## Comparative Analysis of PSNH's Proposal with PBR Plans in Massachusetts – Exogenous Factors

| Company/Element | Exogenous Z Factor | Exogenous Cost Threshold | Operating Revenues | Number of Customers |
|---|---|---|---|---|
| PSNH Proposed<br><br>(DE 24-070) | Includes but not limited to positive or negative cost changes from (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry.<br>Threshold = $1.5M | $1.5m | $1.5b | 539k |
| National Grid<br><br>(D.P.U. 23-150) | Includes but not limited to positive or negative cost changes from (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. Threshold = 0.001253 times total operating revenues = $3.6m adjusted by GDP-PI annually | $3.6m | $2.8b | 1.3m |
| Unitil Electric PBR1<br><br>(D.P.U. 23-80) | Includes but not limited to positive or negative cost changes from (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. Threshold = 0.001253 times total operating revenues = $110,000 adjusted by GDP-PI annually | $110k | $88m | 46k |
| NSTAR PBR2<br><br>(D.P.U. 22-22) | Includes but not limited to positive or negative cost changes from (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. Threshold = 0.001253 times total operating revenues = $4M adjusted by GDP-PI annually | $4m | $3.1b | 1.4m |
| NSTAR GAS PBR1<br><br>(D.P.U. 19-120) | Positive or negative cost changes from (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry.[1]<br>Threshold = 0.001253 times total operating revenues = $700,000 adjusted by GDP-PI annually | $700k | $500m | 296k |
| NSTAR PBR1<br><br>(D.P.U. 17-05) | Includes but not limited to positive or negative cost changes from (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry.<br>Threshold = $5M adjusted by GDP-PI annually | $5m | $3.2b | 1.4m |

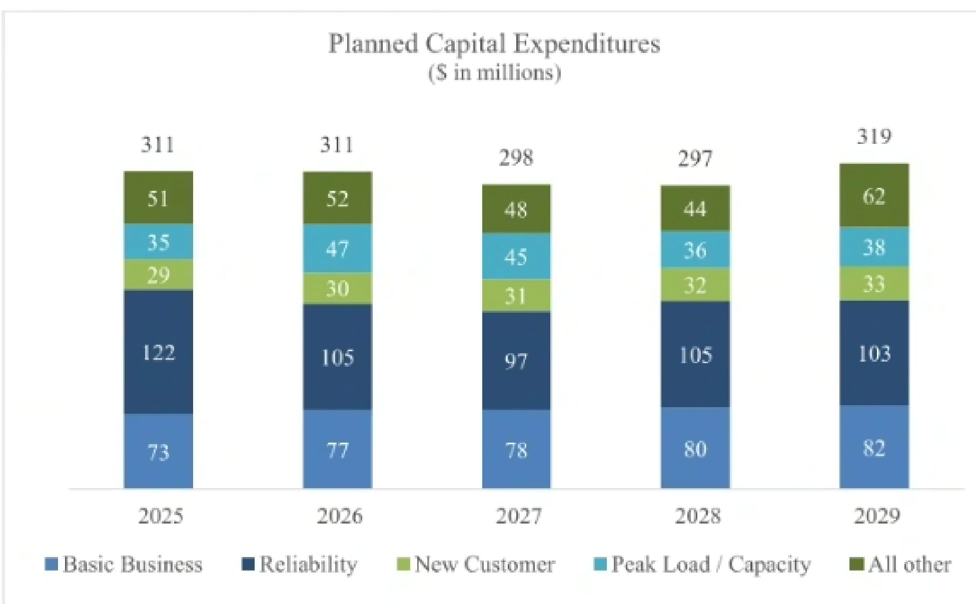
[1] The Department accepted an additional exogenous event due to certain pipeline safety requirements

| **Regulatory Reconciliation Adjustment Mechanism (RRA)** | | | |
|---|---|---|---|
| **Component** | **Current Mechanism** | **Proposed DE 24-070 Test Year Baseline Includes:** | **Company Proposal** |
| Regulatory Assessments and Consultant Costs | Regulatory Commission annual assessments and consultants hired or retained by the Commission and OCA. | 1) Regulatory assessments for the most recent FY<br>2) Consultant costs incurred during the test year | Eliminate annual reconciliation of over/under through RRA; Annual amount to be recovered through base rates, subject to reconciliation at the Company's next rate case. |
| Property Tax | Property tax expenses, as compared to the amount in base rates (DE 19-057) | 2024 Tax Year property expense | Eliminate annual reconciliation of amount over/under base rates |
| Vegetation Management | Vegetation management program variances as compared to the amount in base rates (DE 19-057) | 2023 actual plus post-TY adjustment for $2m budget increase | Eliminate annual reconciliation of amount over/under base rates |
| Storm Cost LTD True-Up | Storm cost amortization final reconciliation and annual reconciliation updated for actual cost of long-term debt | Proposed LTD cost in proceeding | Eliminate annual reconciliation of amount over/under base rates |
| Lost Base Revenues - Net Metering | Lost-base distribution revenues associated with net metering, as calculated consistent with RSA 362-A:9, VII and the Commission's approved method in Order No. 26,029 (June 23, 2017) in Docket No. DE 16-576. | Not Included | Eliminate annual recovery for expenses incurred after August 1, 2024 |
| Rate Case Expense | Order No. 26,634 (May, 27, 2022) at 1. The Commission approved a settlement agreement relating to Eversource's motion to recover rate case expenses for DE 19-057. Pursuant to that agreement, Eversource is authorzied to collect $1,762,807 through its Regulatory Reconciliation Adjustment mechanism over five years, beginning August 1, 2022. | 1) Recover remaining balance of approved rate case expense from DE 19-057 over 5 years<br>2) DE 24-070 rate case expense over 5 years | Eliminate annual reconciliation of over/under through RRA, subject to reconciliation at the Company's next rate case. |
| **Pole Plant Adjustment Mechanism** | | | |
| **Component** | **Current Mechanism** | **Proposed DE 24-070 Test Year Baseline Includes:** | **Company Proposal** |
| Pole Replacement O&M Transfer costs | The actual costs associated with replacement poles for the prior calendar year based on the actual number of poles replaced and the actual Eversource cost to transfer the conductor from the old to the new poles. | Actual expenses for 2023 Test Year | Eliminate annual recovery for expenses incurred after August 1, 2024 |
| Annual Inspection Costs | The actual inspection costs and other upfront costs for the prior calendar year consisting of the number of poles inspected in the former Consolidated maintenance area and the per pole rate in effect. Upfront costs of $250,000 in years 1 and 2 and $75,000 in year 3 will also be included. | Actual expenses for 2023 Test Year | Eliminate annual recovery for expenses incurred after August 1, 2024 |
| Pole Attachment Revenue | Incremental third-party pole attachment revenues is applied as an offset to the items in (a) and (b). Pole attachment revenues for formerly Consolidated owned poles will be tracked separately and billed at the Consolidated rate at the time of closinguntil a full pole attachment survey is conducted and, or a single, unified rate is applied to all poles. | Not Included - amount not known and measurable at this time | Eliminate annual recovery for expenses incurred after August 1, 2024 |
| Vegetation Management Expense | The incremental vegetation management expense is calculated as the vegetation management expenses formerly billed to Consolidated. | Normalized actual expenses for 2023 Test Year by reflecting a monthly average of CCI vegetation management billings from November 2017 through December 2023 annualized to reflect a twelve-month period. This resulted in a decrease to the actual test year vegetation management expense of $902,206. | Eliminate annual recovery for expenses incurred after August 1, 2024 |
| **Other** | | | |
| **Component** | **Current Mechanism** | **Proposed DE 24-070 Test Year Baseline Includes:** | **Company Proposal** |
| Lost Base Revenues - Energy Efficiency | Systems Benefits Charge | Not Included | Eliminate annual recovery for expenses incurred after August 1, 2024 |

