauber Pole Trailer Use

CO-1133 - Bucket/Digger Truck Compliance Review

CO-1143 - Inspection of Lever Operated Hoists

CO-1155 - Isolation of Capacitor Banks on Distribution Circuits

Training & Methods

CO-1030 - Lineworker Progression

Eversource System Operating Procedures (ESOPs)

ESOP-100 - Operating and Control of the Eversource Transmission & Distribution Electric System

ESOP-15 - Real-time Data and Analysis Quality, and Alarm Processor Monitoring

ESOP-33 - Human Error Reduction

ESOP-9 - Communications

NH ESCC Control Center SOPs

OP-0001 - Responsibility and Authority of the ISOC

OP-0002 - Support Equipment Maintenance

OP-0003 - Outage Application Requests

OP-0004 - Capacity Deficiency Actions

OP-0005 - Voltage Reduction

OP-0006 - System Restoration

OP-0007 - Actions in an Emergency

OP-0008 - HEATSMART

OP-0009 - Communications

OP-0010 - Power System Emergency Reporting

OP-0011 - ESCC Actions for M/LCC 2

OP-0012 - Voltage and Reactive Control

OP-0013 - NHEC Outage Coordination

OP-0018 - ISOC Information Policy

OP-0019 - Transmission Operations

OP-0020 - Geomagnetic Disturbance

OP-0021 - ISOC Emergency Response Plan

OP-0022 - ESCC Records Policy

OP-0023 - ESCC Enhancement Procedure

OP-0024 - Dispatcher Print Standards and Revisions

OP-0025 - UF Relay Description and Restoration Procedure

OP-0026 - ISOC Building Evacuation Procedures

OP-0027 - Contract Tree Trimmer Location Tracking

OP-0028 - Do Not Reclose Policy

OP-0030 - Emergency Patrols and Actions for Line Faults

OP-0031 - Underground System Tracking

OP-0032 - ISOC Emergency Staffing Plan

OP-0033 - Tower Warning Lights

OP-0034 - ISOC Reference Documents Policy

OP-0035 - ISOC Training Manual

OP-0036 - Policy for ESCC Tours

OP-0038 - Load Flow and RTNET/RTCA Instruction

OP-0040 - ISOC Shift Responsibilities and Turnover

OP-0042 - Switching Orders

OP-0045 - NH-LCC Minimum Telemetering and Communication Requirements of Merchant Generators

OP-0046 - Dam Failure Emergency Action Plan Response

OP-0050 - Emergency Notification Procedure

OP-0051 - ISOC Loss of EMS or Data Communications

OP-0052 - ISOC Telecommunications Testing

OP-0053 - ESCC Entry Alarm Procedure

OP-0054 - ISOC Loss of Voice Communications

OP-0055 - ISOC Conduct of Operations

OP-0058 - Single Phase Switching

OP-0060 - Work Observation Program

OP-1002 - ESCC Building Security and Access Description

OP-1011 - ESCC Print Standard and Revisions

NH SOC Control Center SOPs

SOC-11001 - All Call Radio Procedure

SOC-11002 - Priority Call Procedure

SOC-11003 - Major Incident/Accident Communications

SOC-11004 - Planned Outage Notification

SOC-11005 - Emergency Broken Pole Replacement

SOC-11006 - Distribution Trouble Call Procedure

NH Station Orders
NH Station Orders (OI)
NH Storm Maps
NH System One-lines

Energy Delivery Administrative Procedures

ED-3013 - Safety Training Guidelines for Energy Delivery Employees

ED-3026 - Employee Fatigue Guideline

ED-3028 - Device Operations Reporting Guidelines

Distribution Maintenance & Construction

ED-3001 - Test Results Analysis

ED-3012 - Tailboard Conference Plan Procedure

ED-3031 - Aerial Lift Used for Fall Protection

ED-3044 - Mobile Substation Use Priority

ED-3046 - 1250 Hooksett Road Used Material

ED-3051 - Updating Plant Records

ED-3059 - System Electrician Progression

ED-3066 - Monitor & Repair Leaking Substation Equipment

Engineering & Design

ED-3004 - Project Coordination

ED-3005 - Field Coordination

ED-3042 - Work Order Closeout

ED-3047 - Substation One-Line Drawing Management

ED-3050 - Service Distribution Easements

ED-3054 - Standard Substation Design

ED-3056 - Distribution Protection & Controls Engineering - Shared System Documents

ED-3058 - Water Crossing and Public Land Crossing Licenses

ED-3063 - Project Management

ED-3064 - Capital Budget Estimating

ED-3069 - Substation Equipment Numbering - Substations below 34.5kV

Field Engineering & Operations

ED-3014 - KPF 34.5 kV Switch Operating Policy

ED-3015 - Customer Voltage Policy

ED-3017 - Thermovision Guidelines

ED-3018 - Circuit Patrols

ED-3019 - Tapping Distribution Lines in ROW

ED-3033 - Distribution Circuit Numbering Procedure

ED-3035 - System Operation Review Committee Procedure

ED-3053 - Recloser Control Battery Replacement

ED-3060 - Field Electrician Progression

ED-3067 - Field Electrician Training for Blackstart System Restoration

ED-3068 - Testing of Critical Voice Communication Equipment

Field Services

ED-3009 - Supply Chain - Inventory Accuracy

System Planning & Strategy

ED-3002 - Distribution System Planning and Design Criteria Guideline

ED-3010 - New Engineer in Training Guideline Policy

ED-3022 - Joint Planning Process for Wholesale Delivery Service

ED-3023 - Procedure for Comprehensive System Planning Studies

ED-3024 - Calculation of Independent Power Producer Line Loss Adjustment Factor

ED-3025 - Feasibility Study for the Interconnection of Independent Power Producers

ED-3029 - Calculation of Annual Peak Load Forecast

ED-3043 - PUC Complaint Process for Operational Issues

ED-3045 - Single Phase Switching

ED-3062 - ED Capital Budget Procedure

Environmental

ENV-5002 - Environmental Preventive and Corrective Actions

ENV-5003 - Self-Transportation of PSNH Hazardous Waste

ENV-5004 - Transportation of Oil Filled Equipment

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PT-9006 - 1.3 - Security and Access

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PT-9031 - 8.1 - Receive and Transfer Meters in District Receive

PT-9032 - 9.1 - Update Data with Service Wizard

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SH-6028 - Industrial Safety Eyewear

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TD-012 - Verifying Compliance with Relay Testing and Maintenance Requirements

TD-013 - Self Assessment Process

TD-016 - CASCADE Access Control

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TD-230 - Requirements for Deenergized Equipment

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TD-512 - Construction of Distribution Facilities on Transmission Right-of-Way

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TD-852 - Lockout/Tagout: Electrical Equipment (<600 volts) and Other Equipment Related Energy Sources

TD-853 - Infrared Thermographic Inspections

TD-855 - Grounding for Personnel Protection on Overhead Distribution Lines

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TD-1001 - Vegetation Management

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 10/28/2019 **Date of Response: 11/14/2019**
Request No. TS 2-048 **Page 1 of 1**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Joseph A. Purington, Lee G. Lajoie

Request:
Regarding the October 2019 wind storm, please provide the following:
a. number of poles replaced; type/class of poles replaced; location of poles replaced; and cause of the broken pole;
b. wire down – amount of bare wire, tree wire and spacer cable;
c. number of impacted single services.

Response:
a) There were approximately 59 broken poles during this storm event. The Company does not track the type/class of poles that are replaced. Rather, the Company tracks the type/class of poles that are installed. Ultimately wind caused the vast majority of these broken poles, in most cases by knocking down trees and/or large limbs onto the poles and wires.
b) There were approximately 484 spans of primary conductor down, plus 247 locations with secondary wire down. The work to identify the conductor type at each location would be a manual effort at this time and cannot be completed in a timely manner.
c) There were 370 single customer outages during the event; however, some of these are likely primary events impacting just one customer.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 08/13/2019 **Date of Response: 08/27/2019**
Request No. OCA 6-053 **Page 1 of 2**
Request from: Office of Consumer Advocate

Witness: Joseph A. Purington, Lee G. Lajoie

Request:
Reference Purington and Lajoie Testimony, Bates 433, Lines 17-19, stating "The Company estimates that approximately 80 percent of the 600 miles of off-road lines are constructed with undersized bare wire that will need to be upgraded for resiliency and to prepare the grid for integration of advanced energy solutions." Please provide:

a. Any analysis conducted by or for the utility that demonstrates the upgraded wired will improve resiliency and by how much. Include in your response, but do not limit it to, a detailed definition of resiliency and how it is measured.
b. Any analysis conducted by or for the utility on the need for the upgraded wire "to prepare the grid for integration of advanced energy solutions." Include in your response, but do not limit it to, a detailed definition of "advanced energy solutions."
c. A discussion of the functionality and grid services provided by the upgraded wire that will enable "integration of advanced energy solutions."

Response:
a. There is no in-depth analysis that is needed to demonstrate that the upgraded wire will improve resiliency; and no available, accepted or feasible method for quantifying what that improvement would be. Grid resiliency relates to the ability of a distribution system to recover from adversity due to more widespread disruptive events. Disruptive events can and do occur and the goal of improved resilience is to reduce the impact from disruptive events to less than would otherwise occur. Resilience improvements are generally focused on achieving at least one of three primary goals: (1) preventing or minimizing damage to help avoid adverse events; (2) expanding alternatives and enabling systems to continue operating despite damage; and (3) promoting a rapid return to normal operations when a disruption occurs (i.e., expedite the rate of recovery). Resilience relates both the system improvements that prevent or reduce the impact of risks on reliability and to the ability of the system to recover more quickly. Unlike reliability, there are no commonly used metrics for the resilience of the electric grid, and threats to system resilience are typically associated with high-intensity, low-frequency events with an infinite range of circumstances that may affect one or more parts of the distribution system, which makes it very difficult to quantify or ascertain the increment of harm and damage avoided by the system (and its customers) in the absence of resilience improvement.

   That said, the improvement in resiliency relating to the upgrade overhead conductor is an engineering certainty . As discussed in response to STAFF 10-026 and OCA-6-035, bare #4 copper conductor has a breaking strength of 1,580 lbs; bare 1/0 ACSR has a breaking strength of 4,250 lbs; and 477 MCM spacer cable has a breaking strength of 7,940 lbs. The messenger from which spacer cable is suspended has a breaking strength of 17,120 lbs. Therefore, as a matter of the physical properties, replacing smaller conductor with covered conductor increases resistance to breaking due to falling trees and limbs. In addition, the covering on the conductor helps to prevent arcing faults, which assists in preventing pitting and damage to the strands of a bare conductor. Where outages do not occur and where damage is mitigated, lessening overall restoration time, costs will be avoided both in terms of routine operating and maintenance expense and storm-related restoration costs.

b. There is no in-depth analysis that is needed to demonstrate that upgraded conductor is necessary to prepare the grid for the integration of advanced energy solutions. This conclusion is a matter of engineering certainty. For the distribution system to be prepared to accommodate interconnected resources, it is necessary to create "visibility" into the principal components of the distribution system. "Visibility" is knowledge of which resources are interconnected, as well as the locations, capabilities and operation of those resources. Advanced communication and information technologies facilitate visibility because visualization requires data collection and analysis. The Company's proactive investment in distribution automation and SCADA capabilities is an important first step to this prerequisite for distributed energy resource accommodation on the electric system. However, there is significant work to be completed in relation to the foundational infrastructure platform that is required to integrate these types of solutions without causing disruption to the system. This work includes upgrading the delivery infrastructure that will carry this load on a safe and reliable basis. Please refer also to the Company's response to OCA-6-026.

c. The replacement of overhead conductor through the GTEP program, if approved by the Commission, would be prioritized on the basis on condition assessments and performance issues, i.e., the Company is not suggesting that overhead conductor would be replaced for the singular purpose of enabling the integration of advanced energy solutions. The conductor will be upgraded for the core purpose of maintaining and improving grid reliability and resiliency, as discussed in detail in part (a) of this question. Conversely, the Company cannot maintain the distribution system successfully where distribution energy resources are integrated to the system indiscriminately and without the technological controls and communications that are necessary to operate the system safely and reliably with the integration of distributed energy resources. As a result, the replacement of overhead conductor in poor condition and experiencing performance degradation will provide the integrity necessary to tie in these other system components.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 08/13/2019
Request No. OCA 6-037
Request from: **Office of Consumer Advocate**

Date of Response: 08/27/2019
Page 1 of 1

Witness: **Joseph A. Purington, Lee G. Lajoie**

Request:
Reference Purington and Lajoie Testimony, Bates 400, Lines 10-12, identifying oil circuit breakers as "[T]he cause of some widespread outages in the past, when the breakers failed to operate as quickly as intended." Please identify any widespread outages causes by oil circuit breakers in the past five years.

Response:
Due to the Company's efforts to replace oil circuit breakers or "OCBs" over the past 15 years, there have been no widespread outages in the last five years. On April 9, 2005, an OCB at Laconia Substation failed to operate as intended in response to a fault on the line that it supplied. This properly activated the "breaker failure" system and all breakers at the substation opened, interrupting service to approximately 25,000 customers. That breaker was repaired and placed back in service. On December 9, 2005 a different OCB at the same substation also failed to operate properly and power was interrupted to the same 25,000 customers. These events negatively affected substation SAIDI, as shown in Attachment OCA 6-037. Breaker replacements have aided in reducing substation SAIDI to less than a minute for multiple years since 2012. See Attachment OCA 6-037.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 08/13/2019
Request No. OCA 6-038
Request from: Office of Consumer Advocate

Date of Response: 08/28/2019
Page 1 of 1

Witness: Joseph A. Purington, Lee G. Lajoie

Request:

Reference Purington and Lajoie Testimony, Bates 400, Lines 13-14, stating that failure of bushing containing high levels of PCBs "have resulted in extensive and costly cleanup efforts." Please identify any cleanup efforts and the relevant costs associated with the aforementioned bushing failures.

Response:

Although GE Type U bushings can contain up to 10,000 ppm PCBs, the event referred to in the testimony was a PCB contaminated Potential Transformer, which failed at Eddy Substation in Manchester, NH. This failure resulted in an extensive and costly cleanup.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 08/13/2019 **Date of Response: 08/27/2019**
Request No. OCA 6-039 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Joseph A. Purington, Lee G. Lajoie

Request:
Reference Purington and Lajoie Testimony, Bates 400, Line 15, describing the maintenance requirements of vacuum breakers as lower cost than the maintenance requirements of oil circuit breakers. Please provide the projected maintenance costs associated with vacuum circuit breakers and oil circuit breakers.

Response:
Both vacuum and oil filled circuit breakers are tested every six years and maintained every 12 years. Testing oil circuit breakers requires, on average, two people for two days, while maintenance typically requires three people for three days and an oil tanker with oil filtration equipment. Testing and maintenance of vacuum breakers each require, on average, two people for two days. Over the course of the 12-year maintenance cycle, this means the oil breaker requires 325% of the labor required by a vacuum breaker, plus additional equipment for handling and processing the oil (there is no oil in a vacuum circuit breaker). There are other costs associated with oil-filled circuit breakers, such as annual oil samples that are collected and analyzed, which are not required for vacuum breakers. Approximate costs over the 12-year cycle are over $11,000 for oil circuit breakers and around $3,200 for vacuum breakers.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 08/13/2019 **Date of Response: 08/27/2019**
Request No. OCA 6-064 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Joseph A. Purington, Lee G. Lajoie

Request:
Reference Purington and Lajoie Testimony, Bates 445, Lines 12-17, describing the oil circuit breaker replacement program.

a. Please provide any quantitative data the Company is relying on to justify its assertions relative to the risk of leaks, employee safety, or improved substation reliability for oil circuit breaker replacement.
b. How many substations, and at what cost, does the Company plan to upgrade due to OCBs?

Response:

a) The Company has been replacing OCBs with vacuum circuit breakers since 2003. Through 2018, the Company has completed 85 such replacements, both as part of base capital budgets and as part of the NHPUC approved Reliability Enhancement Program (REP). An average of eight oil leaks on OCBs have been reported every year since 2002 as part of monthly substation inspections. The number has decreased as OCBs are replaced with VCBs, yet still averages five per year since 2008. Maintenance of oil circuit breakers involves removing the operating mechanism from the tank of oil, which has the potential for oil spills. Vacuum breakers do not contain oil.

   On April 9, 2005 an OCB at Laconia Substation failed to operate as intended in response to a fault on the line it feeds. This properly activated the "breaker failure" system and all breakers at the substation opened, interrupting service to approximately 25,000 customers. That breaker was repaired and placed back in service. On December 9, 2005 a different OCB at the same substation also failed to operate properly and power was interrupted to the same 25,000 customers. These events drove substation SAIDI, shown in attachment OCA 6-064. Breaker replacements have aided in reducing substation SAIDI to less than one minute for multiple years since 2012. As OCBs continue to age it is reasonable to expect that failures will increase, unless they continue to be replaced with newer equipment.

b) The level of funding proposed under GTEP is expected to fund the replacement of five OCBs per year at a cost of approximately $500,000 each.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 08/13/2019 **Date of Response: 08/27/2019**
Request No. OCA 6-036 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Joseph A. Purington, Lee G. Lajoie

Request:
Reference Purington and Lajoie Testimony, Bates 400, Lines 3-6, describing the age of the Company's oil circuit breakers. Please provide the expected useful life of the aforementioned oil circuit breakers.

Response:
Oil circuit breakers are recorded in FERC Account 362, Distribution Substation Equipment. Based on the most recent depreciation study, items recorded to Account 362 have an average expected useful life of 55 years. Expected useful lives of individual pieces of equipment are not available.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 10/28/2019 **Date of Response: 11/14/2019**
Request No. TS 2-031 **Page 1 of 1**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Joseph A. Purington, Lee G. Lajoie, Robert D. Allen

Request:
Regarding the Company ETT activities, please provide:
a. The total circuit miles of "backbone" circuits that have had ETT performed.
b. The total circuit miles of "backbone" circuits that are planned to have ETT performed.
c. The total circuit miles that are not considered "backbone" where ETT was performed. Provide the circuit, number of phases, circuit miles, and reasoning for ETT work.
d. The total circuit miles that are not considered "backbone" where ETT is planned to be performed. Provide the circuit, number of phases, circuit miles, and reasoning for ETT work.
e. The schedule of circuits that had ETT performed from inception of program to present
f. Average 3 year cost of ETT per circuit mile.

Response:
a) ETT program miles completed from 2009 - 2019 YTD = 1,085.63

b) The plan is to perform ETT on all backbone miles on system. The Company estimates it has 1,600 miles of roadside circuit backbone.

c) Three examples that meet the criteria:

336X1 circuit, single phase, four (4) miles trimmed to ETT, history of tree issues, no backfeed/tie, impacting 338 customers in Chatham
348X5 circuit, single phase, one (1) mile trimmed to ETT history of tree issues, off road section attached to backbone, line is located on White Mountain School property in Bethlehem
360X5 circuit, single phase, two and eighty eight hundredths (2.88) miles trimmed to ETT, several complaints from customer regarding reliability, this is a direct tap off 3194X1 and is considered the main line for this circuit affecting 516 customers

d) The Company does not have any ETT planned for non backbone circuit miles.

e) See Excel Attachment TS 2-031.

f)

YEAR	MILES COMPLETED	TOTAL SPEND
2016	173.11	10,203,782
2017	159.63	5,089,804
2018	125.96	4,267,224
TOTAL	**458.7**	**19,560,810**
3 YEAR AVERAGE COST/MILE		**42,644**

Year	SMT Miles Total Miles Reported
2009	2528.85
2010	2575
2011	2395.44
2012	2674.01
2013	2690.11
2014	2622.8
2015	2777.88
2016	2679
2017	2639.98
2018	2599.56

*** miles taken from PUC year end report**

SMT Miles		
Year	**Total Miles Reported**	**Total Spend**
2009	2,528.85	$7,548,974
2010	2,575.00	$7,733,320
2011	2,329.94	$7,422,598
2012	2,674.01	$8,469,324
2013	2,585.31	$2,409,306
2014	2,268.73	$9,771,996
2015	2,225.43	$12,909,485
2016	2,679.00	$12,666,369
2017	2,589.40	$13,165,511
2018	2,599.56	$15,525,658

*** miles taken from PUC year end report**

SMT Miles			
Year	**Total Miles Reported**	**Total Spend**	**COST PER MILE**
2009	2,528.85	7,264,594	2,872.69
2010	2,575.00	7,732,196	3,002.79
2011	2,329.94	7,306,079	3,135.74
2012	2,674.01	8,325,718	3,113.57
2013	2,585.31	10,249,076	3,964.35
2014	2,268.73	9,716,420	4,282.76
2015	2,225.43	12,795,440	5,749.65
2016	2,679.00	12,637,405	4,717.21
2017	2,589.40	13,165,511	5,084.39
2018	2,599.56	15,385,102	5,918.35

*** miles taken from PUC year end report**

ETT Miles

2009	45.76
2010	56.19
2011	51.31
2012	62.41
2013	102.23
2014	99.59
2015	67.77
2016	173.71
2017	139.63
2018	125.88

**Miles from ETT folder 1999-presentcopy_Update this one"

ETT Miles

Year	Total Miles	Total Spend
2009	45.76	1,943,846
2010	56.19	1,990,512
2011	51.31	1,932,136
2012	62.41	2,430,575
2013	102.23	4,071,248
2014	197.25	4,677,027
2015	68.04	5,212,174
2016	173.71	10,209,333
2017	161.1	5,085,663
2018	60.27	4,268,208

**Miles from ETT folder 1999-presentcopy_Update this one"

ETT Miles

Year	Total Miles Reported	Total Spend
2009	45.76	1,651,042
2010	56.19	1,732,200
2011	51.31	1,624,198
2012	62.41	1,995,114
2013	102.23	3,929,659
2014	83.33	4,647,925
2015	67.77	5,206,763
2016	173.11	10,203,782
2017	159.63	5,089,804
2018	125.96	4,267,224

**Miles from ETT folder 1999-presentcopy_Update this one"

COST PER MILE	**new report**	New Cost per mile	
$36,080.46		36,080.46	
$30,827.55		30,827.55	
$31,654.61		31,654.61	
$31,967.86		31,967.86	
$38,439.39		38,439.39	
$55,777.33		55,777.33	
$76,829.91		76,829.91	**Lucas & Northern crews
$58,943.92		58,943.92	1,264,522 - non-REP 8939260 - REP
$31,885.01		31,885.01	4,137,197 - non-REP 948,467 - REP
$33,877.61		33,877.61	3,403,430 - non-REP 863,794 - REP

METT Miles

2009	n/a
2010	n/a
2011	65.5
2012	116.8
2013	87.65
2014	124.35
2015	88.38
2016	169.96
2017	132.84
2018	58.61

*no METT work for 2009 & 2010
**Miles 2011 from METT Tracking AWC
***Miles 2012-2017 from QA/QC spreadsheet

	SMT Miles
Year	Total Miles Reported
2009	2528.85
2010	2575
2011	2395.44
2012	2674.01
2013	2690.11
2014	2622.8
2015	2777.88
2016	2679
2017	2639.98
2018	2599.56

*** miles taken from PUC year end report**

SMT Miles		
Year	Total Miles Reported	Total Spend
2009	2,528.85	$7,548,974
2010	2,575.00	$7,733,320
2011	2,329.94	$7,422,598
2012	2,674.01	$8,469,324
2013	2,585.31	$2,409,306
2014	2,268.73	$9,771,996
2015	2,225.43	$12,909,485
2016	2,679.00	$12,666,369
2017	2,589.40	$13,165,511
2018	2,599.56	$15,525,658

*** miles taken from PUC year end report**

SMT Miles			
Year	Total Miles Reported	Total Spend	COST PER MILE
2009	2,528.85	7,264,594	2,872.69
2010	2,575.00	7,732,196	3,002.79
2011	2,329.94	7,306,079	3,135.74
2012	2,674.01	8,325,718	3,113.57
2013	2,585.31	10,249,076	3,964.35
2014	2,268.73	9,716,420	4,282.76
2015	2,225.43	12,795,440	5,749.65
2016	2,679.00	12,637,405	4,717.21
2017	2,589.40	13,165,511	5,084.39
2018	2,599.56	15,385,102	5,918.35

*** miles taken from PUC year end report**

ETT Miles

2009	45.76
2010	56.19
2011	51.31
2012	62.41
2013	102.23
2014	99.59
2015	67.77
2016	173.71
2017	139.63
2018	125.88

**Miles from ETT folder 1999-presentcopy_Update this one"

ETT Miles

Year	Total Miles	Total Spend
2009	45.76	1,943,846
2010	56.19	1,990,512
2011	51.31	1,932,136
2012	62.41	2,430,575
2013	102.23	4,071,248
2014	197.25	4,677,027
2015	68.04	5,212,174
2016	173.71	10,209,333
2017	161.1	5,085,663
2018	60.27	4,268,208

**Miles from ETT folder 1999-presentcopy_Update this one"

ETT Miles		
Year	**Total Miles Reported**	**Total Spend**
2009	45.76	1,651,042
2010	56.19	1,732,200
2011	51.31	1,624,198
2012	62.41	1,995,114
2013	102.23	3,929,659
2014	83.33	4,647,925
2015	67.77	5,206,763
2016	173.11	10,203,782
2017	159.63	5,089,804
2018	125.96	4,267,224

**Miles from ETT folder 1999-presentcopy_Update this one"

COST PER MILE	**new report**	New Cost per mile	
$36,080.46		36,080.46	
$30,827.55		30,827.55	
$31,654.61		31,654.61	
$31,967.86		31,967.86	
$38,439.39		38,439.39	
$55,777.33		55,777.33	
$76,829.91		76,829.91	**Lucas & Northern crews
$58,943.92		58,943.92	1,264,522 - non-REP 8939260 - REP
$31,885.01		31,885.01	4,137,197 - non-REP 948,467 - REP
$33,877.61		33,877.61	3,403,430 - non-REP 863,794 - REP

METT Miles

2009	n/a
2010	n/a
2011	65.5
2012	116.8
2013	87.65
2014	124.35
2015	88.38
2016	169.96
2017	132.84
2018	58.61

*no METT work for 2009 & 2010
**Miles 2011 from METT Tracking AWC
***Miles 2012-2017 from QA/QC spreadsheet

Midcyle Miles **Not tracked by miles - or work order - all we can supply is total spend for each year**

Year	Total Spend
2009	468,312
2010	232,419
2011	96,661
2012	261,707
2013	130,484
2014	9,672
2015	5,636
2016	5,192
2017	n/a
2018	

Hyperion Data - NH - Arborist, P1 - Mid-Cycle - T&M

Midcyle Miles	
Year	**Total Spend**
2009	$468,312
2010	$232,419
2011	$96,661
2012	$261,707
2013	$130,484
2014	$9,672
2015	$5,636
2016	$5,192
2017	n/a
2018	n/a

Hyperion Data - NH - Arborist, P1 - Mid-Cycle - T&M
Not tracked by miles - or work order - all we can supply is total spend for each year

2009	Spend
REP O&M	7,548,974.00
Capital	1,290,054.00

2010	Spend
REP O&M	7,548,974.00
Capital	1,465,556.00

2011	Spend
REP O&M	7,548,974.00
Capital	2,037,212.00

2012	Spend
REP O&M	7,548,974.00
Capital	2,033,967.00

2013	Spend
REP O&M	7,548,974.00
Capital	1,957,788.00

2014	Spend
REP O&M	7,548,974.00
Capital	1,696,896.00

2015	Spend
REP O&M	7,548,974.00
Capital	1,606,520.00

2016	Spend
REP O&M	7,548,974.00
Capital	2,863,579.00

2017	Spend
REP O&M	2,668,796.00
Capital	2,668,796.00

2018	Spend
REP O&M	7,548,974.00
Capital	2,149,698.00

Hazard Trees

Year	Total Takedowns Reported	
2009	8213	
2010	8426	
2011	7191	
2012	7871	
2013	11342	
2014	22026	
2015	14311	
2016	12404	
2017	17232	
2018	15351	
2019	12343	**YTD July
	136710	

*hazard tree # from "take downs" in trim 1995-2018
**hazard tree # for 2016 from NH Work Plan Slides Jan 2017

Hazard Trees		
Year	**Total Miles Reported**	**Total Spend**
2009	8213	$2,035,684.00
2010	8426	$3,621,586.00
2011	7191	$2,585,393.00
2012	7923	$1,840,231.00
2013	11342	$2,920,144.00
2014	22026	$3,067,881.00
2015	14311	$4,067,892.00
2016	12404	$5,514,994.00
2017	17232	$7,792,829.00
2018	15351	$11,446,062.00

*hazard tree # from "take downs" in trim 1995-2018
**hazard tree # for 2016 from NH Work Plan Slides Jan 2017

3 year average cost (2016, 2017, 2018)
$8,251,295.00

Hot Spot Trimming & Trouble Shooting	
Year	Spend
2009	$181,800
2010	$182,437
2011	$102,497
2012	$298,839
2013	$147,211
2014	$302,914
2015	$381,490
2016	$267,877
2017	$433,758
2018	$534,385

TDS			
	Total	Hazard	Maintenance
TOTAL BILLED 2018	413,989.04	361,629.19	52,359.85
TOTAL BILLED 2017	404,560.98	138,289.09	266,271.87
TOTAL BILLED 2016	644,446.84	249,359.22	395,087.62
TOTAL BILLED 2015	775,227.16	301,672.41	473,554.75
TOTAL BILLED 2014	670,657.78	341,395.58	329,262.20
TOTAL BILLED 2013	1,462,996.86	749,277.50	713,719.34
TOTAL BILLED 2012	449,680.00	90,718.00	358,963.00
TOTAL BILLED 2011	216,342.00	80,084.00	136,258.00
TOTAL BILLED 2010	666,022.00		
TOTAL BILLED 2009	189,728.00		

Fairpoint			
	Total	Hazard	Maintenance
TOTAL BILLED 2018	8,097,464.73	5,034,516.59	3,062,948.06
TOTAL BILLED 2017	4,973,964.61	2,899,520.48	2,074,444.13
TOTAL BILLED 2016	4,368,963.27	2,304,561.03	2,064,402.24
TOTAL BILLED 2015	3,254,552.02	1,120,256.06	2,134,295.96
TOTAL BILLED 2014	3,742,296.54	1,399,509.32	2,341,983.62
TOTAL BILLED 2013	2,359,562.00	642,463.00	1,717,099.00
TOTAL BILLED 2012	2,564,863.00	698,477.00	1,866,386.00
TOTAL BILLED 2011	2,201,870.00	882,233.00	1,320,785.00
TOTAL BILLED 2010	1,520,647.00	342,587.00	1,186,062.00
TOTAL BILLED 2009	1,759,445.00	460,370.00	1,299,075.00

Year	Total Acres	Acres Cost	Total Trim Miles	Side Trim Cost	
2009	1852	$129,480.00	57.28	$218,830.00	
2010	1686	$311,784.00	123.4	$148,218.00	
2011	1643	$400,024.00	100.66	$452,692.00	
2012	1063	$325,601.00	75.03	$484,753.00	
2013	2158	$433,295.00	110.39	$163,143.00	
2014	1623	$462,444.00	125.19	$303,097.00	2014 taken from Hyperion Brown contractor only
2015	1274.14	$378,674.16	128.76	$336,946.12	
2016	1356.52	$400,551.22	86.61	$323,175.58	
2017	1370.73	$514,334.29	90.09	$409,680.53	
2018	1163.04	$333,052.84	127.14	$448,905.40	

*2009-2014 based on JCB invoicing (Pete Henk)

*Total acres/trim and cost based on Farley tracking spreadsheet (invoicing 2015-2018)

*Side trim based on records of ROW's mowed (total miles/ROW)

Year	Total Acres	Acres Cost	Total Trim Miles	Side Trim Cost
2009	1852	$129,480.00	57.28	$218,830.00
2010	1686	$311,784.00	123.4	$148,218.00
2011	1643	$400,024.00	100.66	$452,692.00
2012	1063	$325,601.00	75.03	$484,753.00
2013	2158	$433,295.00	110.39	$163,143.00
2014*	1623	$462,444.00	125.19	$303,097.00
2015	1274.14	$378,674.16	128.76	$336,946.12
2016	1356.52	$400,551.22	86.61	$323,175.58
2017	1370.73	$514,334.29	90.09	$409,680.53
2018	1163.04	$333,052.84	127.14	$448,905.40

*2009-2014 based on JCB invoicing (Pete Henk)

*Total acres/trim and cost based on Farley tracking spreadsheet (invoicing 2015-2018)

*Side trim based on records of ROW's mowed (total miles/ROW)

Year	SMT Traffic
2009	1,112,256
2010	958,448
2011	1,092,945
2012	2,179,362
2013	2,002,315
2014	2,225,842
2015	11,296
2016	280
2017	n/a
2018	n/a

SMT Traffic Control			
Year	**SMT**	**ETT**	**Hazard**
2,009	1,112,256	349,353	n/a
2,010	958,448	282,542	n/a
2,011	1,092,945	363,532	n/a
2,012	2,179,362	498,305	41,539
2,013	2,002,315	132,259	948,168
2,014	2,225,842	29,102	352,078
2,015	11,296	5,411	8,952

YEAR	Total Miles	Cost
2009		
2010		
2011		$641,529.00
2012		$1,982,271.00
2013		
2014	34.57	$1,798,397.00
2015	20.4	$759,677.33
2016	6.62	$623,562.99
2017	5.8	$372,741.05
2018	10.5	$941,905.73

*Spend based on invoicing and hyperion

YEAR	Total Miles	Cost
2009	n/a	n/a
2010	9	$90,497
2011	29	$622,982
2012	30	$1,914,900
2013	22	$919,402
2014	34.57	$1,798,397
2015	20.4	$759,677
2016	6.62	$623,563
2017	5.8	$372,741
2018	10.5	$941,906

*Spend based on invoicing and hyperion

YEAR	ROW #	AWC	COST	COMMENTS
2019	328	Bedford	$285,000.00	Northern Tree
2018	3271	Bedford	$279,057.68	Northern Tree

PUC Reporting

					Miles	Spend
2009	Miles	Spend				
SMT	2528.85	7,548,974.00		Planned Maintenance	2528.85	10,835,814.00
ETT	45.7	1,943,846.00				
Hazard Tree	8213	2,035,684.00				

2010	Miles	Spend				
SMT	2206.13	7,733,320.00		Planned Maintenance	2575	12,843,562.00
ETT	56.19	1,990,512.00				
Hazard Tree	8426	3,621,586.00				

2011	Miles	Spend				
SMT	2329.94	7,422,598.00		Planned Maintenance	2395.44	11,352,669.00
ETT	51.31	1,932,136.00				
Hazard Tree	7191	2,585,393.00				

2012	Miles	Spend				
SMT	2560.23	8,469,324.00		Planned Maintenance	2674.01	13,076,202.00
ETT	62.41	2,430,575.00				
Hazard Tree	7923	1,840,231.00				

2013	Miles	Spend				
SMT	2585.31	2,409,306.00		Planned Maintenance	2690.11	17,094,835.00
ETT	102.23	4,071,248.00				
Hazard Tree	11342	2,920,144.00				

2014	Miles	Spend				
SMT	2268.73	9,771,996.00		Planned Maintenance	2622.8	15,646,910.00
ETT	197.25	4,677,027.00				
Hazard Tree	22026	3,067,881.00				

2015	Miles	Spend				
SMT	2225.43	12,909,485.00		Planned Maintenance	2777.88	16,442,470.00
ETT	68.04	5,212,174.00				
Hazard Tree	14311	4,067,892.00				

2016	Miles	Spend				
SMT	1994.38	12,666,369.00		Planned Maintenance	2679	18,976,094.00
ETT	173.71	10,209,333.00				
Hazard Tree	12404	5,514,994.00				

2017	Miles	Spend				
SMT	2589.4	13,165,511.00		Planned Maintenance	2639.98	21,625,568.00
ETT	161.1	5,085,663.00				
Hazard Tree	17232	7,792,829.00				

2018	Miles	Spend				
SMT	1781.44	15,525,658.00		Planned Maintenance	2599.56	28,616,634.00
ETT	60.27	4,268,208.00				
Hazard Tree	15351	11,446,062.00				

2009	Spend
REP O&M	7,548,974.00
Capital	1,290,054.00

2010	Spend
REP O&M	7,548,974.00
Capital	1,465,556.00

2011	Spend
REP O&M	7,548,974.00
Capital	2,037,212.00

2012	Spend
REP O&M	7,548,974.00
Capital	2,033,967.00

2013	Spend
REP O&M	7,548,974.00
Capital	1,957,788.00

2014	Spend
REP O&M	7,548,974.00
Capital	1,696,896.00

2015	Spend
REP O&M	7,548,974.00
Capital	1,606,520.00

2016	Spend
REP O&M	7,548,974.00
Capital	2,863,579.00

2017	Spend
REP O&M	2,668,796.00
Capital	2,668,796.00

2018	Spend
REP O&M	7,548,974.00
Capital	2,149,698.00

Please provide an active Excel file showing the annual spending for each category of Base REP O&M and Capital from 2009 through 2018. Please include a column with 2019 budgeted items. O&M items should include cycle trimming, hot spot trimming, mid-cycle trimming, ROW clearing, etc.

23X5	Hazard	558	
	Spend	23,020	
23X6	Hazards	503	
	Spend	85,890	Outsource crews used

Reference Allen testimony on Bates Page 722, lines 13 through 16. Please provide the cost and number of Hazard trees removed that were part of the three phase mainline and laterals separately.