| Other Mechanisms (No Changes) | | | |
|---|---|---|---|
| **Component** | **Current Mechanism** | **Proposed DE 24-070 Test Year Baseline Includes:** | **Company Proposal** |
| Systems Benefit Charge | To fund energy efficiency and energy assistance programs | No costs included in DE 24-070 | No change except for the elimination of energy efficiency-related lost base revenues as shown in Attachment PUC TS1-004(a). |
| Stranded Cost Recovery Charge (SCRC) | The SCRC is the portion of the unbundled retail delivery service bill that is a non-bypassable charge as provided by RSA 369-B:4,IV and RSA 374-F:3, XII to recover the portion of the Company's Part 1 and Part 2 Stranded Costs that are allowed by the Settlement Agreement. The SCRC include the RRB Charge defined in RSA Chapter 369-B, overmarket or under-market IPP and Power Purchase Agreement costs, Non-Securitized Stranded Costs, and other costs and expenses allowed or as authorized by the Commission. The SCRC also includes the:<br>- Regional Greenhouse Gas Initiative ("RGGI") refund as required by RSA 125-O:23,II and Order No. 25,664 dated May 9, 2014, which directs the Company to refund RGGI auction revenue it receives to its Customers through the SCRC.<br>- Costs of implementing 2018 N.H. Laws, Chapter 340, "AN ACT requiring the public utilities commission to revise its order affecting the Burgess BioPower plant in Berlin, … " per Order No. 26,332 ("Ch. 340" costs).<br>- Costs of implementing Section 7.1 of the DE 19-057 Settlement Agreement as approved in Order No. 26,433 to recover Environmental Remediation costs.<br>- Costs of the DE 20-136 Settlement Agreement to recover Net Metering and Group Host costs. | No costs included in DE 24-070 | No change |
| Transmission Cost Adjustment Mechanism (TCAM) | The Transmission Cost Adjustment Mechanism ("TCAM") recovers, on a fully reconciling basis, the costs incurred by the Company for transmission related services. These costs include charges under the ISO-NE Tariff; charges billed to the Company by Other Transmission Providers; third party charges billed to the Company for transmission related services such as charges relating to the stability of the transmission system which the Company is authorized to recover by order of the regulatory agency having jurisdiction over such charges; and transmissionbased assessments or fees billed by or through regulatory agencies, including those associated with the ISO-NE, regional transmission organization ("RTO") and the FERC. | No costs included in DE 24-070 | No change |

**Capital Expenditure Long Range Plan**
**$ Thousands**

| Sum of Amount | | Year | | | | | |
|---|---|---|---|---|---|---|---|
| Budget Category | Budget Sub-Category | 2025 | 2026 | 2027 | 2028 | 2029 | Grand Total |
| Basic Business | 3rd Party/Joint Owner Work | $ 5,253.00 | $ 5,410.59 | $ 5,572.91 | $ 5,740.09 | $ 5,912.30 | $ 27,888.89 |
| | Basic Business - Other | $ 565.47 | $ 582.43 | $ 599.91 | $ 617.90 | $ 636.44 | $ 3,002.16 |
| | Capital Tool Purchases | $ 3,017.39 | $ 3,077.27 | $ 3,138.95 | $ 3,202.49 | $ 3,267.94 | $ 15,704.04 |
| | Emergent Equipment Failure - Substation | $ 2,850.00 | $ 2,850.00 | $ 2,850.00 | $ 2,850.00 | $ 2,850.00 | $ 14,250.00 |
| | Emergent Equipment Failures - Line | $ 31,402.64 | $ 32,344.72 | $ 33,315.06 | $ 34,314.51 | $ 35,343.95 | $ 166,720.88 |
| | Environmental | $ 412.00 | $ 424.36 | $ 437.09 | $ 449.84 | $ 463.71 | $ 2,187.00 |
| | Insurance Claim/Keep Cost | $ 1,442.00 | $ 1,485.26 | $ 1,529.82 | $ 1,575.71 | $ 1,622.21 | $ 7,655.00 |
| | Lighting | $ 1,534.70 | $ 1,580.74 | $ 1,295.04 | $ 1,653.89 | $ 1,727.32 | $ 7,791.68 |
| | Line Relocations/Act of Public Authority | $ 3,701.82 | $ 5,812.87 | $ 3,927.26 | $ 3,927.26 | $ 4,166.43 | $ 21,535.65 |
| | Pre-Cap Line Transformers | $ 23,194.57 | $ 23,890.41 | $ 24,607.12 | $ 25,345.33 | $ 26,105.69 | $ 123,143.12 |
| Basic Business Total | | $ 73,373.59 | $ 77,458.66 | $ 77,273.16 | $ 79,677.03 | $ 82,095.99 | $ 389,878.43 |
| New Customer | Customer Driven | $ 29,349.85 | $ 30,230.35 | $ 31,137.26 | $ 32,071.37 | $ 33,033.51 | $ 155,822.34 |
| New Customer Total | | $ 29,349.85 | $ 30,230.35 | $ 31,137.26 | $ 32,071.37 | $ 33,033.51 | $ 155,822.34 |
| Reliability | Distribution Line Reliability | $ 35,764.00 | $ 19,315.88 | $ 9,156.73 | $ 26,436.63 | $ 27,529.68 | $ 118,202.91 |
| | Distribution ROW Line Reliability | $ 21,347.00 | $ 20,468.00 | $ 14,610.00 | $ 15,100.00 | $ 23,550.00 | $ 95,075.00 |
| | Distribution Automation | $ 9,200.00 | $ 9,200.00 | $ 5,200.00 | $ 5,200.00 | $ 5,200.00 | $ 34,000.00 |
| | Substation Reliability | $ 50,091.00 | $ 52,966.00 | $ 68,345.00 | $ 58,520.00 | $ 47,050.00 | $ 276,972.00 |
| | CCI Reject Pole Replacement | $ 6,000.00 | $ 3,000.00 | $ - | $ - | $ - | $ 9,000.00 |
| Reliability Total | | $ 122,402.00 | $ 104,949.88 | $ 97,311.73 | $ 105,256.63 | $ 103,329.68 | $ 533,249.91 |
| Peak Load | Distribution Line Capacity | $ 9,102.00 | $ 18,643.00 | $ 18,926.00 | $ 12,000.00 | $ 14,000.00 | $ 72,671.00 |
| | Substation Capacity | $ 25,582.00 | $ 28,574.00 | $ 26,320.00 | $ 24,000.00 | $ 24,000.00 | $ 128,476.00 |
| Peak Load Total | | $ 34,684.00 | $ 47,217.00 | $ 45,246.00 | $ 36,000.00 | $ 38,000.00 | $ 201,147.00 |
| All Other | Ops Services | $ 15,133.30 | $ 15,429.31 | $ 15,290.53 | $ 16,025.60 | $ 16,622.43 | $ 78,501.18 |
| | Engineering | $ 6,518.23 | $ 6,920.00 | $ 14,620.00 | $ 6,645.00 | $ 7,645.00 | $ 42,348.23 |
| | Facilities | $ 14,500.00 | $ 21,000.00 | $ 7,800.00 | $ 11,700.00 | $ 28,800.00 | $ 83,800.00 |
| | Information Technology | $ 7,410.92 | $ 1,800.25 | $ 3,247.66 | $ 4,072.46 | $ 3,376.30 | $ 19,907.59 |
| | Customer Group | $ 5,982.00 | $ 5,066.59 | $ 5,088.59 | $ 5,108.00 | $ 5,130.00 | $ 26,375.18 |
| | Material Logistics | $ 1,600.00 | $ 1,300.00 | $ 1,550.00 | $ 800.00 | $ 800.00 | $ 6,050.00 |
| | Internal Audit | $ 95.00 | $ 95.00 | $ 95.00 | $ 95.00 | $ 95.00 | $ 475.00 |
| All Other Total | | $ 51,239.45 | $ 51,611.15 | $ 47,691.78 | $ 44,446.06 | $ 62,468.73 | $ 257,457.18 |
| Regulatory Improveme | Regulatory Improvements | $ - | $ - | $ - | $ - | $ - | $ - |
| Regulatory Improvements Total | | $ - | $ - | $ - | $ - | $ - | $ - |
| Grand Total | | $ 311,048.89 | $ 311,467.04 | $ 298,659.91 | $ 297,451.10 | $ 318,927.92 | $ 1,537,554.86 |