Public Service Company of New Hampshire dba Eversource Energy										
DE 19-057										
Staff Data Requests - Set #1; Question 1-3										
2009 - 2018 Annual Spending										
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
	Actual	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**
O&M - Total	**12,198,400**	**14,183,500**	**13,337,694**	**14,700,782**	**13,601,818**	**11,792,472**	**14,761,818**	**12,551,237**	**15,307,889**	**17,424,182**
Base - Total	-	-	-	-	-	-	-	-	-	-
SMT										
METT										
Hot Spot										
Mid-Cycle										
REP - Total	-	-	-	-	-	-	-	-	-	-
SMT										
METT										
Hot Spot										
Mid-Cycle										
Capital - Total	**2,057,312**	**1,983,804**	**2,057,100**	**5,854,498**	**8,423,205**	**7,862,764**	**10,483,840**	**15,177,975**	**11,617,644**	**14,375,384**
Base - Total	2,057,312	1,983,804	2,057,100	3,122,503	918,275	3,434,274	3,492,811	2,170,396	10,563,607	11,440,416
ETT	2,057,312	1,983,804	2,057,100	3,122,503	(33,676)	-	-	2,011,632	6,278,756	3,967,656
ETR	-	-			32,549	1,607,468	2,062,712	1,319	4,119,116	6,098,672
ROW	-	-			919,402	1,826,806	1,430,100	157,445	165,735	1,374,088
REP - Total	-	-	-	2,731,995	7,504,930	4,428,490	6,991,029	13,007,579	1,054,037	2,934,968
ETT				2,731,995	4,199,789	4,418,562	6,939,141	8,614,394	496,813	1,099,893
ETR					3,305,141	9,928	51,888	3,645,393	194,365	1,736,922
ROW								747,792	362,859	98,153

C:\Users\Kurt.F.Demmer\AppData\Local\Temp\OneNote\16.0\NT\1\19-057_res_staff_ts2_31_att_eversource1.xlsx
Summary '09-'18 Act

Public Service Company of New Hampshire dba Eversource Energy
DE 19-057
Staff Data Requests - Set #1; Question 1-3
2009 - 2018 Annual Spending and 2019 Budget

	2019 Forecast	**2020 Forecast**	**2021 Forecast**	**2022 Forecast**	**2023 Forecast**
O&M - Total	**31,079,577**	**32,732,964**	**33,714,953**	**34,726,402**	**35,768,194**
Base - Total	14,979,577	15,428,964	15,891,833	16,368,588	16,859,646
SMT					
METT					
Hot Spot					
Mid-Cycle					
REP - Total	16,100,000	17,304,000	17,823,120	18,357,814	18,908,548
ETT	5,000,000	5,150,000	5,304,500	5,463,635	5,627,544
ETR	10,000,000	10,300,000	10,609,000	10,927,270	11,255,088
ROW	1,100,000	1,854,000	1,909,620	1,966,909	2,025,916

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 10/28/2019 **Date of Response: 11/15/2019**
Request No. TS 2-033 **Page 1 of 1**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Joseph A. Purington, Lee G. Lajoie, Robert D. Allen

Request:
Regarding the Company's outage data for vegetation management:

a. Please provide the following for 2009-2018, in a live excel spreadsheet:
   i. Tree related SAIFI and SAIDI IEEE (including planned outages)
   ii. SAIDI and SAIFI for tree related outages that were part of a sidetap/ lateral location (fuse, tripsaver, single phase recloser, etc.)
   iii. SAIDI and SAIFI for tree related outages that were part of a three phase location (breaker, recloser, etc.).
   iv. SAIFI and SAIDI listed above (i. through iii.) broken down by the more granular tree related causal factors in the OMS system e.g. inside trim zone.

Response:
Please see Excel Attachment TS 2-033 for the requested information. Note that the responses to parts ii and iii can only be provided back as far as September 2015 with the implementation of the Company's OMS.

Docket No. DE 19-057
Data Request TS 2-033
Dated 11/01/19
Attachment TS 2-033

NHPUC Data Request - 2009 - 2018 - NH Tree Related - IEEE Criteria

Year	SAIDI	SAIFI
2009	56.94	0.4826
2010	108.69	0.7518
2011	85.25	0.6482
2012	79.38	0.6024
2013	75.85	0.5524
2014	61.81	0.5822
2015	57.23	0.5517
2016	82.53	0.7297
2017	77.12	0.5994
2018	70.25	0.5197

Docket No. DE 19-057
Data Request TS 2-033
Dated 11/01/19
Attachment TS 2-033

NHPUC Data Request - September 13 2015 - 2018 - NH Tree Related - IEEE Criteria - Single Phase Devices

Year	Phase_IND	SAIDI	SAIFI
Sep 13 -YE 2015	1_PH	7.25	0.06
2016	1_PH	37.15	0.26
2017	1_PH	36.42	0.25
2018	1_PH	33.98	0.26

a.iv - September 13 2015 - 2018 - Single Phase By Trim Zone - IEEE Criteria

Year	Phase_IND	TRIM_ZONE	SAIDI	SAIFI
Sep 13 -YE 2015	1_PH	Inside Zone	0.14	0.0014
2016	1_PH	Inside Zone	0.28	0.0028
2017	1_PH	Inside Zone	0.42	0.0042
2018	1_PH	Inside Zone	0.58	0.0060
Sep 13 -YE 2015	1_PH	Outside Zone	7.11	0.0569
2016	1_PH	Outside Zone	36.86	0.2577
2017	1_PH	Outside Zone	36.00	0.2491
2018	1_PH	Outside Zone	33.40	0.2507

Docket No. DE 19-057
Data Request TS 2-033
Dated 11/01/19
Attachment TS 2-033

NHPUC Data Request - September 13 2015 - 2018 - NH Tree Related - IEEE Criteria - Three Phase Devices

Year	Phase_IND	SAIDI	SAIFI
Sep 13 -YE 2015	3_PH	7.21	0.1065
2016	3_PH	42.92	0.4561
2017	3_PH	35.40	0.3270
2018	3_PH	32.89	0.2494

a.iv - September 13 2015 - 2018 - Three Phase By Trim Zone - IEEE Criteria

Year	Phase_IND	TRIM_ZONE	SAIDI	SAIFI
Sep 13 -YE 2015	3_PH	Inside Zone	0.59	0.0084
2016	3_PH	Inside Zone	1.60	0.0441
2017	3_PH	Inside Zone	1.51	0.0140
2018	3_PH	Inside Zone	0.38	0.0053
Sep 13 -YE 2015	3_PH	Outside Zone	6.62	0.0982
2016	3_PH	Outside Zone	41.32	0.4120
2017	3_PH	Outside Zone	33.89	0.3130
2018	3_PH	Outside Zone	32.51	0.2441

Docket No. DE 19-057
Data Request TS 2-033
Dated 11/01/19
Attachment TS 2-033

a.iv - 2009 - 2018 - NH Tree Related By Trim Zone - IEEE Criteria

Year	TRIM_ZONE	SAIDI	SAIFI
2009	Inside Zone	10.45	0.0927
2010	Inside Zone	9.74	0.0747
2011	Inside Zone	13.74	0.0953
2012	Inside Zone	11.94	0.0780
2013	Inside Zone	7.34	0.0629
2014	Inside Zone	6.85	0.0658
2015	Inside Zone	4.30	0.0438
2016	Inside Zone	1.92	0.0473
2017	Inside Zone	1.95	0.0184
2018	Inside Zone	1.14	0.0120
2009	Outside Zone	46.48	0.3898
2010	Outside Zone	98.95	0.6771
2011	Outside Zone	71.51	0.5529
2012	Outside Zone	67.44	0.5244
2013	Outside Zone	68.51	0.4895
2014	Outside Zone	54.96	0.5163
2015	Outside Zone	52.92	0.5079
2016	Outside Zone	80.62	0.6824
2017	Outside Zone	75.17	0.5810
2018	Outside Zone	69.11	0.5077

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 09/20/2019 **Date of Response: 10/09/2019**
Request No. STAFF 12-040 **Page 1 of 2**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Robert D. Allen

Request:
(TS) Follow-up to Tech session held on 9/5/19, Robert Allen stated that the ILEC Joint Owner does not contribute to Eversource's ETT costs. In addition, Robert Allen also stated that in the case where circuit ETT was coincident with the normal pruning cycle trim, the ILEC did not contribute to the ETT section or the pruning cycle offset cost.

a) Please confirm or reconcile this stated position.
b) During the period of ETT inception and execution through today, please provide each of the following by each year from 2015 through 2018:
   i. Costs of ETT per circuit per year.
   ii. Avoided cost of cycle pruning on circuits that had ETT.
   iii. Contribution from ILEC for ETT and/or cycle pruning miles (separately) that were done under ETT.

Response:
a) In the annual discussion with the ILEC the ETT budget was presented along with the SMT and Hazard Tree budgets. The SMT and Hazard tree programs are part of the IOP whereas the ETT program was not part of the IOP. Therefore, the ETT budget was listed as a cost to Eversource but not one that would be shared with the ILECs. This response is to confirm that the ILEC did not contribute to the ETT trimming costs.

b)
i.

Year	ETT Miles	ETT Spend	Average ETT cost per mile
2015	67.77	5,212,174.00	76,909.75
2016	173.71	10,209,333.00	58,772.28
2017	139.63	5,085,663.00	36,422.42
2018	125.88	4,268,208.00	33,906.96

ii.

Year	Average SMT cost per mile	ETT/SMT Miles	ILEC avoided cost
2015	4,955.54	31.09	30,813.55
2016	5,003.27	74.50	74,548.72
2017	5,078.68	67.30	68,359.03
2018	5,019.08	62.66	62,899.11
		235.55	**236,620.41**

iii. As described in part a, the ILECs did not contribute to the costs of ETT because ETT program is not covered under the IOP.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 06/05/2019 **Date of Response: 06/19/2019**
Request No. OCA 1-051 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Robert D. Allen

Request:
Tree Trimming. Provide for each year 2014 through 2018, and 2019 year-to-date, the number of miles trimmed, the total number of miles of overhead line, the total number of miles that require trimming and the cost budgeted and expensed. (If the Company maintains records that distinguish the vegetation maintenance between trimming, danger tree removal, mowing and/or spraying provide the information at that level of detail) Also, provide any amount capitalized for each respective type of expenditure and identify how it is being reflected in the filing. Provide the comparable amount included in O&M for each of the rate years.

Response:
Eversource maintains approximately 12,000 miles of overhead distribution line and is required to trim on a maximum of a five-year cycle in accordance with Puc 307.10. This equates to a minimum of 2,400 miles per year. The actual number of miles trimmed by year are shown in the table below.

Year	Miles
2014	2,622.80
2015	2,777.88
2016	2,679.00
2017	2,639.98
2018	2,599.56
2019*	657.16
*1st quarter	

Please refer to Attachment OCA 1-051 A for budgeted and actual vegetation management O&M costs by program for the period 2014 through 2018 and Attachment OCA 1-051 B for budgeted and actual vegetation management capital costs by program for the period 2014 through 2018. Note that ETT, Hazard Tree, and Full Width ROW programs, which were previously part of the capital budget, have transitioned to the O&M budget starting in 2019. Eversource does not use herbicide spraying for vegetation maintenance.

Public Service Company of New Hampshire dba Eversource Energy
2014 - 2019 Annual Spending and Budget
O&M Expense

O&M Actuals						
	2014	**2015**	**2016**	**2017**	**2018**	**YTD May 2019**
O&M - Total	**11,792,472**	**14,761,818**	**12,551,237**	**15,330,257**	**17,424,182**	**12,447,886**
SMT	11,086,612	14,071,559	11,669,569	14,522,846	16,390,188	5,763,857
METT	689,208	684,115	876,885	807,411	1,033,994	756,239
Hot Spot	-	-	-	-	-	-
Mid-Cycle	16,651	6,143	4,783	-	-	4,085
ETT [1]	N/A	N/A	N/A	N/A	N/A	1,582,326
ETR [1]	N/A	N/A	N/A	N/A	N/A	3,241,380
ROW [1]	N/A	N/A	N/A	N/A	N/A	1,100,000

O&M Budget						
	2014	**2015**	**2016**	**2017**	**2018**	**2019**
O&M - Total	**13,638,000**	**14,102,761**	**14,740,000**	**14,740,002**	**14,979,577**	**31,779,577**
SMT [1]						14,979,577
METT [1]						
Hot Spot [1]						
Mid-Cycle [1]						
ETT [2]	N/A	N/A	N/A	N/A	N/A	5,000,000
ETR [2]	N/A	N/A	N/A	N/A	N/A	10,000,000
ROW [2]	N/A	N/A	N/A	N/A	N/A	1,800,000

[1] Base O&M is budgeted at a high level and not typically allocated to the individual programs such as METT, mid-cycle, customer requests/hot spots, etc

[2] Prior to 01/01/2019 enhanced tree trimming (ETT), enhanced tree/hazard tree removals, and full width clearing (ROW) programs were capitalized. These programs were transferred to O&M per the PUC on 01/01/2019.

Docket No. DE 19-057
Data Request OCA 1-051
Dated 6/5/2019
Attachment OCA 1-051 B
Page 1 of 1

Public Service Company of New Hampshire dba Eversource Energy
2014 - 2019 Annual Spending and Budget

Capital						
	2014 Actual	**2015 Actual**	**2016 Actual**	**2017 Actual**	**2018 Actual**	**YTD May 2019 Actual**
Capital - Total	**7,862,764**	**10,483,840**	**15,177,975**	**11,617,644**	**14,375,384**	**(472,536)**
ETT	4,418,562	6,939,141	10,626,026	6,775,569	5,067,549	49,188
ETR	1,617,396	2,114,600	3,646,712	4,313,481	7,835,594	(226,618)
ROW	1,826,806	1,430,100	905,237	528,594	1,472,241	(295,106)
	2014 Budget	**2015 Budget**	**2016 Budget**	**2017 Budget**	**2018 Budget**	**2019 Budget**
Capital - Total	**7,600,878**	**7,600,800**	**13,601,320**	**24,995,536**	**25,000,000**	**N/A**
ETT	3,090,033	3,000,000	5,999,470	9,999,000	9,000,000	
ETR	1,068,126	3,000,000	4,400,530	9,994,455	12,000,000	
ROW	3,442,719	1,600,800	3,201,320	5,002,081	4,000,000	

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 10/11/2019 **Date of Response: 10/23/2019**
Request No. STAFF 15-014 **Page 1 of 1**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Joseph A. Purington, Lee G. Lajoie

Request:
Reference Staff 12-030A Excel Spreadsheet. Please provide the individual outage information that in the OMS for each of the events for those outages that are categorized as:

a) OVLD
b) MISC
c) OPER
d) PLAN
e) PSIO
f) EMPL

Response:
See the Excel Attachment Staff 15-014. Note that lines with duplicate "Parent Event" numbers (column G) are step restoration pieces of the same outage event.

2012 - 2018 NH OMS Events - **All In** - Causes: OVLD, MISC, OPER, PLAN, PSIO, EMPL

Please note: MISC, OPER and PSIO are causes new to OMS and did not exist in TR/UPER, the outage system prior to OMS so there is no data prior to October 2015

Year	CAUSE	# Parent Events	CI	CMI	Cust Served	SAIDI	CAIDI	SAIFI	CIII
2018	EMPL	94	12,247	644,542	528,668	1.22	53	0.02	130
2017	EMPL	96	15,267	152,794	525,227	0.29	10	0.03	159
2016	EMPL	74	8,475	116,724	522,081	0.22	14	0.02	115
2015	EMPL	141	28,190	670,683	510,645	1.31	24	0.06	200
2014	EMPL	137	11,180	1,165,818	504,039	2.31	104	0.02	82
2013	EMPL	109	29,029	1,984,468	501,490	3.96	68	0.06	266
2012	EMPL	104	33,451	2,250,553	500,069	4.50	67	0.07	322
		108	**19,691**	**997,940**		**1.97**			
2018	MISC	33	6,256	415,814	528,668	0.79	66	0.01	190
2017	MISC	35	465	230,059	525,227	0.44	495	0.00	13
2016	MISC	25	454	50,085	522,081	0.10	110	0.00	18
2015	MISC	1	1	46	510,645	0.00	46	0.00	1
		24	**1,794**	**174,001**	**521,655**	**0.33**			
2018	OPER	5	134	11,050	528,668	0.02	82	0.00	27
2017	OPER	14	1,783	282,228	525,227	0.54	158	0.00	127
2016	OPER	68	5,035	209,632	522,081	0.40	42	0.01	74
2015	OPER	44	6,252	88,283	510,645	0.17	14	0.01	142
		33	**3,301**	**147,798**	**521,655**	**0.28**			
2018	OVLD	219	8,216	464,283	528,668	0.88	57	0.02	38
2017	OVLD	56	1,488	126,255	525,227	0.24	85	0.00	27
2016	OVLD	100	2,215	207,913	522,081	0.40	94	0.00	22
2015	OVLD	96	3,421	352,410	510,645	0.69	103	0.01	36
2014	OVLD	93	2,743	482,124	504,039	0.96	176	0.01	29
2013	OVLD	206	10,442	997,390	501,490	1.99	96	0.02	51
2012	OVLD	184	4,062	509,475	500,069	1.02	125	0.01	22
		136	**4,655**	**448,550**		**0.88**			
2018	PLAN	2,262	102,087	7,240,367	528,668	13.70	71	0.19	45
2017	PLAN	2,899	82,764	7,031,332	525,227	13.39	85	0.16	29
2016	PLAN	1,692	42,877	3,574,224	522,081	6.85	83	0.08	25
2015	PLAN	591	23,170	1,650,717	510,645	3.23	71	0.05	39
2014	PLAN	875	10,655	1,513,082	504,039	3.00	142	0.02	12
2013	PLAN	942	10,221	1,130,702	501,490	2.25	111	0.02	11
2012	PLAN	758	21,839	1,289,613	500,069	2.58	59	0.04	29
		1,431	**41,945**	**3,347,148**		**6.43**			
2018	PSIO	7	85	4,254	528,668	0.01	50	0.00	12
2017	PSIO	23	1,889	349,907	525,227	0.67	185	0.00	82
2016	PSIO	27	1,135	203,939	522,081	0.39	180	0.00	42
2015	PSIO	9	787	8,915	510,645	0.02	11	0.00	87
		17	**974**	**141,754**	**521,655**	**0.27**			

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 10/28/2019 **Date of Response: 11/14/2019**
Request No. TS 2-041 **Page 1 of 1**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Joseph A. Purington, Lee G. Lajoie

Request:
Refer to Attachment to Staff 15-14. For outages classified as planned:
a. Please provide a narrative of each sample of a planned outage in OMS as it complies with PUC 304.03 and 1203.19 and Company procedure SOC-11004
i. Parent Events (Column G) 3832257, 3832562, 3832921, 3821074, 3819444

Response:
See Attachment TS 2-041 for a narrative on how each of the listed outages complies with or exceeds the requirements of PUC 304.03, PUC 1203.19, and SOC-11004.

Parent Event 3832257

Planned outage, Customers notified via emergency dialer. Line reconfigured to minimize customer impact, outage taken due to arcing hot line clamp. Crew made safe, ESCC re-energized line. Conductor not damaged.

DIR #18-12-27-03 ESCC EMERGENCY OUTAGE. TROUBLESHOOTER EN ROUTE TO MAKE REPAIRS. Bowley ETA 1750, Bischof ETA 1800 Isolated to single customer, further repairs to be made on event 3832266

Planned outage due to arcing hot line clamp. This was an emergency situation which needed to be addressed immediately in order to prevent additional damage and an unplanned outage in accordance with 1203.19(d)(1). Work was performed on a scheduled basis meeting the requirements of PUC 1203(a). This minimizes the inconvenience to customers in accordance with 304.03(e) and 1203.19 (b). All impacted customers were notified by the emergency dialer meeting the requirements of PUC 304.03 (f) and SOC-11004, and exceeding the requirements of PUC 304.03 (g) and PUC 1203.19 (c).

3832562

2353 A. Franchini and I. Hill, 2353 D. Urban and I. Hill, and 2350 K. Macneil: Planned outage for pole transfer. New pole was set due to vehicle accident (Event# 3832334). Customers notified via dialer. Work complete, customers restored.

Planned outage for pole transfer (car vs. pole earlier). Customers notified via dialer.

Planned outage to transfer to a new pole which was replaced after being broken as a result of a vehicle accident. The crews on site determined that the safe way to complete the pole transfer was by de-energizing the lines, in accordance with 1203.19(d)(1). Work was performed on a scheduled basis meeting the requirements of PUC 1203(a). This minimizes the inconvenience to customers in accordance with 304.03(e) and 1203.19 (b). All impacted customers were notified by the emergency dialer meeting the requirements of PUC 304.03 (f) and SOC-11004, and exceeding the requirements of PUC 304.03 (g) and PUC 1203.19 (c).

3832921

4530 JImmy Z: planned outage to remove limb from primary in off road area. Customers notified by dialer. Limb removed, refused cutout and restored all customers.

Tree down on cutout pole, planned outage

Planned outage to remove a limb/tree which had fallen on a pole where a cutout is located which feeds a side tap off the single phase main line. The crews on site determined that the safe way to complete the work was by de-energizing the lines, in accordance with 1203.19(d)(1). Work was performed on a scheduled basis meeting the requirements of PUC 1203(a). This minimizes the inconvenience to customers in accordance with 304.03(e) and 1203.19 (b). All impacted customers were notified by the emergency dialer meeting the requirements of PUC 304.03 (f) and SOC-11004, and exceeding the requirements of PUC 304.03 (g) and PUC 1203.19 (c).

3821074

AWC 3252/S Parenteau responded. Failed insulators at pole 30/15-3. Insulators replaced and work completed. Power restored. Customers contacted via dialer.

AWC 3252/S Parenteau responded. Failed insulator

Planned outage due failed insulators on a 12.47 kV three phase deadend pole. This was an emergency situation which needed to be addressed immediately in order to prevent additional damage and an unplanned outage in accordance with 1203.19(d)(1). Work was performed on a scheduled basis meeting the requirements of PUC 1203(a). This minimizes the inconvenience to customers in accordance with 304.03(e) and 1203.19 (b). All impacted customers were notified by the emergency dialer meeting the requirements of PUC 304.03 (f) and SOC-11004, and exceeding the requirements of PUC 304.03 (g) and PUC 1203.19 (c).

Parent Event 3819444 (3 customers, 144 minutes)

Planned outage to remove tree from primary. Called and knocked, no answer.

*****Planned Outage*** to remove tree from primary**

Planned outage to remove a tree which was in contact with energized primary on a side tap off the single phase main line. The crews on site determined that the safe way to complete the work was by de-energizing the lines, in accordance with 1203.19(d)(1). Work was performed on a scheduled basis meeting the requirements of PUC 1203(a). This minimizes the inconvenience to customers in accordance with 304.03(e) and 1203.19 (b). An attempt was made to notify all three impacted customers by knocking on their doors and calling their phone numbers meeting the requirements of PUC 304.03 (f) and SOC-11004, and exceeding the requirements of PUC 304.03 (g) and PUC 1203.19 (c).

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. IR 19-017

Date Request Received: 03/07/2019 **Date of Response: 03/21/2019**
Request No. STAFF 1-001 **Page 1 of 1**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Donald R. Nourse

Request:
Public Service Company of New Hampshire d/b/a Eversource Energy (Eversource): a. Provide all written company policies, procedures, manuals, or booklets etc. that describe how the company conducts planned outages. b. Indicate whether the Company has separate written policies, procedures, manuals, or booklets, etc. for planned outages of different scales/impacts/power configuration, for example, residential versus commercial/industrial, or single customer versus multiple customers, or single phase versus three phase. If yes, please describe the significant differences contained in these documents. c. Please provide specific page references to any existing tariffs that address planned outages, including any provisions indicating any measures that customers are required or advised to take to minimize damage to customer equipment during any outage.

Response:
Please find the attached Procedure which establishes the guidelines to be followed when scheduling planned and unplanned service interruptions. This Procedure covers all aspects of the varying scales of interruptions, either Eversource or customer initiated and describes in detail the process for handling each instance.

References:
- NHPUC NO. 9, Tariff for Electric Delivery Service: Section 3, Original page 9 and Section 15, Original page 16.
- NHPUC Code of Administrative Rules, Chapter PUC 300, Rule 304.03.
- NHPUC Code of Administrative Rules, Chapter 1200, Rule 1203.19
- Eversource Requirements for Electric Service, Page 60, Article 705 and 706 (attached).

SOC-11004 Planned and Unplanned Outage Scheduling and Customer Notification

I. PURPOSE

To establish guidelines to be followed when scheduling planned or unplanned service interruptions, affecting Eversource NH customers.

II. AREAS/PERSONS AFFECTED

- System Operations
- Corporate Communications
- Electric Operations
- Customer Care
- System Engineering

III. POLICY

It is the policy of Eversource NH to schedule service interruptions, whether planned or unplanned, with proper notification and at a time causing minimum inconvenience to customers.

Planned outages shall be scheduled during normal working hours. Should a customer request a planned outage outside of normal working hours, provided no other customer impacted by the outage protests, Eversource will work to meet the customer's request, only if the customer agrees to pay all associated costs, consistent with NHPUC rulings.

When an unplanned outage is needed under emergency situations or when directed/requested by police, fire, or other public safety officials, notification to affected customers is not required. The System Operations Center may initiate a proactive telephone notification to the customers that will be affected by the emergency outage, if doing so, will not delay the actions required to mitigate the emergency.

All outages, planned or unplanned, with a duration greater than five minutes shall be documented in the Outage Management System.

IV. DEFINITIONS

AWC – Area Work Center
CSD - Customer Services Division
DSO – Distribution System Operator
ESSC - Electric Service Support Center
FSED - Field Supervisor-Electric Design
FSL - Field Supervisor-Lines
FSL-R - Field Supervisor-Lines (Remote)
ME Customer – Medical Emergency Customer
OMS – Outage Management System

PCED - Project Coordinator - Electric Design
Planned Outage - The preplanned temporary interruption of electric service to customers in order to perform work on the Eversource or customer's electric system
SDL – Supervisor-Distribution-Lines
SOC - System Operations Center
Supervisor – Supervisor responsible for employees and work being performed, including: FSED, FSL, FSL-R, SDL, Supervisor – Distribution Contract Project Services, Construction Representatives or their designees.
Technician/Specialist – Field Technicians, Field Tech Specialist, or Project Coordinator-Electric Design positions.
Unplanned Outage – Outage required due to emergency circumstances and written notification is not practical.

V. SAFETY MANUAL

No	Should a copy of this procedure be inserted in the functional area's safety manual?

VI. OVERVIEW

There are generally three types of service interruptions:

- Planned Outage – Eversource Initiated
- Unplanned Outage – Eversource Initiated
- Planned Outage – Customer Initiated

Planned Outage – Eversource Initiated
Company initiated planned outages are typically initiated by the Technician/Specialist writing the work. The Technician/Specialist will arrange for the notification during the design and planning phase of the work. Mailing or hand-delivering notices to customers is acceptable and will be determined by the supervisor. Verbal notice to customers will not be employed for planned outages that fall within this category.

> Written planned outage notifications are initiated via the Planned Outage Notification System (PONS). Refer to **Appendix I**. Adequate time must be allowed for mailing. System validation prevents entry of a transaction for a planned outage within the next five calendar days. If the planned outage date is within the next five calendar days, then affected customers must be contacted on a local basis (i.e., by telephone contact, hand delivery of notification, or other personal contact).
>
> The Job Owner (FSL/SDL or FSEB) is responsible for verifying and approving planned outages within their area of responsibility utilizing the PONS application.

Unplanned Outage – Eversource Initiated

Company initiated unplanned outages are typically initiated by a line crew working in the field. When a line crew determines an outage will be required to perform work, the need must first be approved by the supervisor, his or her designee, or the SOC/DSO. Prior to authorizing and scheduling the work, the supervisor/SOC/DSO will consider all the contingents that could occur at the time the work is to be completed, in order to minimize the duration of the unplanned outage. The line crew is responsible for notifying customers of the unplanned outage either through verbal notification or a door hanger left at the premise affected. All medical emergency (ME) customers must be verbally notified prior to causing an unplanned outage other than circumstances provided for under New Hampshire Public Utilities Commission Code of Administrative Rule 1203.11.

The SOC may initiate a proactive call to all customers who will be affected by the unplanned outage in the event that the line crew cannot or if it is impractical to do so. The line crew shall supply the details of the device being opened and the duration that customers are to be interrupted. The DSO shall document the unplanned outage in the OMS, reason for the outage and the estimated time of restoration.

Planned Outage – Customer Initiated

Customer initiated planned outages are typically scheduled to be performed at a specific time requested by the customer. When Eversource moves forward with a customer initiated planned outage, the requesting customer shall be apprised of Eversource work practices and safety policies. Preferred completion dates and alternate dates are also reviewed. Once agreed to, dates shall be confirmed in writing with the customer including the office and field contact information for both Eversource and the customer. Other customers who may be affected by the work must also be notified. Depending on the timing, this may be accomplished either through written or verbal communications, as appropriate.

VII. PROCEDURE

A. Planned Outage – Eversource Initiated

RESPONSIBILITY	ACTION
Field Technician/Field Tech Specialist/PCEB	1. Determine if a planned outage is necessary for work to be performed. 2. Review planned outage need with supervisor, including proposed date/alternate date, time, and duration.

RESPONSIBILITY		ACTION
FSL/FSL-R/FSED	3.	Determine customers affected by planned outage by utilizing the PONS application. Enter the request into the PONS application. **NOTE: Ensure that all customers affected are captured in the request, customer connectivity must be validated.**
	4.	Review request and provide confirmation for the planned outage and scheduling details. If a planned outage is not justified, provide the alternate work practice.
	5.	Inform Community Relations Specialist/ Manager/Account Executive/Corporate Communications of any sensitive and/or GV/LPB customers affected, as appropriate.
Utility Worker/ Rep. A-Records	6.	Add the PONS request to the SOC Planned Outage Tracking Database. Planned Outage Tracking.accdb (Command Line) Follow the process outlined in the User's guide (**Appendix II**)
Community Relations Specialist/Manager	7.	Inform Corporate Communications and/or communities of the pending outage, if appropriate.
Account Executive	8.	Inform Large Power Customers of the pending outage, if appropriate.

B. Unplanned Outage – Eversource Initiated

RESPONSIBILITY		ACTION
Line Crew/SOC	1.	Determine if an unplanned outage is necessary for work to be performed and identify the customers affected.
	2.	Notify the appropriate supervisor before taking any course of action or leaving the job site.
FSL/FSL-R/FSDB/SOC	3.	Provide confirmation and approve the need for the unplanned outage.
Line Crew	4.	Attempt to speak with every affected customer. If customer does not come to the door, complete a door hanger and leave it on the door knob.
	5.	Contact the SOC to determine if any customer who did not come to the door is a ME customer and request that the representative call the ME customer(s) to notify them of the impending unplanned outage.

RESPONSIBILITY		ACTION
DSO	6.	Check the accounts for ME's as requested by the line crew. Call any ME customers to notify them of the impending unplanned outage.
	7.	Note the customer's account with the results of the telephone call for both consent and non consent.
	8.	Immediately inform the line crew of the results of searching the accounts and calling ME customers.
Line Crew/SOC	9.	If any ME customer does not answer the telephone, or states they cannot take an interruption of service at that time, the work will be postponed until written notification can be made. Refer to section A. Planned Outage – Eversource Initiated of this procedure.
	10.	If the work is to be postponed, door hangers should be removed.
	11.	If the interruption of service is going to proceed, the crew may remove door hangers from the premises of customers notified by telephone.
	12.	Provide the DSO with the method which the customers were notified of the unplanned outage: door hanger, contacted by telephone, verbal notification, etc.

C. Planned Outage – Customer Initiated

RESPONSIBILITY		ACTION
Field Technician/Field Tech Specialist/PCDB	1.	Determine if a planned outage is necessary for work to be performed.
Field Technician/Field Tech Specialist/PCED (continued)	2.	Provide the customer with information about Eversource scheduling practices, payment issues and safety policies, as needed.
	3.	Obtain customer contact information for both office and site, the preferred customer outage completion date, nature of the customer's work, and preliminary Eversource billing estimates.
	4.	Establish work scope and construction standards.
	5.	Meet with FSL/FSL-R/FSED or designee, and review work scope, standards, and preferred customer outage completion date.
FSL/FSL-R/FSED	6.	Perform a field review prior to scheduling to identify and discuss any design considerations. The working foreman may participate in the field review and the job safety assessment as deemed appropriate.

RESPONSIBILITY		ACTION
	7.	Assume responsibility to schedule proposed and alternate customer outage dates.
	8.	Schedule appropriate resources in local schedule using I-Scheduler.
	9.	Notify other affected customers of the customer initiated planned outage. Depending on the timing, this may be through written notification (refer to Appendix I) or through direct contact with the affected customers.
FSL/FSL-R/FSED (continued)	10.	Review job schedule and expected conditions for the work to be performed approximately 1 week ahead of the scheduled date.

- If the anticipated conditions may prevent the job from being accomplished, contact the customer, apprise the customer of the situation, and discuss the option to postpone the work.
  - If the customer chooses to maintain the schedule, provide the cancellation deadline, Eversource contact phone number, and Eversource employee name.
  - The working foreman will perform a final job safety analysis, on site, on the day of the job but in advance of the appointment to determine if the job can proceed. It is the working foreman's responsibility to notify the customer of the status of the job.
- In the event the job is postponed to the alternate date, notify other affected customers and the SOC.

VIII. SOC-11004 REVISION HISTORY

Revision Number	Date	Reason
Rev 0	11/06/08	Original issue
Rev 1	10/31/16	Removed appendices to update procedure with new technology

SOC-11004 Planned and Unplanned Outage Scheduling and Customer Notification

IX. APPENDIX

Appendix I – PONS User Guide
Appendix II – Instructions for SOC Planned Outage Tracking Database

Northeast Utilities System

Planned Outage Notification System (PONS)

User Guide

Provided by

IT Enterprise Applications

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1.0 Revision History

Ver#	*Date*	*Version Information*
1.0	6/05/13	Initial Version

2.0 System Overview

The **Planned Outage Notification System or PONS** is a system application that allows you to create planned outage notifications to inform customers of an upcoming planned electrical outage through Customer Letter Correspondence, or through Predictive Dialer files. PONS utilizes EDS and C2 information to generate a list of customers affected by a Planned Outage. That list is then used to generate notifications to those affected customers. PONS has the capability of generating notifications in two forms, Customer Letter Correspondence or Predictive Dialer.

Letter Correspondence
The main form of notifying customers of a Planned Outage is via a letter. These letters are generated by the C2 correspondence batch process, printed on 8.5 x 11 letter stock, and directly mailed to the customer through the U.S. Postal Service. These notifications need to be created at least 5 days in advance. In addition, the letter is attached to the C2 customer account.

Predictive Dialer
The second form of notifying customers of a Planned Outage is by phone. PONS creates a file that can be used by a third party dialer application (not part of this application) that can call the customers associated with the outage.

There are several steps to utilize this form of communication. These steps include:

Step 1: Creating an affected customer list in PONS
Step 2: Creating a voice recording of the details
Step 3: Utilizing a third party dialer application to perform the calling

3.0 System Requirements

PONS is web-based system; it can be run on any PC that has network access and Internet Explorer.

To run reports, the following software is necessary, which is standard on NU standard computers:

- Acrobat Reader
- Microsoft Excel

4.0 User Security Requirements

PONS is a secure application that is set up with certain user levels. The two levels are as follows:

Level 1 - Ability to create Postcards.
Level 2 – Ability to create Predictive Dialer filers.

A user can be authorized in both levels, allowing them to create both postcards and/or predictive dialer files.

5.0 How to Access ERAS

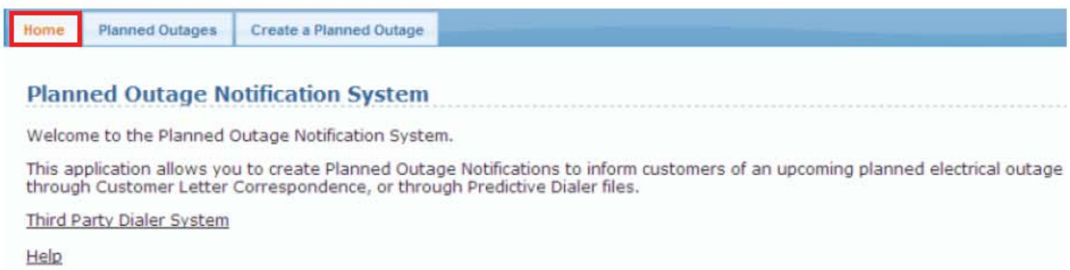
PONS can be accessed directly via the link below:

http://apps.nu.com/apps/eds/pons/Default.aspx

6.0 Overview and Basic Navigation

There are three tabs in PONS: "Home", "Planned Outages", and "Create a Planned Outage".

Home: The "Home" tab contains a Welcome statement, a link to the third party dialer website for predictive dialers, and a help link.