| **Charge Cost Center** | **Parent 1** | **Parent 2** |
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| D01:NH Operations | Peak Load / Capacity-ED | Capacity - Other |
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| D01:NH Operations | Regulatory Commitments-ED | Regulatory Commitments-Other |
| D01:NH Operations | Regulatory Commitments-ED | Regulatory Commitments-Other |
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| D01:NH Operations | Regulatory Commitments-ED | Reliability Enhancement Program |
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| D01:NH Operations | Reliability-ED | Distribution Line Reliability |
| D01:NH Operations | Reliability-ED | Network Reliability |
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| D01:NH Operations | Reliability-ED | Network Reliability |
| D01:NH Operations | Reliability-ED | Obsolete Equipment - Line |
| D01:NH Operations | Reliability-ED | Obsolete Equipment - Line |
| D01:NH Operations | Reliability-ED | Obsolete Equipment - Line |
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| D01:NH Operations | Reliability-ED | Obsolete Equipment - Line |
| D01:NH Operations | Reliability-ED | Obsolete Equipment - Substation |
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| D01:NH Operations | Reliability-ED | Obsolete Equipment - Substation |
| D01:NH Operations | Reliability-ED | Reliability - Other |
| D01:NH Operations | Reliability-ED | Reliability - Other |
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| D01:NH Operations | Reliability-ED | System Resiliency/Expanded Reliability |
| D01:NH Operations | Reliability-ED | System Resiliency/Expanded Reliability |
| D01:NH Operations | Reliability-ED | System Resiliency/Expanded Reliability |
| D01:NH Operations | Reliability-ED | URD/DB Cable Improvements |
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| Parent Project | Parent Project Description | Project |
|---|---|---|
| A22N27 | COMCAST NON-BILLABLE LACONIA | A22N27 |
| A22N27 | COMCAST NON-BILLABLE LACONIA | A22N27 |
| A22N28 | COMCAST BILLABLE LACONIA | A22N28 |
| A22N28 | COMCAST BILLABLE LACONIA | A22N28 |
| C01SPA01 | JOINT POLES PURCHASE & SALE | C01SPA01 |
| C01SPA01 | JOINT POLES PURCHASE & SALE | C01SPA01 |
| C01SPA01 | JOINT POLES PURCHASE & SALE | C01SPA01 |
| C01SPA01 | JOINT POLES PURCHASE & SALE | C01SPA01 |
| C01SPA01 | JOINT POLES PURCHASE & SALE | C01SPA01 |
| C01SPA01 | JOINT POLES PURCHASE & SALE | C01SPA01 |
| C01SPA01 | JOINT POLES PURCHASE & SALE | C01SPA01 |
| C01SPA01 | JOINT POLES PURCHASE & SALE | C01SPA01 |
| C01SPA01 | JOINT POLES PURCHASE & SALE | C01SPA01 |
| C03CTV | CABLE TV PROJECTS ANNUAL | C03CTV |
| C03CTV | CABLE TV PROJECTS ANNUAL | C03CTV |
| C03TEL | TELEPHONE PROJECTS ANNUAL | C03TEL |
| C03TEL | TELEPHONE PROJECTS ANNUAL | C03TEL |
| C03TEL | TELEPHONE PROJECTS ANNUAL | C03TEL |
| C03TEL | TELEPHONE PROJECTS ANNUAL | C03TEL |
| C03TEL | TELEPHONE PROJECTS ANNUAL | C03TEL |
| C03TEL | TELEPHONE PROJECTS ANNUAL | C03TEL |
| C03TEL | TELEPHONE PROJECTS ANNUAL | C03TEL |
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| C03TEL | TELEPHONE PROJECTS ANNUAL | C03TEL |
| C03TEL | TELEPHONE PROJECTS ANNUAL | C03TEL |
| A16X01 | ESCC control of Generation | A16X01 |
| A16X01 | ESCC control of Generation | A16X01 |
| A16X01 | ESCC control of Generation | A16X01 |
| A16X01 | ESCC control of Generation | A16X01 |
| A16X01 | ESCC control of Generation | A16X01 |
| A16X05 | NH Energy Park: audio visual equip | A16X05 |
| A16X06 | NH SOC/ESCC Backup | A16X06 |
| A16X08 | 1250 Hooksett Rd - AV Project | A16X08 |
| A18W22 | Peterborough Roadway and Bridge Pro | A18W22 |
| A18W22 | Peterborough Roadway and Bridge Pro | A18W22 |
| A18W22 | Peterborough Roadway and Bridge Pro | A18W22 |
| A18W22 | Peterborough Roadway and Bridge Pro | A18W22 |
| A18W22 | Peterborough Roadway and Bridge Pro | A18W22 |
| A21C38 | ANIMAL PROTECTION AT BROOK ST SS | A21C38 |
| A21C40 | ANIMAL PROTECTION AT EDDY SS | A21C40 |
| A21C40 | ANIMAL PROTECTION AT EDDY SS | A21C40 |
| A21E41 | Animal Protection Madbury SS | A21E41 |
| A22C54 | 3271X Sound Barrier Pad-Mount Step | A22C54 |
| A22C54 | 3271X Sound Barrier Pad-Mount Step | A22C54 |
| A22E79 | Animal Protection Brentwood SS | A22E79 |
| A22N80 | ANIMAL PROTECTION OAK HILL SS | A22N80 |

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| A22S81 | Animal Protection Hudson SS | A22S81 |
| A22S82 | Animal Protection Reeds Ferry SS | A22S82 |
| A23E44 | 15W4 Commercial Alley | A23E44 |
| A23W27 | W15 Lattice Tower Removal | A23W27 |
| A23X47 | NH Rubber Goods Lab Rebuild | A23X47 |
| DTC9R | 2022 Elec Sys Ops Equip Annual | DTC9R |
| DTC9R | 2022 Elec Sys Ops Equip Annual | DTC9R |
| GF9R | Misc office equipment | GF9R |
| GF9R | Misc office equipment | GF9R |
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| PT9R | Temporary Work Annual | PT9A |
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| PW9R | Private Work Annual | PW9Z |
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| GE9R | Tools and Equipment - Engineering | GE9R |
| GE9R | Tools and Equipment - Engineering | GE9R |
| GE9R | Tools and Equipment - Engineering | GE9R |
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| GE9R | Tools and Equipment - Engineering | GE9R |
| GM9R | Tools/equipment - S/S Operations | GM9R |
| GM9R | Tools/equipment - S/S Operations | GM9R |
| GM9R | Tools/equipment - S/S Operations | GM9R |
| GM9R | Tools/equipment - S/S Operations | GM9R |
| GM9R | Tools/equipment - S/S Operations | GM9R |
| GM9R | Tools/equipment - S/S Operations | GM9R |
| GM9R21 | Tools/equipment - S/S Operations | GM9R21 |
| GM9R21 | 2021 NH D SS Capital Tool Annual | GM9R21 |
| GM9R21 | 2021 NH D SS Capital Tool Annual | GM9R21 |
| GM9R22 | 2022 NH D SS Capital Tool Annual | GM9R22 |
| GM9R22 | 2022 NH D SS Capital Tool Annual | GM9R22 |
| GM9R22 | 2022 NH D SS Capital Tool Annual | GM9R22 |
| GM9R23 | 2023 NH D SS Capital Tool Annual | GM9R23 |
| GM9R23 | 2023 NH D SS Capital Tool Annual | GM9R23 |
| GT9R | Tools and Equipment- Troubleshooter | GT9R |
| GT9R | Tools and Equipment- Troubleshooter | GT9R |
| GT9R | Tools and Equipment- Troubleshooter | GT9R |
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| GT9R | Tools and Equipment- Troubleshooter | GT9R |
| GT9R | Tools and Equipment- Troubleshooter | GT9R |
| GX9R | Tools/equipment - Field Operations | GX9R |
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| A19E39 | REPLACE FAILED CABLE SPRING RD RYE | A19E39 |
| A21X95 | Mobile Utility & Mobile Pole Assemb | A21X95 |
| A21X95 | Mobile Utility & Mobile Pole Assemb | A21X95 |
| DQ9R | DQ Planned Obsolescense Annual | ARDB9A |
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| DQ9R | DQ Planned Obsolescense Annual | DQDB9K |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9L |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9L |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9L |
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| DQ9R | DQ Planned Obsolescense Annual | DQDB9L |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9N |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9N |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9N |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9N |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9N |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9P |
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| DQ9R | DQ Planned Obsolescense Annual | DQDB9P |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9P |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9P |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9S |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9S |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9S |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9S |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9S |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9W |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9W |
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| DQ9R | DQ Planned Obsolescense Annual | DQDB9Y |
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| DQ9R | DQ Planned Obsolescense Annual | DQDB9Y |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9Z |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9Z |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9Z |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9Z |
| DQ9R | DQ Planned Obsolescense Annual | DQDB9Z |
| DQ9R | DQ Planned Obsolescense Annual | DQOH9A |
| DQ9R | DQ Planned Obsolescense Annual | DQOH9A |
| DQ9R | DQ Planned Obsolescense Annual | DQOH9A |
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| DQ9R | DQ Planned Obsolescense Annual | DQOH9B |
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| DQ9R | DQ Planned Obsolescense Annual | DQOH9B |
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| DQ9R | DQ Planned Obsolescense Annual | DQOH9B |
| DQ9R | DQ Planned Obsolescense Annual | DQOH9C |
| DQ9R | DQ Planned Obsolescense Annual | DQOH9C |
| DQ9R | DQ Planned Obsolescense Annual | DQOH9C |
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| DQ9R | DQ Planned Obsolescense Annual | DQOH9D |
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| DQ9R | DQ Planned Obsolescense Annual | DQOH9K |
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| DQ9R | DQ Planned Obsolescense Annual | DQOH9R |
| DQ9R | DQ Planned Obsolescense Annual | DQOH9R |
| DQ9R | DQ Planned Obsolescense Annual | DQOH9R |
| DQ9R | DQ Planned Obsolescense Annual | DQOH9R |
| DQ9R | DQ Planned Obsolescense Annual | DQOH9R |
| DQ9R | DQ Planned Obsolescense Annual | DQOH9S |
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| DQ9R | DQ Planned Obsolescense Annual | DQOH9Z |
| DQ9R | DQ Planned Obsolescense Annual | DQUG9A |

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| DQ9R | DQ Planned Obsolescense Annual | DQUG9Z |
| DQ9R | DQ Planned Obsolescense Annual | IFDB9M |
| DQ9R | DQ Planned Obsolescense Annual | IFDB9N |
| DQ9R | DQ Planned Obsolescense Annual | IFDB9S |
| DQ9R | DQ Planned Obsolescense Annual | IFDB9S |
| DQ9R | DQ Planned Obsolescense Annual | IFDB9Y |
| DQ9R | DQ Planned Obsolescense Annual | IFDB9Z |
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| DQ9R | DQ Planned Obsolescense Annual | IFDB9Z |
| DQ9R | DQ Planned Obsolescense Annual | IFOH9A |
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| DQ9R | DQ Planned Obsolescense Annual | IFOH9A |
| DQ9R | DQ Planned Obsolescense Annual | IFOH9C |
| DQ9R | DQ Planned Obsolescense Annual | IFOH9D |
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| DQ9R | DQ Planned Obsolescense Annual | IFOH9S |
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| DQ9R | DQ Planned Obsolescense Annual | IFOH9Z |
| DQ9R | DQ Planned Obsolescense Annual | IFOH9Z |
| DQ9R | DQ Planned Obsolescense Annual | IFOH9Z |
| DS9RE | ROW REPLACE FAILED EQUIPMENT-ANNUA | DS9RE |
| DS9RE | ROW REPLACE FAILED EQUIPMENT-ANNUA | DS9RE |
| DS9RE | ROW REPLACE FAILED EQUIPMENT-ANNUA | DS9RE |
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| DS9RE | ROW REPLACE FAILED EQUIPMENT-ANNUA | DS9RE |
| DS9RE | ROW REPLACE FAILED EQUIPMENT-ANNUA | DS9RE |
| DS9RE | ROW REPLACE FAILED EQUIPMENT-ANNUA | DS9RE |
| MINOR9R | Minor Storms Annual | MINOR9A |
| MINOR9R | Minor Storms Annual | MINOR9A |