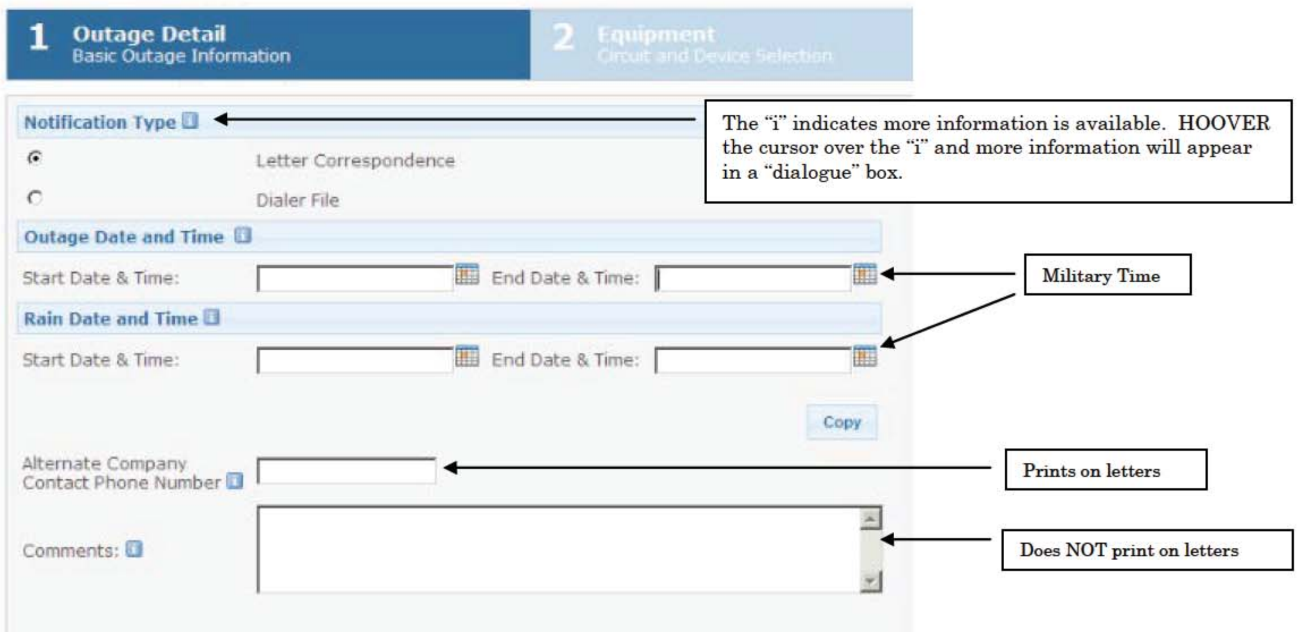
Planned Outages: The "Planned Outages" tab is where you will see any previous or pending requests. This page contains several filers and sort options to help you located specific outage requests. The filter criteria allows you to filter on specific criteria, which includes: outage dates, just your requests, all requests, *cancelled requests, and circuit number. To see the results of your criteria selection CLICK the APPLY button.

By default, the "Just My Requests" filter will show when you log in. This filter will display only the requests you have created. If you wish to see all requests for other users, you can UNCHECK this box and CLICK "Apply".

Each grid heading can be used as a sort function by simply CLICK on the column heading and the data will automatically sort.

*Note: Cancelled Requests does not imply a cancelled outage. It indicates that the notification request was cancelled prior to the print date.

Create a Planned Outage: The "Create a Planned Outage" tab allows the user to select: the type of notification, the outage dates, equipment affected, and customers affected. This tab walks you through three screens: 1. Outage Detail, 2. Equipment Selection, and 3. Customer Selection.



7.0 Create a Planned Outage Steps

Before you create your job, make sure you know your information related to the outage. Once you have your information and are ready to create your job, open the PONS website.

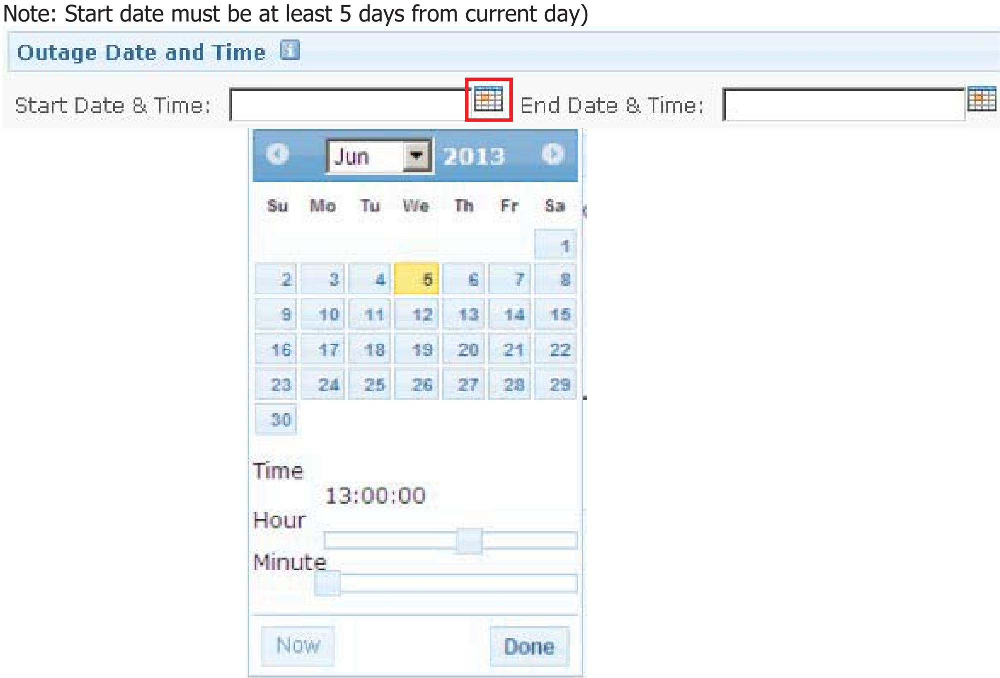
7.1 "Outage Detail"

The "Outage Detail" tab is the first step in creating an outage notification. This tab is where you will:

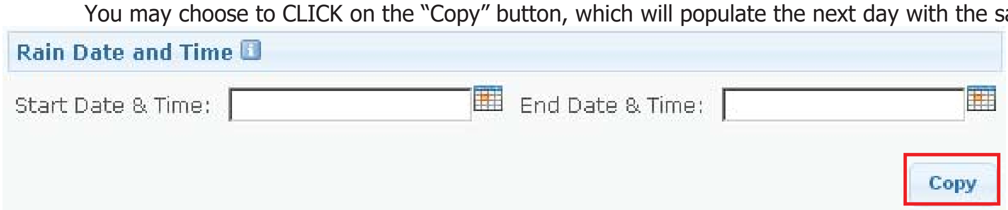
CHOOSE the "Notification Type"
ENTER the "Outage Date and Time" and "Rain Date and Time" in military time
ENTER an "Alternate Company Contact Phone Number" if applicable
NOTE: This phone number will print on the letters.
INDICATE any "Comments" that will help you identify the outage within PONS
NOTE: This information is NOT printed on the letters.
CLICK "Next" button to move to "Equipment Selection"

STEP 1: CLICK the radio button to choose the notification type

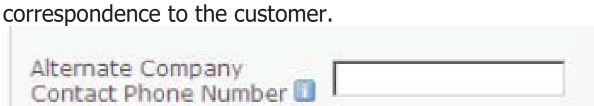
STEP 2: CLICK on the Calendar to SELECT the outage date and times
Note: Start date must be at least 5 days from current day)



STEP 3: CLICK on the Calendar to **SELECT** the rain date and times (if applicable)
You may choose to CLICK on the "Copy" button, which will populate the next day with the same times.



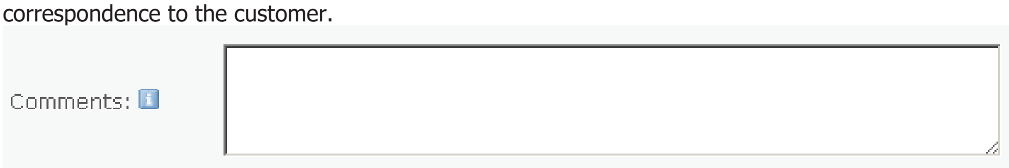
STEP 4: ENTER an alternate company contact phone number (if applicable). This phone number will **PRINT** on the letter correspondence to the customer.



Example of Alternate Phone Number in Letter:

If you have any questions, please contact our Area Work Center at (860) 665-2129 Monday-Friday between 7:00 a.m. and 3:30 p.m. Outside those times, we invite you to call our Customer Service Center at 1-800-286-2000 (860-947-2000 Hartford/Meriden) or visit our Web site at www.cl-p.com. Our representatives are available to assist you Monday through Friday from 7:00 a.m. - 7:00 p.m. and Saturday from 10:00 a.m. - 3:30 p.m..

STEP 5: ENTER any comments that will help you to identify the outage. This information does **NOT print** on the letter correspondence to the customer.



STEP 6: CLICK "Next" button to move to "Equipment Selection"

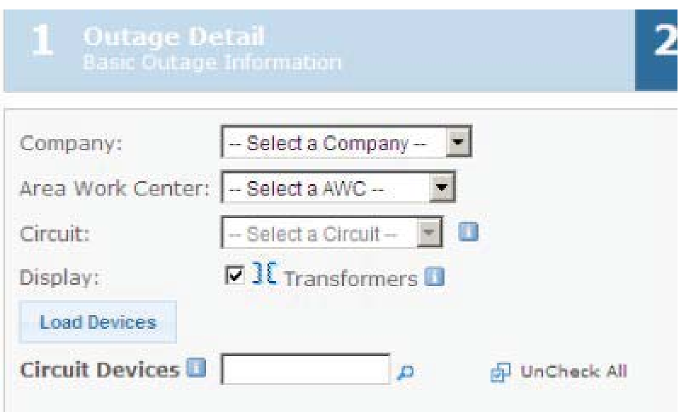
7.2 "Equipment" Selection

The "Equipment" selection screen allows you to select the affected devices that will determine the customers affected by the outage. You will need to select all devices that will be affected by the outage. Multiple devices can be chosen.

To select the circuit you will need to select the state, Area Work Center (AWC) and then the circuit. By default, transformers are excluded from the list. If you would like the transformers to appear in the tree, CHECK the box next to "Display" Transformers .

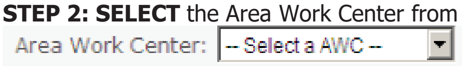
As you select the state and AWC, the list of circuits will be dynamically created based on that AWC. Once the tree is created, you will also have the ability to search for text in the tree.

You will want to look over the devices that are selected and make sure it looks correct. If it does not look correct, you can uncheck the device and start over. If it looks correct, you will click on the "Next" button to continue.

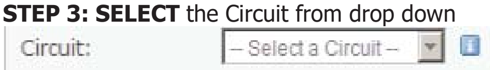


STEP 1: SELECT the company from drop down

STEP 2: SELECT the Area Work Center from drop down



STEP 3: SELECT the Circuit from drop down

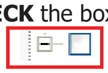


STEP 4: CHECK box if you would like to display Transformers

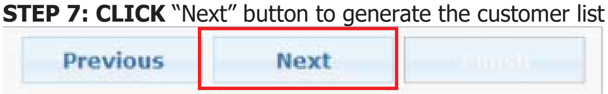
STEP 5: CLICK "Load Devices"

Once the devices load, you may search information by entering the information in the Circuit Devices field and CLICKing the magnifying glass.

STEP 6: CHECK the box next to each device affected



STEP 7: CLICK "Next" button to generate the customer list and move to the "Customer Selection" screen



7.3 "Customer" Selection

The customer selection screen is the last step in the process for the letter correspondence. If you are creating a predictive dialer, please see NEXT STEPS to PREDICTIVE DIALER.

This screen allows you to review the customer list and select or deselect the customers you would like to notify. By default, all customers will be selected to receive the notification. Critical customers are displayed at the top of the list. The screen displays the following information:

a. **Notification** – The type of outage notification (Letter Correspondence or Dialer File)
b. **Company** – The company that the outage affects (CL&P or WMECO)

c. **AWC** – The AWC that the outage affects
d. **Circuit** – The Circuit that the outage affects
e. **Outage Date** – These are main dates and times you selected for the outage.
f. **Rain Date** – These are the rain dates and times (if applicable)
g. **Devices** – This shows the circuit and all devices that are part of the outage
h. **Customer List** – This will show all the customers that could be selected as part of the outage, as well as the following information about the customer:

1. **Critical Customer –** These customers will show at the top of the list and flagged with the critical customer code next to the them.
2. **Last Name**
3. **First Name**
4. **Street No**
5. **Street Site**
6. **Unit No**
7. **Site Town**
8. **Site State**
9. **Phone Number**
10. **Customer Account**

STEP 1: REVIEW the customer list
STEP 2: SELECT the customers that will be notified about the outage

By default, ALL customers associated with your selected devices will be included in the notification

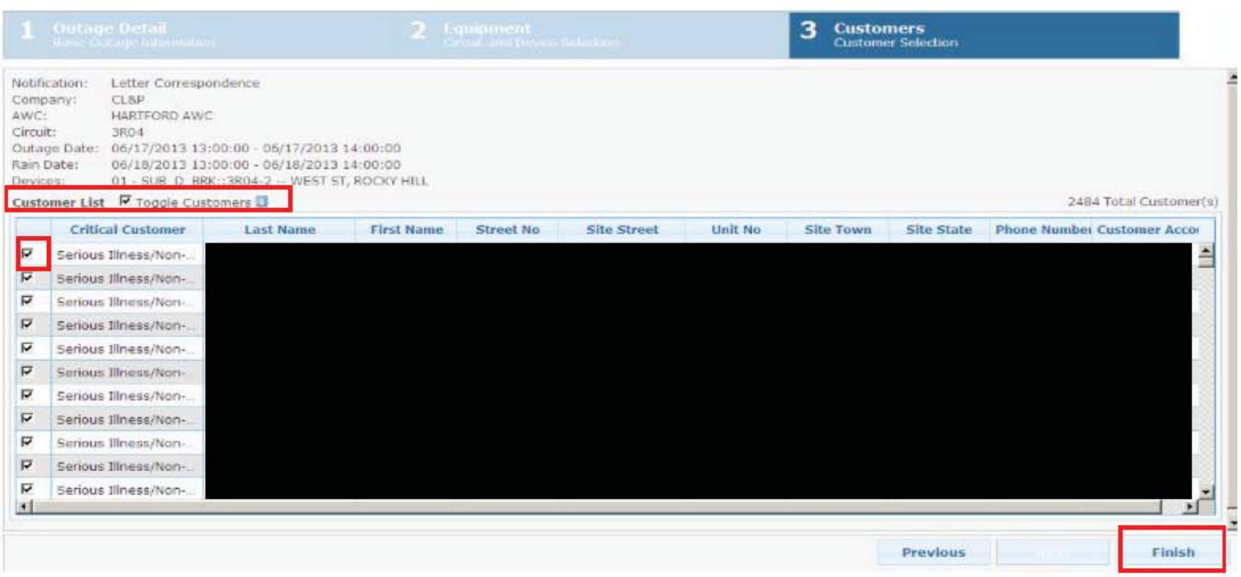
Customer List ☑ Toggle Customers

2.1: UNCHECK box to deselect customers

☐

NOTE: To Deselect ALL customers UNCHECK the box next to Customer List Customer List ☐ Toggle Customers

STEP 3: CLICK "Finish" button. Wait for your request to process. Once completed, the job has been created. Letters will be batched and printed overnight.

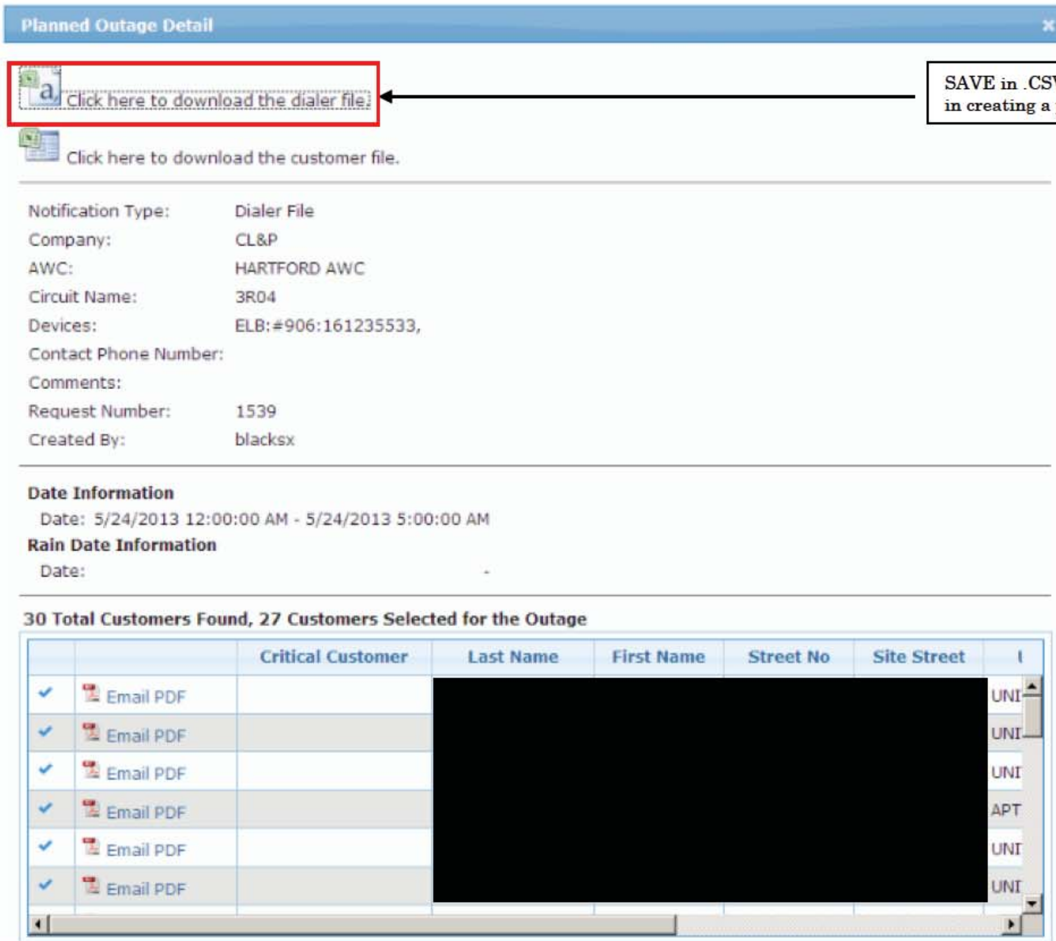


7.4 "Planned Outage Detail" Summary Screen

The Planned Outage Detail Summary screen is a detailed view of the entire job submitted. This includes all the information you filled in from the first step to the last. Please take the time to review this information and if it is incorrect in any way, you will want to cancel the job and recreate it. Please refer to "Cancelling a Request" for instructions.

NOTE: If you created a dialer file, it will be located on this screen. You must **CLICK** to download file and **SAVE** this file in .CSV format, in order to proceed with the creation of the predictive dialer.

The customer file is available for download for both types of notifications.



SAVE in .CSV format for the next steps in creating a predictive dialer

8.0 Cancelling a Request

To cancel an active request, you will need to be in the "Planned Outages" tab. Make sure you have your requests showing – "Just My Requests"

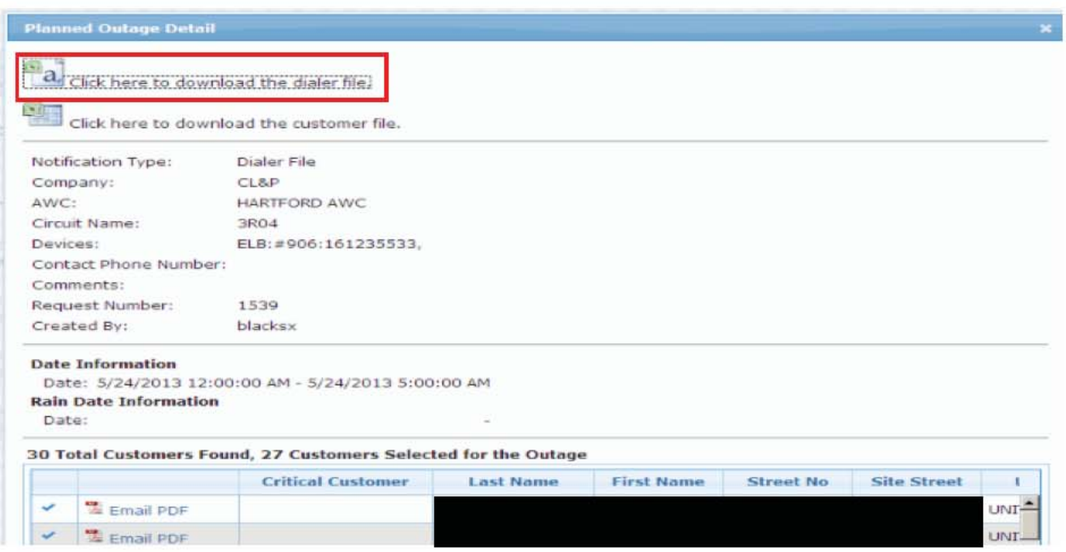
SELECT the request you need to cancel by clicking on the to the left of the request.

NOTE: If the request has been sent to the printer, you will not be able to cancel the request.

9.0 Next Steps to Creating a Predictive Dialer

Follow the STEPS in 7.0 Create a Planned Outage. Remember to choose "Dialer File" on the "Outage Detail" screen.

From the "Planned Outage Detail" Summary screen, you must **CLICK** to download file and **SAVE** this file in .CSV format, in order to proceed create the predictive dialer.



Record the message to be played to the customers

STEP 1 – SCRIPT your message and have it in front of you ready to read. Be sure that the message has been approved by Corporate Communications.

Here is an example:

"This is Connecticut Light and Power calling to inform you that our previously scheduled power outage for September 9th, 2010 with a rain date of September 10th, 2010 has been CANCELLED.

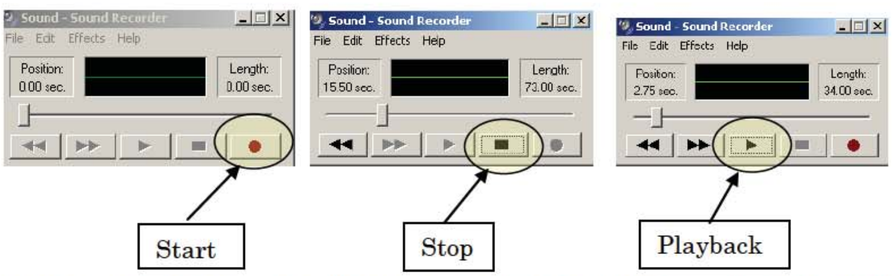
We are planning another scheduled power outage for September 15th, 2010 with a rain date of September 16th, 2010.

We apologize for any inconvenience this may have caused.

Thank you"

STEP 2 – OPEN your sound recorder by going to "Start→ Programs → Accessories → Entertainment → Sound Recorder"

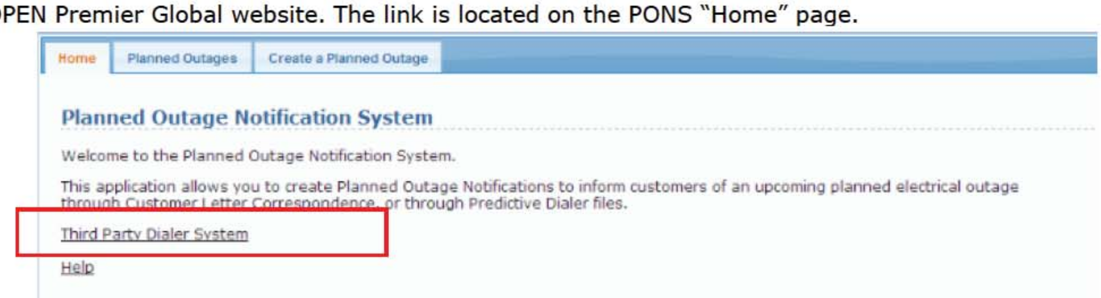
STEP 3 – CLICK the record button  and slowly read your scripted message into your microphone (you will experience better quality if you have a separate microphone headset) and stop button  when you are finished. Playback to review



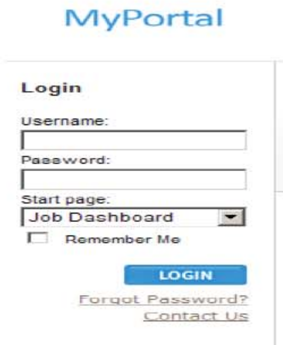
Step 4 – Once you have a successful recording, CLICK "File → Save" and SAVE to a location where you can retrieve it easily.

Sending the notification out to customers

Step 1 – OPEN Premier Global website. The link is located on the PONS "Home" page.



Step 2 – SELECT Input Username = "nu-bd" and Password = "request from PONS admin"



Step 3 – CLICK login

Step 4 – SELECT "Jobs" tab from the portal screen

Step 5 – SELECT "Create/Send Job" from the selections in the "Jobs" tab

Step 6 – SELECT the job type of the notification to be delivered.
SELECT " Voice .

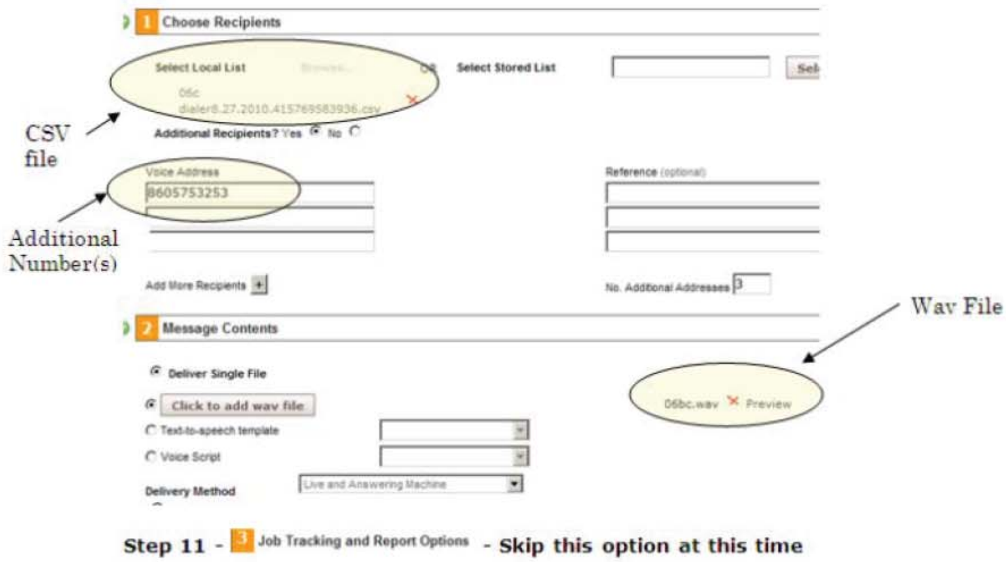
Step 7 – 1 Choose Recipients Choose the recipients of the message. You created this csv file from PONS. To select the .csv file, CLICK Browse... from "Select Local List" Browse to Add a File to find the .csv file you saved earlier. Once selected, CLICK Upload. This will load the file selected into the "Select Local List" window. Once loaded, CLICK Done .

Step 8 (OPTIONAL) – ADD additional recipients not in the list of customers. You may want to have your own number called when the callout is started. If you want to add additional recipients, CLICK "Yes' next to Additional Recipients" and ADD the numbers you want called in the boxes provided.

Step 9 - 2 Message Contents Select the message contents. This is the .wav file you created with the sound recorder earlier.

To add the .wav file you recorded earlier, SELECT Click to add wav file . This will open the file upload window. CLICK Browse to Add a File to find the .wav file. Once selected, CLICK Upload . This will load the file selected into the "Select Local List" window. Once loaded, CLICK Done .

Step 10 – VERIFY the correct csv and wav files are listed.



Step 11 - 3 Job Tracking and Report Options **- Skip this option at this time**

Step 12 – 4 Delivery Schedule This enables you to either send the job out immediately or schedule it for a later date and time.

Deliver Immediately – To deliver as soon as you are done setting up the notification, SELECT Send Now (Express) and then Review & Send

Schedule Delivery - To deliver at a later date and time, SELECT Scheduled and pick Start Date Time 10/19/10 6:00 PM and then Review & Send

Step 13- REVIEW the details of the notification.

REVIEW & SEND

1 Recipients

Click to hide

Recipient List(s):	06c dialer8.27.2010.415769583936.csv
Additional Recipient(s):	None selected.

2 Voice Message Contents

Click to hide

Live Answer File :	06bc.wav
File Type :	WAV
Answering Machine File:	
File Type :	
Alternate Answering Machine File:	
File Type :	

3 Job Tracking & Report Options

Click to hide

Campaign Name (Cust Ref):	
Billing Code:	
Delivery Method:	PAMD
Report Type:	detail
# of Retries	DEFAULT

4 Delivery Schedule

Click to hide

Back Submit

Step 14- CLICK Submit to start the notification

Notification has been sent

Planned Outage Notification Process

This process is required for **all** Planned Outages greater than a single transformer. Customer notification and SOC notification is still required for **all** Planned Outages.

Why the change?

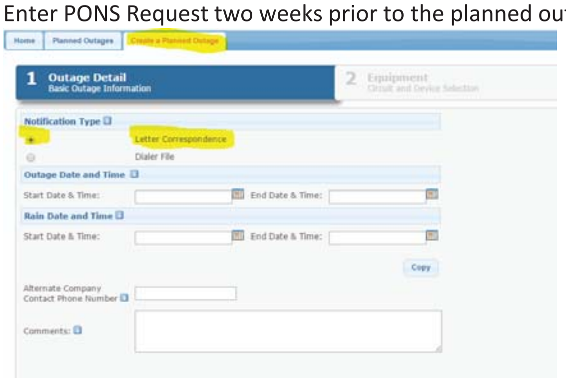
PONS will continue to be the tool to utilize to send Planned Outage Letter Correspondence to our customers, which is required by the NHPUC. The Planned Outage Database was created to help track all planned outages. The database is a place for everyone to see all planned outages on the system in one location. This will replace the need to manage/email spreadsheets at the Regional level. The SOC will be initiating "Reminder" IVR calls the day before every Planned Outage and will initiate "Rain Date" and "Cancel" IVR calls as required.

Please email any questions/changes to NHSOC@eversource.com.

Procedure CO-1144 will be revised in the near future. Until then , please use the following steps as a guideline:

Step 1

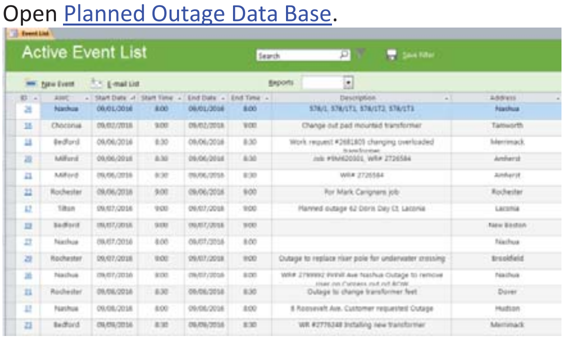
Enter PONS Request two weeks prior to the planned outage. (Always select Letter Correspondence)



PONS Link
PONS User Guide

Step 2

Open Planned Outage Data Base.

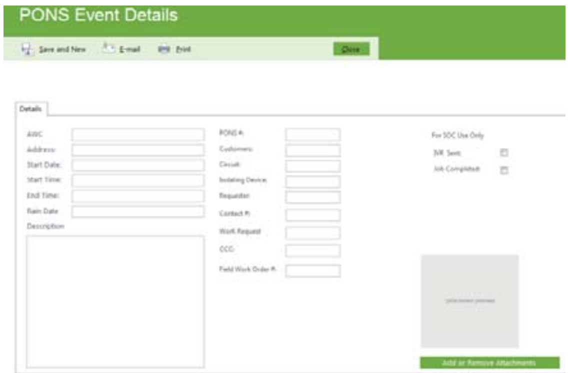


Step 3

Click on “New Event”

Enter all information regarding the planned outage that was entered into the PONS request in the corresponding fields shown below:

Please note;
*All fields are mandatory.
*Please enter a detailed description of work, as it will assist to ensure the proper messaging is sent.



Click “Save and New”

Your event will then be added to the Active Events list.

Step 4

Crew in the field notifies the SOC before and after the outage so an Event can be created in OMS, also required by the NHPUC. **If the outage is cancelled or delayed, please see the important message at the bottom of this guideline.**

Reminder of the contact numbers for the SOC:

NH Distribution System Operations Center Phone Listings		
Manager	Don Nourse	(603) 634-3117
Supervisor	Chris Piccolo	(603) 634-3150
Supervisor	Tom Boulter	(603) 634-3152
Supervisor Line		(603) 634-3120
General Inquiries		(603) 634-2400
Central Region	Local	(603) 634-2799
	Toll Free	(844) 647-6212
Eastern Region	Local	(603) 634-2999
	Toll Free	(844) 647-6214
Northern Region	Local	(603) 634-2699
	Toll Free	(844) 647-6211
Southern Region	Local	(603) 634-2899
	Toll Free	(844) 647-6213
Western Region	Local	(603) 634-3099
	Toll Free	(844) 647-6215

SOC Initiated IVR Call

The SOC will be initiate "Reminder" IVR calls the day before every Planned Outage.

Hello, this is an important message from Eversource. We're calling to remind you that our crews will be working in your area tomorrow, 00/00/0000, to make reliability improvements to our electric system. To enable our crews to perform this work as quickly and as safely as possible, a temporary power outage will occur from 00:00am to 00:00am. We're sorry for any inconvenience. If you have any questions, please call us at 1-800-662-7764. Thank you, good bye!

The SOC will be initiate "Rain Date" And "Cancel" IVR calls as needed.

Rain Date Utilization call:
Hello, this is an important message from Eversource. We're calling with an update regarding our work in your area. Due to unforeseen circumstances, the temporary power outage that was originally scheduled for 00/00/0000, has been rescheduled to 00/00/0000 from 00:00am to 00:00am. This temporary power outage will enable our crews to perform their work as quickly and as safely as possible. We're sorry for any inconvenience. If you have any questions, please call us at 1-800-662-7764. Thank you, good bye!

Cancel Planned Outage call:
Hello, this is an important message from Eversource. We're calling with an update regarding our work in your area. Due to unforeseen circumstances the temporary power outage that was originally scheduled for 00/00/0000, has been canceled, and your power will not be interrupted. We look forward to contacting you if this work is rescheduled. If you have any questions, please call us at 1-800-662-7764. Thank you, good bye!

*__Important__! Please email NHSOC@eversource.com if any changes or Rain date/Cancel calls are needed.

Information

& Requirements

For Electric Supply

NH 2017 Edition

This publication supersedes similar publications previously issued.

EVERSOURCE ENERGY

SAFETY FIRST

The safety of customers, contractors, company employees, and the general public is the number one priority of providing electric service connections.

This booklet has been prepared to establish standardized rules and regulations for the installation of electric service connections made within the areas served by Eversource (hereinafter referred to as the "Company"). Any service not installed in accordance with the terms and conditions of this booklet will not be connected to the Company's system. Willful disregard of these rules and regulations will result in the service being disconnected.

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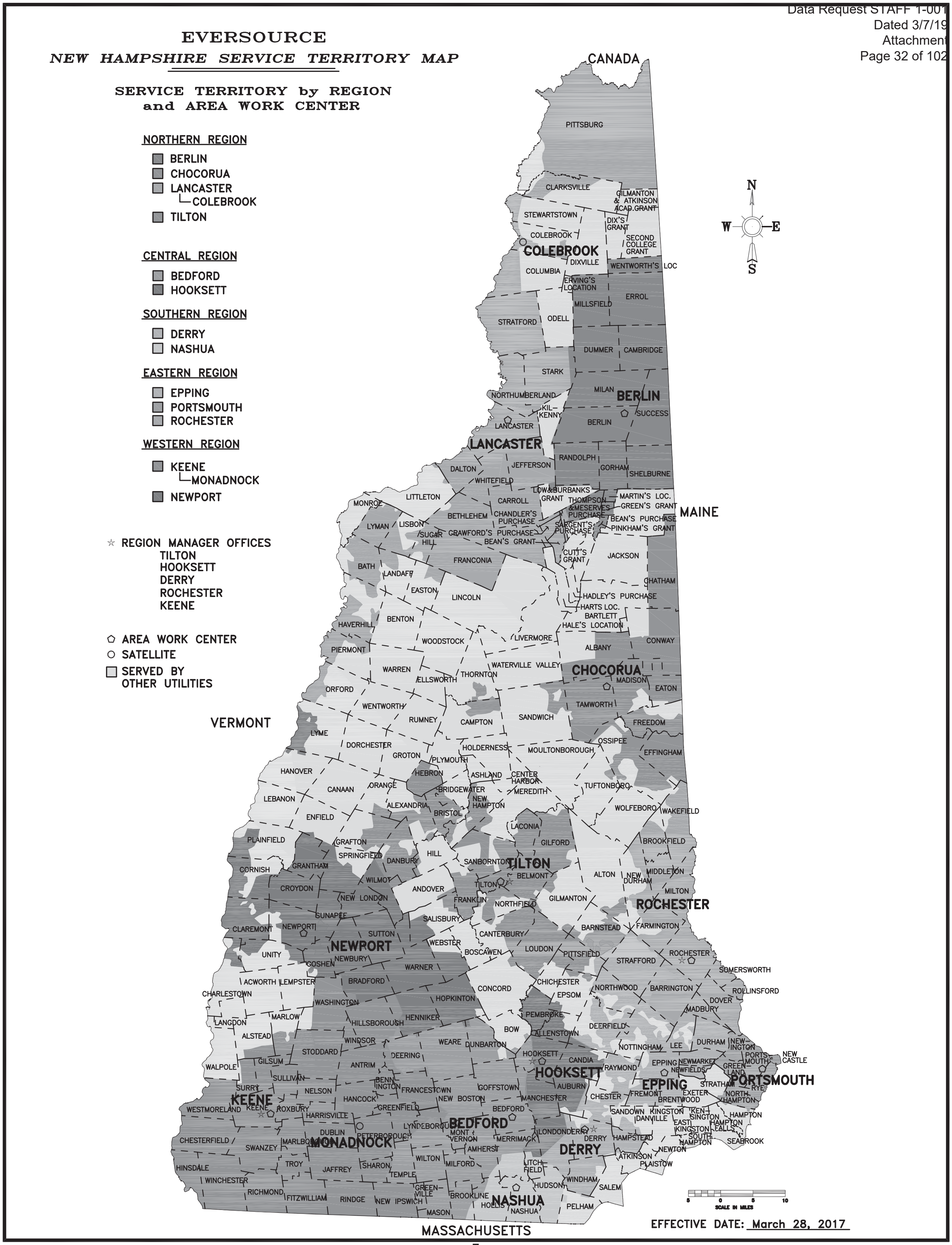
Mon- Fri 7am- 4:30pm

Bedford Area Work Center	12 Bellemore Drive, Bedford NH 03110
Berlin Area Work Center	68 Jericho Road, Berlin NH 03570
Chocorua Area Work Center	169 White Mountain Hwy, Tamworth, NH 03817
Derry Area Work Center	16 A Street, Derry NH 03038
Epping Area Work Center	265 Calef Highway, Epping NH 03042
Hooksett Area Work Center	13 Legends Drive, Hooksett NH 03106
Keene Area Work Center	19 Production Avenue, Keene NH 03431
Lancaster Area Work Center	425 Main Street, Lancaster NH 03584
Nashua Area Work Center	370 Amherst Street, Nashua NH 03063
Newport Area Work Center	280 Sunapee Street, Newport NH 03773
Portsmouth Area Work Center	1700 Lafayette Road, Portsmouth NH 03801
Rochester Area Work Center	74 Old Dover Rd, Rochester NH 03867
Tilton Area Work Center	64 Business Park Drive, Tilton NH 03276


EVERSOURCE
NEW HAMPSHIRE SERVICE TERRITORY MAP
SERVICE TERRITORY by REGION and AREA WORK CENTER
NORTHERN REGION
BERLIN
CHOCORUA
LANCASTER
COLEBROOK
TILTON
CENTRAL REGION
BEDFORD
HOOKSETT
SOUTHERN REGION
DERRY
NASHUA
EASTERN REGION
EPPING
PORTSMOUTH
ROCHESTER
WESTERN REGION
KEENE
MONADNOCK
NEWPORT
REGION MANAGER OFFICES
TILTON
HOOKSETT
DERRY
ROCHESTER
KEENE
AREA WORK CENTER
SATELLITE
SERVED BY OTHER UTILITIES
CANADA
VERMONT
MAINE
MASSACHUSETTS
N
W
E
S
PITTSBURG
CLARKSVILLE
GILMANTON & ATKINSON ACAD.GRANT
STEWARTSTOWN
DIX'S GRANT
SECOND COLLEGE GRANT
COLEBROOK
DIXVILLE
COLUMBIA
WENTWORTH'S LOC
ERVING'S LOCATION
MILLSFIELD
ERROL
STRATFORD
ODELL
DUMMER
CAMBRIDGE
STARK
MILAN
NORTHUMBERLAND
KILKENNY
SUCCESS
LANCASTER
RANDOLPH
GORHAM
SHELBURNE
JEFFERSON
DALTON
WHITEFIELD
LOW&BURBANKS GRANT
THOMPSON &MESERVES PURCHASE
MARTIN'S LOC.
GREEN'S GRANT
BEAN'S PURCHASE
PINKHAM'S GRANT
MONROE
LITTLETON
CARROLL
CHANDLER'S PURCHASE
SARGENT'S PURCHASE
LYMAN
LISBON
BETHLEHEM
SUGAR HILL
CRAWFORD'S PURCHASE
BEAN'S GRANT
CUTT'S GRANT
JACKSON
BATH
LANDAFF
FRANCONIA
CHATHAM
EASTON
LINCOLN
HADLEY'S PURCHASE
HARTS LOC.
BARTLETT
HALE'S LOCATION
HAVERHILL
BENTON
WOODSTOCK
LIVERMORE
CONWAY
ALBANY
PIERMONT
WARREN
ELLSWORTH
THORNTON
WATERVILLE VALLEY
CHOCORUA
MADISON
EATON
ORFORD
WENTWORTH
TAMWORTH
RUMNEY
CAMPTON
SANDWICH
FREEDOM
LYME
DORCHESTER
GROTON
PLYMOUTH
HOLDERNESS
MOULTONBOROUGH
OSSIPEE
EFFINGHAM
HANOVER
HEBRON
ASHLAND
CENTER HARBOR
MEREDITH
TUFTONBORO
CANAAN
ORANGE
BRIDGEWATER
LEBANON
ALEXANDRIA
NEW HAMPTON
WOLFEBORO
WAKEFIELD
ENFIELD
BRISTOL
LACONIA
PLAINFIELD
GRAFTON
GILFORD
BROOKFIELD
SPRINGFIELD
DANBURY
HILL
SANBORNTON
TILTON
CORNISH
GRANTHAM
BELMONT
ALTON
NEW DURHAM
MIDDLETON
CROYDON
WILMOT
ANDOVER
MILTON
NEW LONDON
FRANKLIN
NORTHFIELD
GILMANTON
ROCHESTER
SUNAPEE
SALISBURY
CLAREMONT
NEWPORT
SUTTON
BARNSTEAD
FARMINGTON
CANTERBURY
WEBSTER
LOUDON
NEWPORT
NEWBURY
BOSCAWEN
PITTSFIELD
UNITY
GOSHEN
WARNER
STRAFFORD
SOMERSWORTH
ACWORTH
LEMPSTER
BRADFORD
CONCORD
CHICHESTER
NORTHWOOD
BARRINGTON
ROLLINSFORD
CHARLESTOWN
WASHINGTON
HOPKINTON
EPSOM
DOVER
MADBURY
LANGDON
MARLOW
HILLSBOROUGH
HENNIKER
PEMBROKE
DEERFIELD
ALSTEAD
WINDSOR
WEARE
DUNBARTON
BOW
ALLENSTOWN
NOTTINGHAM
LEE
DURHAM
NEWINGTON
NEW CASTLE
STODDARD
GILSUM
ANTRIM
DEERING
HOOKSETT
CANDIA
EPPING
NEWMARKET
NEWFIELDS
GREENLAND
PORTSMOUTH
WALPOLE
SULLIVAN
BENNINGTON
FRANCESTOWN
GOFFSTOWN
RAYMOND
STRATHAM
RYE
SURRY
NELSON
HANCOCK
NEW BOSTON
MANCHESTER
AUBURN
CHESTER
FREMONT
BRENTWOOD
EXETER
NORTH HAMPTON
KEENE
WESTMORELAND
ROXBURY
HARRISVILLE
GREENFIELD
BEDFORD
SANDOWN
KINGSTON
DANVILLE
EAST KINGSTON
KENSINGTON
HAMPTON
HAMPTON FALLS
DUBLIN
PETERBOROUGH
LYNDEBOROUGH
MONT VERNON
MERRIMACK
LONDONDERRY
HAMPSTEAD
SOUTH HAMPTON
SEABROOK
CHESTERFIELD
SWANZEY
MARLBOROUGH
MONADNOCK
AMHERST
DERRY
NEWTON
HINSDALE
TROY
JAFFREY
SHARON
WILTON
MILFORD
LITCHFIELD
ATKINSON
PLAISTOW
WINCHESTER
TEMPLE
HUDSON
WINDHAM
SALEM
RICHMOND
FITZWILLIAM
RINDGE
NEW IPSWICH
GREENVILLE
BROOKLINE
HOLLIS
NASHUA
PELHAM
MASON
SCALE IN MILES
EFFECTIVE DATE: March 28, 2017

TOWN	Eversource Area Work Center	TOWN	Eversource Area Work Center	TOWN	Eversource Area Work Center
Albany	Chocurua	Chichester*	Tilton	Gilmanton*	Tilton
Alexandria*	Tilton	Claremont*	Newport	Gilsum	Keene
Allenstown*	Hookett	Clarksville*	Lancaster	Goffstown	Bedford
Alstead*	Keene	Colebrook*	Lancaster	Gorham	Berlin
Alton*	Rochester, Tilton	Columbia*	Lancaster	Goshen*	Newport
Amherst	Bedford, Nashua	Concord*	Newport, Tilton	Grafton*	Tilton
Andover*	Tilton	Contoocook*	Bedford	Grantham	Newport
Antrim	Keene	Conway*	Chocurua	Greenfield	Keene
Atkinson*	Derry	Cornish*	Newport	Greenland*	Portsmouth
Auburn*	Derry, Hookett	Croydon*	Newport	Green's Grant	Berlin
Barnstead*	Tilton	Dalton	Lancaster	Greenville	Bedford
Barrington	Epping, Rochester	Danbury*	Tilton	Hampstead*	Derry
Bath*	Lancaster	Danville*	Derry	Hampton*	Portsmouth
Bean's Grant	Lancaster	Deerfield*	Hookett, Epping	Hancock	Keene
Bedford	Bedford	Deering	Keene, Newport	Hanover*	Tilton
Belmont*	Tilton	Derry*	Derry	Harrisville	Keene
Bennington	Keene	Dover	Rochester	Haverhill*	Lancaster
Berlin	Berlin	Dublin	Keene	Hebron*	Tilton
Bethlehem*	Lancaster	Dummer	Berlin	Henniker	Newport, Keene
Boscawen*	Newport, Tilton	Dunbarton*	Newport	Hill*	Tilton
Bow*	Bedford	Durham*	Epping, Rochester	Hillsborough	Bedford, Keene
Bradford	Keene, Newport	Easton*	Lancaster	Hinsdale	Keene
Brentwood*	Epping	Eaton*	Chocurua	Hollis	Bedford, Nashua
Bridgewater*	Tilton	Effingham*	Chocurua	Hooksett	Bedford, Hookett
Bristol*	Tilton	Enfield*	Newport	Hopkinton*	Newport
Brookfield*	Rochester	Epping*	Epping	Hudson	Derry, Nashua
Brookline	Bedford, Nashua	Epsom*	Hookett, Epping, Tilton	Jaffrey	Keene
Cambridge	Berlin	Errol	Berlin	Jefferson	Berlin, Lancaster
Campton*	Tilton	Farmington*	Rochester	Keene	Keene
Candia*	Hookett	Fitzwilliam	Keene	Laconia*	Tilton
Canterbury*	Tilton	Francestown	Bedford, Keene	Lancaster	Lancaster
Carroll	Lancaster	Franconia	Lancaster	Landaff*	Lancaster
Charlestown*	Newport	Franklin*	Tilton	Lee*	Epping, Rochester
Chatham	Chocurua	Freedom*	Chocurua	Lempster*	Newport
Chester*	Derry, Epping	Fremont*	Epping	Lisbon*	Lancaster
Chesterfield	Keene	Gilford*	Tilton	Litchfield	Derry, Hookett, Nashua

Municipalities partially or wholly served by Eversource NH

TOWN	Eversource Area Work Center	TOWN	Eversource Area Work Center	TOWN	Eversource Area Work Center
Littleton*	Lancaster	North Hampton*	Portsmouth	Stark	Berlin, Lancaster
Londonderry*	Derry, Hookett, Nashua	Northfield*	Tilton	Stewartstown*	Lancaster
Loudon*	Tilton	Northumberland	Lancaster	Stoddard	Keene
Lyman*	Lancaster	Northwood*	Epping	Strafford	Epping, Rochester
Lyme*	Newport	Nottingham*	Epping	Stratford	Lancaster
Lyndeboro	Keene, Bedford	Orange*	Tilton	Stratham*	Portsmouth
Madbury	Epping, Rochester	Orford*	Lancaster	Success	Berlin
Madison*	Chocurua	Ossipee*	Chocurua	Sugar Hill*	Lancaster
Manchester	Bedford, Hookett	Pelham*	Derry	Sullivan	Keene
Marlborough	Keene	Pembroke	Hookett	Sunapee*	Newport
Marlow*	Keene	Peterborough	Bedford, Keene	Surry*	Keene
Martin's Location	Berlin	Piermont*	Lancaster	Sutton*	Newport
Mason	Bedford	Pinkham's Grant	Berlin	Swanzey	Keene
Meredith*	Tilton	Pittsburg*	Lancaster	Tamworth*	Chocurua
Merrimack	Bedford, Nashua	Pittsfield*	Tilton	Temple	Bedford, Keene
Middleton	Rochester	Plainfield*	Newport	Thornton*	Tilton
Milan	Berlin	Plymouth*	Tilton	Tilton	Tilton
Milford	Bedford	Portsmouth	Portsmouth	Troy	Keene
Millsfield	Berlin	Randolph	Berlin	Tuftonboro*	Chocurua
Milton	Rochester	Raymond*	Epping, Hookett	Unity*	Newport
Mont Vernon	Bedford	Richmond	Keene	Wakefield*	Rochester
Nashua	Nashua	Rindge	Keene	Warner	Newport
Nelson	Keene	Rochester	Rochester	Washington*	Keene
New Boston	Bedford, Keene	Rollinsford	Rochester	Waterville*	Chocurua
New Castle	Portsmouth	Roxbury	Keene	Weare	Newport
New Durham*	Rochester	Rye	Portsmouth	Webster*	Newport
New Hampton*	Tilton	Salisbury*	Newport, Tilton	Wentworth's Location	Berlin
New Ipswich	Bedford, Keene	Sanbornton*	Tilton	Westmoreland	Keene
New London	Newport	Sandown*	Derry	Whitefield	Lancaster
Newbury	Newport	Sandwich*	Chocurua	Wilmot*	Newport, Tilton
Newfields	Epping	Sharon	Keene	Wilton	Newport
Newington	Portsmouth	Shelburne	Berlin	Winchester	Keene
Newmarket	Epping	Somersworth	Rochester	Windham*	Derry, Nashua
Newport*	Newport	Springfield*	Newport	Windsor	Keene

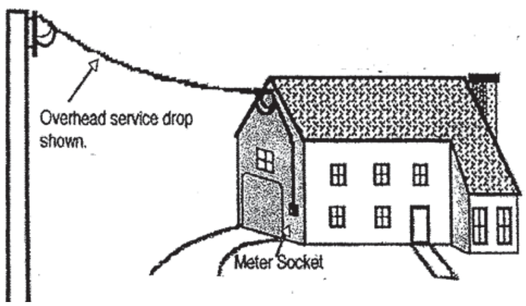
*** denotes municipalities are served by multiple utility companies.** **NOTE**: Contact ESSC at 1-800-362-7764 for the names of other utilities providing service to municipalities partially served by Eversource NH.

Service Attachments and Meter Locations

Please consult with an Eversource Technician prior to installing any meter socket to ensure acceptable placement on the structure.

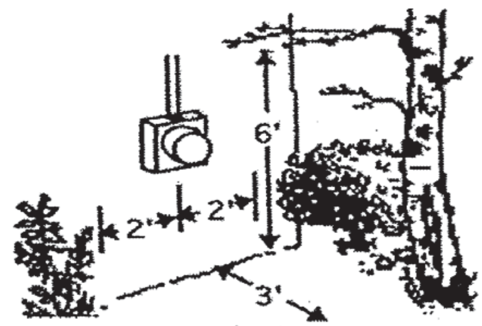
Acceptable

Service Attachment



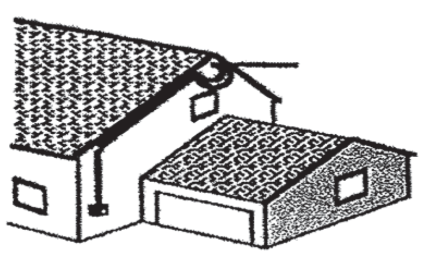
Attachment to gable end of house, 12' to 25' above finish grade. Generally meter should be located on gable end, driveway side of house.

Meter Socket Location

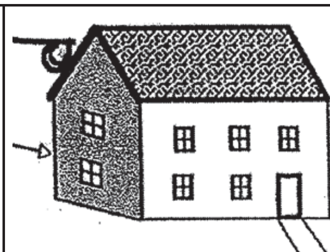


No shrubs, debris, fences or other structures in 4' side x 3' deep x 6' high space. (Article 324)

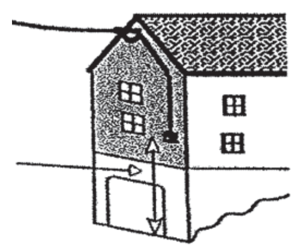
Unacceptable



Article 402 - Over roof, not accessible by ladder

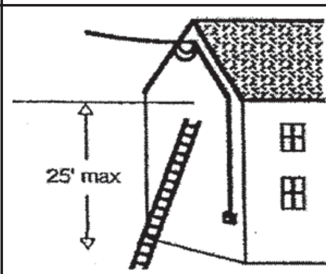


Article 325 -Meter on back of house

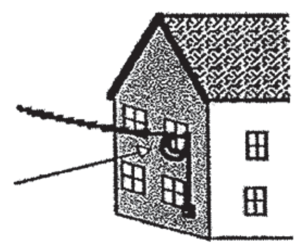


Article 316 - Meter above 5 ft

Article 404 - Mast not strong enough or guyed.



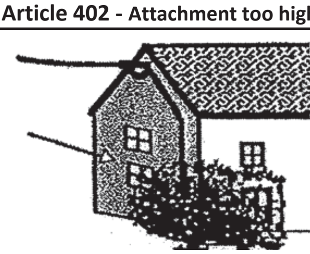
Article 402 - Attachment too high.



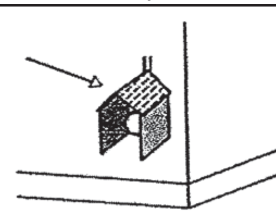
DTR 04.151.4 - Conductors too close to window/door.

EVERSOURCE ENERGY

For more information:
NH Electric Service Support Ctr
800-362-7764
NHnewservice@eversource.com
Monday - Friday 7 AM - 4:30 PM



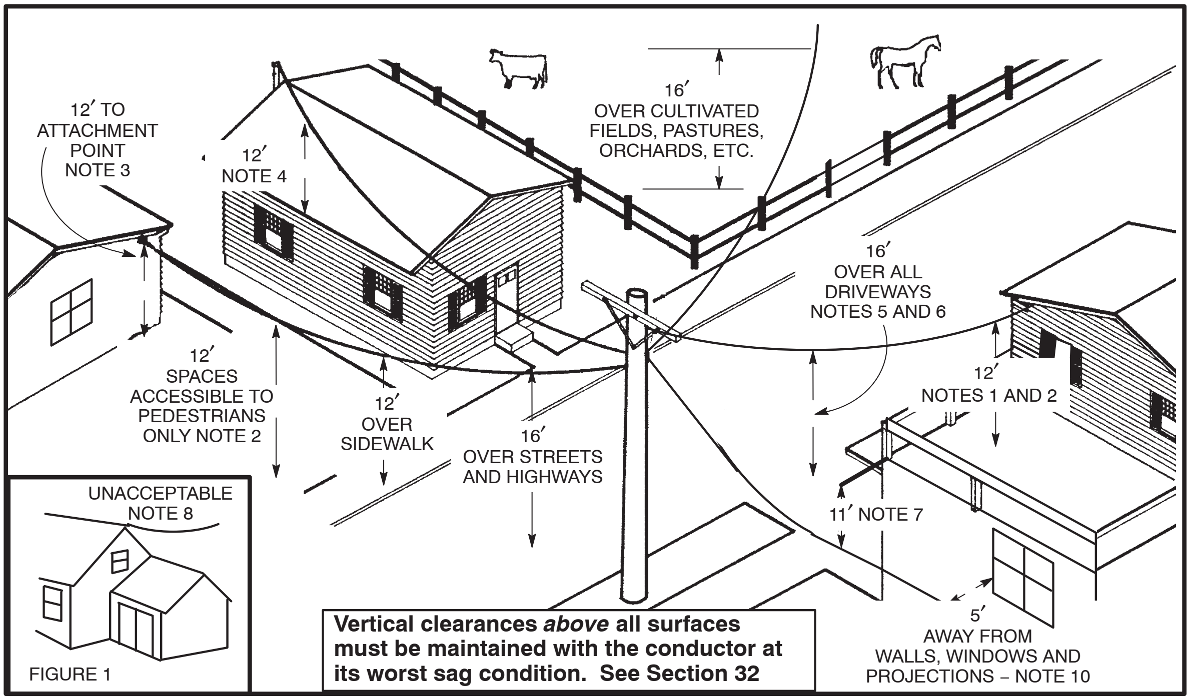
Article 324 - Meter not accessible



Article 324 - Meter Enclosed

GENERAL – This Standard specifies the clearance of ***services, 300 volts or less to ground***. These clearances define the position of these conductors when they are ***at rest***. For triplex and quadruplex cables which are not attached to buildings, refer to other pages in **Section 04**. The dimensions shown above are based on Rule 232 for vertical clearance, and Rule 234 for horizontal clearances and for clearances adjacent to buildings.

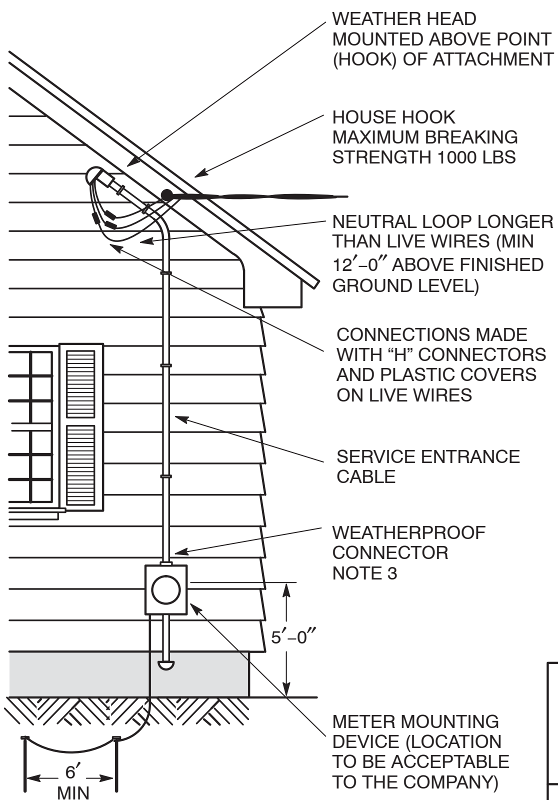
CLEARANCE FROM COMMUNICATIONS CABLES – Power company service drops, running above and parallel to communications service drops, shall have a minimum of 12 inches of clearance at any point in the span and at the building (in part, from the National Electrical Code–1996 edition Article 800–10(4)).

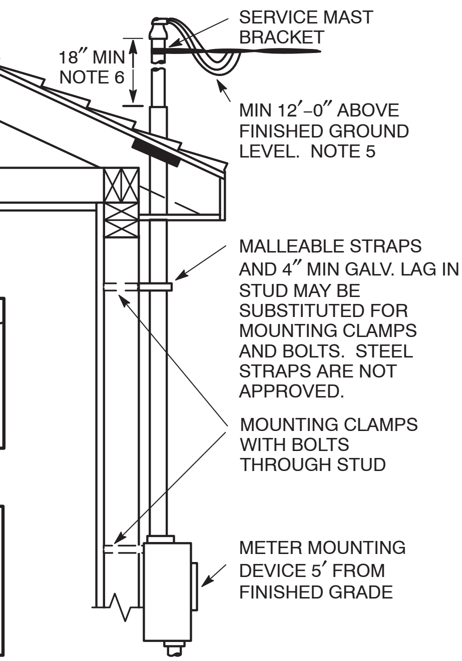


Notes

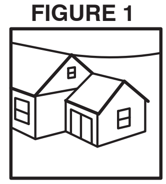
1. This clearance applies above flat roofs, balconies, and areas restricted to pedestrians only or to vehicles not exceeding 8 feet in height. Whenever possible, locate the service so that these service connections can be directly reached from a ladder placed securely on the ground.
2. Where the height of attachment at the building does not permit service drops to meet this value, the clearance may be reduced to 10 feet 6 inches.
3. The distance to the bottom of drip loops may be reduced to 10 feet 6 inches.
4. This clearance may be decreased to 3 feet 6 inches if the roof is ***NOT*** accessible to pedestrians by means of a doorway, ramp, window, stairway, or a permanently mounted ladder whose bottom rung is closer than 8 feet to the ground or other accessible surface.
5. This includes residential, commercial, and industrial driveways, parking lots, and other areas subject to truck traffic.
6. Where the height of attachment at the building does not permit service drops to meet this value, the clearance may be reduced to 12 feet 6 inches over ***residential driveways only***.
7. The clearance of a service that is ***below*** the level of an area accessible to pedestrians must be maintained with the service conductor at ***0 °F, initial sag***. See **Section 32**.
8. Service attachment located above building extension as shown in figure 1 is not acceptable because the service connections cannot be directly reached from a ladder placed securely on the ground.
9. Clearances shall conform to governmental requirements ***if*** the clearances are greater than those shown above (when crossing state highways in Massachusetts, for example).
10. Service conductors shall not be installed beneath openings through which material may be moved, nor shall they obstruct entrance to these openings (in part, from the National Electrical Code–1996 edition Article 230–9).

ORIGINAL 7/5/90 APPROVED 09/17/15	**MINIMUM CLEARANCES FOR SERVICES 0–300 VOLTS TO GROUND BASED ON NESC RULES 232 AND 234**			
	EVERSOURCE ENERGY	DESIGN & APPLICATION STANDARD	**DTR 04.151**	**4**





NOTE 1
FIGURE 1



NOTE 4
FIGURE 2

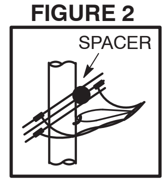


TABLE showing the size of support and the maximum distance in inches from the roof to the conductor deadend	Max Loaded Tension	Galvanized Rigid Conduit Support (Do Not Use Aluminum Conduit)		
Conductor	Lbs	2″	2 1/2″	3″
#4 & #2 Triplex	500	31″	58″	113″
1/0 Triplex	700	22″	41″	81″
#2 Quadruplex	600	28″	48″	94″
1/0 Quadruplex	840	18″	34″	87″

CUSTOMER RESPONSIBILITY

1. Furnish and install service mast, if required, adequate in strength to support service drop and sufficient height to meet minimum clearance (as shown in TABLE).
2. The meter mounting device shall be installed approximately 5 feet above the final grade except where specifically approved otherwise by the Company. It shall be plumb level and attached to the finished exterior of the building with rust resistant screws extending through the finish and into the sheathing.
3. Furnish and install service entrance cable from meter mounting device to service entrance switch box.
4. Furnish, install and connect NEC approved ground electrodes.
5. Equipment and installation must comply with the latest revision of the National Electrical Code and local codes.

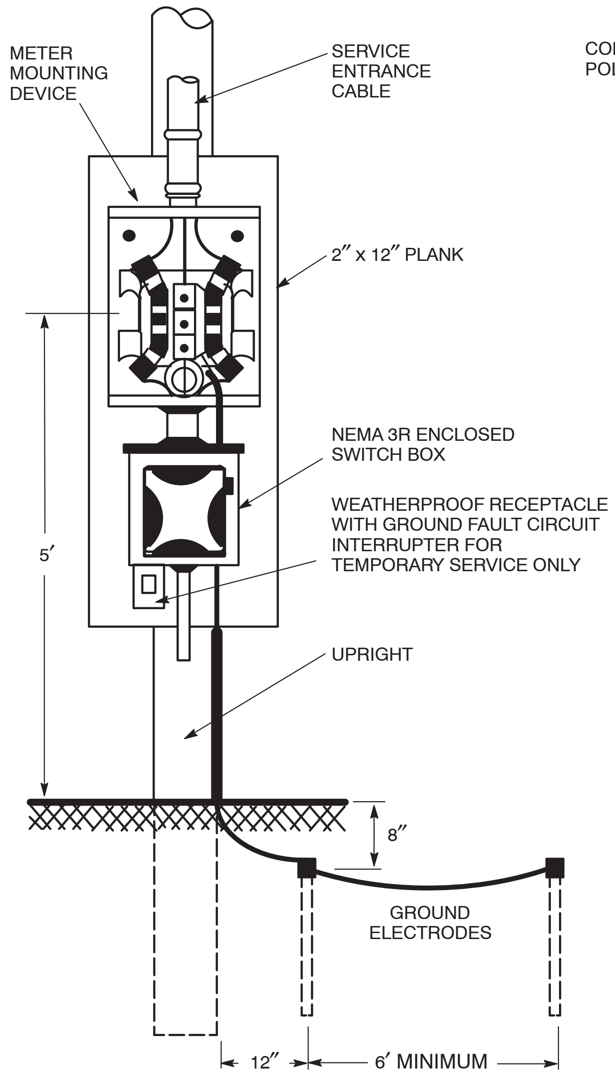
COMPANY RESPONSIBILITY

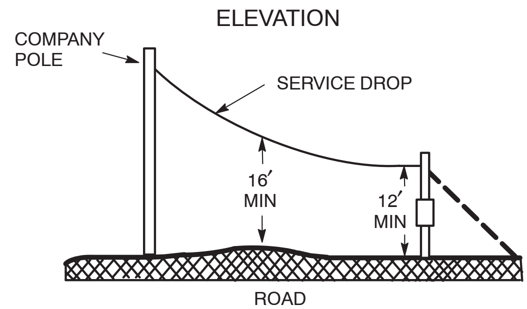
1. Furnish meter mounting device.
2. Furnish and install service entrance cable to meter mounting device (single–phase service only 200 amps or less).

Notes

1. Service attachment located above a building extension as shown in figure 1 is not acceptable because service connections cannot be directly reached from a ladder placed securely on the ground.
2. Consideration should be given to place service attachment high enough on the building to allow communication company attachment below it with the NESC required 12–inch separation.
3. Apply rubber silicone sealant to the weatherproof cable connector at top of meter.
4. Neutral loops shall be longer than the live conductor loops so that live wires part first under extreme tensions (figure 2).
5. The distance to the bottom of drip loops may be reduced to 10′–6″ if voltage is 300 volts or less to ground and 10 feet for 150 volts or less to ground.
6. See **DTR 04.151** for clearances beyond the house that shall be maintained in accordance with the NESC.

ORIGINAL 7/25/94 APPROVED 8/4/05	**OVERHEAD SERVICE ENTRANCE 200 AMPS AND SMALLER**		NH
	EVERSOURCE ENERGY	CONSTRUCTION STANDARD	**DTR 14.106** 3





COMPANY RESPONSIBILITY

1. Furnish meter mounting device, for permanent services only.
2. Furnish and install meter service entrance cable to meter mounting devices.

CUSTOMER RESPONSIBILITY

1. Install meter mounting device with rust−resistant screws on a 2″ x 12″ plank.
2. Provide NEMA 3R enclosed switch box below meter mounting device.
3. Furnish, install, and connect NEC approved ground electrodes.
4. Furnish and install service entrance cable from meter mounting device to switch box.
5. Equipment and installation must comply with the latest edition of the National Electrical Code, National Electrical Safety Code, and all local codes.

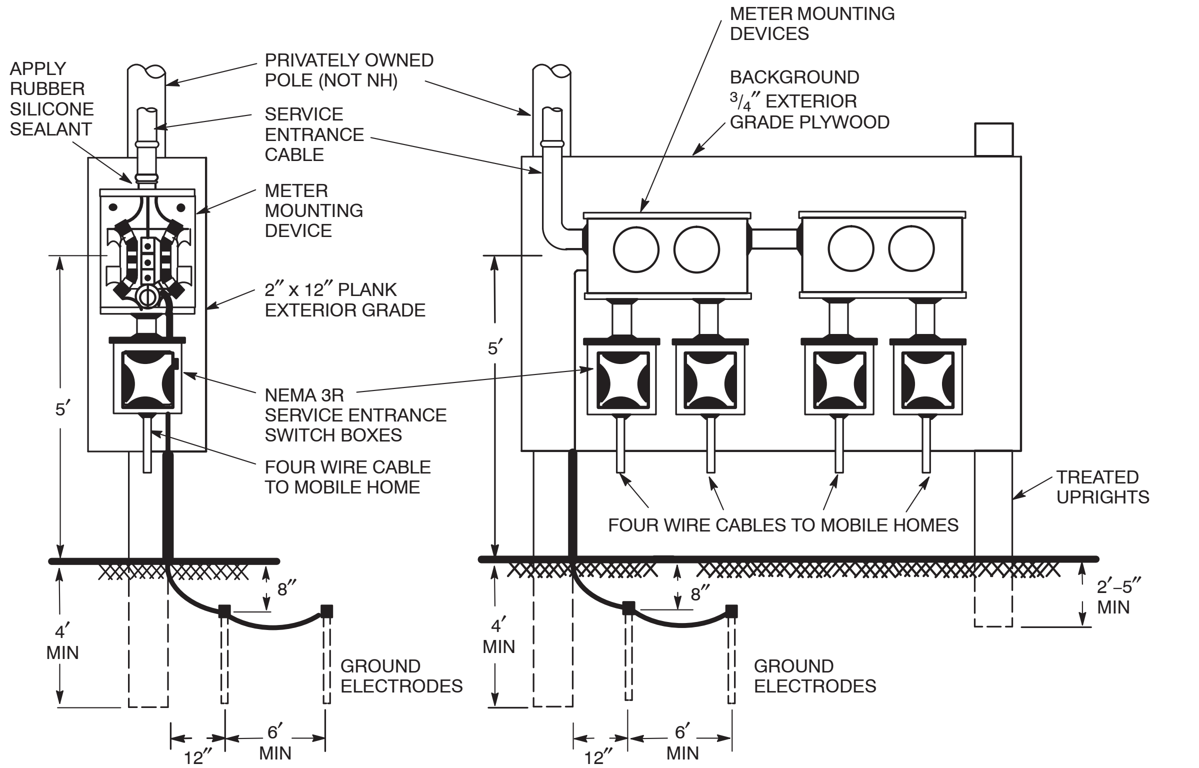
CUSTOMER RESPONSIBILITY
for Permanent Service Only

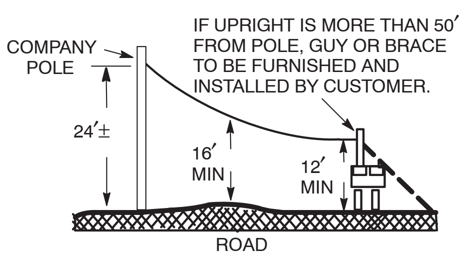
1. Furnish and install treated upright no less than solid 6″ x 6″ or laminated from three 2″ x 6″ uprights set 4′ in the ground suitably braced and sufficiently stable to support a person on a ladder and tall enough to provide the required 12′ or 16′ of clearance, (See elevation view) or a substitute acceptable by the Company.
2. Furnish and install 2″ PVC conduit on upright if upright is suitable for climbing.

CUSTOMER RESPONSIBILITY
for Temporary Service Only

1. Furnish and install treated upright no less than 4″ x 6″ set 4′ in the ground suitably braced and sufficiently stable to support a person on a ladder and tall enough to provide the required 12′ or 16′ of clearance (See elevation view), or a substitute acceptable by the Company.
2. Furnish and install meter mounting device, weatherproof receptacle with ground fault circuit interrupter below switch box.
3. Furnish, install, and connect NEC approved ground electrodes.

ORIGINAL 7/25/94 APPROVED 7/30/14	TEMPORARY OR PERMANENT SINGLE−PHASE SERVICE MOUNTED ON METER PEDESTAL		NH
	EVERSOURCE ENERGY	CONSTRUCTION STANDARD	DTR 14.105	6





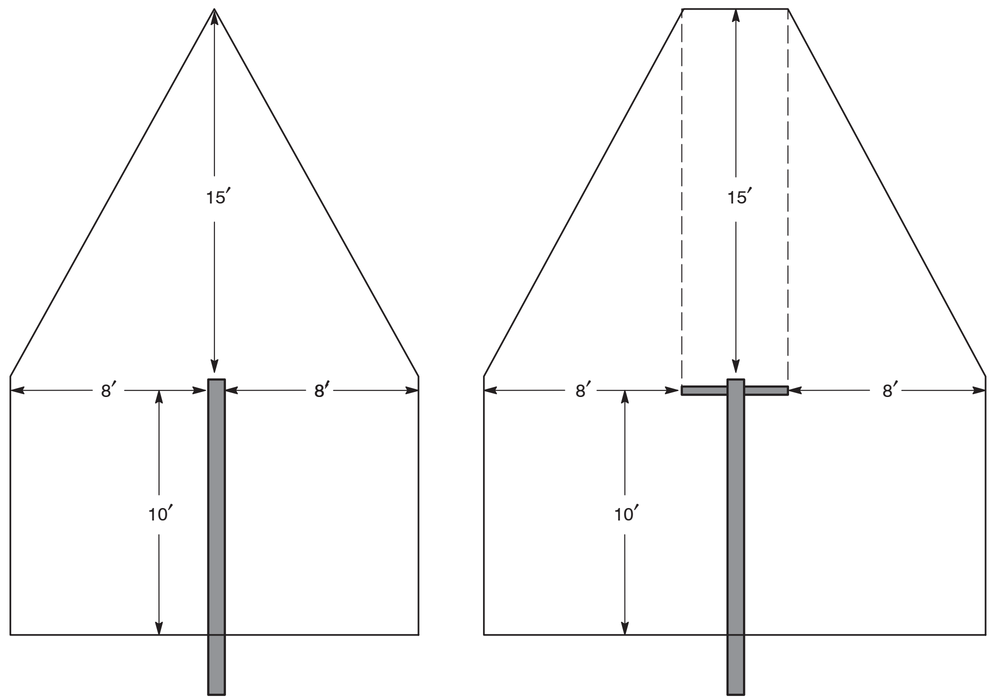
ELEVATION

CUSTOMER RESPONSIBILITY

1. Furnish and install treated upright no less than solid 6″ x 6″ or laminated from three 2″ x 6″ uprights set 4 feet in the ground suitably braced and sufficiently stable to support a person on a ladder and tall enough to provide the required 12 feet or 16 feet of clearance (see elevation view). Any substitute shall be acceptable to the Company.
2. Install meter mounting device with rust–resistant screws on a 2″ x 12″ plank or $^3/_4$–inch exterior grade plywood as shown above.
3. Furnish and install 2–inch PVC conduit on upright if upright is suitable for climbing.
4. Furnish, install, and connect NEC approved ground electrodes.
5. Furnish and install service entrance cable from meter mounting device to switch box(es).
6. Furnish and install NEMA 3R switch boxes with overcurrent devices.
7. Equipment and installation shall comply with the latest edition of the National Electrical Code, National Electrical Safety Code, and all local codes.