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| MINOR9R | Minor Storms Annual | MINOR9B |
| MINOR9R | Minor Storms Annual | MINOR9C |
| MINOR9R | Minor Storms Annual | MINOR9C |
| MINOR9R | Minor Storms Annual | MINOR9C |
| MINOR9R | Minor Storms Annual | MINOR9D |
| MINOR9R | Minor Storms Annual | MINOR9D |
| MINOR9R | Minor Storms Annual | MINOR9D |
| MINOR9R | Minor Storms Annual | MINOR9E |
| MINOR9R | Minor Storms Annual | MINOR9E |
| MINOR9R | Minor Storms Annual | MINOR9E |
| MINOR9R | Minor Storms Annual | MINOR9K |
| MINOR9R | Minor Storms Annual | MINOR9K |
| MINOR9R | Minor Storms Annual | MINOR9K |
| MINOR9R | Minor Storms Annual | MINOR9K |
| MINOR9R | Minor Storms Annual | MINOR9K |
| MINOR9R | Minor Storms Annual | MINOR9L |
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| MINOR9R | Minor Storms Annual | MINOR9N |
| MINOR9R | Minor Storms Annual | MINOR9N |
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| MINOR9R | Minor Storms Annual | MINOR9P |
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| MINOR9R | Minor Storms Annual | MINOR9S |
| MINOR9R | Minor Storms Annual | MINOR9S |
| MINOR9R | Minor Storms Annual | MINOR9S |
| MINOR9R | Minor Storms Annual | MINOR9W |
| MINOR9R | Minor Storms Annual | MINOR9W |
| MINOR9R | Minor Storms Annual | MINOR9W |
| MINOR9R | Minor Storms Annual | MINOR9W |
| MINOR9R | Minor Storms Annual | MINOR9Y |
| MINOR9R | Minor Storms Annual | MINOR9Y |
| MINOR9R | Minor Storms Annual | MINOR9Y |
| MINOR9R | Minor Storms Annual | MINOR9Y |
| MINOR9R | Minor Storms Annual | MINOR9Y |
| MINOR9R | Minor Storms Annual | MINOR9Z |
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| MINOR9R | Minor Storms Annual | MINOR9Z |
| MINOR9R | Minor Storms Annual | MINOR9Z |
| NHLC03 | NH LINE CONTRACTORS | NHLC03 |
| NHLC03 | NH LINE CONTRACTORS | NHLC03 |
| NHLC03 | NH LINE CONTRACTORS | NHLC03 |
| NHLC03 | NH LINE CONTRACTORS | NHLC03 |
| NHLC03 | NH LINE CONTRACTORS | NHLC03 |
| NHLC03 | NH LINE CONTRACTORS | NHLC03 |
| NHLC03 | NH LINE CONTRACTORS | NHLC03 |
| NHLC03 | NH LINE CONTRACTORS | NHLC03 |
| NHLC03 | NH LINE CONTRACTORS | NHLC03 |
| STORMCAP | NH STORM CAPITALIZATION | STORMCAP |
| STORMCAP | NH STORM CAPITALIZATION | STORMCAP |
| STORMCAP | NH STORM CAPITALIZATION | STORMCAP |
| STORMCAP | NH STORM CAPITALIZATION | STORMCAP |
| STORMCAP | NH STORM CAPITALIZATION | STORMCAP |
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| STORMCAP | NH STORM CAPITALIZATION | STORMCAP |
| STORMCAP | NH STORM CAPITALIZATION | STORMCAP |
| STRM0617C | NH STORM CAP: Mar 2, 2017 event | STRM0617C |
| STRM0617N | NH STORM CAP: Oct 29, 2017 event | STRM0617N |
| STRM0617N | NH STORM CAP: Oct 29, 2017 event | STRM0617N |
| STRM0617N | NH STORM CAP: Oct 29, 2017 event | STRM0617N |
| STRM0618C | NH STORM CAP: Mar 7-8, 2018 event | STRM0618C |
| STRM0618D | NH STORM CAP: Apr 4-5, 2018 event | STRM0618D |
| STRM0618D | NH STORM CAP: Apr 4-5, 2018 event | STRM0618D |
| A12N01A | BERLIN 4KV SYSTEM RECONFIGURATION | A12N01A |
| A14N21 | BERLIN EASTSIDE 34.5KV LINE BREAKER | A14N21 |
| A14N21 | BERLIN EASTSIDE 34.5KV LINE BREAKER | A14N21 |
| A14N21 | BERLIN EASTSIDE 34.5KV LINE BREAKER | A14N21 |
| A21C43 | REPLACE LTC CONTROLS EDDY SS | A21C43 |
| A21C43 | REPLACE LTC CONTROLS EDDY SS | A21C43 |
| A21C43 | REPLACE LTC CONTROLS EDDY SS | A21C43 |
| A21C43 | REPLACE LTC CONTROLS EDDY SS | A21C43 |
| A21N78 | BERLIN EAST SIDE SS REPLACE TRANSFO | A21N78 |
| A21N78 | BERLIN EAST SIDE SS REPLACE TRANSFO | A21N78 |
| A21N78 | BERLIN EAST SIDE SS REPLACE TRANSFO | A21N78 |
| A21N78 | BERLIN EAST SIDE SS REPLACE TRANSFO | A21N78 |
| DS9RD2 | 2022 NH D SS Emergent Annual | DS9RD2 |
| DS9RD2 | 2022 NH D SS Emergent Annual | DS9RD2 |
| DS9RD2 | 2022 NH D SS Emergent Annual | DS9RD2 |
| DS9RD3 | 2023 NH D SS Emergent Annual | DS9RD3 |
| DS9RD3 | 2023 NH D SS Emergent Annual | DS9RD3 |
| CO1PCB | PCB TRANSFORMER CHANGEOUT PROGRAM | CO1PCB |
| CO1PCB | PCB TRANSFORMER CHANGEOUT PROGRAM | CO1PCB |

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| CO1PCB | PCB TRANSFORMER CHANGEOUT PROGRAM | CO1PCB |
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| CO1PCB | PCB TRANSFORMER CHANGEOUT PROGRAM | CO1PCB |
| CO1PCB | PCB TRANSFORMER CHANGEOUT PROGRAM | CO1PCB |
| CO1PCB | PCB TRANSFORMER CHANGEOUT PROGRAM | CO1PCB |
| INS9R | Insurance Claim Annual | INSDB9A |
| INS9R | Insurance Claim Annual | INSDB9A |
| INS9R | Insurance Claim Annual | INSDB9A |
| INS9R | Insurance Claim Annual | INSDB9A |
| INS9R | Insurance Claim Annual | INSDB9A |
| INS9R | Insurance Claim Annual | INSDB9B |
| INS9R | Insurance Claim Annual | INSDB9B |
| INS9R | Insurance Claim Annual | INSDB9C |
| INS9R | Insurance Claim Annual | INSDB9C |
| INS9R | Insurance Claim Annual | INSDB9C |
| INS9R | Insurance Claim Annual | INSDB9D |
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| INS9R | Insurance Claim Annual | INSDB9S |
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| INS9R | Insurance Claim Annual | INSOH9A |
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| INS9R | Insurance Claim Annual | INSOH9R |
| INS9R | Insurance Claim Annual | INSOH9R |
| INS9R | Insurance Claim Annual | INSOH9S |
| INS9R | Insurance Claim Annual | INSOH9S |
| INS9R | Insurance Claim Annual | INSOH9S |
| INS9R | Insurance Claim Annual | INSOH9S |
| INS9R | Insurance Claim Annual | INSOH9S |
| INS9R | Insurance Claim Annual | INSOH9W |
| INS9R | Insurance Claim Annual | INSOH9W |
| INS9R | Insurance Claim Annual | INSOH9W |
| INS9R | Insurance Claim Annual | INSOH9W |
| INS9R | Insurance Claim Annual | INSOH9W |
| INS9R | Insurance Claim Annual | INSOH9Y |
| INS9R | Insurance Claim Annual | INSOH9Y |
| INS9R | Insurance Claim Annual | INSOH9Y |
| INS9R | Insurance Claim Annual | INSOH9Y |
| INS9R | Insurance Claim Annual | INSOH9Y |
| INS9R | Insurance Claim Annual | INSOH9Z |
| INS9R | Insurance Claim Annual | INSOH9Z |
| INS9R | Insurance Claim Annual | INSOH9Z |
| INS9R | Insurance Claim Annual | INSOH9Z |
| INS9R | Insurance Claim Annual | INSOH9Z |
| INS9R | Insurance Claim Annual | INSUG9A |
| INS9R | Insurance Claim Annual | INSUG9B |
| INS9R | Insurance Claim Annual | INSUG9B |
| INS9R | Insurance Claim Annual | INSUG9B |