COMPANY RESPONSIBILITY

1. Furnish meter mounting device.
2. Furnish and install meter service entrance cable to meter mounting devices.

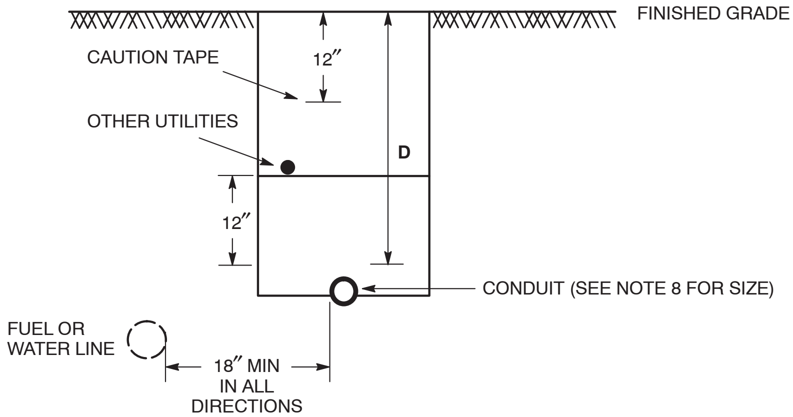


SINGLE PHASE **THREE PHASE**

Notes

1. **Overhead Primary (2.4 – 34.5 kV) Conductors** – See single–phase and three–phase figures. Minimum ten feet clearance to the nearest primary conductor. Species recognized as fast growing and/or structurally weak are to be removed; examples include red maple, ash, white pine, cherry, silver maple, poplar, birch and willow. All other trees and limbs are to be trimmed back to suitable laterals consistent with approved arboricultural practices.
2. **Hazardous Trees** – Trees and/or limbs up to 16–inches diameter at breast height outside or inside the specified trim zone shall be removed when deemed structurally weak and likely to be a risk to the electrical system.
3. **Secondary And Service Wire Conductors** – Vegetation shall be trimmed if necessary to prevent hard rubbing and chafing which could lead to wear and failure of the conductors.
4. **Inspections** – An inspection of proper trimming clearances will be made by a NH representative. New services will not be installed or energized unless properly cleared of vegetation.

ORIGINAL 10/21/03 APPROVED	**VEGETATION CLEARING SPECIFICATION FOR NEW SERVICES**			**NH**
09/09/15 CWP	EVERSOURCE ENERGY	DESIGN & APPLICATION STANDARD	**DTR 14.103**	**2**



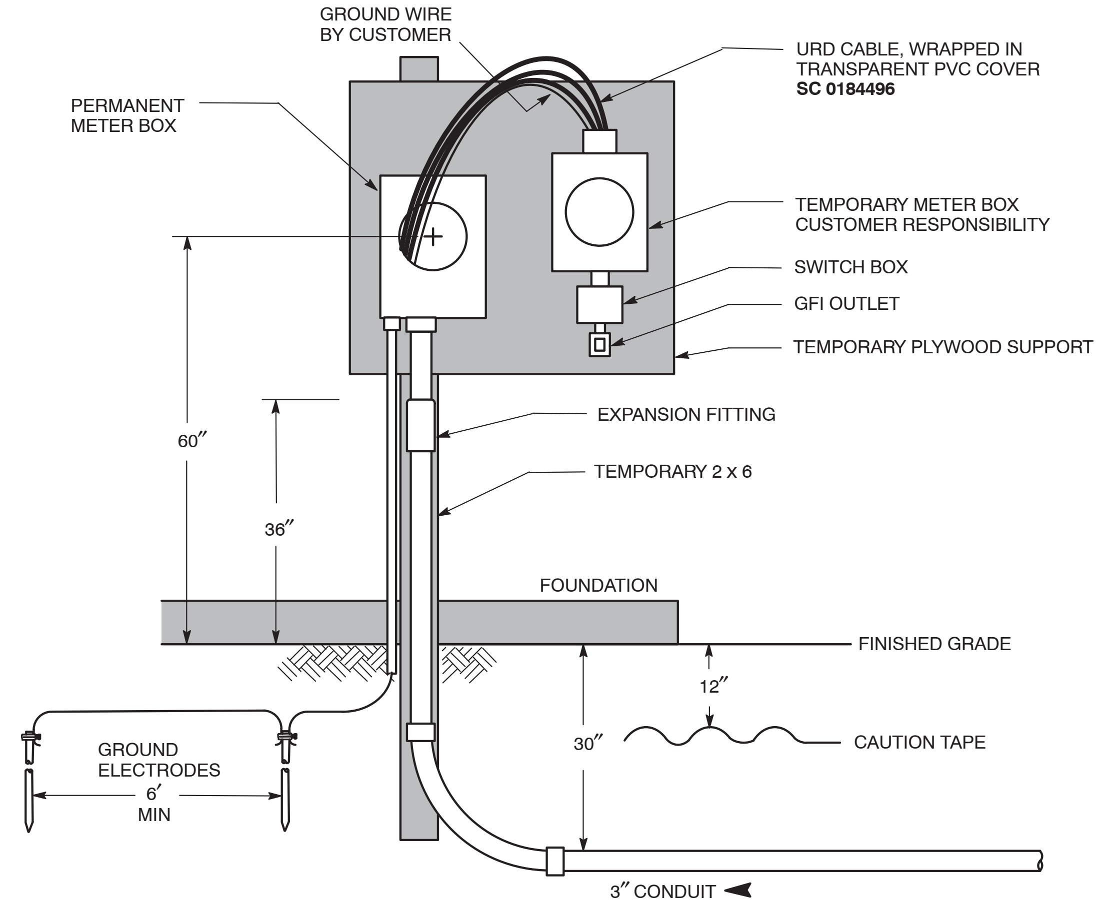
D = 36 inches for primary voltage cable
30 inches for secondary cables

Notes

1. All non−metallic conduit and fittings shall be electrical grade, Schedule 40 PVC, and shall conform to the applicable sections of NEMA TC2−1990 and be UL Listed. **Only gray−colored conduit will be accepted.** Any PVC conduit not having the proper NEMA and UL markings will not be accepted. All steel conduits shall conform to ASTM A120 and be rigid galvanized steel. All PVC conduit joints must be cemented. Steel fittings shall be sealed with compound.
2. All 90 degree sweeps will be made using rigid galvanized steel with a minimum radius of 24 inches for three inch, 36 inches for four and five inch, and 48 inches for six inch conduit. All steel sweeps within eighteen inches of surface shall be properly grounded.
3. ➤ A ten−foot horizonal sections of rigid galvanized steel conduit will be required at each sweep for primary. For secondary and services a ten−foot horizontal section if schedule 40 as per ANSI/NEMA TC2−1990.
4. The conduit should cross paved areas at approximately 90 degrees.
5. Backfill may be made with excavated material or comparable, unless material is deemed unsuitable by PSNH. Backfill shall be free of frozen lumps, rocks, debris, and rubbish. Organic material shall not be used as backfill. Backfill shall be thoroughly compacted in six−inch layers.
6. A suitable pulling string, capable of 200 pounds of pull, must be installed in the conduit before PSNH is notified to install cable. The string should be blown into the conduit after the run is assembled to avoid bonding the string to the conduit.
7. Routing of the conduit and inspection prior to backfill will be provided by PSNH. Installation of the conduit will be done by the contractor. The PSNH supervisor must be notified two business days prior to backfilling the trench. In the event that a cable cannot be successfully pulled through the completed conduit system due to a construction error, it will be the contractor's responsibility to locate and repair the involved conduit. The contractor will be responsible for all resulting expenses.
8. Normal conduit sizes for PSNH are three−inch for single−phase primary and secondary voltage cables, four−inch for three−phase secondary, and five−inch for three−phase primary.
9. All conduit installations must conform to the current edition of the *National Electric Safety Code,* state and local codes and ordinances, and where applicable, the *National Electric Code*.

ORIGINAL 04/10/06 APPROVED 4/9/12	**PRIMARY/SECONDARY CABLE INSTALLATION**			NH
	NORTHEAST UTILITIES	CONSTRUCTION STANDARD	**DTR 50.102**	**3**

1/2″ : 1′



CUSTOMER RESPONSIBILITY

1. The meter mounting device shall be installed approximately 5 feet above the final grade except where specifically approved otherwise by the Company. It shall be plumb level and attached to the finished exterior of the building with rust−resistant screws extending through the finish and into the sheathing.
2. Furnish, install, and connect NEC approved ground electrodes.
3. Furnish and install service entrance cable from meter mounting device to switch box.
4. Furnish and install Schedule 40 PVC conduit except as noted. Install caution tape 12 inches below grade. Provide a rigid steel elbow.
5. Equipment and installation must comply with the latest edition of the National Electrical Code (NEC) and all local codes. Expansion joint in conduit shall comply with NEC 300−7(b).
6. For services in excess of 200 feet servicing homes larger than 3,000 square feet, parallel 3−inch conduits shall be installed to a below−ground service enclosure located no more than 10 feet from the meter mounting device. A single 3−inch conduit from the service enclosure to the meter mounting device is sufficient, see **DTR 54.215**.
7. For services with any elevation change, PSNH may require a service enclosure located no more than ten feet from meter mounting device.

COMPANY RESPONSIBILITY

1. Furnish meter mounting device (permanent service only). Furnish caution tape.
2. Furnish and install cable and meter.
3. Attach 2 1/2″ x 2 1/2″ adhesive−backed signs: “WARNING, UNDERGROUND CABLE” and 3″ x 5″ “ELECTRIC SERVICE IN CONDUIT”. See **MAT L−013**.
4. Attach lettering to identify the source. See **DTR Section 43**.

ORIGINAL 10/21/03 APPROVED 4/7/11	**TEMPORARY/PERMANENT UNDERGROUND SERVICE 400 AMP & BELOW**			NH
	NORTHEAST UTILITIES	CONSTRUCTION STANDARD	**DTR 54.116**	3

SERVICE TRENCH – By Customer

The trench shall be in as direct a line as possible without reverse bends from the distribution facility to the customer service entrance. In order to minimize cable pulling forces, no more than two bends (not including riser at house or pole) exceeding a total combined change of 45 degrees shall be permitted.

1. Trench shall be of such depth to accommodate 30 inches minimum cover for service cables in conduit.
2. In order to prevent the conduit from being pulled out of the meter box, conduit shall be installed on virgin or well tamped soil. Trench bottom shall be undisturbed or relatively smooth earth, well tamped, and free of any debris that may be detrimental to the conduit.
3. Conduit in the trench should have a 4–inch–per–100 feet downward pitch toward the distribution facility, if physically possible. (This provides drainage away from the service entrance, and prevents stagnant water in the duct.)
4. Backfill shall not contain frozen material or stones larger than 2 inches in maximum dimension. Care shall be exercised to avoid damage to conduit during backfilling. Backfill shall be compacted, and shall be completed before the Company schedules cable installation.
5. When required, coordination with telephone, cable TV, or other utilities is the Customer's responsibility.

CONDUIT – By Customer

Standard conduit shall be minimum 3–inch diameter, rigid PVC, heavy wall, sunlight resistant (6 percent – 7 percent titanium dioxide by weight), Schedule 40 as per ANSI/NEMA TC 2–2003.

1. All 90 degree sweeps will be made using rigid galvanized steel with a minimum radius of 24 inches for three inch, 36 inches for four and five inch, and 48 inches for six inch conduit.
2. Conduit should cross paved areas at approximately 90 degrees.
3. A $^{1}/_{4}$–inch–diameter nylon pull rope, including 10 feet of slack, shall be installed in the conduit. Secure the pull line to a plastic conduit plug (e.g., **SC 0175161** for 3–inch diameter), at each end of the conduit run. Plugged ends of the conduit shall be left accessible.

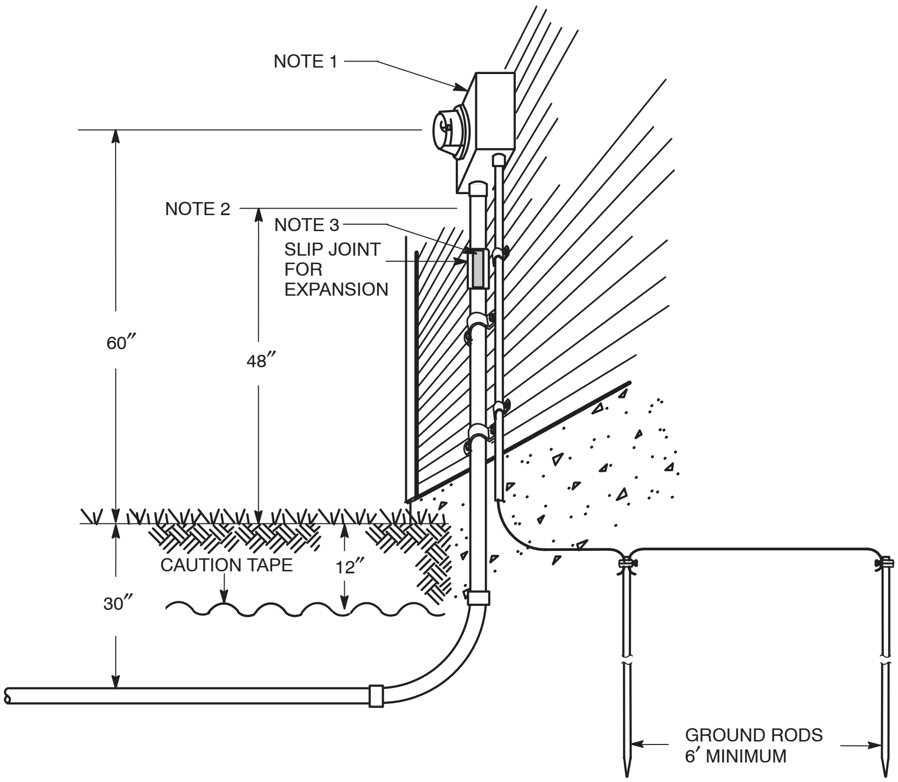
SERVICE FROM POLE – If service is from an overhead system, a grounded 90 degree galvanized steel bend shall be installed at the pole. See **DTR 12.057**.

SERVICE FROM HANDHOLE/TRANSFORMER – Extend conduit to distribution facility and mate to previously installed 10–foot conduit stub. Tie pull lines, slide conduit sleeve over both ends and secure with conduit cement. See **DTR 54.203**.

CAUTION – Customer shall not enter any Company structure because it could be energized.

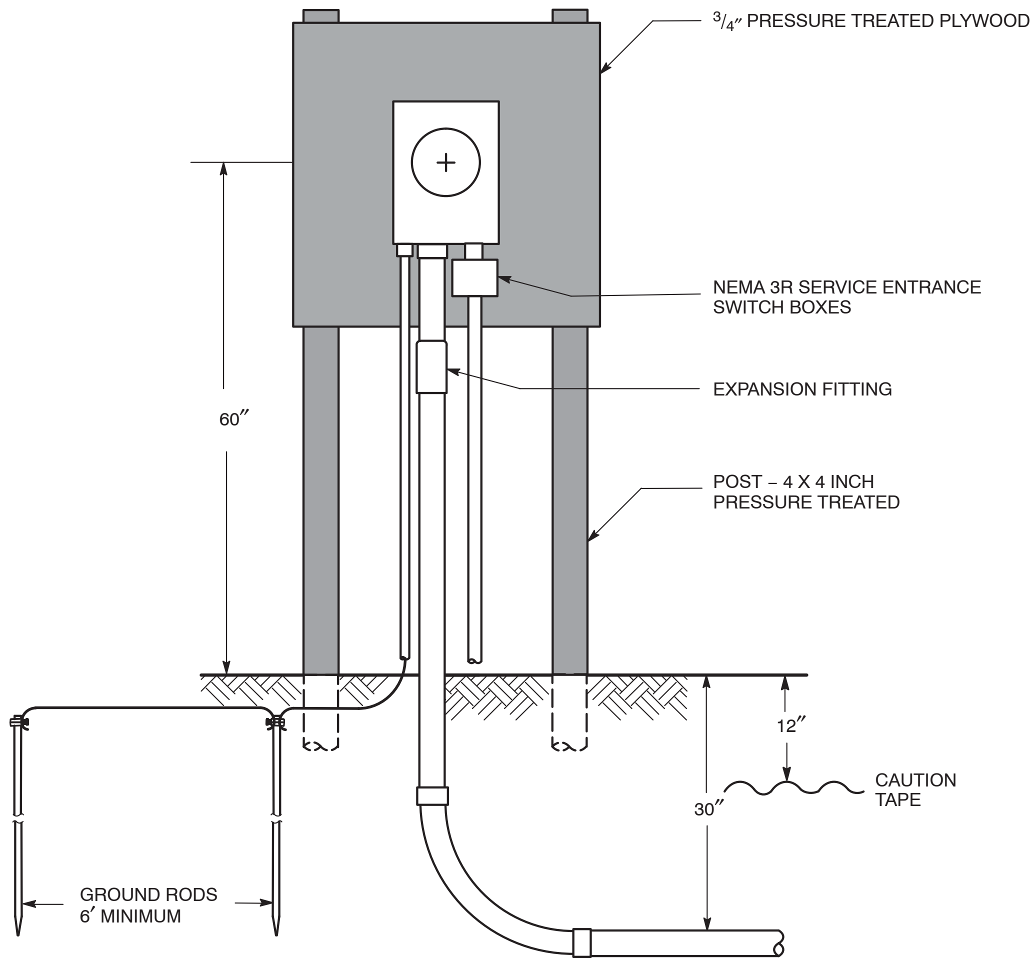
LIMITATIONS – In the event that a cable cannot be successfully pulled through the completed conduit system due to construction, it will be the contractors responsibility to locate and repair the involved conduit. The contractor will be responsible for all resulting expenses.

COMPANY CONSIDERATIONS – Services in conduit shall be identified at the transformer or handhole with a brass "SVC IN CNDT" tag. To aid troubleshooting, conduit service shall be clearly designated on mapping records.



Notes
1. Set meter socket plumb (by Customer).
2. Attach 2 1/2″ x 2 1/2″ adhesive backed signs: “WARNING, UNDERGROUND CABLE” and 3″ x 5″ “ELECTRIC SERVICE IN CONDUIT.” See **SPC’s L–019.01** and **L–014.01**.
3. Attach lettering to identify the source. See **DTR 43.061** and **DTR 43.062** – Note 3.
4. Furnish standard meter mounting device (permanent service only). Furnish caution tape.

ORIGINAL 12/6/12 APPROVED	**SERVICES IN CONDUIT 600 VOLT AND BELOW**			NH
5/1/14	NORTHEAST UTILITIES	DESIGN & APPLICATION STANDARD	**DTR 54.110**	**1**



COMPANY RESPONSIBILITY

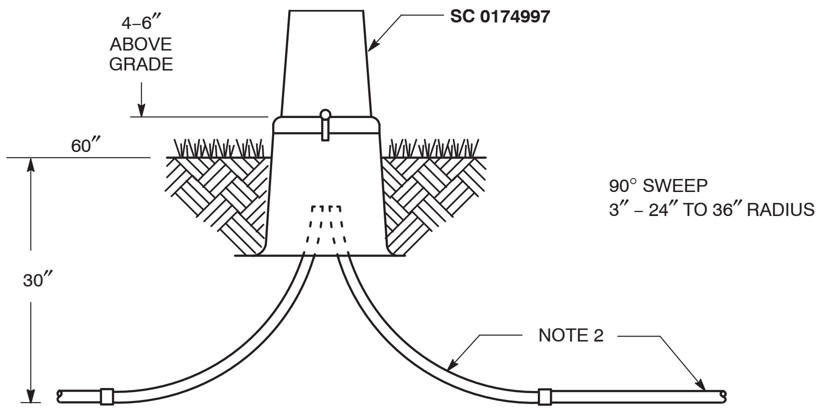
1. Furnish and install service cable to mobile home meter pedestal.
2. Furnish and install one warning sign on the meter pedestal **SC 0194107**.

CUSTOMER RESPONSIBILITY

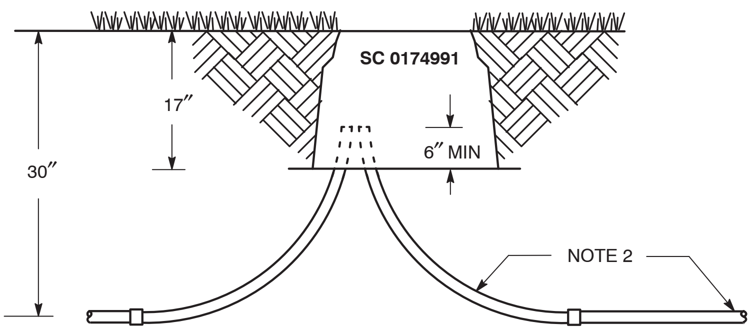
1. Furnish and install treated upright no less than solid 4″ X 4″ set four feet in the ground securely. Any substitute shall be approved by company prior.
2. Furnish and install breakers, receptacles and wiring.
3. Secure front panel.
4. Furnish, install and connect NEC approved ground electrodes.
5. Cable to mobile home must be four–wire. Equipment and installation must comply with the National Electrical Code and all other local codes.
6. Conduit shall be electrical grade, Schedule 40, polyvinyl chloride (PVC) as noted and shall conform to the applicable sections of NEMA TC2–1990 and be UL approved. Minimum size to be three inches. Provide a rigid steel elbow.

ORIGINAL 8/1/94 APPROVED	**MOBILE HOME METER PEDESTAL INSTALLATION REQUIREMENTS**			NH
4/7/11	NORTHEAST UTILITIES	CONSTRUCTION STANDARD	**DTR 54.115**	5

ABOVE GROUND PEDESTAL



BELOW GROUND ENCLOSURE

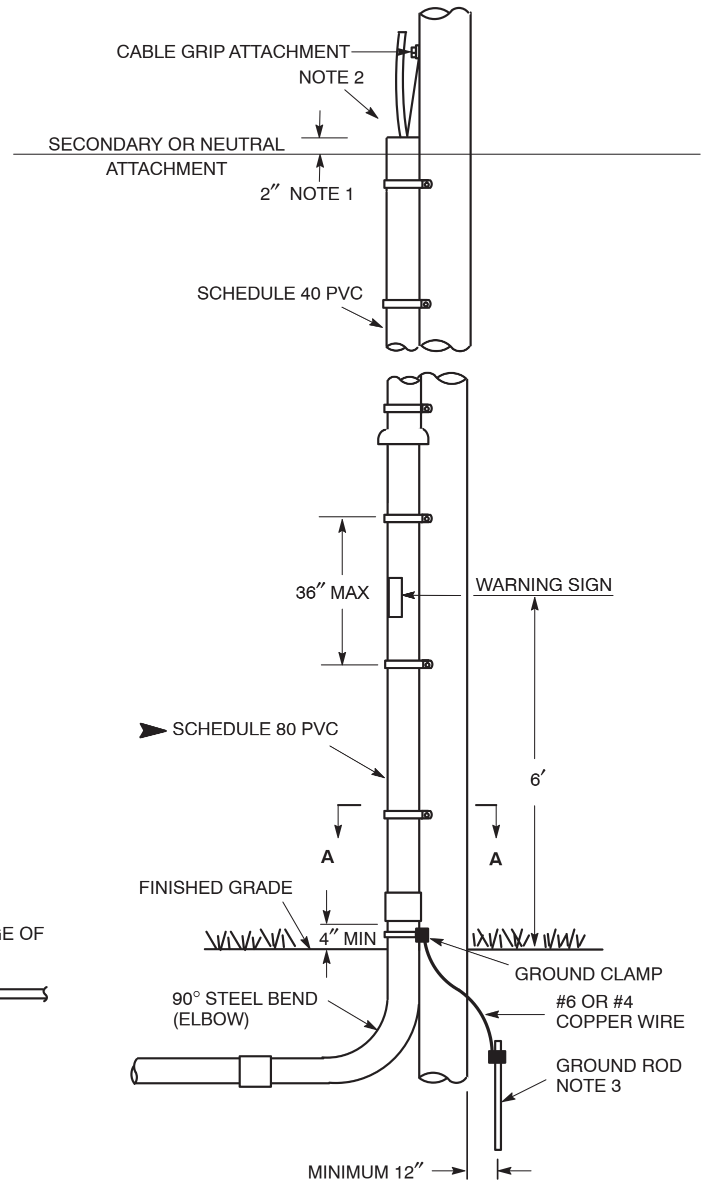


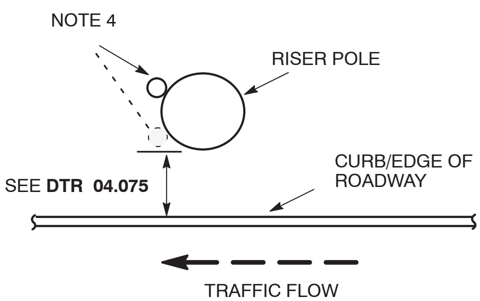
Notes

1. All PVC conduit shall be UL approved, gray in color, and at least Schedule 40 electrical grade that meets NEMA TC2–1990 requirements. Rigid galvanized steel conduit may also be used. **CAUTION:** See NOTE 2 – Galvanized Sweep Elbows.
2. All sweep elbows shall be galvanized steel type approved for electrical cables and have approved sealing compound applied to threaded coupling.
3. Temporary approved conduit end caps shall be placed on the exposed ends of conduit. Necessary measures shall be taken to prevent water, sand, and other objects from entering the conduit during and after construction. After construction is complete, seal conduits using proper methods (one method is expanding polyurethane foam sealant).
4. A suitable pulling string, capable of 200 pounds of pull, shall be installed in the conduit system. Avoid bonding the string to the conduit with the fresh PVC cement.
5. A sweep elbow and a 10–foot section of conduit, with a watertight end cap, shall be installed for all known future load to be fed from an enclosure.
6. Remove all organic topsoil under enclosure and compact native material. Backfill, if necessary, with clean, well compacted gravel.
7. Watertight, URD service entrance multiple outlet connectors shall be used in the below ground enclosure.
8. On below ground enclosure, bring both conduits in at one end. This will allow the secondaries to be installed lengthwise in the enclosure so that working slack is available.
9. Enclosures/pedestals shall be installed by the customer per Eversource specifications.

ORIGINAL 9/19/94 APPROVED 11/12/15	**TYPICAL SECONDARY CABLE ENCLOSURE INSTALLATION**			NH
	EVERSOURCE ENERGY	CONSTRUCTION STANDARD	**DTR 54.215**	**5**

See **DSEM Section 07.82** for trench specifications



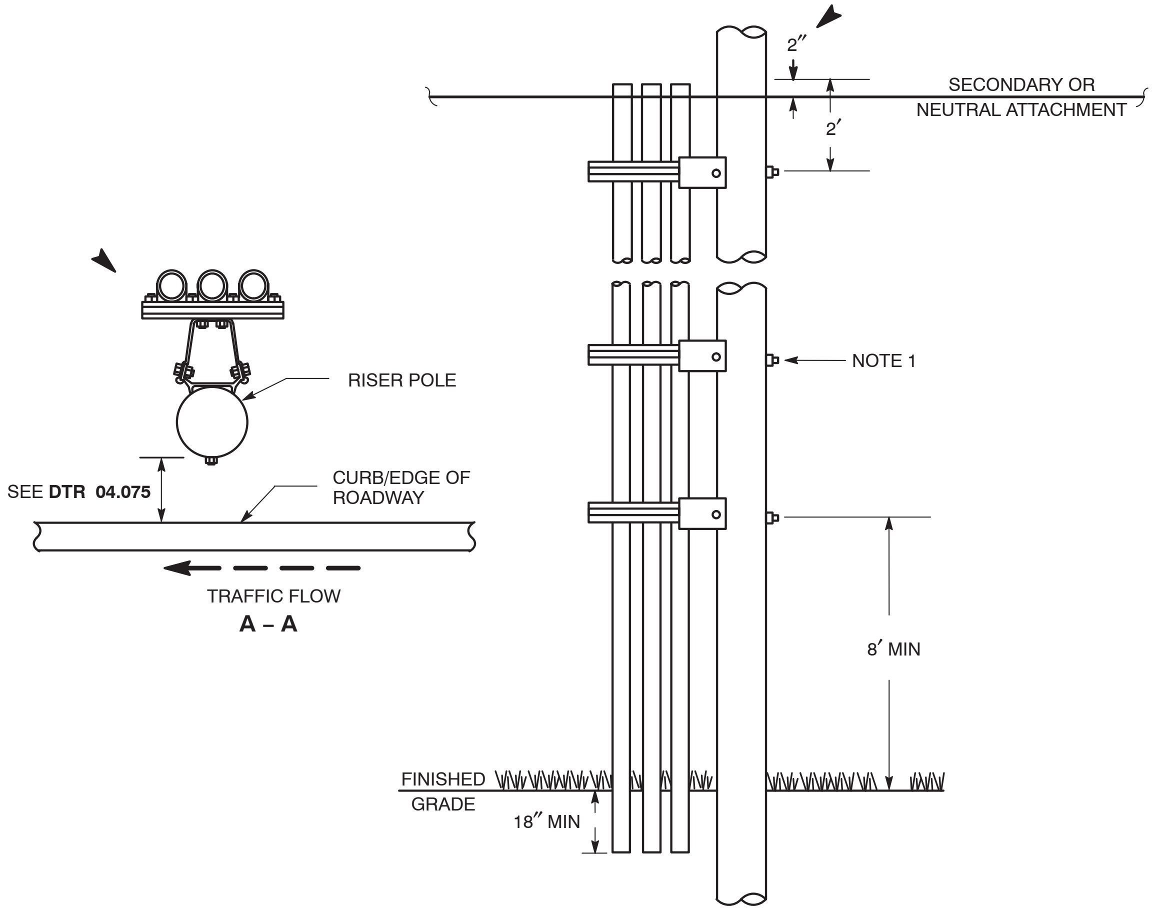


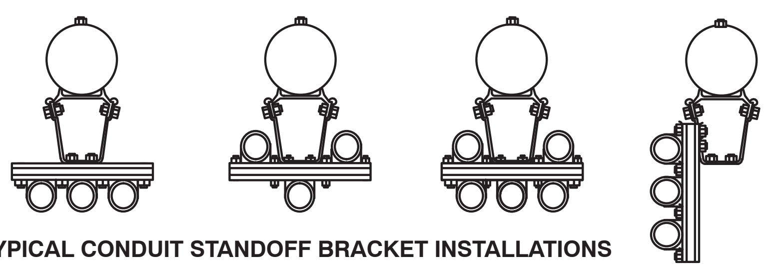
A – A

Notes

1. Top of conduit to extend at least 2 inches above the neutral/secondary attachment.
2. Seal conduit from water entry at top of riser for services installed in conduit for the entire run. See **DTR 12.010**.
3. Steel conduit shall be grounded. If the steel elbow is installed in a nonmetallic conduit installation, it shall also be grounded. Use $^{5}/_{8}$″ x 8′ galvanized steel ground rod and ground clamp.
4. Preferred location for riser placement is on field side of pole opposite the direction of traffic. Check riser path for obstructions, and coordinate with other utilities for placement of risers and any equipment. (Road side of pole opposite the direction of traffic is reserved for road crossings.)
5. Contact the toll−free telephone number to locate buried cables before driving ground rods.

ORIGINAL 11/23/76	**SECONDARY AND SERVICE RISERS – 600 VOLT CABLE**			
APPROVED 3/18/13	NORTHEAST UTILITIES	CONSTRUCTION STANDARD	**DTR 12.057**	**8**



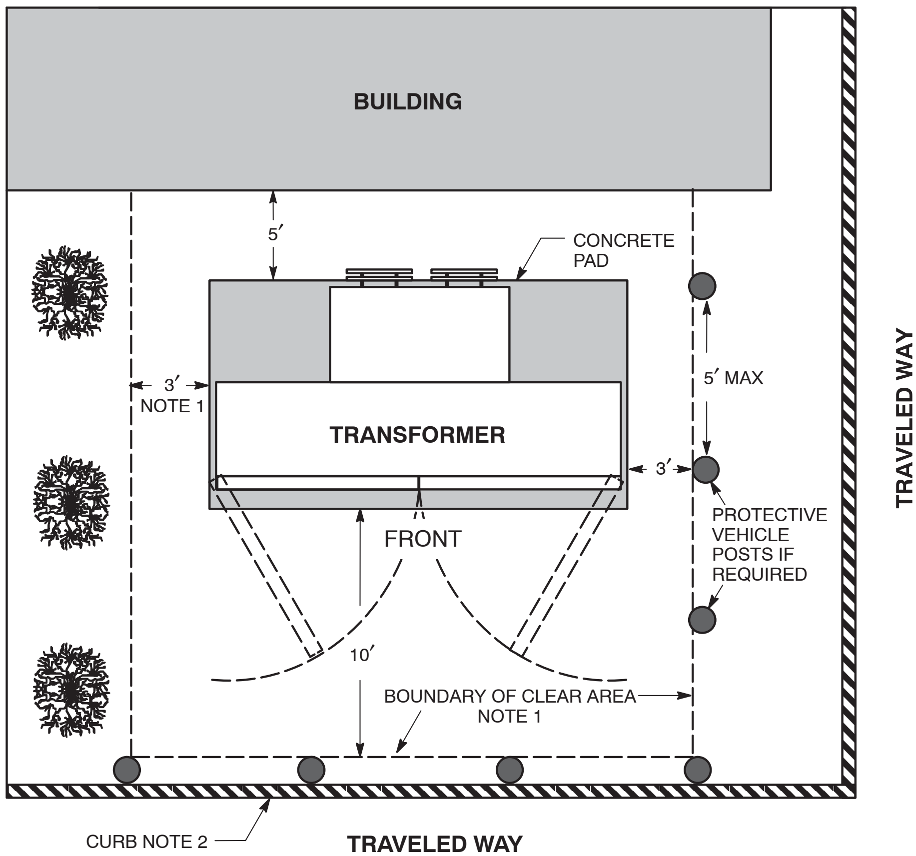


TYPICAL CONDUIT STANDOFF BRACKET INSTALLATIONS

Notes

1. Install the intermediate standoff bracket equidistant from the upper and lower brackets.
2. Whenever possible install electrical facilities nearest to the pole.
3. Preferred location for riser placement is on field side of pole opposite the direction of traffic. Check riser path for obstructions, and coordinate with other utilities for placement of risers and any equipment. (Road side of pole opposite the direction of traffic is reserved for road crossings.)

ORIGINAL 8/16/94	**CABLE RISER STANDOFF BRACKET INSTALLATION**			NH
APPROVED 7/13/11	NORTHEAST UTILITIES	CONSTRUCTION STANDARD	**DTR 12.017**	**2**



Notes

1. To inspect, provide access, operate elbow connectors and ventilate the transformer, the above specified clear area distances to buildings or shrubs shall be maintained. The distance from the building is to the concrete transformer pad. Property line shall be considered an obstruction, since fences, shrubs, etc. may be installed at a future date by adjacent property owners. Because of the possibility of cooling fins overhanging the pad, side clearances to be increased to 5 feet for transformers 1000 kVA and larger.
2. If no curb exists, or transformer is located closer than 10 feet to the traveled way, protective vehicle posts (●) shall be installed as specified in **DTR 42.061**.
3. Top of transformer pad shall be installed 3 inches above final grade.
4. Transformer shall not be located on steep grades where access to or elbow operation is made difficult.
5. Transformer shall meet the minimum distances to doors, windows, fire escapes, air intakes and walls as specified in **DTR 42.061**.
6. Transformer ***is not*** to be located with its doors facing the building.
7. Refer to **DTR 58.301** for specific instructions on the installation of the transformer pad.
8. Refer to **DSEM Section 06.32** and **DTR 58.311** (NH) for information on environmental considerations.

ORIGINAL	PAD–MOUNTED TRANSFORMERS LOCATION TO BUILDINGS AND ROADWAYS			
4/10/91				
APPROVED				
7/8/10	NORTHEAST UTILITIES	CONSTRUCTION STANDARD	**DTR 42.047**	**7**

GENERAL − Pad−mounted oil insulated equipment (such as transformers, transclosures, switches, etc) should be installed so as to be accessible, not constitute an environmental hazard or a fire hazard, and be protected from damage. In URD areas transformers installed at residential front lot lines are not subject to the requirements of this Standard, refer to **DTR 42.031**.

LOCATION − The pad−mounted equipment should be installed at a location where permanent access will be assured for future operation and maintenance as well as to permit installation, replacement and removal of the equipment by means of a winch truck with the boom up. Where noise may be a problem, careful consideration should be given when selecting a location. Areas subject to flooding should be avoided, as should other environmentally sensitive areas noted in **DSEM Section 06.32**. The building owner's and/or tenant's fire insurance carrier may restrict the proximity of the equipment to doors, windows or combustible materials and such requirements are the responsibility of the customer subject to the requirements of Northeast Utilities. In the absence of other requirements, the equipment shall be located with the following minimum clearances from various building facilities. The distances mentioned in this section shall not supersede any local ordinance or code which requires greater clearances.

Item	Minimum Distance In Front of In Feet	To Side of In Feet	Below In Feet
Door	20	10	−
Air intake	10	10	25
Window	10	3	5
Fire escape	20	20	−
Combustible wall	6	6	−
Noncombustible wall	5	3	−
Fuel tanks (above and below grade)	10	10	−
Natural gas or propane connections			
CT/MA	3	3	−
NH	15	15	−
Gasoline dispensing unit	20	20	−

OIL SUMP − If the surrounding grade pitches toward critical areas, it is recommended that an oil sump be provided. This should consist of 3/4−inch trap rock fill under and around the equipment pad adequate to contain the quantity of oil in the equipment to be installed at the given location.

ADDITIONAL FIRE PROTECTION − If the building owner's and/or tenant's combustible facilities adjacent to the equipment require fire protection beyond that provided by oil sump, it shall be their responsibility to provide such protection in the form of space separation, fire resistant barriers, automatic spray systems, other oil containment facilities, or other means approved by their fire insurance company.

EQUIPMENT PROTECTION − Where pad−mounted equipment would be exposed to possible damage by vehicular traffic, protective bumpers are to be installed on exposed sides. Galvanized steel pipes 4−inch minimum diameter filled with concrete, I−beams 5−inch minimum, or other suitable means of protection may be used as bumpers. Such pipes or I−beams shall extend 42−inch minimum both above and below grade. Heavier bumpers set deeper should be considered where exposed to heavy trucks. Bumpers should be 10−foot minimum from the operating side of concrete pad and on the other sides 36−inch minimum from equipment or pad, whichever projects farther. The maximum spacing between bumpers on exposed sides should be 60 inches.

EQUIPMENT LOCKS − Any equipment, with provisions for locking, that is left on site and is accessible to the general public, shall be padlocked. This includes installations that are not complete and not energized. Completed pad−mount transformer installations shall meet "TAMPERPROOF EQUIPMENT LOCK" requirements, **DTR 03.401**.

ENVIRONMENTAL CONSIDERATIONS

Permits – Prior to the start of construction, all necessary environmental permits, whether federal, state and/or local should be secured. It should be noted that jurisdiction over utility company activities varies within each state, and exemptions may exist for some utility maintenance activities. Where environmental considerations exist, our policy is typically to notify and consult with local agencies regarding significant maintenance activities, even in cases where we do not have a legal requirement to do so.

Work in areas where the following issues exist will usually draw public attention, and may require permits:

- Coastal zone
- Inland wetlands
- Tidal wetlands
- Water bodies (rivers, lakes, streams, ponds, etc.)
- Scenic roads (these are state designated)
- Historic districts
- Tree trimming/removal
- Cultural/archaeological sites.

Specific issues for each project should be addressed with the appropriate Regional/Zone Environmental Coordinator.

Placement of Oil–filled Distribution Equipment – Oil–filled equipment must be placed in the best possible environmental location, considering the potential for oil spills and the effect on the environment, and avoiding sensitive sites whenever feasible. Sensitive sites include hospitals, schools, food preparation centers, agricultural areas, inland wetlands and water bodies, etc.

For pad–mounted transformers, refer to **DTR Section 42** for more information.

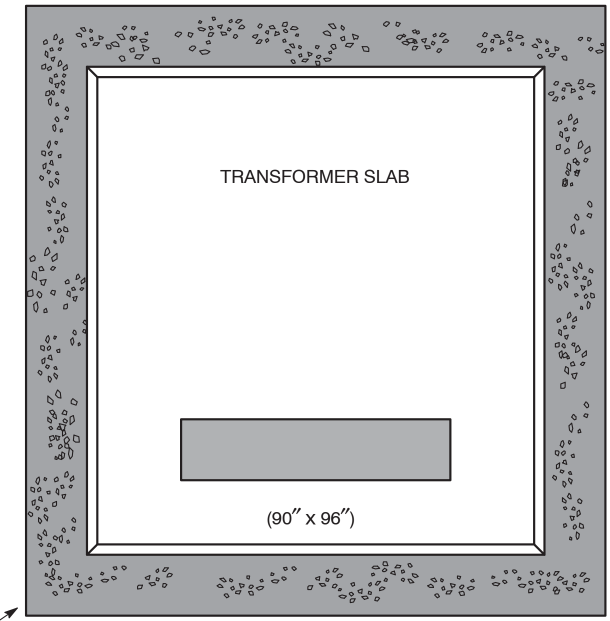
The locating of oil–filled equipment should consider: Waterways (e.g., adjacent to a stream, catch basin); public health (e.g., school yard); vandalism potential (e.g., location); and damage potential (e.g., sharp curve, large trees, etc.). Where the placement of the oil–filled equipment is questionable, consult the appropriate Regional/Zone Environmental Coordinator.

The following guidelines are recommended, where possible, to avoid placement of oil–filled equipment in the vicinity of water resources:

- 200 feet from rivers/perennial streams/bodies of water/inland and tidal wetlands
- 400 feet from public drinking water supply.

Asbestos Precautions – Projects involving removal and disposal of asbestos–containing duct or cable require that sufficient precautions be taken to prevent the asbestos from becoming friable (crumbling). This might be a concern on projects requiring duct or riser repair/replacement or cable replacements (e.g., Orangeberg, Transite, Parkway, etc.). For further information refer to the “Environmental Coordinators Manual,” or contact the Environmental, Health and Safety Department.

3/8″ : 1′



3/4″ STONE–FILLED TRENCH SURROUNDING TRANSFORMER SLAB
(SEE TABLE BELOW FOR WIDTH)

Notes

To calculate dimension of the stone–filled moat:

1. Convert gallons of oil in the transformer to cubic feet: Divide gallons by 7.48 to get cubic feet of oil.
2. Divide this number by 0.35 to determine the volume of stone–filled moat required.
3. From the table below select the width necessary to contain the oil.
4. In environmentally sensitive areas, seal all conduits. See **DTR 44.353**.
5. Refer to **DSEM Section 06.32** for when an oil detention moat should be used.

Volume in Cubic Feet of 24″ Deep Stone–Filled Moat

Width of Moat (Feet)	Slab Dimensions in Inches		
	66 x 50	80 x 92	90 x 96
1	47	65	70
2	109	147	156
3	188	244	258

ORIGINAL 8/5/03	OIL DETENTION FOR PAD–MOUNTED TRANSFORMERS		NH
APPROVED 7/8/10 Cwp	NORTHEAST UTILITIES	CONSTRUCTION STANDARD	DTR 58.311 — 2

REQUIREMENTS FOR PADMOUNTED TRANSFORMER SLAB DETAILS

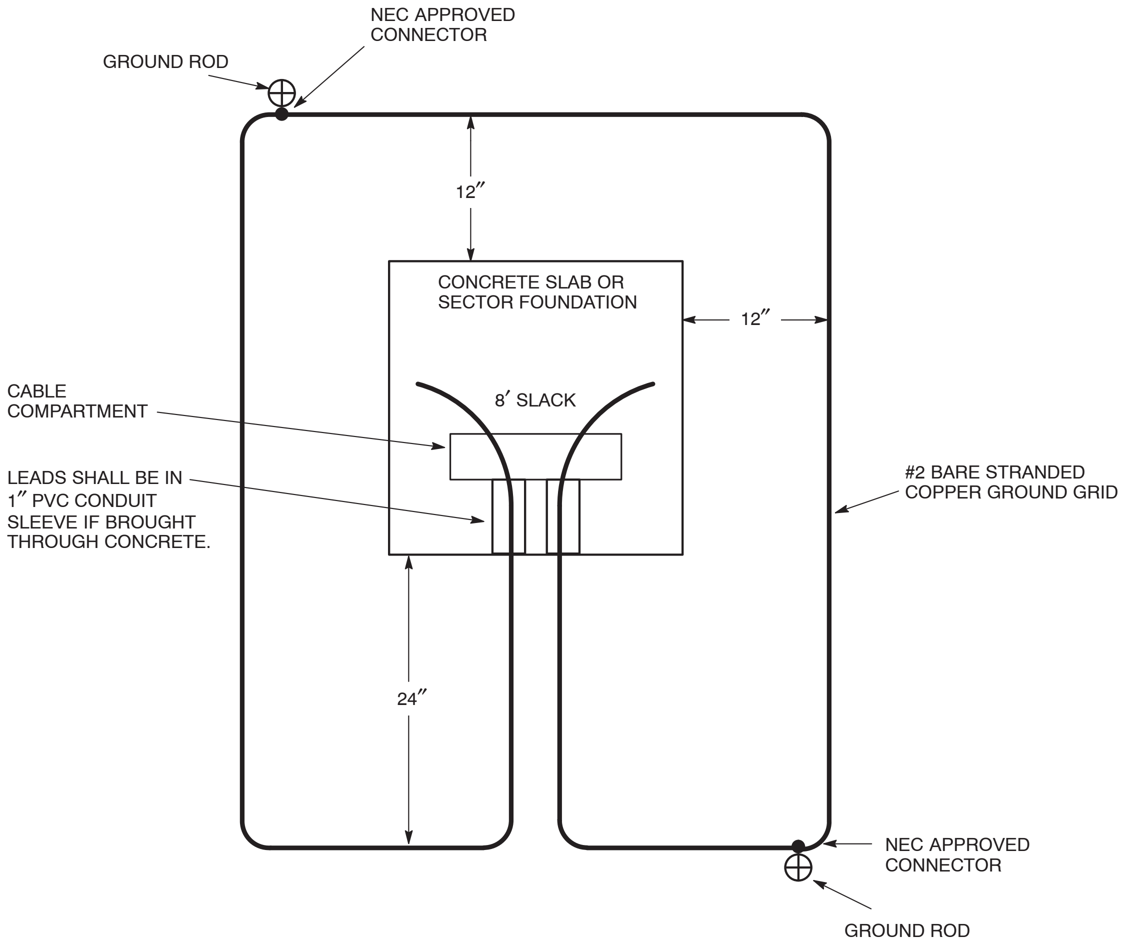
Preparation of Slab:

1. Remove all organic topsoil under foundation and compact native material. Backfill, if necessary, with clean well compacted gravel.
2. Concrete shall have a minimum compressive strength of 3,500 PSI at 28 days.
3. All reinforcing bars shall meet A.S.T.M. #615 grade 60 specifications.
4. All reinforcing shall be tied as one unit.
5. Minimum concrete cover over reinforcing steel shall be 3 inches.
6. Top of slab should be no more than 6 inches above ground level.
7. Chamfer all exposed concrete edges 1 inch.
8. Top of slab shall have a wood float finish.

Notes:

1. Elbows should be cut 4 inches above bottom of concrete pad, surrounded with sand, and have a protective cap bushing on them.
2. A 1 inch PVC conduit sleeve shall be incorporated into concrete slab to allow ground grid leads to enter pit openings as shown on details.
3 Installation of Padmounted Equipment Grounding Grid is outlined in Construction Standard DTR 56.223

EVERSOURCE ENERGY	CONSTRUCTION REQUIREMENT	ISSUE	DATE
		Original	2/1/83
		Rev.	1/4/06

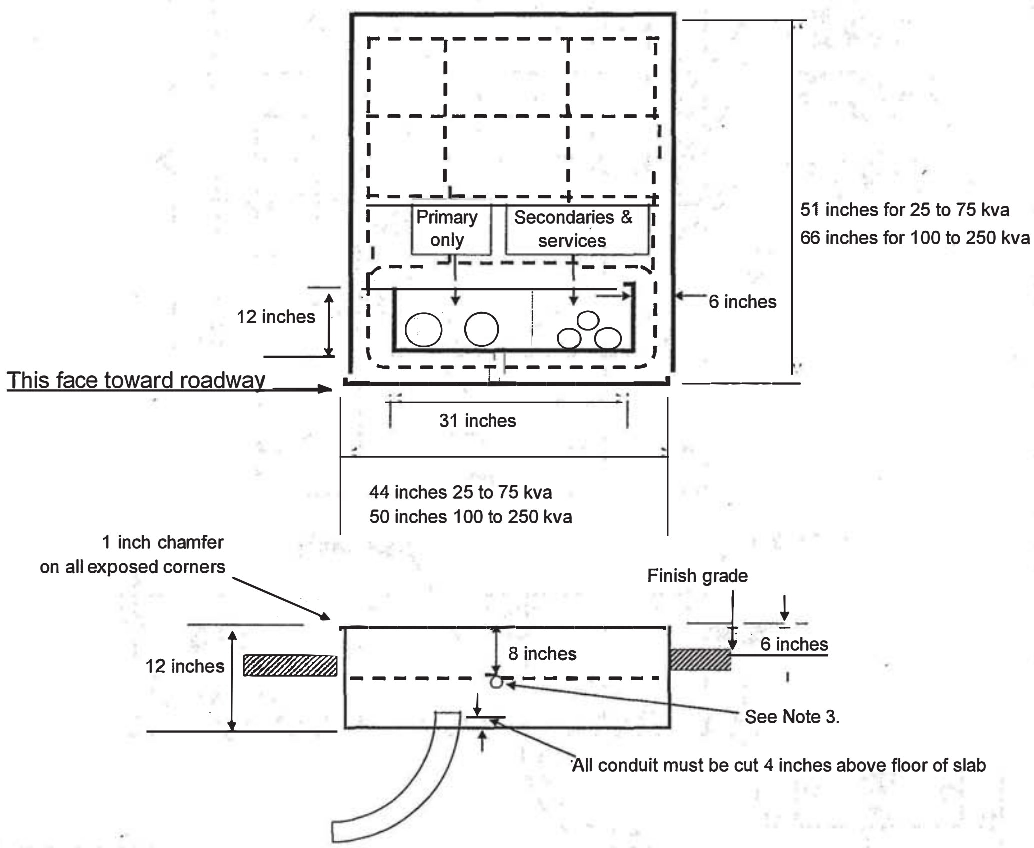


CUSTOMER RESPONSIBILITY

The ground grid shall be supplied and installed by the customer and is to be buried at least 12 inches below grade. Eight feet of extra wire for each ground grid leg shall be left exposed in the cable compartment to allow for the connection to the transformer. The two 8−foot ground rods may be either galvanized steel or copperweld and they shall be connected to the grid with NEC approved connectors.

ORIGINAL 2/4/94 APPROVED 8/4/05	PAD−MOUNT EQUIPMENT GROUNDING GRID		NH
	NORTHEAST UTILITIES	CONSTRUCTION STANDARD	DTR 56.223	4

SINGLE PHASE TRANSFORMER FOUNDATION DETAIL



Notes:

1. See sheet "Requirements for Padmounted Transformer Slab Details."
2. All reinforcing to be #6 bars
3. 1 inch PVC conduit sleeve for ground grid leads
4. See sheet "Pad-Mount Equipment Grounding Grid" DTR 56.223

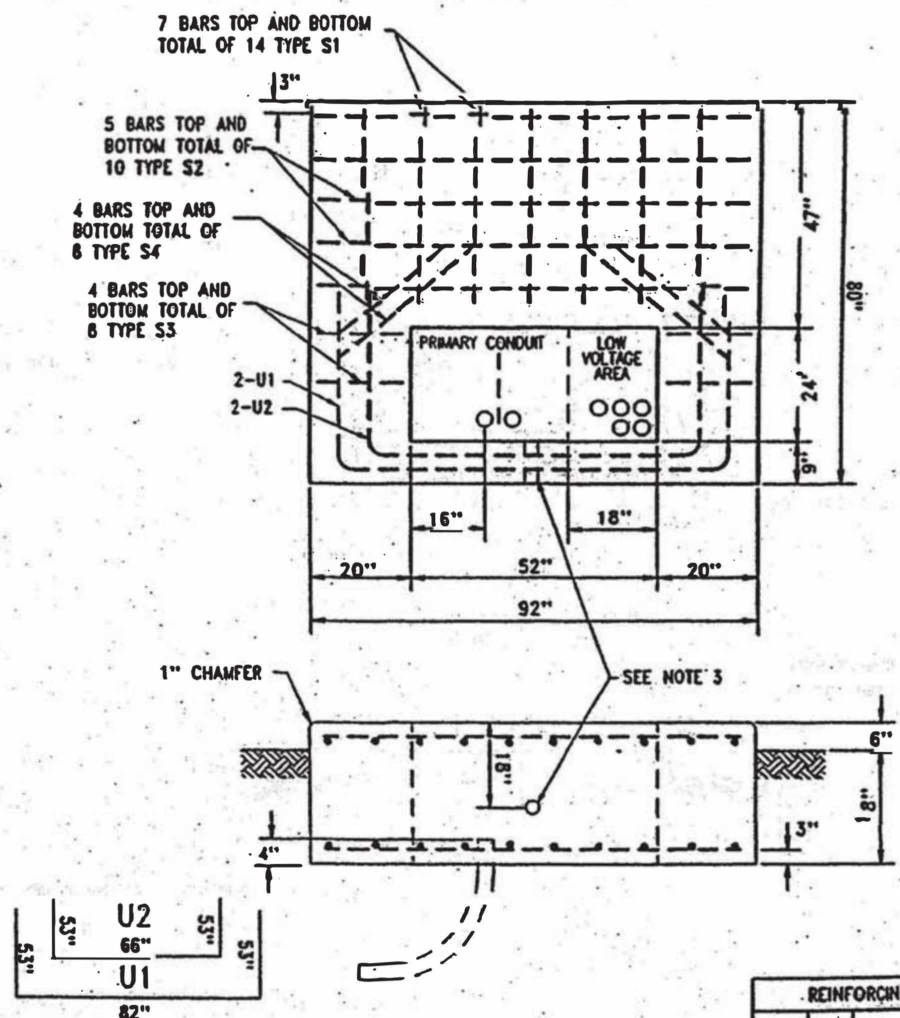
EVERSOURCE ENERGY

CONSTRUCTION REQUIREMENT

ISSUE	DATE
Original	1/75
Rev.	3/6/00

3 Ø PADMOUNTED TRANSFORMER SLAB DETAIL 75 TO 500 KVA DEAD FRONT 15 KV AND BELOW

(53) 1 1.1



REINFORCING SCHEDULE			
TYPE	NO.	LENGTH	TOTAL
S1	14	3'-4"	46'-6"
S2	10	7'-0"	70'-0"
S3	8	1'-3"	10'-0"
S4	8	2'-0"	16'-0"
CONC. VOLUME=3.87 c.y.			

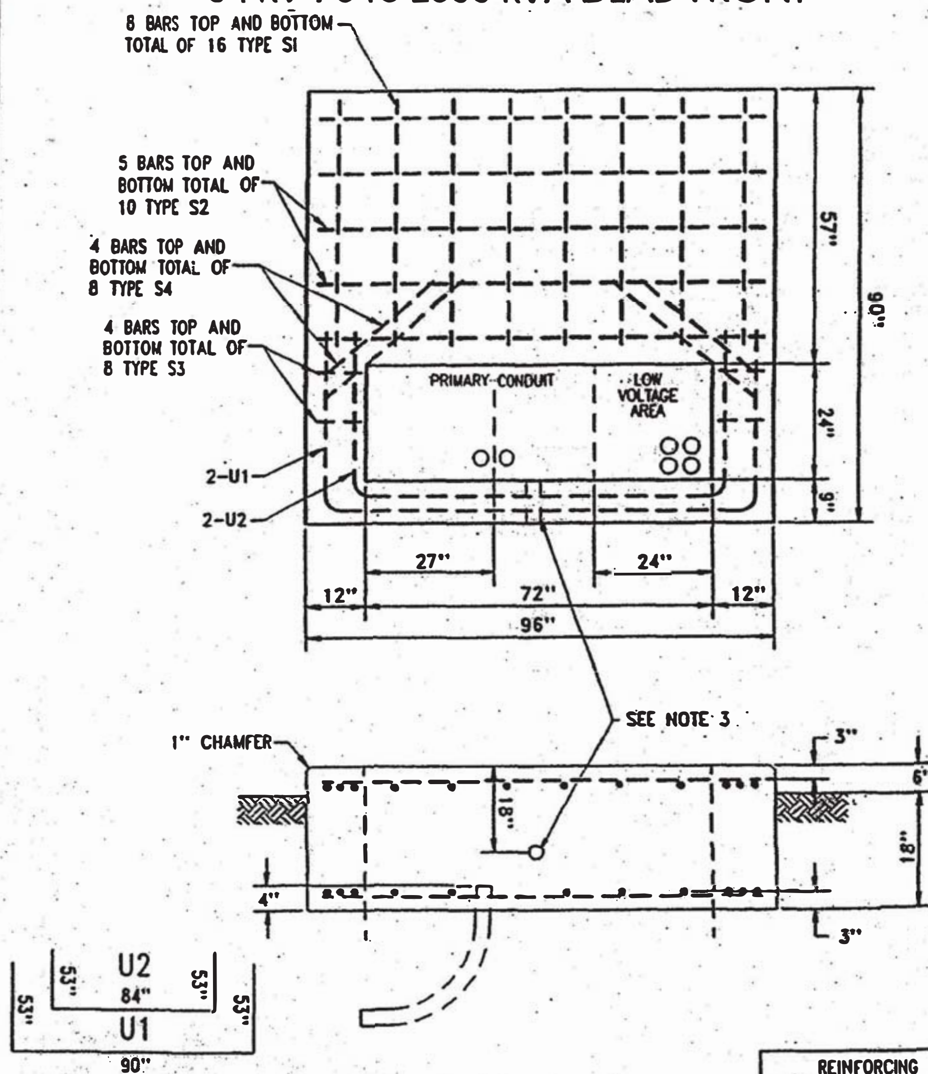
NOTES:

1. SEE PAGE (53) 101 REQUIREMENTS FOR SLAB DETAILS.
2. SEE DTR 56.223 FOR GROUNDING GRID.
3. 1" PVC CONDUIT FOR GROUND LEADS.
4. ALL REBAR TO BE #6Ø.
5. CONDUITS CUT 4" ABOVE SLAB BASE.

EVERSOURCE ENERGY	CONSTRUCTION REQUIREMENT	ISSUE	DATE
		Original	11/1/83
		Rev.	2/1/01

(53)116

3 Ø PADMOUNTED TRANSFORMER SLAB DETAIL
15 KV 750 TO 2500 KVA DEAD FRONT
34 KV 75 to 2500 KVA DEAD FRONT



REINFORCING SCHEDULE			
TYPE	NO.	LENGTH	TOTAL
S1	16	4'-6"	72'-0"
S2	10	7'-6"	75'-0"
S3	8	0'-6"	4'-0"
S4	8	2'-0"	16'-0"
CONC. VOLUME=4.44 c.y. TOP SECTION ONLY			

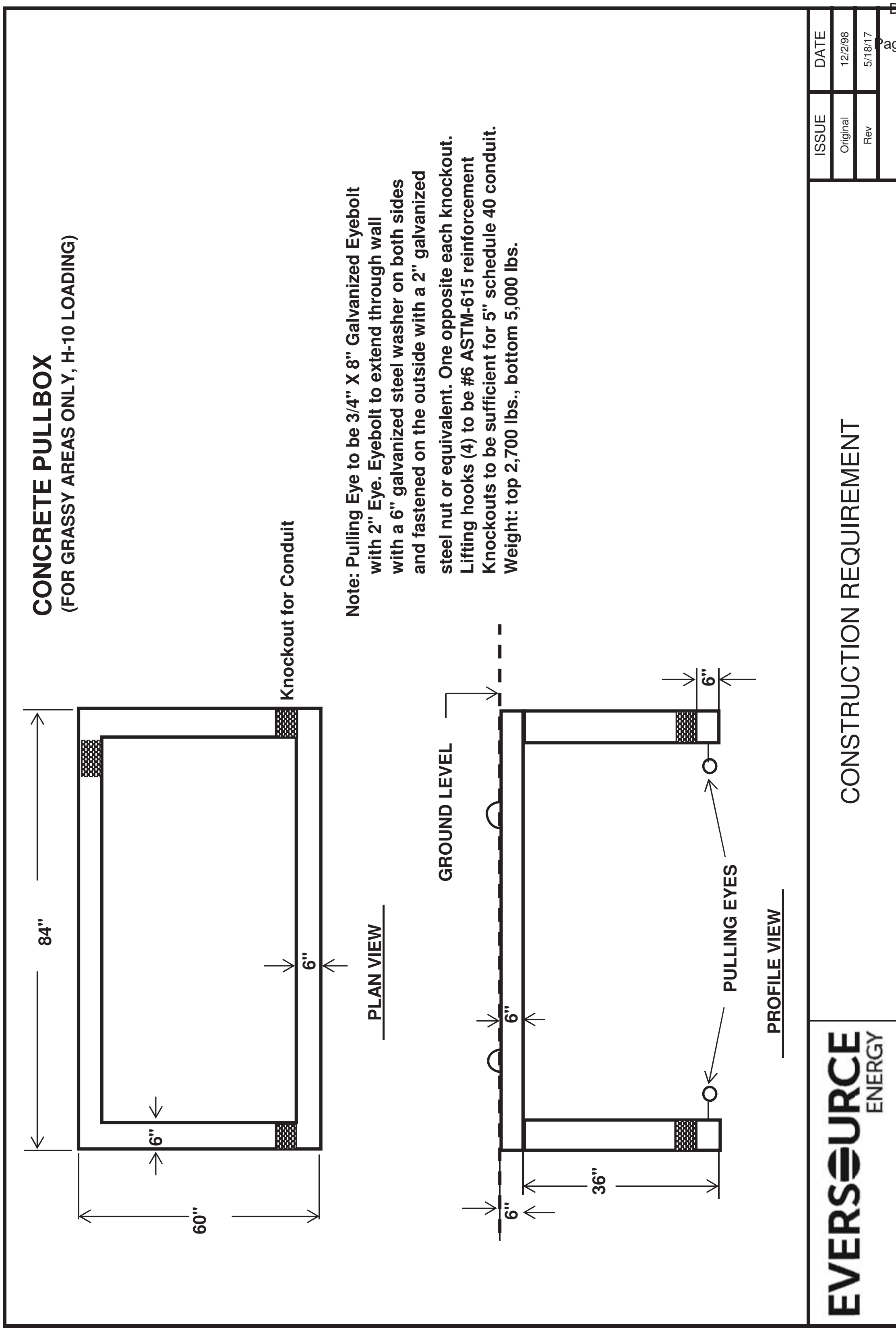
NOTES:

1. SEE PRINT (53) 101 REQUIREMENTS FOR SLAB DETAILS.
2. SEE DTR 56.223 FOR GROUNDING GRID.
3. 1" PVC CONDUIT FOR GROUND LEADS.
4. ALL REBAR TO BE #6Ø.
5. CONDUITS CUT 4" ABOVE BASE OF SLAB.

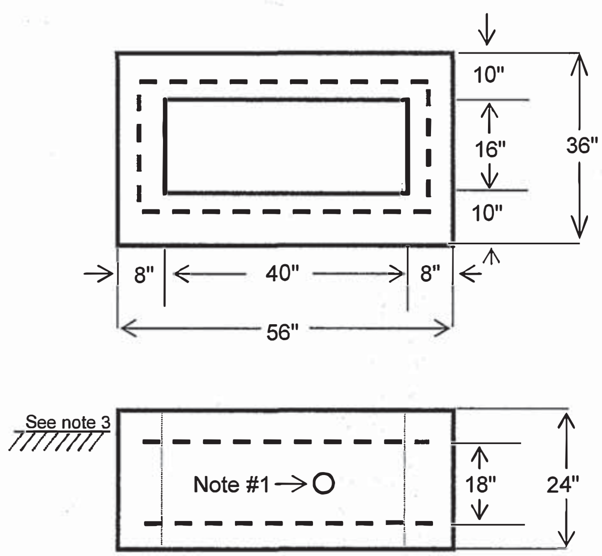
EVERSOURCE ENERGY

CONSTRUCTION REQUIREMENT

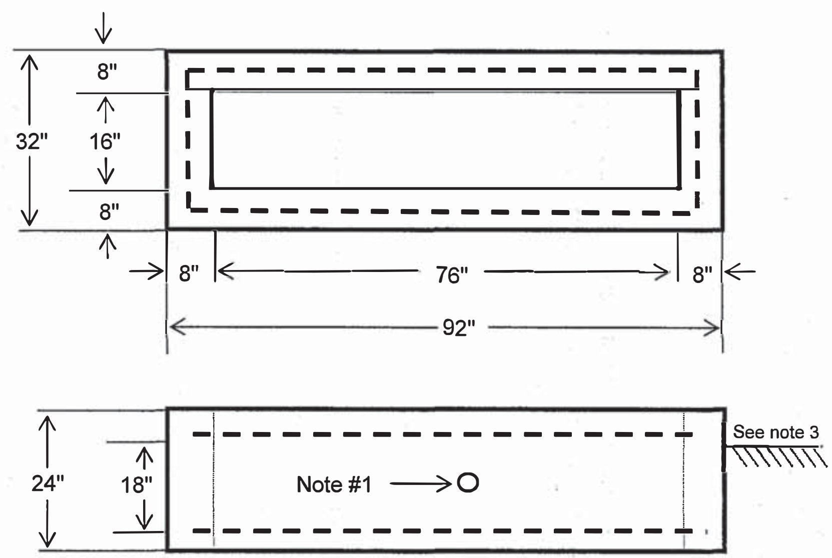
ISSUE	DATE
Original	2/1/83
Rev.	1/4/06


CONCRETE PULLBOX
(FOR GRASSY AREAS ONLY, H-10 LOADING)
Note: Pulling Eye to be 3/4" X 8" Galvanized Eyebolt
with 2" Eye. Eyebolt to extend through wall
with a 6" galvanized steel washer on both sides
and fastened on the outside with a 2" galvanized
steel nut or equivalent. One opposite each knockout.
Lifting hooks (4) to be #6 ASTM-615 reinforcement
Knockouts to be sufficient for 5" schedule 40 conduit.
Weight: top 2,700 lbs., bottom 5,000 lbs.
Knockout for Conduit
84"
60"
6"
6"
6"
PLAN VIEW
GROUND LEVEL
6"
6"
36"
PULLING EYES
PROFILE VIEW
CONSTRUCTION REQUIREMENT
ISSUE
DATE
Original
12/2/98
Rev
5/18/17
EVERSOURCE
ENERGY

SINGLE PHASE SECTOR CABINET FOUNDATION DETAIL



THREE PHASE SECTOR CABINET FOUNDATION DETAIL



Notes:
1. 1" PVC conduit sleeve through foundation for grounding leads
2. All rebar to be #5
3. Top of foundation should be exposed 3 to 6 inches above ground level.
4. Concrete shall have a minimum compression strength of 3500 PSI
5. All reinforcing shall be tied as one unit.
6. Chamfer all exposed concrete edges 1 inch
7. Remove all organic material under foundation
8. Minimum of 3 inches of concrete over reinforcing steel

EVERSOURCE ENERGY

CONSTRUCTION REQUIREMENT

ISSUE	DATE
Original	5/9/94
Rev.	10/27/00

Pre-cast Concrete Suppliers

Partial List

The following is a partial list of suppliers of pre-cast concrete products in the State of New Hampshire. This is not intended to be a comprehensive list and Eversource is in no way recommending any particular supplier.

Central NH Concrete Corp.	4 Bradford Rd, Henniker	1-800-982-9596 (603) 428-7900
Concrete Systems Inc.	9 Commercial St., Hudson	1-800-342-3374 (603) 889-2417
Andrew J. Foss, Inc.	100 Cocheco Rd., Farmington	(603) 755-2515
Gilbert Block Co. Inc.	427 Province Rd., Laconia	(603) 524-1353
Michie Corp.	173 Buxton Industrial Dr, Henniker	(603) 428-3218
Phoenix Precast Products	77 Regional Dr., Concord	1-800-639-2199
Shea Concrete Products	160 Old Turnpike Rd, Nottingham	603-942-5668
Tuffcrete Concrete Corp	84 Exeter Rd, S Hampton	(603) 485-1969

Any changes to this list must be reviewed and approved by the Supervisor-Electric Service Support Center

1-800-362-7764

NHnewservice@eversource.com

Rev. 06/21/16

Article 100-103

100. These requirements have been developed to ensure reliable and adequate service to the user of electricity and to improve communication and coordination between Customers, Contractors, Architects, Engineers, Civic Planning Groups, and the Company. These requirements supplement the Company's Tariff as filed from time to time with the New Hampshire Public Utilities Commission and contain the most recent revisions (at the time of publishing) to the Company's Construction and Meter Standards.

101. The character of electric service made available in accordance with rate provisions will differ to some extent from one location to another on the Company's system. Customers, Contractors, Architects, Engineers, and Civic Planning Groups should therefore determine from the Company the types of service available for any new installation and for any existing installation which is to be enlarged or modified.

102. It is impractical to attempt to cover in a booklet of this type all Company approved Standards or all of the conditions and problems which may be encountered in various installations. Accordingly, Customers, Contractors, Architects, Engineers, and Civic Planning Groups are urged to make use of the advisory services of the Company's New Service Technicians, and Account Executives without charge or obligation. Electric distribution system design services, after the initial design (i.e. redesign at a developer's or Customer's request or due to municipal requirements), and inspections after a failed inspection will be billed to the developer or Customer, unless the failed inspection was caused by Company's design.

103. With respect to Customer's wiring and electrical installations, no requirement, interpretation, or standard specified in this booklet is intended to supersede or conflict with the standards and regulations of the National Electrical Code (hereinafter referred to as the NEC), or with any state or municipal law, rule, or ordinance now in force or hereafter enacted or promulgated. The Company shall have no obligation to determine whether or not the Customer's wiring and electrical installations are proper and safe or comply with the NEC or any other code or regulation in effect at the Customer's location. However, if it should come to the Company's attention that the Customer's wiring and electrical installations are not proper and safe, or do not comply with such codes, the Company shall have the right to refuse or discontinue service. In all municipalities which require permits

Article 104-108

and/or certificates of inspection for electrical work, it shall be the responsibility of the Customer or Contractor to obtain such documents from the proper authorities and provide copies to the Company before electric service is provided.

104. Safe and adequate access shall be maintained to Company owned equipment located on a Customer's premises. The Company shall have free right at all reasonable times to enter the Customer's premises to enable the Company to install, read, inspect, repair, remove, replace, disconnect, or otherwise maintain its meters, equipment, facilities, and for all other proper purposes. The Customer, if a tenant, shall authorize and request his landlord to permit the Company to enter said premises. If safe and adequate access to the meter is not available for the Company's employees, the Company reserves the right to discontinue service upon proper notice. The Customer shall not permit access to the Company's meters, equipment, and facilities located on his premises by other than an authorized representative of the Company or of the New Hampshire Public Utilities Commission. In case of loss or damage to Company property on the Customer's premises due to Customer negligence, the Customer shall pay to the Company the value of such property or the cost of repairs.

105. All employees authorized by the Company to visit the Customer's premises are required to carry means of identification which will be shown upon request. The Company will be responsible for the actions and workmanship of such employees.

106. Should the use or operation of any equipment by a Customer including but not limited to electric motors, welders, electronic power supplies or speed controls, adversely affect the Company's ability to render adequate service to others, the Company reserves the right to discontinue service until suitable corrections are made by the Customer.

107. The Company reserves the right to install protective apparatus so arranged as to disconnect or limit service to the Customer if the Company's capability to render service at the point of delivery is exceeded.

108. The Company will make or cause to be made, application for any necessary street permits or licenses for its facilities, and will not be required to make electricity available on the premises of the Customer until a reasonable time after such permits or licenses are granted.

Article 109-110

Construction of lines on or across private property will be done only if the Customer provides, without expense or cost to the Company, the necessary permits, easements, and consents for a satisfactory right-of-way for the erection, maintenance, and operation of a line to be used exclusively to serve the Customer. The Customer shall also be responsible for any on-going fees associated with any required permits or consents for rights-of-way located on or across private property. The Company shall be responsible for the construction and maintenance of all electric distribution facilities to serve the customer's premises, as outlined in Section 34 of the Tariff.

Additionally, per RSA 370:12, customers requiring a line extension on private property may opt to hire and pay a private line contractor, licensed by the state and approved by the Company, to construct a required overhead or underground power line extension on private property. The contractor shall supply and install all materials as specified by the Company. Line extensions must be designed by the Company and built to its specifications in order for the Company to assume ownership of the line. The Company has the right to not accept a customer built line extension that does not conform to the Company's specifications. Customers may not contract with private line contractors to construct line extensions along public ways.

109. The actual cost to the Company of moving meters and services shall be billed to the Customer in the following cases:

(a) If a meter or service is relocated on the same premises at the request of the Customer.

(b) If a meter or service is discontinued or removed temporarily at the request, or for the convenience, of the Customer.

(c) If a service is covered instead of being moved or temporarily removed, the actual cost to the Company of covering the service that exceeds the cost of one crew hour shall be billed to the Customer.

110. The cost of installing and removing a temporary overhead or underground service, which is not converted to a permanent service, shall be billed to the Customer.

Article 111-112

111. The Distribution and Meter Standards included in this booklet are not all inclusive of Company Standards. Because Distribution and Meter Standards are revised periodically and are subject to Article 103, the Standards in this booklet may be obsolete. Any person who is uncertain or has a question as to the latest standard applicable, should contact the nearest Work Center for information before proceeding.

112. Installation of oil filled equipment within 400 feet of public or community water systems are subject to special requirements. Customers, Contractors, Architects, Engineers, and Civic Planning Groups should determine from the Company the requirements applicable to any new installations and for any existing installation which is to be enlarged or modified. The Company's requirements were developed based on NH Department of Environmental Services rules which are available on their web site.

SECTION 2 – Service Voltages

Article 200-205

Low Voltage Service

200. Low voltage service for secondary rate Customers will be supplied from the nearest suitable distribution line of the Company at one of the following standard service voltages. All loads shall be balanced as equally as possible.

Phase	Wires	Nominal Voltage	Article Reference
1	3	120/240	202
3	4	120/208	203,204
3	4	277/480	204

201. The foregoing voltages are nominal and subject to reasonable variations in accordance with regulatory commission standards.