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| INS9R | Insurance Claim Annual | INSUG9C |
| INS9R | Insurance Claim Annual | INSUG9C |
| INS9R | Insurance Claim Annual | INSUG9C |
| INS9R | Insurance Claim Annual | INSUG9D |
| INS9R | Insurance Claim Annual | INSUG9D |
| INS9R | Insurance Claim Annual | INSUG9D |
| INS9R | Insurance Claim Annual | INSUG9E |
| INS9R | Insurance Claim Annual | INSUG9K |
| INS9R | Insurance Claim Annual | INSUG9K |
| INS9R | Insurance Claim Annual | INSUG9K |
| INS9R | Insurance Claim Annual | INSUG9K |
| INS9R | Insurance Claim Annual | INSUG9K |
| INS9R | Insurance Claim Annual | INSUG9L |
| INS9R | Insurance Claim Annual | INSUG9L |
| INS9R | Insurance Claim Annual | INSUG9L |
| INS9R | Insurance Claim Annual | INSUG9N |
| INS9R | Insurance Claim Annual | INSUG9N |
| INS9R | Insurance Claim Annual | INSUG9N |
| INS9R | Insurance Claim Annual | INSUG9P |
| INS9R | Insurance Claim Annual | INSUG9P |
| INS9R | Insurance Claim Annual | INSUG9P |
| INS9R | Insurance Claim Annual | INSUG9S |
| INS9R | Insurance Claim Annual | INSUG9S |
| INS9R | Insurance Claim Annual | INSUG9S |
| INS9R | Insurance Claim Annual | INSUG9W |
| INS9R | Insurance Claim Annual | INSUG9W |
| INS9R | Insurance Claim Annual | INSUG9Y |
| INS9R | Insurance Claim Annual | INSUG9Y |
| INS9R | Insurance Claim Annual | INSUG9Y |
| INS9R | Insurance Claim Annual | INSUG9Z |
| INS9R | Insurance Claim Annual | INSUG9Z |
| INS9R | Insurance Claim Annual | INSUG9Z |
| DA9R | Non-Roadway Lighting Annual | DA9A |
| DA9R | Non-Roadway Lighting Annual | DA9A |
| DA9R | Non-Roadway Lighting Annual | DA9A |
| DA9R | Non-Roadway Lighting Annual | DA9A |
| DA9R | Non-Roadway Lighting Annual | DA9A |
| DA9R | Non-Roadway Lighting Annual | DA9B |
| DA9R | Non-Roadway Lighting Annual | DA9B |
| DA9R | Non-Roadway Lighting Annual | DA9B |
| DA9R | Non-Roadway Lighting Annual | DA9B |
| DA9R | Non-Roadway Lighting Annual | DA9B |
| DA9R | Non-Roadway Lighting Annual | DA9C |
| DA9R | Non-Roadway Lighting Annual | DA9C |
| DA9R | Non-Roadway Lighting Annual | DA9C |
| DA9R | Non-Roadway Lighting Annual | DA9C |
| DA9R | Non-Roadway Lighting Annual | DA9C |

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| DA9R | Non-Roadway Lighting Annual | DA9D |
| DA9R | Non-Roadway Lighting Annual | DA9D |
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| DA9R | Non-Roadway Lighting Annual | DA9E |
| DA9R | Non-Roadway Lighting Annual | DA9E |
| DA9R | Non-Roadway Lighting Annual | DA9K |
| DA9R | Non-Roadway Lighting Annual | DA9K |
| DA9R | Non-Roadway Lighting Annual | DA9K |
| DA9R | Non-Roadway Lighting Annual | DA9K |
| DA9R | Non-Roadway Lighting Annual | DA9K |
| DA9R | Non-Roadway Lighting Annual | DA9L |
| DA9R | Non-Roadway Lighting Annual | DA9L |
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| DA9R | Non-Roadway Lighting Annual | DA9N |
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| DA9R | Non-Roadway Lighting Annual | DA9N |
| DA9R | Non-Roadway Lighting Annual | DA9N |
| DA9R | Non-Roadway Lighting Annual | DA9N |
| DA9R | Non-Roadway Lighting Annual | DA9P |
| DA9R | Non-Roadway Lighting Annual | DA9P |
| DA9R | Non-Roadway Lighting Annual | DA9P |
| DA9R | Non-Roadway Lighting Annual | DA9P |
| DA9R | Non-Roadway Lighting Annual | DA9P |
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| DA9R | Non-Roadway Lighting Annual | DA9R |
| DA9R | Non-Roadway Lighting Annual | DA9R |
| DA9R | Non-Roadway Lighting Annual | DA9S |
| DA9R | Non-Roadway Lighting Annual | DA9S |
| DA9R | Non-Roadway Lighting Annual | DA9S |
| DA9R | Non-Roadway Lighting Annual | DA9S |
| DA9R | Non-Roadway Lighting Annual | DA9S |
| DA9R | Non-Roadway Lighting Annual | DA9W |
| DA9R | Non-Roadway Lighting Annual | DA9W |
| DA9R | Non-Roadway Lighting Annual | DA9W |
| DA9R | Non-Roadway Lighting Annual | DA9W |
| DA9R | Non-Roadway Lighting Annual | DA9W |
| DA9R | Non-Roadway Lighting Annual | DA9Y |
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| DA9R | Non-Roadway Lighting Annual | DA9Y |
| DA9R | Non-Roadway Lighting Annual | DA9Y |
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| DA9R | Non-Roadway Lighting Annual | DA9Z |
| DA9R | Non-Roadway Lighting Annual | DA9Z |
| DA9R | Non-Roadway Lighting Annual | DA9Z |
| DA9R | Non-Roadway Lighting Annual | DA9Z |
| DA9R | Non-Roadway Lighting Annual | DA9Z |
| HPS9R | Roadway Lighting Annual | D79A |
| HPS9R | Roadway Lighting Annual | D79A |
| HPS9R | Roadway Lighting Annual | D79A |
| HPS9R | Roadway Lighting Annual | D79A |
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| HPS9R | Roadway Lighting Annual | D79B |
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| HPS9R | Roadway Lighting Annual | D79C |
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| HPS9R | Roadway Lighting Annual | D79C |
| HPS9R | Roadway Lighting Annual | D79D |
| HPS9R | Roadway Lighting Annual | D79D |
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| HPS9R | Roadway Lighting Annual | D79K |
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| HPS9R | Roadway Lighting Annual | D79K |
| HPS9R | Roadway Lighting Annual | D79K |
| HPS9R | Roadway Lighting Annual | D79L |
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| HPS9R | Roadway Lighting Annual | D79N |
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| HPS9R | Roadway Lighting Annual | D79N |
| HPS9R | Roadway Lighting Annual | D79N |

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| HPS9R | Roadway Lighting Annual | D79N |
| HPS9R | Roadway Lighting Annual | D79P |
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| HPS9R | Roadway Lighting Annual | D79P |
| HPS9R | Roadway Lighting Annual | D79P |
| HPS9R | Roadway Lighting Annual | D79P |
| HPS9R | Roadway Lighting Annual | D79S |
| HPS9R | Roadway Lighting Annual | D79S |
| HPS9R | Roadway Lighting Annual | D79S |
| HPS9R | Roadway Lighting Annual | D79S |
| HPS9R | Roadway Lighting Annual | D79S |
| HPS9R | Roadway Lighting Annual | D79W |
| HPS9R | Roadway Lighting Annual | D79W |
| HPS9R | Roadway Lighting Annual | D79W |
| HPS9R | Roadway Lighting Annual | D79W |
| HPS9R | Roadway Lighting Annual | D79W |
| HPS9R | Roadway Lighting Annual | D79Y |
| HPS9R | Roadway Lighting Annual | D79Y |
| HPS9R | Roadway Lighting Annual | D79Y |
| HPS9R | Roadway Lighting Annual | D79Y |
| HPS9R | Roadway Lighting Annual | D79Y |
| HPS9R | Roadway Lighting Annual | D79Z |
| HPS9R | Roadway Lighting Annual | D79Z |
| HPS9R | Roadway Lighting Annual | D79Z |
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| HPS9R | Roadway Lighting Annual | HPS9R |
| HPS9R | Roadway Lighting Annual | HPS9R |
| 9N031138P | LINE RELOCATE EAST HOLLIS ST NASHUA | 9N031138P |
| A18C21 | MANCHESTER AIRPORT DUCT RELOCATION | A18C21 |
| A18E23 | Rochester Comcast Make Ready | A18E23 |
| A18E23 | Rochester Comcast Make Ready | A18E23 |
| A18E23 | Rochester Comcast Make Ready | A18E23 |
| A18E23 | Rochester Comcast Make Ready | A18E23 |
| A18W13 | Route 9 Roxbury-Sullivan 10439 | A18W13 |
| A18W13 | Route 9 Roxbury-Sullivan 10439 | A18W13 |
| A18W13 | Route 9 Roxbury-Sullivan 10439 | A18W13 |
| A18W13 | Route 9 Roxbury-Sullivan 10439 | A18W13 |
| A20N29 | LACONIA COMCAST NON-BILLABLE 2020 | A20N29 |
| A20N29 | LACONIA COMCAST NON-BILLABLE 2020 | A20N29 |
| A20N29 | LACONIA COMCAST NON-BILLABLE 2020 | A20N29 |