202. Single-phase, three wire, grounded neutral service is generally available for residential, small commercial and industrial use. Except as provided for in Article 203, the voltage shall be 120/240.

203. In some areas, the only available service is three-phase, four-wire 120/208 volts wye connected. In these areas all services shall be three-phase, four-wire except that small commercial and industrial loads of 100 amperes or less, and residential buildings with one or two dwelling units shall be supplied through single-phase, three-wire 120/208 volt services. Residential buildings with three or more dwelling units may be supplied through a three-phase, four-wire service with individual single-phase, three-wire subservices and meters such that the loads on each of the three phases shall be balanced as nearly as possible.

204. 120/208 and 277/480 volt three-phase, four-wire wye are the available voltages for commercial and industrial services and can be supplied where three-phase distribution is available except areas included in Article 203.

205. Three-phase, three-wire service at nominal voltage of 240, 480, or 600 volts is available for current Customers at existing locations only. Any major upgrade to the Customer's premises or service entrance may require upgrade to a three-phase, four-wire system. The Company reserves the right to remove Company owned equipment supplying three-phase, three-wire services if such services should become inactive.

Article 206-211

206. In locations where space limitations or other factors make it impossible or inadvisable, in the opinion of the Company, for a primary rate Customer (Rate GV or Rate LG) to have transforming apparatus devoted to their exclusive use, low voltage service shall be supplied to such a Customer in accordance with Tariff provisions from Company-owned transforming apparatus which also supplies other Customers. The transforming apparatus rental fee will be based upon the equivalent transforming apparatus that would be required for the exclusive use by the Customer.

207. Each residence in a new or newly renovated multi-tenant building will be metered separately and each meter will be billed as an individual Customer. Hotels, motels, dormitories, time share condominiums, and campgrounds are excluded from this requirement and may be master metered. Master metering is defined as the use of a single meter to supply electric service to a building that contains two or more residences Reference PUC 303.02.

High Voltage Service

208. High voltage service for primary or transmission rate Customers will be supplied at one of the following standard service voltages as available at the Customer's location.

Phase	Wires	Nominal Voltage
3	4	2,400/4,160
3	4	4,800/8,320
3	4	7,200/12,470
3	4	19,920/34,500
3	3	34,500
3	3	115,000

209. The foregoing voltages are nominal and subject to reasonable variations in accordance with regulatory commission standards. All loads shall be balanced as equally as possible among the three phases.

210. Under certain circumstances, primary rate Customers may be supplied with low voltage service instead of high voltage service. See Article 206.

Customers supplied by a high voltage service are responsible for the installation and maintenance of all secondary equipment, in addition to equipment as described in Articles 415 and 527.

Article 300-308

General

300. The Company may refuse to connect a service or install a meter on any metering installation that does not conform to the requirements in this booklet.

301. Where interference with proper registration of an electric meter has been established, the Customer or person responsible for the interference, as determined by a Company investigation, may be required to reimburse the Company for lost revenue, damages to equipment, expenses incurred during the investigation, and may be subject to criminal prosecution.

302. Meters will be furnished, owned, and maintained by the Company and shall be installed, removed, and changed only by authorized Company employees.

303. A means must be provided by the Customer for disconnecting the service entrance conductors from all ungrounded conductors in the building or structure. The disconnection means shall comply with NEC Article 230 Section VI.

304. In multiple meter installations, each meter mounting device and Customer disconnecting means shall be permanently marked by the Customer and/or landlord to indicate the location which it serves, as required by the NEC, Section 230.72. When apartment/condominium units are renumbered, it is the Customer's and/or landlord's responsibility to notify the Company of such a change.

305. Typical meter installations are shown in Meter Standards 04-3-G-1, 2, 3, 8, 11, 26B, 34, 38 and43.

306. Unmetered (line) conductors shall not be run in a trough with metered (load) conductors.

307. Jumpers or other devices that result in unmetered electric service shall not be used.

308. Meters shall not be installed on Company owned poles except when providing service to equipment located on that pole, as in the case of cable TV power supplies or where, in the Company's sole determination, it is necessary to install a meter on a pole. Meters shall not be attached to Company owned padmount transformers unless authorized by a Meter & Service Supervisor.

Article 309-315

Meter Mounting Devices - Company Owned

309. Meter mounting devices will normally be furnished, owned, and maintained by the Company.

310. The Customer may be held responsible for all undue damage to Company metering equipment. If the Company deems it appropriate, meters installed outdoors in isolated locations or where accidental or malicious damage is likely, shall be moved to an alternate location or installed in a protective enclosure at the Customer's expense.

311. Meter mounting devices may be obtained by contacting the Company Work Center which serves the area in which the service will be located.

Meter Mounting Devices - Customer Owned

312. Meter mounting devices, enclosures, or meter pedestals may be supplied by the Customer provided that they meet UL requirements and are approved by the Company's Meter and Service Supervisor prior to installation. Although ring-less construction is preferred, ring-type sockets may be acceptable on multiple position metering or other installations at the discretion of the Meter and Service Supervisor.

313. Meter mounting devices provided by the Customer shall include all necessary parts (fifth terminals, hubs, connectors, etc.), shall remain the property of the Customer, and shall be maintained either by the Customer, or by the Company at the Customer's expense.

314. A manual lever bypass is required on all three phase and all 320 amp single phase, self-contained meter mounting devices. The block must be provided with a plastic protective shield and flashover barriers between the phases. No bypass or locking jaws will be allowed in single phase self-contained or network sockets.

315. When the Customer provides meter mounting devices, the Company, upon written application, will reimburse the Customer an amount based upon the cost of meter mounting devices normally used by the Company.

Article 316-322

Meter Mounting Devices – Installation

316. The meter mounting devices shall be installed by the Customer approximately five feet above final grade, except where specifically approved otherwise by the Company. It shall be plumb, level, and attached to the finished exterior of the building, or to a suitable pressure treated backboard permanently attached to the building, with screws sufficiently long to extend through the exterior finish and into the sheathing. Rust resistant screws shall be used in damp areas. See Meter Standard 04-3-G-1. If the sheathing will not support the installation, other provisions shall be made to ensure a sturdy and stable base for the meter mounting device and the service entrance cable. The Company shall not be liable for damage to a structure caused by water penetration behind the meter mounting device. Meter mounting device locations must be approved by the Company prior to installation.

317. All attachments of meter mounting devices should allow for future removal of equipment. Explosive anchors shall not be used.

318. Multiple position meter mounting devices shall be mounted so that the center of any meter is not over six feet, nor less than two feet six inches, above the final grade surface.

319. In cases where the meter is mounted outside on an upright remote from the building being served, the customer shall provide a fused disconnect or circuit breaker in a weatherproof enclosure immediately below the meter mounting device.

Sealing of Meter Equipment

320. Three phase and transformer rated meters will be sealed by the Company in an approved manner, and seals shall not be broken by the Customer or his representative.

321. Single phase meters will be sealed by the Company in an approved manner, and seals shall not be broken by the Customer or his representative without prior approval of the local Company Work Center.

322. The Company reserves the right to seal all points of access to unmetered conductors. These seals shall not be broken by the Customer or his representative without prior approval of the local Company Work Center.

Article 323-329

323. The Company monitors all metering equipment and services for tampering or unmetered wires and will investigate all instances of broken or altered seals.

Locations

324. Each meter location shall be designated by the Company. The location must be safely accessible to the Company during normal working hours for reading and servicing the meter. Sufficient wall space and a clear work area of at least three feet in front of the meter, free of shrubbery or other obstructions, shall be provided by the Customer. Generally, meter locations will be on the driveway end of the house to facilitate access. Enclosures shall not be built around meter mounting devices.

325. The preferred location for all meters is outdoors. The meter location will be chosen to protect the meter from falling ice and snow, heavy amount of water, or other environmental hazards. Meter locations will generally be on the gable end of the house, unless otherwise agreed to in advance by a Company Representative.

326. When outdoor meter locations are not feasible, meters will be located indoors near the service entrance in a clean, dry, and vibration free location with adequate illumination.

327. When indoor meter locations are not conveniently accessible to Company employees through a public entrance, Customers are requested to provide utility service doors, or keys by which authorized Company employees may gain access to metering equipment.

328. Inside meter locations may be designated by the Company under the following conditions:

a. To avoid undue damage to the meter.
b. Multiple meter installations where a main switch is required on the line side of the meters.
c. When the Company specifies instrument transformer metering.
d. Commercial and industrial installations where the meter is readily accessible.

329. Meters in multiple occupancy buildings not over two floors in height shall be grouped in one central location, unless otherwise designated by the Company. Meters in multiple occupancy buildings of over two floors in height may be grouped in suitable meter rooms, clearly marked and used only for electric service equipment.

Article 330-337

330. Electric meters must be located a minimum of three feet from natural gas or propane meters, regulators, or vents, and ten feet from gas cylinders and fuel tanks.

Single Phase Installations

331. Single phase services will be metered with three wire, socket type meters except as otherwise designated by the Company. Three wires or a three conductor cable shall be run from the meter mounting device to the service entrance cabinet. For single phase, 120 volt loads not in excess of 20 amperes, two wires may be run by the Customer from the meter mounting device to the service entrance cabinet.

Three Phase Installations

332. Three phase services 400 amperes or less and 480 volts or less will normally be metered with a socket type meter except as otherwise designated by the Company.

333. A disconnecting means and overcurrent device shall be installed on the line side of each 277/480 volt self-contained meter mounting device or on any self-contained meter installation where the line-to-line voltage is greater than 300 volts.

Transformer Rated Installations

334. Electrical services with a current rating larger than 400 amperes or voltage in excess of 480 volts will generally require instrument transformers. This determination will be made by the Company.

335. The Company will furnish and the Customer shall install the necessary instrument transformers and enclosures.

336. The Company shall furnish any connectors necessary to attach the service conductors to the instrument transformers if such connectors are not provided with the instrument transformer enclosure, or if the connectors provided are not suitable for the service conductors being used at the installation.

337. The Customer shall furnish and install all necessary conduit between the instrument transformer enclosure and the meter mounting device. Generally the minimum trade size of this conduit will be 1 ¼ inches.

Article 338-341

338. If the instrument transformers are located on a Company owned structure, the Company will install the instrument transformers and conduit on the structure.

339. The Company will furnish and install all secondary wiring from the instrument transformers to the meter mounting device.

340. No Customer owned equipment shall be placed in the instrument transformer enclosure.

341. The load terminals of instrument transformers or meter mounting devices shall not be used as a junction or distribution point for the Customer's wiring unless specifically authorized by the Company.

Article 400-405

Low Voltage Service

400. Before proceeding with the wiring of a new building or the rewiring of an existing building, a service entrance location shall be arranged with the nearest Company work center.

401. Only one service of the same characteristics will be run to a single building except as otherwise permitted by the NEC.

402. The point of attachment of a service to a Customer's building shall not be less than 12 feet nor more than 25 feet above permanent ground level. The ground shall be reasonably level to permit the use of a ladder by Company employees to attach the service. Service attachments shall be so installed as to permit the service connections to be directly reached from a ladder placed securely on the ground, and as to permit the maintenance of the following minimum clearances as per the National Electrical Safety Code (hereinafter referred to as the NESC).

- Twelve feet above finished grade, sidewalks, residential driveways, and commercial areas not subject to truck traffic.
- Sixteen feet above roads, streets, alleys, residential driveways, cultivated fields, and areas subject to truck traffic.

For other areas and uses see the NESC, and DTR 04.151.

403. The maximum length of service drop which the Company will install is determined by the characteristics of the load to be served and the terrain over which the service drop passes. Under no circumstances will attachments be made to trees.

404. Where a building is too low to provide minimum clearance, the Customer shall install a service mast of suitable height and strength, guyed if deemed necessary. When such a service mast is installed, the Customer shall assume full responsibility for it, including roof leaks and the ability of the installation to support the required service drop. Per NEC requirements, only power service drop conductors may be attached to such mast. See DTR 14.106.

405. When temporary service is required, the installation shall be in accordance with DTR 14.105. "Temporary" is defined as one year by the Federal Energy

Article 406-412

Regulatory Commission. To continue service beyond this time, the service must be converted to a permanent service and meet all pertinent requirements of this booklet.

406. It is recommended that the service entrance provided for single family residences be single-phase 120/240 volt with a minimum capacity of 100 amps.

407. For single-phase entrances of 200 amps capacity and less, the Company will furnish and install the service drop and service entrance cable to the meter mounting device in accordance with DTR 14.106, except that in cases where the meter mounting device is located inside the building the customer must furnish and install the service entrance cable.

408. For single-phase service entrances larger than 200 amps, and for all low voltage three-phase service entrances, the Company will furnish and install the service drop to the point of attachment to the building or other location, and connectors to connect the service drop to the Customer's service entrance conductors. The Customer shall furnish and install all necessary conduit and cable beyond the service drop point of attachment.

409. Where it is considered necessary by the Company for the proper installation of large capacity overhead services, the Company will furnish and the Customer shall install, under the Company's direction, suitable eye bolt(s) in the building's exterior wall to support the service drop(s).

410. For services to semi-permanent mobile homes, the Customer shall install the meter mounting device and service entrance switchbox on an upright separated from the mobile home. See DTR 14.107.

411. In trailer parks, the Company will install poles not less than one hundred feet apart, and the park owner or operator shall install and maintain a suitable service entrance board with meter mounting devices, service entrance switchboxes, and mobile home connection receptacles. See DTR 14.107 for suggested method of installation.

412. Meter mounting devices may be temporarily detached from buildings by Company personnel at the customer's request for remodeling purposes. This is to be considered temporary in nature and provisions for re-attachment must be made by the customer within one year.

Article 413-415

413. For service to buildings with asbestos siding, the customer must install a suitable mast for the installation of service conductors.

High Voltage Service

414. High voltage service will be supplied from the nearest suitable high voltage line in accordance with Tariff provisions. The Customer shall arrange with the Company for the construction of service extensions and other facilities necessary to supply such service.

415. Substation foundations, structures, equipment support poles, and all necessary transformers, controlling, and regulating apparatus shall be furnished, owned, and maintained by the Customer at his expense. However, transformers, controlling, and regulating apparatus may be rented from the Company in accordance with Tariff provisions.

Article 500-507

Definitions

500. **Customer(s)**: One or more individuals, a developer, municipality, civic authority, or other duly authorized organization responsible for community planning, development, or redevelopment programs who may contract with the Company for the installation of underground electric distribution facilities or for electric service.

501. **Development**: A single parcel of land or contiguous parcels of land used for building construction and under the ownership and control of one or more individuals or a partnership or corporation (referred to as the developer) who can contract with the Company for the establishment of an underground electrical distribution system in the entire Development or a portion thereof.

502. **Excess Costs**: The amount by which the installed cost of a padmounted transformer exceeds the installed cost of an equivalent overhead transformer. The Company reserves the right to determine Excess Costs or portions thereof on the basis of average cost formulas consistently and equitably applied to all qualifying installations as defined by the Company.

503. **Urban Areas**: A high-density business district devoted primarily to commercial and/or industrial uses as determined by the Company.

504. **Underground Distribution System**: An underground system utilizing a conventional manhole/duct/vault system. Such systems include both network and non-network systems typically found in established urban areas.

505. **Underground Residential Distribution**: An underground system consisting of cable in conduit found in residential areas.

506. **Payment Terms:** Each customer shall make a lump sum payment of the costs prior to the start of construction.

General

507. Underground electric distribution facilities will be provided by the Company when feasible and practicable, and when consistent with the normal availability of manpower and the orderly scheduling of construction projects, all as reasonably determined by the Company. Subject to the above stated limitations on the availability of underground facilities, such facilities will be provided by the Company on a consistent and equitable basis to all who qualify. Such underground facilities will be provided in accordance with mutually acceptable plans and agreements between the Company and the Customer and in accordance with the provisions of these requirements. It is the intent of the Company that such underground distribution facilities will generally consist of those facilities located within or immediately adjacent to the boundaries of a tract or area under the ownership and control of the Customer, and associated primarily with service to occupants of that tract or area. It is understood that the Company may be required to install overhead facilities in order to meet its electric service obligations unless acceptable plans and agreements are finalized in sufficient time to permit the installation of underground facilities to meet such obligations.

508. The Company will furnish, install, own, and maintain all underground electric distribution facilities necessary to provide proper service under the provisions of the Company's Tariff and these Requirements.

509. The Customer will furnish and install to the Company's specifications, and the Company will own and maintain, all necessary non-electrical facilities required for the Company to install underground electric distribution facilities described in this Section. These facilities include, but are not limited to; trenching, backfill, conduits, ducts, concrete slabs and manholes.

510. For new installations the Customer is responsible for the cost of such installations, as specified in the Company's Tariff.

511. Underground electric service lateral and meter mounting device locations will be established by the Company upon application.

512. Easements satisfactory to the Company shall be provided by the Customer at no cost to the Company.

513. The Company should be consulted in advance with respect to service to high-rise buildings or other structures which may involve unusual electric service requirements. Failure to do so may impact Customer schedules due to long lead times for some equipment and the availability of sufficient Company manpower.

514. No permanent overhead service will be supplied in any area served exclusively from underground electric distribution facilities.

515. The Company reserves the right to determine any of the costs or portions thereof specified under the provisions of this Section on the basis of average cost formulas consistently and equitably applied to all qualifying installations as defined by the Company.

Article 516-519

516. In some cases the type, nature, and/or size of the service requested by a Customer may not be available at a desired location.

517. Replacement of the Company's primary overhead facilities with underground facilities as requested by a Customer may be done at the expense of the Customer and at the discretion of the Company after a determination by the Company has been made on the impact to the system and/or future expansions. The Customer is responsible for the Excess Cost of the underground installation plus cost of premature retirement and removal of the existing overhead facilities less any salvage value of the existing overhead facilities. The Company reserves the right to refuse the replacement if, in the Company's opinion, placing the line underground may result in operational or other problems.

518. In the case of underground facilities, a Customer shall not erect or maintain or permit to be erected or maintained any building, structure, or septic system over such facilities, shall not plant or permit to be planted any trees or shrubs over such facilities, and shall not substantially change the grade over or adjacent to such facilities.

519. Adequate clearances shall be maintained between the padmounted electrical equipment and the surrounding area

A minimum of a ten foot clearance in front of the equipment doors and accessibility for the Company's heavy duty vehicles shall be maintained at all times.

Protective barriers/bumpers are necessary in areas where vehicle traffic or snow removal equipment may cause damage to the equipment. The Customer must contact the Company to determine appropriate clearances. Clearances from doors, windows, air intakes, and fire escapes shall conform to Company Standards. **See DTR 42.047 and DTR 42.061 for additional requirements.**

These clearances shall not supersede any local ordinance or code which requires greater clearance. If additional fire protection is necessary for insurance and/or other purposes, it is the responsibility of the building/property owner and/or Customer to provide additional protection.

vehicle traffic or snow removal equipment may cause damage to the equipment. The Customer must contact the Company to determine appropriate clearances. Clearances from doors, windows, air intakes, and fire escapes shall conform to Company Standards. See DTR 42.047 and DTR 42.061 for additional requirements.

These clearances shall not supersede any local ordinance or code which requires greater clearance. If additional fire protection is necessary for insurance and/or other purposes, it is the responsibility of the building/property owner and/or Customer to provide additional protection.

520. The following requirements are applicable to new Customer owned vaults and locations where there is a major upgrade to the Customer's service. Customer vaults shall conform to NEC 450.41 through 48 (2008 or latest revision). All oil-filled equipment shall be positioned such that anyone operating the unit can exit without having to go toward the unit. A minimum of a three foot clearance between equipment and the vault wall is necessary, unless a greater distance is required to operate the equipment. Each vault shall be equipped with two means of exit. Exit doors shall swing out and be equipped with panic bars, pressure plates, etc. that are normally latched but open under simple pressure. Both new and existing Customer vaults shall under no circumstances be used by Customers for storage or contain any equipment not specified by the Company. Doors shall be kept locked, access being allowed only to qualified persons. When vault locations are not conveniently accessible to Company employees through a public entrance, Customers are requested to provide utility service doors, or keys by which authorized Company employees may gain access. Company owned oil filled equipment shall not be installed in vaults.

Underground Electric Distribution Facilities

521. The costs for new installations of underground electric distribution facilities (exclusive of lighting facilities) will be apportioned as follows:

A. The following underground electric distribution facilities will be provided entirely at the Company's expense and pertain to the installation of underground electric facilities on public property:

1. Underground facilities leaving substations where the installation of overhead facilities, in the sole judgment of the Company, would detract substantially from the appearance of the immediate area or is not feasible.

Article 522-523

2. Underground facilities in areas where overhead facilities would be impaired by substantial above-ground congestion or by proximity to buildings or other structures, in the sole judgment of the Company.

3. Underground facilities where the cost to construct required new facilities overhead or to replace or supplement inadequate existing overhead facilities, would exceed the cost of the underground installation.

B. For distribution facilities not qualifying under 521(A):

1. The Customer shall pay to the Company the costs for the underground facilities as specified in the Company's Tariff.

2. The Customer shall furnish at his expense and to Company specifications all trenching, backfilling, manholes, duct bank, conduit, and transformer slabs necessary for the installation of underground electric distribution facilities including lighting facilities, if any. See Appendix for applicable standards. The Customer should contact the Company's local Work Center for specifications.

522. Where agreements to take lighting service under the Company's Tariff have been executed, standard facilities for the underground source of power for street or area lighting will be provided by the Company, the additional cost of such underground facilities will be apportioned as specified in the Company's Tariff. Any trenching, backfilling, conduit, and transformer slabs required for the installation of a standard source of power for street or area lighting will be provided by the Customer at his expense. The Customer should contact the Company's local Work Center for specifications.

Underground Secondary Service From Underground Secondary Network

523. In areas where the Company maintains an underground secondary distribution system (i.e. a secondary network), service will be furnished, installed, owned, and maintained by the Company to the Customer's main switch. The Customer will be responsible for the installation of all facilities described in Article 509 to the Company's manhole. .

Article 524-528

Underground Service From Underground Primary Network

524. (This section does not apply to services detailed in Article 521 of this book.) In underground areas where there is no underground secondary distribution system, or where, in the Company's opinion, the amount or nature of the Customer's load is such that the load will not be fed from such a system, the Customer will be fed from the primary underground distribution system. These types of services are subject to negotiations between the Customer and the Company. Due to the nature of this type of supply, Customers should contact the Company as soon as possible to determine the apportionment of costs.

525. As deemed necessary by the Company, residential, commercial, and industrial Customers may be required to provide adequate space on private property for Company/Customer owned transformers, switchgear, and protective equipment. The procurement of the necessary easements will be the responsibility of the Customer. The location of such equipment will be designated or approved by the Company. See DTRs 42.047, 42.061.

526. In certain instances, it may be necessary for the Company to install equipment on private property which is used to serve more than one Customer. The cost associated with the duct bank, cables, conduit, manholes, switchgear, and concrete slabs located on public property or located on private property when such facilities are utilized to provide service to additional customers, shall be negotiated between the affected Customers and the Company. The procurement of the necessary easements will be the responsibility of the affected Customers.

527. Customers taking underground service from a primary source may be required to provide, own, and maintain the main disconnect switch, transformer slab, switchgear, duct bank, conduit, and manholes which are exclusively for the Customer's use. The Customer will buy or rent transformation and be responsible for locating transformation and services in accordance with Tariff provisions.

Underground Low Voltage Service From Company Overhead Lines

528. The Company may limit, at its discretion, the size of underground low voltage services from its overhead lines to those which can physically be installed on its poles. The Company may require the installation of a padmounted transformer or a pole on the Customer's property which is dedicated to providing the low voltage service.

SECTION 6 - Grounding

Article 600-605

600. A permanent and effective grounding electrode system furnished, installed, and maintained by the Customer is an essential part of any two or three wire, single phase and any four wire three phase installation, and must be used for equipment grounding on three phase three wire installations. The Company will not be liable for electrical equipment damage due to loss of the Company's service neutral if the Customer's electric service entrance is not properly grounded in accordance with the provisions of this booklet and the NEC.

601. The grounded service entrance conductor must be connected at each individual service entrance switchbox, including the water heating service entrance switchbox, if any. The grounding electrode system must be connected to the grounded service entrance conductor, preferably in the meter mounting device.

602. A grounding electrode system consists of one or more grounding electrodes bonded together and connected to the grounded service entrance conductor by a grounding electrode conductor. A grounding electrode may consist of a metal underground water pipe in direct contact with the earth for ten feet or more, and supplemented by and bonded to an additional approved made electrode or approved made electrodes of driven ground rods, driven pipes, or buried plates. Approved electrodes shall comply with NEC section 250.52 and 250.53.

603. As far as practicable, made electrodes shall be embedded below permanent moisture level. If rod or pipe electrodes are used, they shall be driven full length. When rock bottom is encountered, the electrode may be driven at an oblique angle, up to 45 degrees from vertical, or buried full length in a trench at least 2 ½ feet deep. Where more than one electrode system is used, each electrode of one system shall not be less than six feet from any electrode of another system.

604. The grounding electrode conductor shall be connected to the grounding electrode by suitable lugs, pressure connectors, clamps, or other listed means. Connections depending on solder shall not be used. The grounding electrode clamps must be compatible with the material of the electrode, electrode conductor, and the environment. Not more than one conductor shall be connected to the grounding electrode by a single clamp or fitting unless the clamp or fitting is approved for multiple conductors.

605. Where the resistance of the made electrode to ground is more than 25 ohms, at least two made electrodes, at a minimum of six feet apart and bonded together, shall be used.

Article 606-608

606. The size of the grounding electrode conductor shall not be smaller than specified in the following chart, except the grounding electrode conductor connected to made electrodes (Article 602) need not be larger than No. 6 copper wire. The grounding electrode conductor shall be run in conduit, electrical metallic tubing, or cable armor if the size is smaller than No. 4 copper except as permitted by the NEC. Reference NEC 250.66.

Size of Largest Service Entrance Conductor or Equivalent Area for Parallel Conductors **Aluminum**	**Size of Grounding Electrode Conductor** **Copper**
1/0 or smaller	8
2/0 or 3/0	6
4/0 or 250 kcmil	4
Over 250 kcmil through 500 kcmil	2
Over 500 kcmil through 900 kcmil	1/0
Over 900 kcmil through 1750 kcmil	2/0
Over 1750 kcmil	3/0

607. Meter mounting devices, instrument transformer enclosures, and metal conduit installed by the Customer must be grounded by a grounding electrode system.

608. A suitable means must be provided by the Customer for attachment of other utilities to the Customer's grounding electrode system. Attachments to the meter mounting device are not acceptable.

SECTION 7 – Utilization Equipment Specifications

Article 700-703

General

700. When Customer owned equipment could or actually does interfere with the operation of any components of the Company's electric system or the electric supply to others, the Company reserves the right to refuse service or to disconnect the service upon proper notice. Such instances include, but are not limited to, harmonic distortion, poor power factor, voltage fluctuations, and unacceptable transformer and capacitor installations. Customers should consult with the Company in advance of making any commitments for large motors, air conditioning equipment, welders, X-ray machines, electric tankless water heaters, phase converters, or other equipment which may have a high instantaneous electric demand. The Company will determine the effect such installations may have on the Company's system. Should the Company determine that the installation is likely to cause interference with the electric system or the electric service to others, the Company may refuse to connect service, discontinue service, require the Customer to make modifications to their system or require that the Customer pay the cost of modifications to the Company's system to enable the equipment to be operated. It is the Customer's responsibility to determine and correct the problems such equipment may have on their own system.

Motor/Motor Driven Equipment Including Air Conditioning Equipment

701. The Customer should ascertain from the Company the character of service for the proposed location and application before purchasing motors and motor driven equipment. In general, motors of 3 hp. or less will be supplied from single phase services, and motors larger than 3 hp. will be supplied from three phase services.

702. The electrical limitations of the supply circuits may, in some cases, make it necessary to limit the size of the largest motor to be operated on any given part of the Company's system. Written information as to such limitations is available upon inquiry to the Company.

703. In general, single phase 120/240 volt and three phase 120/208 volt equipment with an instantaneous draw of 68 amps or less, and three phase 277/480 volt equipment with an instantaneous draw of 30 amps or less, may be installed without modifications to the equipment or the Company's system. The installation of equipment which has an instantaneous draw which is greater than specified in this paragraph may only be done upon written approval by the Company.

SECTION 7 – Utilization Equipment Specifications

Article 704-707

704. Upon application to the Company, the Company will determine those locations where exceptions to rules of this Section may be permissible. All exceptions to these rules must be in writing.

705. All motors and motor driven equipment should be equipped with suitable protective devices. Among such devices to be considered are those to provide clearance at the beginning and end of interruptions to service against overloads, voltage and frequency variations, single phase operation of poly-phase motors, and reversal of rotation in poly-phase motors.

706. The Company will not be responsible for damage caused to Customer owned equipment where such damage is caused by the absence, failure, or misapplication of any Customer owned protective device. The Company will not be held responsible for damage caused by lightning or other acts of nature.

Voltage Sensitive Equipment

707. Customers owning or planning to purchase computer, reproduction, X-ray equipment or other voltage sensitive equipment, should consult the manufacturer of their equipment, and install suitable devices on their system to protect against power system transients and/or loss of voltage.

SECTION 8 – Radio and Television Equipment

Article 800-805

800. Antenna wires or masts shall not be attached to Company owned poles.

801. Antenna guy wires should not pass over or under Company wires nor run in the proximity of wires carrying voltages in excess of 150 volts to ground.

802. Antenna lead-in wires should be run and supported so as to prevent them from swinging closer than two feet from conductors of 250 volts or less to ground, or 10 feet from conductors of more than 250 volts to ground.

803. Structures supporting outdoor antennas should be located to eliminate the possibility of such structures falling into, or otherwise making accidental contact with, Company overhead conductors of over 150 volts to ground.

804. If in the Company's opinion, the Customer's antenna guy wires, lead-in wires, or structures supporting outdoor antennas are located so as to interfere with the supply of electric service to the Customer, the Company shall have the right to discontinue or refuse service to the Customer until suitable changes in the antenna system are made.

805. The Company has no authority to require the correction or removal of equipment belonging to others which may be causing interference with reception of radio, television, or other communication signals.

SECTION 9 – Generating Equipment Owned By Customers

Article 900-902

General

900. The installation, connection, and operation of Customer-owned generating equipment by a Customer who takes service from the Company may be restricted under the provisions of rates in the Company's Tariff. The Customer shall contact the Company to obtain this information as part of the Customer's planning to make an installation of generating equipment. Prior to operation of Customer-owned generating equipment, the Company shall have the right to inspect any Customer-owned controlling and safety equipment associated with the generating equipment, together with the manner in which the generator is electrically connected to the Customer's load and/or Company's electrical system to assure itself that the operation of this equipment will not create an undue risk of damage or injury to the Company or its other Customers. Customers should contact the Company well in advance of equipment installation in order to allow sufficient time for the Company to conduct the necessary interconnection studies.

Standby Generating Equipment

901. Customers may install generating equipment to serve as a standby source of electricity to supply all or a part of the Customer's load in the event of an interruption in the supply of electricity from the Company. The Customer's interconnection shall be arranged so that no electrical connection can occur between the Company's service and the Customer's standby source of supply. The standby source shall be controlled through the use of a double throw switch or equivalent, installed in a manner acceptable to the Company, and designed to prevent the possibility of any electrical connection between the Company's normal electrical supply and the Customer's standby source. Standby generator connections into the meter mounting device are not allowed.

902. At the Company's discretion, the Customer's standby source may be allowed to interconnect and operate in parallel with the Company's supply provided certain conditions set forth by the Company are addressed by the Customer. Any Customer planning to interconnect standby generation in this manner must notify the Company in advance and obtain approval for the method of connection.

Article 903-904

Conjunctional Generating Equipment

903. Customers may install generating equipment to serve as a source of electricity which is operated in parallel with electric service taken from the Company. Such service from the Company is called conjunctional service. In certain cases, a conjunctional service Customer may elect to sell to the Company all of the output from the Customer's generating equipment, or the portion of the output in excess of the Customer's internal load. Customers who want to sell energy to the Company should refer to Articles 904 and 905 below. Generator connections into the meter mounting device are not allowed. Customers with qualifying generating equipment have the option of being serviced under the Net Metering rules established by the NH PUC.

Prior to installing generating equipment, Customers shall contact the Company to obtain the proper application form. The Company will review the application to ensure the equipment can safely be connected and operate in parallel with the Company's electric distribution system. The approved application will be returned to the Customer. After installation of the generator, a Certificate of Completion must be completed by the Customer and delivered to the Company. The form requires a signature from the town electrical inspector. If the town does not have an electrical inspector, a New Hampshire licensed electrician must approve the installation. Once the Company reviews the completed certificate, a meter technician will visit the property to install a new net meter. Once the proper meter has been installed, the Customer will receive notification from the Company that the customer is officially enrolled in the net metering program. No operation of the generator is permitted until all these steps are completed. The Company is not responsible for improper billing that my result whenever the Customer operates a generator prior to the proper net meter being installed. Net Metering is not compatible with sub-meter installations.

Qualifying Co-generators, Qualifying Small Power Producers, and Limited Electrical Energy Producers

904. Customers (and in some instances persons who are not Customers) may install generating equipment which meets the criteria established in federal regulations for qualifying cogeneration facilities or qualifying small power production facilities, or in State of New Hampshire regulations for limited electrical energy producers, and may want to sell some or all of the electric energy they produce to the Company. In order to qualify under the Federal or State regulation, such producers (herein called distributed generators)

Article 905

must either be a qualifying co-generator or produce energy using biomass, waste, or renewable resources such as solar, wind, and water as a primary energy source, and must meet certain other criteria.

905. Any person interested in developing a distributed generation facility should contact the Distributed Generation Department at the Company's General Office in Manchester. This contact should be made at an early date in the planning process in order to allow sufficient time for the Company to conduct the necessary interconnection studies.

SECTION 10 – Water Heating

Article 1000-1003

1000. Electricity taken under any of the Company's residential or general service rates may be used as a source for water heating in homes and other buildings. Electricity for water heating purposes is also available at special prices for existing or new Customers subject to certain restrictions set forth in the applicable rate schedules. The subsections below list several of the optional rate schedules that are available for electric water heating on the date this booklet was published, and refer to standard wiring diagrams at the back of the booklet applicable to the electric service option. Copies of the currently effective rate schedules and standard wiring diagrams are available upon request to the Company.

Uncontrolled Water Heating

1001. Uncontrolled water heating service is available to Customers with approved water heaters under certain residential rates or General Service Rate G. The standard meter installations are shown in Meter Standards 04-3-G-2, 04-3-G-8, 04-3-G-11. Uncontrolled water heaters may have either one or two heating elements, but when there are two elements they must be electrically connected so that both elements cannot operate simultaneously. A typical wiring diagram illustrating an uncontrolled water heater with two elements wired for non-simultaneous operation is shown in Meter Standard 04-3-G-34. The wiring diagram for a single element uncontrolled water heater would be similar, except that there would be no upper heating element, and the conductor labeled E would be typically connected to Terminal 2 of the high limit temperature switch.

Rate LCS Water Heating (Radio Controlled Option)

1002. Electric water heating service under the radio-controlled option of Rate LCS is available to Residential Service Rate R and General Service Rate G customers when taken in conjunction with electric space heating service under the radio-controlled option of Rate LCS. Electric water heating service will be interrupted when electric space heating is interrupted by the Company under the radio-controlled option of Rate LCS. The standard meter installation is shown in Meter Standard 04-3-G-43.

Plumbing for Water Heaters

1003. A typical plumbing diagram for the installation of electric water heaters is shown in Meter Standard 04-3-G-38.

SECTION 11 – Space Heating

Article 1100-1101

General

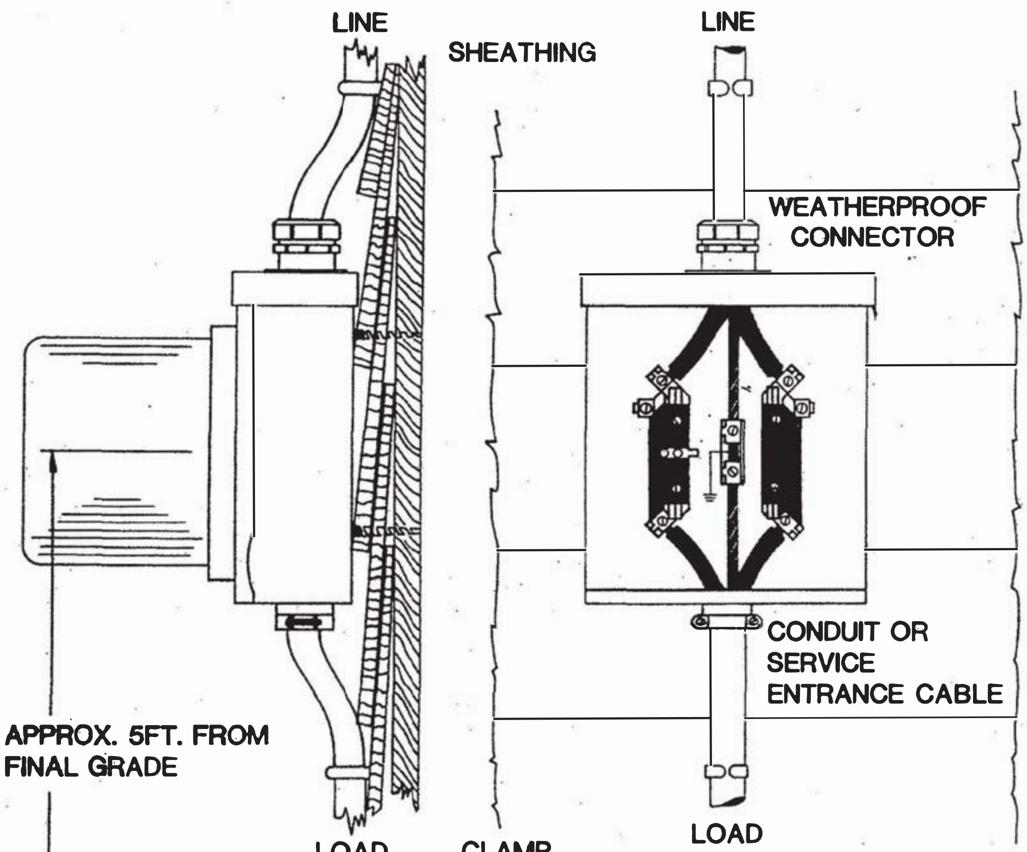
1100. Electricity taken under any of the Company's residential or general service rates may be used as a source for space heating in homes and other buildings. Electricity for space heating purposes is also available at special prices for existing or new Customers subject to certain restrictions set forth in the applicable rate schedules. The subsection below describes one of the optional rate schedules available for electric space heating purposes on the date this booklet was published, and refers to standard wiring diagrams at the back of the booklet applicable to that service option Copies of the currently effective rate schedules and standard wiring diagrams are available upon request to the Company.