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|---|---|---|
| A20N30 | LACONIA COMCAST BILLABLE 2020 | A20N30 |
| A20N30 | LACONIA COMCAST BILLABLE 2020 | A20N30 |
| A20N30 | LACONIA COMCAST BILLABLE 2020 | A20N30 |
| A20N30 | LACONIA COMCAST BILLABLE 2020 | A20N30 |
| A20N31 | GILFORD COMCAST NON-BILLABLE 2020 | A20N31 |
| A20N31 | GILFORD COMCAST NON-BILLABLE 2020 | A20N31 |
| A20N31 | GILFORD COMCAST NON-BILLABLE 2020 | A20N31 |
| A20N32 | GILFORD COMCAST BILLABLE 2020 | A20N32 |
| A20N32 | GILFORD COMCAST BILLABLE 2020 | A20N32 |
| A20N32 | GILFORD COMCAST BILLABLE 2020 | A20N32 |
| A20N50 | NHDOT LINE RELOC RTE 106 LOUDON | A20N50 |
| A20N50 | NHDOT LINE RELOC RTE 106 LOUDON | A20N50 |
| A20N50 | NHDOT LINE RELOC RTE 106 LOUDON | A20N50 |
| A21N28 | ROUTE 16 LINE RELOCATION NHDOT | A21N28 |
| A21N28 | ROUTE 16 LINE RELOCATION NHDOT | A21N28 |
| A21N32 | LACONIA COMCAST NONBILLABLE 2021 | A21N32 |
| A21N32 | LACONIA COMCAST NONBILLABLE 2021 | A21N32 |
| A21N32 | LACONIA COMCAST NONBILLABLE 2021 | A21N32 |
| A21N32 | LACONIA COMCAST NONBILLABLE 2021 | A21N32 |
| A21N33 | LACONIA COMCAST BILLABLE 2021 | A21N33 |
| A21N33 | LACONIA COMCAST BILLABLE 2021 | A21N33 |
| A21N33 | LACONIA COMCAST BILLABLE 2021 | A21N33 |
| A21N34 | GILFORD COMCAST NONBILLABLE 2021 | A21N34 |
| A21N34 | GILFORD COMCAST NONBILLABLE 2021 | A21N34 |
| A21N34 | GILFORD COMCAST NONBILLABLE 2021 | A21N34 |
| A21N34 | GILFORD COMCAST NONBILLABLE 2021 | A21N34 |
| A21N35 | GILFORD COMCAST BILLABLE 2021 | A21N35 |
| A21N35 | GILFORD COMCAST BILLABLE 2021 | A21N35 |
| A21N35 | GILFORD COMCAST BILLABLE 2021 | A21N35 |
| A21S30 | NHDOT PROJ #13065 - 365 Line | A21S30 |
| A21S30 | NHDOT PROJ #13065 - 365 Line | A21S30 |
| A21S30 | NHDOT PROJ #13065 - 365 Line | A21S30 |
| A21S30 | NHDOT PROJ #13065 - 365 Line | A21S30 |
| A21S31 | NHDOT PROJ #13761 3138/3151 LINES | A21S31 |
| A21S31 | NHDOT PROJ #13761 3138/3151 LINES | A21S31 |
| A21S31 | NHDOT PROJ #13761 3138/3151 LINES | A21S31 |
| A21S31 | NHDOT PROJ #13761 3138/3151 LINES | A21S31 |
| A22N27 | COMCAST NON-BILLABLE LACONIA | A22N27 |
| A22N27 | COMCAST NON-BILLABLE LACONIA | A22N27 |
| A22N28 | COMCAST BILLABLE LACONIA | A22N28 |
| A22N29 | COMCAST NON-BILLABLE GILFORD | A22N29 |
| A22N29 | COMCAST NON-BILLABLE GILFORD | A22N29 |
| A22N29 | COMCAST NON-BILLABLE GILFORD | A22N29 |
| A22N30 | COMCAST BILLABLE GILFORD | A22N30 |
| A22N30 | COMCAST BILLABLE GILFORD | A22N30 |
| A23N03 | COMCAST NON-BILLABLE BELMONT | A23N03 |
| A23N04 | COMCAST BILLABLE BELMONT | A23N04 |

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| A23N04 | COMCAST BILLABLE BELMONT | A23N04 |
| A23N05 | COMCAST NON-BILLABLE TILTON | A23N05 |
| A23N06 | COMCAST BILLABLE TILTON | A23N06 |
| C03CTV | CABLE TV PROJECTS ANNUAL | C03CTV |
| C03CTV | CABLE TV PROJECTS ANNUAL | C03CTV |
| C03CTV | CABLE TV PROJECTS ANNUAL | C03CTV |
| C03CTV | CABLE TV PROJECTS ANNUAL | C03CTV |
| C03CTV | CABLE TV PROJECTS ANNUAL | C03CTV |
| C03CTV | CABLE TV PROJECTS ANNUAL | C03CTV |
| C03CTV | CABLE TV PROJECTS ANNUAL | C03CTV |
| C03CTV | CABLE TV PROJECTS ANNUAL | C03CTV |
| C03DOT | NHDOT PROJECT PROGRAM | C03DOT |
| C03DOT | NHDOT PROJECT PROGRAM | C03DOT |
| C03DOT | NHDOT PROJECT PROGRAM | C03DOT |
| C03DOT | NHDOT PROJECT PROGRAM | C03DOT |
| C03DOT | NHDOT PROJECT PROGRAM | C03DOT |
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| C03DOT | NHDOT PROJECT PROGRAM | C03DOT |
| C03DOT | NHDOT PROJECT PROGRAM | C03DOT |
| C03DOT | NHDOT PROJECT PROGRAM | C03DOT |
| DH9R | Line Relocations Annual | DH9A |
| DH9R | Line Relocations Annual | DH9A |
| DH9R | Line Relocations Annual | DH9A |
| DH9R | Line Relocations Annual | DH9A |
| DH9R | Line Relocations Annual | DH9A |
| DH9R | Line Relocations Annual | DH9B |
| DH9R | Line Relocations Annual | DH9B |
| DH9R | Line Relocations Annual | DH9B |
| DH9R | Line Relocations Annual | DH9B |
| DH9R | Line Relocations Annual | DH9B |
| DH9R | Line Relocations Annual | DH9C |
| DH9R | Line Relocations Annual | DH9C |
| DH9R | Line Relocations Annual | DH9C |
| DH9R | Line Relocations Annual | DH9C |
| DH9R | Line Relocations Annual | DH9C |
| DH9R | Line Relocations Annual | DH9D |
| DH9R | Line Relocations Annual | DH9D |
| DH9R | Line Relocations Annual | DH9D |
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| DH9R | Line Relocations Annual | DH9D |
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| DH9R | Line Relocations Annual | DH9E |
| DH9R | Line Relocations Annual | DH9H |