Rate LCS Space Heating (Radio-Controlled Option)

1101. Electric space heating service is available under Load Controlled Service Rate LCS to Residential Service Rate R and General Service Rate G customers who have permanently installed conventional electric space heating (e.g. electric resistance or heat pump) when a dynamic electric thermal storage system or a wood or coal stove is available for use as a backup during times when service is interrupted by the Company. The availability of the radio-controlled option shall be limited to those premises which have electric space heating as the sole source of space heating, excluding the wood stove or coal stove. The wood or coal stove or dynamic electric thermal storage heater must be permanently installed and sized to adequately heat the premises main living area. The standard meter installation is shown in Meter Standard 04-3-G-43.

04 3-G-1

TYPICAL OVERHEAD-SINGLE METER-OUTDOOR



SOCKET MUST BE PLUMB AND LEVEL
SOCKET TO BE LOCATED ON HIGHPOINT OF TWO CLAPBOARDS

NOTE:

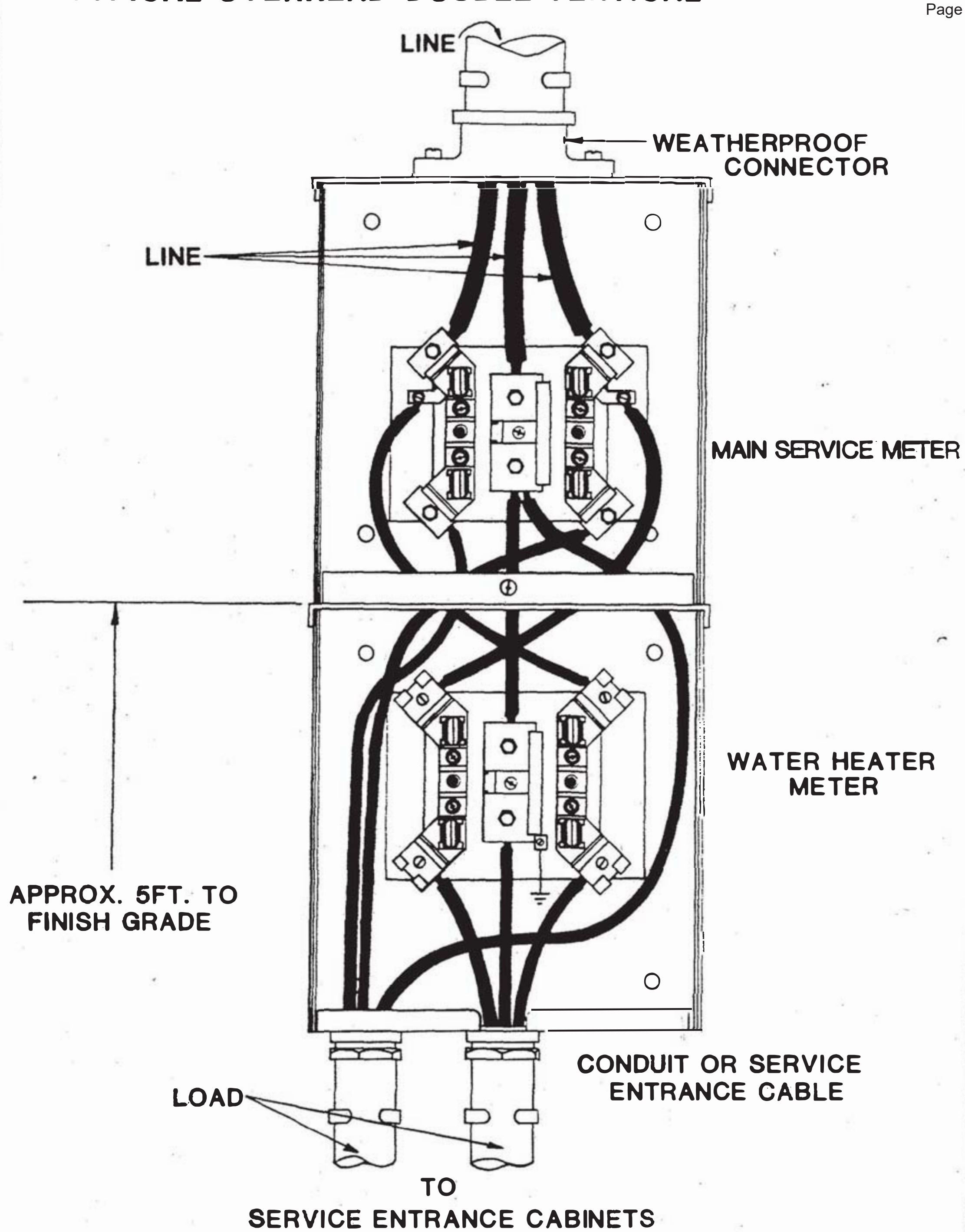
1. THIS INSTALLATION IS SUITABLE FOR 120/208V NETWORK WITH A 5TH TERMINAL INSTALLED AT THE 9 O'CLOCK POSITION.

2. SHEATHING MUST BE CAPABLE OF PROVIDING ADEQUATE SUPPORT TO METER MOUNTING DEVICE AND SERVICE ENTRANCE CABLE.

EVERSOURCE ENERGY	METER STANDARD	ISSUE	DATE
			3-29-84
			12-84
		ORIGINAL	LMN

04 3-G-2

TYPICAL OVERHEAD-DOUBLE VERTICAL



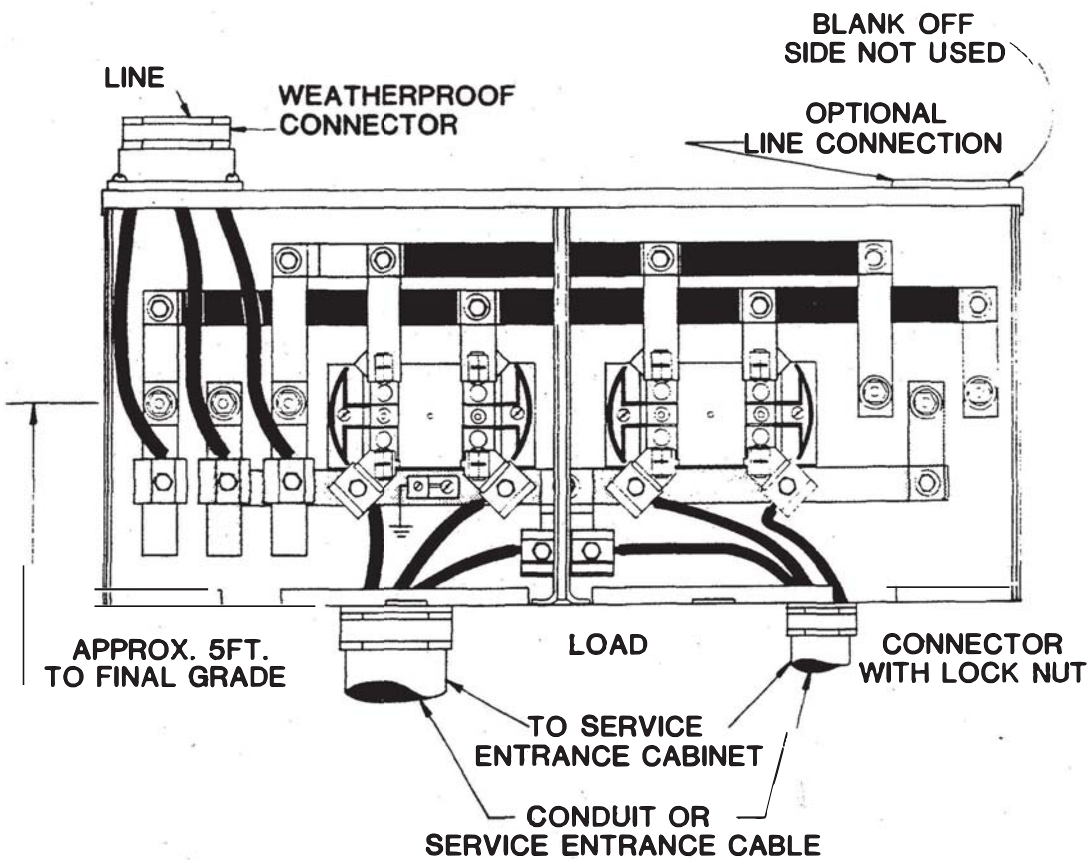
EVERSOURCE ENERGY

METER STANDARD

ISSUE	DATE
	5-85
	3-85
ORIGINAL	12-83

04 3-G-3

TYPICAL OVERHEAD-DOUBLE HORIZONTAL



NOTE: 1.) THIS DIAGRAM IS FOR DOUBLE INSTALLATION, BUT TRIPLE AND QUADRUPLE UNITS ARE ALSO AVAILABLE.

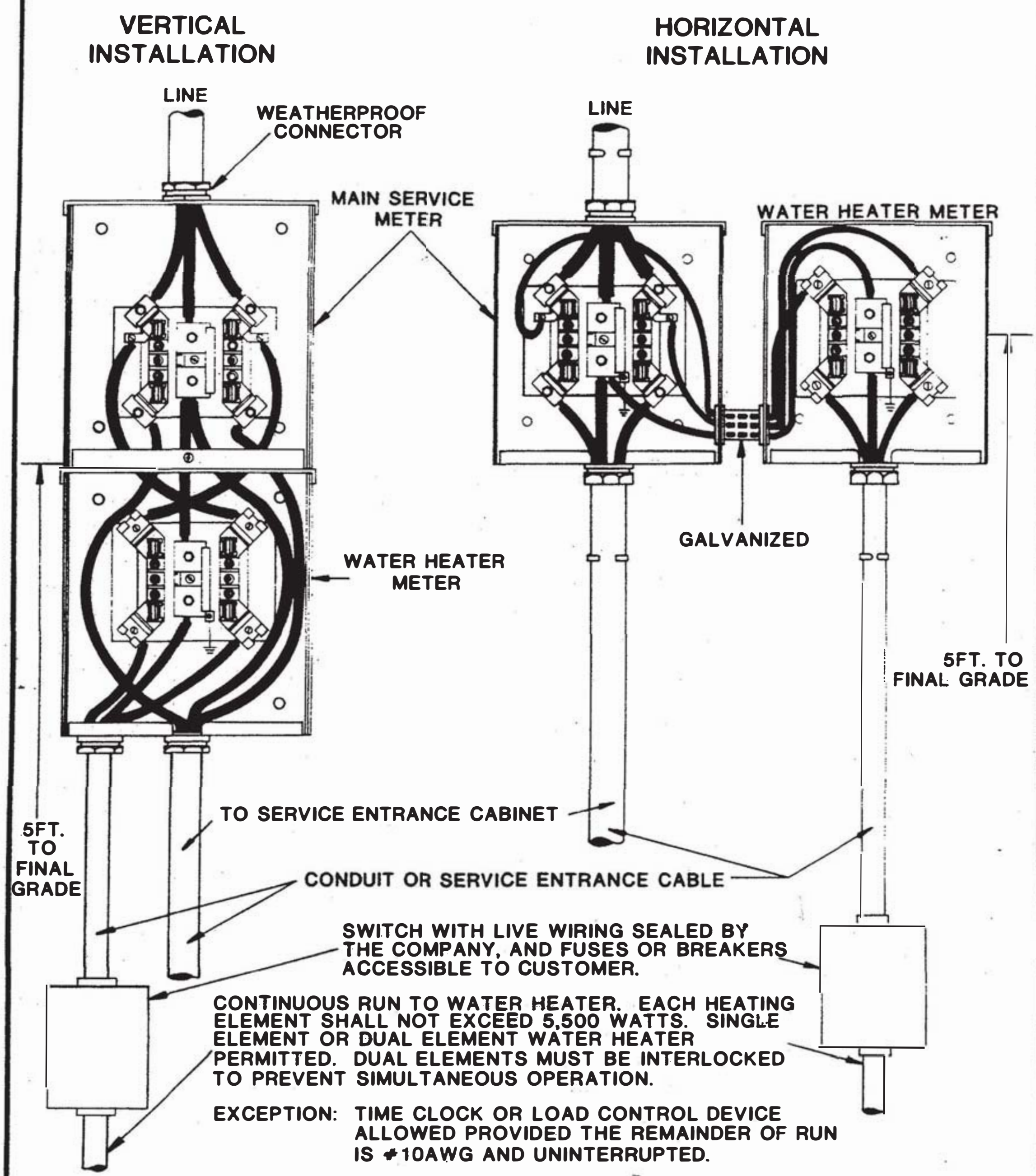
2.) LINE CONNECTIONS CAN BE MADE TO EITHER LEFT OR RIGHT SIDE OF BOX.

3.) HORIZONTAL UNITS CAN ALSO BE USED ON UNDERGROUND SERVICES.

EVERSOURCE ENERGY	METER STANDARD	ISSUE	DATE
		ORIGINAL 12-83	

04 3-G-11

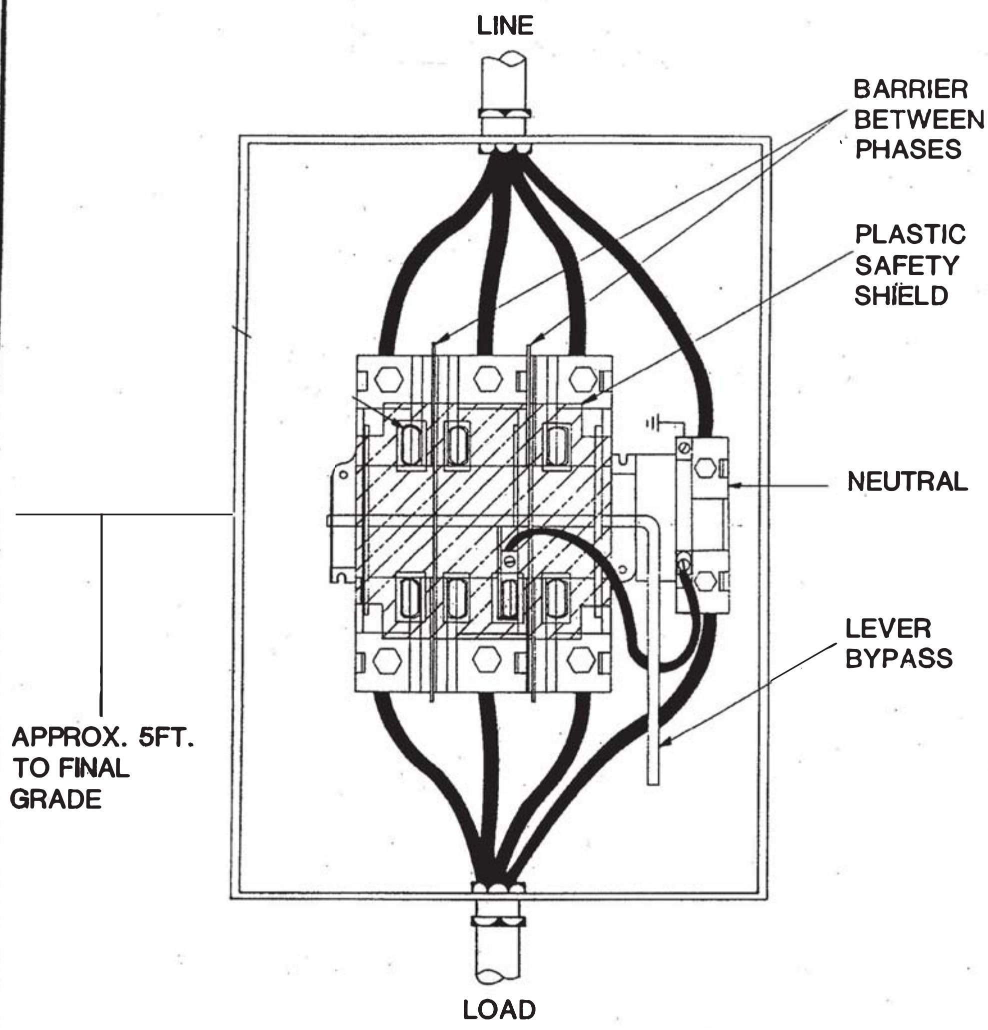
UNCONTROLLED WATER HEATER INSTALLATION



EVERSOURCE ENERGY	METER STANDARD	ISSUE	DATE
		ORIGINAL 12-83	

04 3-G-26B

SOCKET-SELF CONTAINED-
200/400 AMPERE
3Ø 4 WIRE Y

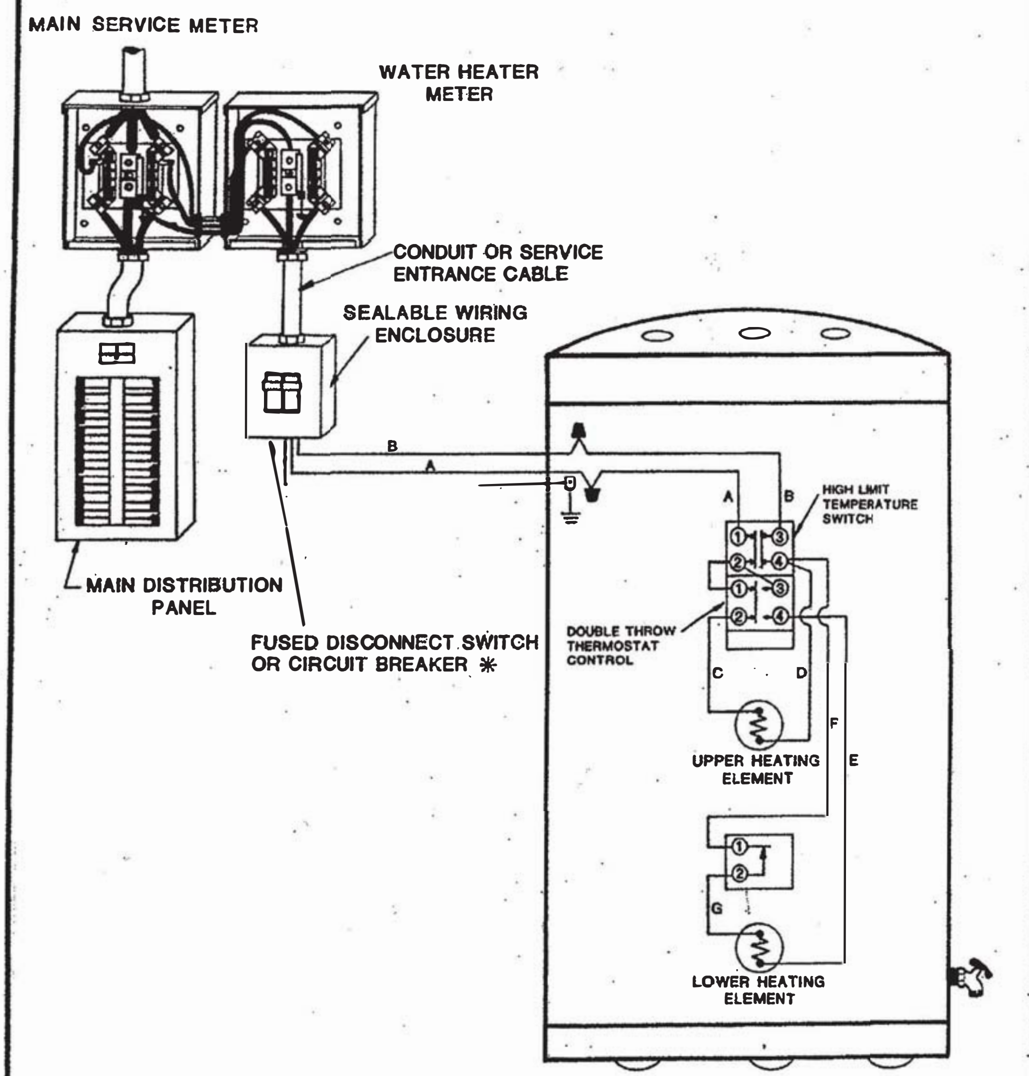


NOTE: MAY BE USED ON
120/208 OR 277/480

EVERSOURCE ENERGY	METER STANDARD	ISSUE	DATE
		REV.	3-85
		ORIGINAL	10-84

(04) 3-G-34

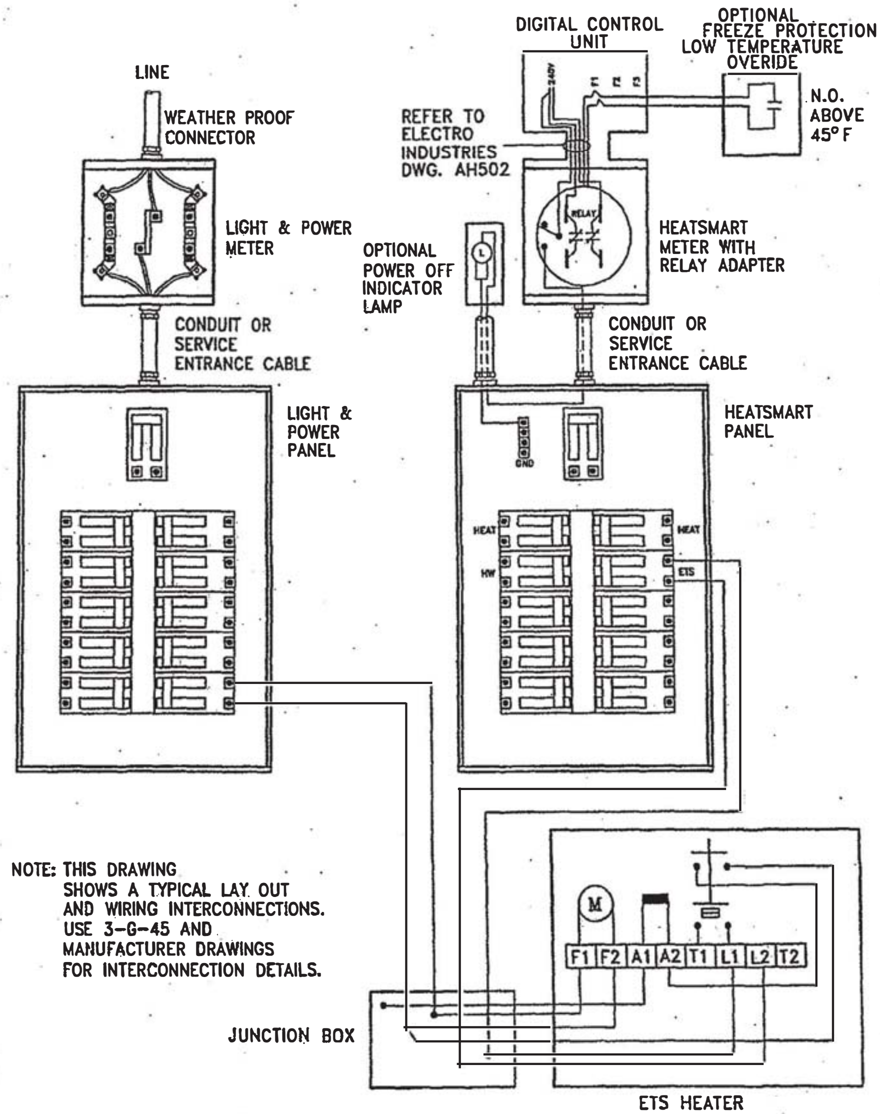
UNCONTROLLED WATER HEATING TYPICAL WIRING DIAGRAM NON-SIMULTANEOUS INSTALLATION



EVERSOURCE ENERGY	METER STANDARD	ISSUE	DATE
			4-2014
			5-85
		ORIGINAL	6-84

3-G-43

HEATSMART TYPICAL DIRECT METERED INSTALLATION



NOTE: THIS DRAWING SHOWS A TYPICAL LAY OUT AND WIRING INTERCONNECTIONS. USE 3-G-45 AND MANUFACTURER DRAWINGS FOR INTERCONNECTION DETAILS.

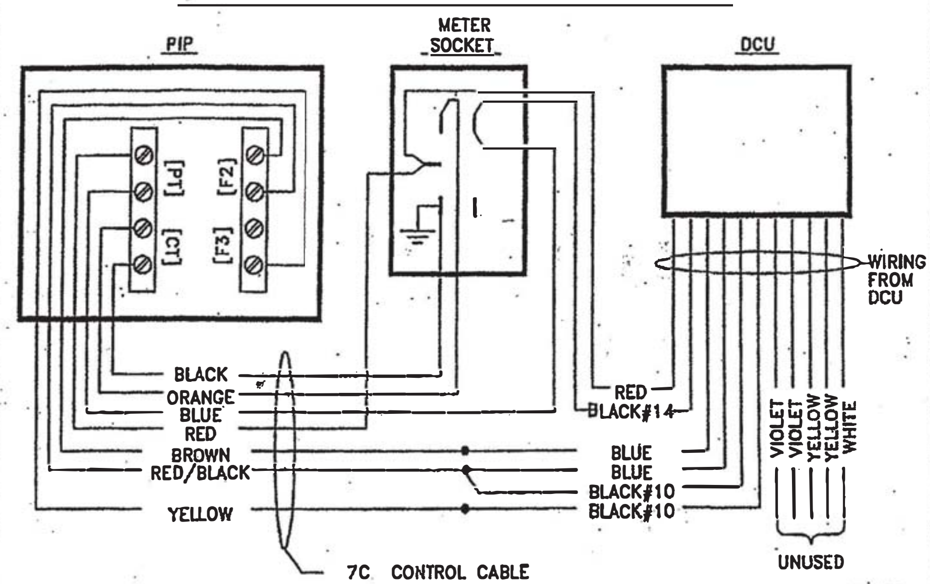
EVERSOURCE ENERGY

METER STANDARD

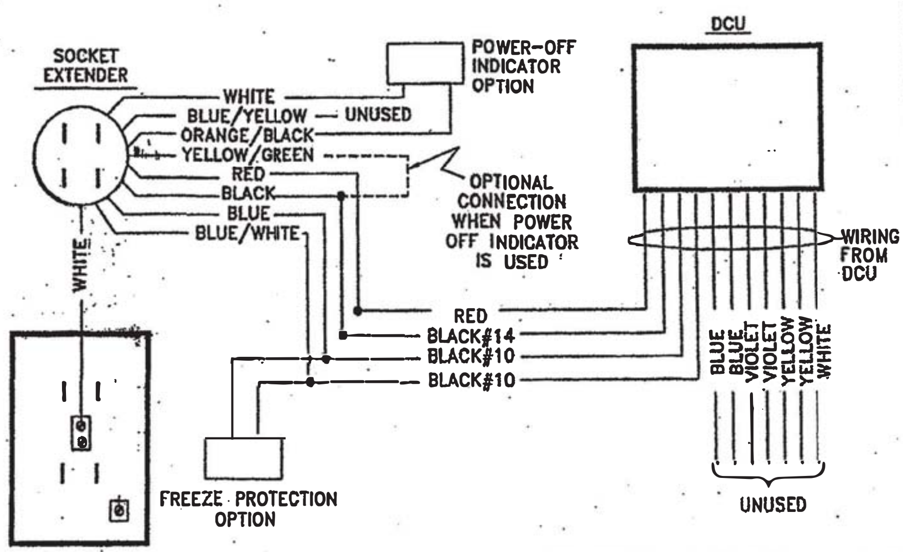
ISSUE	DATE
JPA	6-95
JPA	5-94
JPA	7-94
ORIGINAL	3-94

3-G-45

HEATSMART
STANDARD WIRING/COLOR CODES
USING PEAK INTERRUPTER PANEL



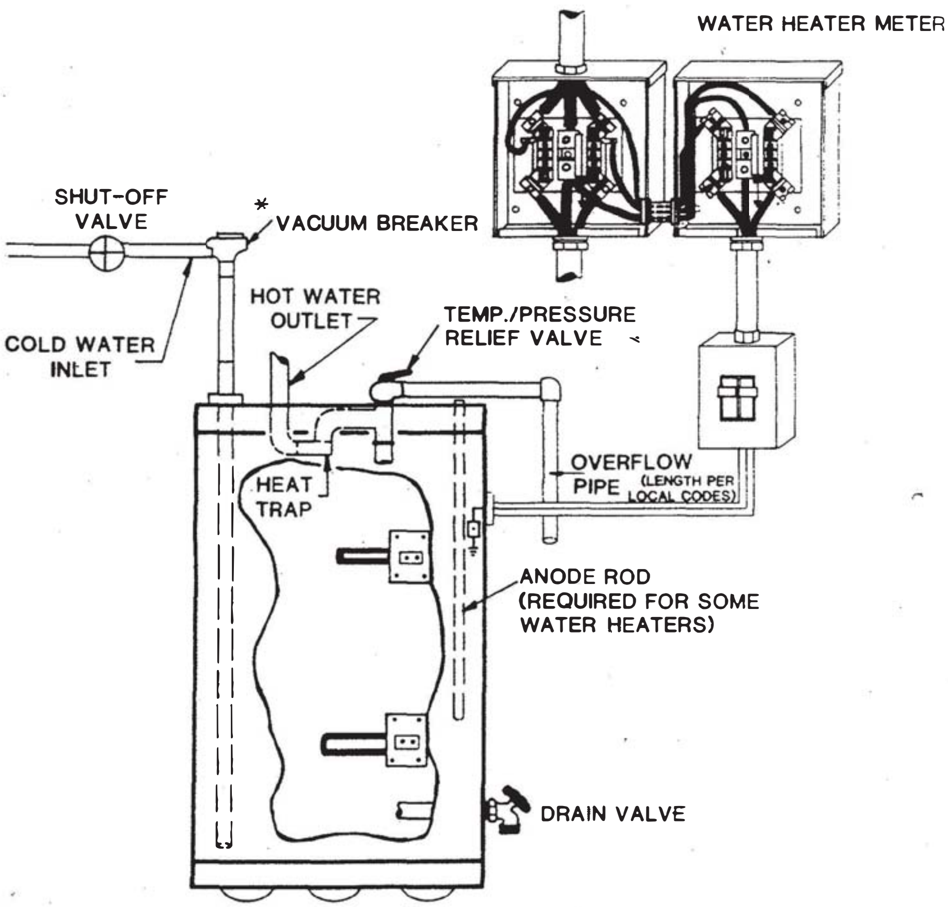
USING SOCKET EXTENDERS



EVERSOURCE ENERGY	METER STANDARD	ISSUE	DATE
			6-95
		ORIGINAL	7-94

04 3-G-38

ELECTRIC STORAGE WATER HEATER TYPICAL PLUMBING DIAGRAM



MINIMUM CAPACITY REQUIREMENT: 40 GALLONS WITH UNCONTROLLED WATER HEATING RATES.

MINIMUM CAPACITY REQUIREMENT: 80 GALLONS WITH CONTROLLED WATER HEATING RATES.

* MAY BE OPTIONAL - CHECK LOCAL CODES

EVERSOURCE ENERGY	METER STANDARD	ISSUE	DATE
			5-85
		ORIGINAL	6-84

(04) 3-G-8

TYPICAL UNDERGROUND-DOUBLE VERTICAL

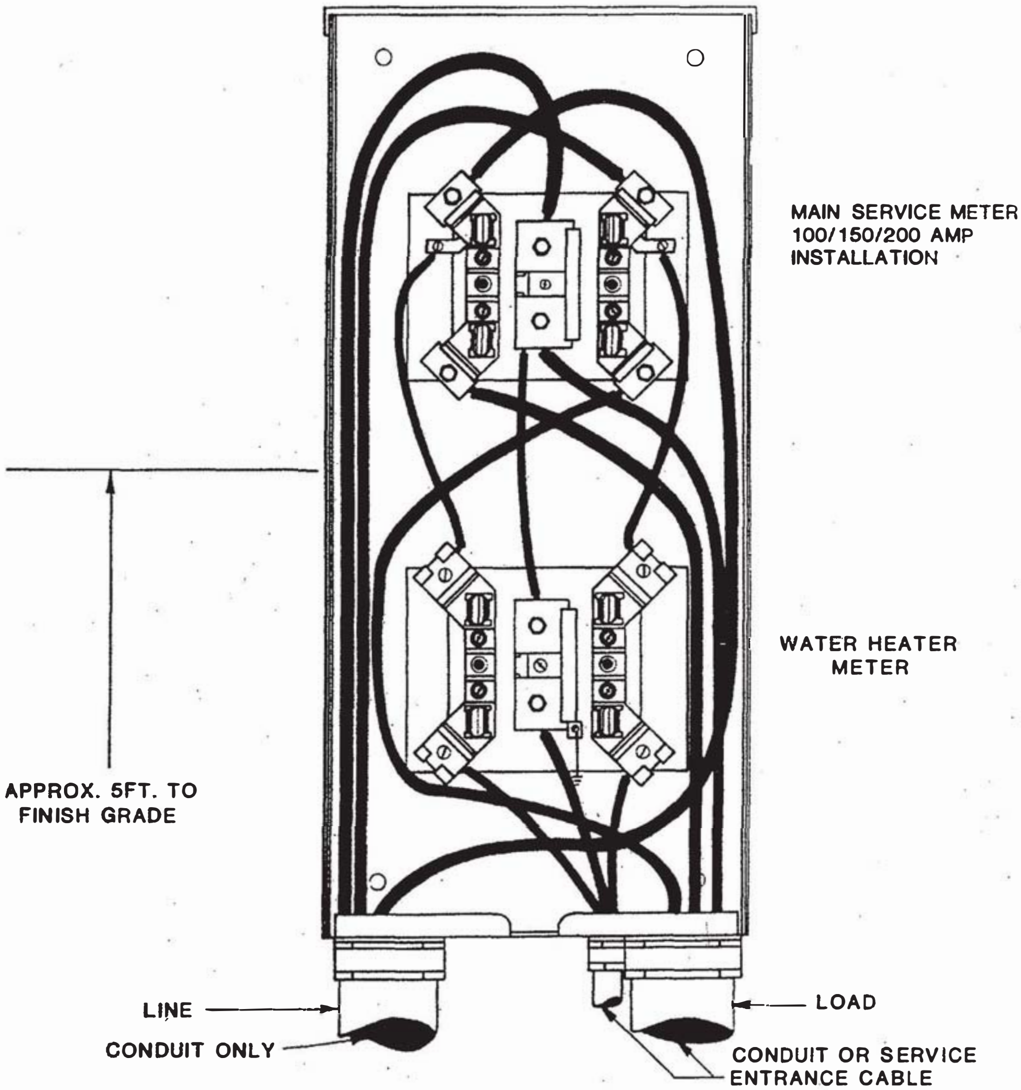


DIAGRAM SHOWING WIRING WITH COVER REMOVED

EVERSOURCE ENERGY	METER STANDARD	ISSUE	DATE
			5-85
			3-85
			12-84
		ORIGINAL	12-83

IMPORTANT INFORMATION FOR BUILDERS AND CONTRACTORS

Eversource NH Electric Service Support Center (ESSC)
Mon-Fri, 7am – 4:30 pm

Phone……………………………………………………………………………………………800-362-7764

Email……………………………………………………………………………………………NHnewservice@eversource.com

Website………………………………………………………………………………………www.eversource.com

Eversource NH Customer Service
Mon – Fri, 8am – 6pm

Residential Customers ……………………………………………………………………800-662-7764

Business Customers ………………………………………………………………………866-554-6025

Streetlight Repairs …………………………………………………………………………800-662-7764

Theft of Service ………………………………………………………………………………800-342-4298

Eversource NH Energy Efficiency

Residential …………………………………………………………………………………800-662-7764

Business ………………………………………………………………………………………866-554-6025

Dig Safe ………………………………………………………………………………888-344-7233

EVERSOURCE ENERGY

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 08/13/2019 **Date of Response: 08/27/2019**
Request No. STAFF 10-040 **Page 1 of 1**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Edward A. Davis

Request:
Reference Eversource's tariff, page 80 regarding Rate EOL which allows the customer to have the Company or private contractor install new lighting fixtures:

> Tariff Page 80: (d) furnish any fixtures utilizing other lighting technologies accepted by the Company, and pay either the Company or a private line contractor, as described under the "Additional Requirements" section below, for the installation of these fixtures.
> Tariff 7th Revised Page 81: Customers who are replacing existing fixtures with these technologies are responsible for the cost of removal and installation. Customers may choose to have this work completed by the
> Company or may opt to hire and pay a private line contractor to perform the work.

Is the Company willing to offer municipal customers the opportunity to have maintenance performed by a private line contractor subject to special agreement with Eversource?

Response:
Although the Company has not proposed to offer these types of service arrangements in this case, it has considered and is amenable to such an arrangement, recognizing a number of conditions and concerns would need to be addressed. From a rates perspective, the potential for such service would also depend on the extent to which the Company's proposed new rate structure is approved, and the alignment of rates with the cost of providing maintenance service by the company vs. a private contractor, including which aspects of maintenance service are contemplated to be performed by either party.