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| DH9R | Line Relocations Annual | DH9H |
| DH9R | Line Relocations Annual | DH9H |
| DH9R | Line Relocations Annual | DH9K |
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| DH9R | Line Relocations Annual | DH9K |
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| DH9R | Line Relocations Annual | DH9L |
| DH9R | Line Relocations Annual | DH9L |
| DH9R | Line Relocations Annual | DH9L |
| DH9R | Line Relocations Annual | DH9M |
| DH9R | Line Relocations Annual | DH9N |
| DH9R | Line Relocations Annual | DH9N |
| DH9R | Line Relocations Annual | DH9N |
| DH9R | Line Relocations Annual | DH9N |
| DH9R | Line Relocations Annual | DH9P |
| DH9R | Line Relocations Annual | DH9P |
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| DH9R | Line Relocations Annual | DH9R |
| DH9R | Line Relocations Annual | DH9S |
| DH9R | Line Relocations Annual | DH9S |
| DH9R | Line Relocations Annual | DH9S |
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| DH9R | Line Relocations Annual | DH9S |
| DH9R | Line Relocations Annual | DH9W |
| DH9R | Line Relocations Annual | DH9W |
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| DH9R | Line Relocations Annual | DH9W |
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| DH9R | Line Relocations Annual | DH9Z |
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| DH9R | Line Relocations Annual | DH9Z |
| DH9R | Line Relocations Annual | DH9Z |

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| E03CTV | EXPENSE PORTION OF CATV PROJECTS | E03CTV |
| E03CTV | EXPENSE PORTION OF CATV PROJECTS | E03CTV |
| E03CTV | EXPENSE PORTION OF CATV PROJECTS | E03CTV |
| E03CTV | EXPENSE PORTION OF CATV PROJECTS | E03CTV |
| E03CTV | EXPENSE PORTION OF CATV PROJECTS | E03CTV |
| ROWLR | ROW Relocations - Reimbursable | ROWLR |
| UB1140 | RELOCATE 12 SECTIONS LONDONDRY TPK | UB1140 |
| DT7P | PURCHASE TRANSFORMERS AND REGULATOR | DT7P |
| DT7P | PURCHASE TRANSFORMERS AND REGULATOR | DT7P |
| DT7P | PURCHASE TRANSFORMERS AND REGULATOR | DT7P |
| DT7P | PURCHASE TRANSFORMERS AND REGULATOR | DT7P |
| DT7P | PURCHASE TRANSFORMERS AND REGULATOR | DT7P |
| DT7P | PURCHASE TRANSFORMERS AND REGULATOR | DT7P |
| DT7P | PURCHASE TRANSFORMERS AND REGULATOR | DT7P |
| DT7P | PURCHASE TRANSFORMERS AND REGULATOR | DT7P |
| DT7P | PURCHASE TRANSFORMERS AND REGULATOR | DT7P |
| DT7P | PURCHASE TRANSFORMERS AND REGULATOR | DT7P |
| 99999906 | PSNH Overheads | 99999906 |
| A18C24 | 922 ELM ST DEVELOPMENT | A18C24 |
| A18C24 | 922 ELM ST DEVELOPMENT | A18C24 |
| A18C24 | 922 ELM ST DEVELOPMENT | A18C24 |
| A18C24 | 922 ELM ST DEVELOPMENT | A18C24 |
| A18C25 | SANBORN CROSSING APARTMENTS | A18C25 |
| A18C25 | SANBORN CROSSING APARTMENTS | A18C25 |
| A18C25 | SANBORN CROSSING APARTMENTS | A18C25 |
| A18C29 | PULPIT RD URD | A18C29 |
| A18C29 | PULPIT RD URD | A18C29 |
| A18C29 | PULPIT RD URD | A18C29 |
| A19C42 | MYRTLE SO. BK. CONV MANCHESTER | A19C42 |
| A19C42 | MYRTLE SO. BK. CONV MANCHESTER | A19C42 |
| A19C60 | BAE GOFFS FALLS RD SERVICE | A19C60 |
| A19C60 | BAE GOFFS FALLS RD SERVICE | A19C60 |
| A19C60 | BAE GOFFS FALLS RD SERVICE | A19C60 |
| A19N37 | 348X3 CUSTOMER LINE EXT | A19N37 |
| A19N37 | 348X3 CUSTOMER LINE EXT | A19N37 |
| A19N37 | 348X3 CUSTOMER LINE EXT | A19N37 |
| A19N37 | 348X3 CUSTOMER LINE EXT | A19N37 |
| A19N37 | 348X3 CUSTOMER LINE EXT | A19N37 |
| A19S43 | WOODMONT COMMONS PHASE 1A 2019 | A19S43 |
| A19S43 | WOODMONT COMMONS PHASE 1A 2019 | A19S43 |
| A19S43 | WOODMONT COMMONS PHASE 1A 2019 | A19S43 |
| A19S43 | WOODMONT COMMONS PHASE 1A 2019 | A19S43 |
| A19S43 | WOODMONT COMMONS PHASE 1A 2019 | A19S43 |
| A19S44 | WOODMONT COMMONS PHASE 1B 2019 | A19S44 |
| A19S44 | WOODMONT COMMONS PHASE 1B 2019 | A19S44 |
| A19S44 | WOODMONT COMMONS PHASE 1B 2019 | A19S44 |
| A19S44 | WOODMONT COMMONS PHASE 1B 2019 | A19S44 |

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| A20S20 | Service to new Nashua Perfoming Art | A20S20 |
| A20S20 | Service to new Nashua Perfoming Art | A20S20 |
| A21N98 | COLEBROOK LINE EXT AMER PERF POLYMR | A21N98 |
| A21N98 | COLEBROOK LINE EXT AMER PERF POLYMR | A21N98 |
| A21N98 | COLEBROOK LINE EXT AMER PERF POLYMR | A21N98 |
| A22C53 | Allenstown School Project | A22C53 |
| A22C53 | Allenstown School Project | A22C53 |
| A23N40 | 355 Line Upgrade and Line Extension | A23N40 |
| CO1 | NEW BUSINESS SPECIFICS UNKNOWN | CO1 |
| CO1 | NEW BUSINESS SPECIFICS UNKNOWN | CO1 |
| CO1 | NEW BUSINESS SPECIFICS UNKNOWN | CO1 |
| DN9R | New/Existing Customers Program | DN9A |
| DN9R | New/Existing Customers Program | DN9A |
| DN9R | New/Existing Customers Program | DN9A |
| DN9R | New/Existing Customers Program | DN9A |
| DN9R | New/Existing Customers Program | DN9A |
| DN9R | New/Existing Customers Program | DN9B |
| DN9R | New/Existing Customers Program | DN9B |
| DN9R | New/Existing Customers Program | DN9B |
| DN9R | New/Existing Customers Program | DN9B |
| DN9R | New/Existing Customers Program | DN9B |
| DN9R | New/Existing Customers Program | DN9C |
| DN9R | New/Existing Customers Program | DN9C |
| DN9R | New/Existing Customers Program | DN9C |
| DN9R | New/Existing Customers Program | DN9C |
| DN9R | New/Existing Customers Program | DN9C |
| DN9R | New/Existing Customers Program | DN9D |
| DN9R | New/Existing Customers Program | DN9D |
| DN9R | New/Existing Customers Program | DN9D |
| DN9R | New/Existing Customers Program | DN9D |
| DN9R | New/Existing Customers Program | DN9D |
| DN9R | New/Existing Customers Program | DN9E |
| DN9R | New/Existing Customers Program | DN9E |
| DN9R | New/Existing Customers Program | DN9E |
| DN9R | New/Existing Customers Program | DN9E |
| DN9R | New/Existing Customers Program | DN9E |
| DN9R | New/Existing Customers Program | DN9K |
| DN9R | New/Existing Customers Program | DN9K |
| DN9R | New/Existing Customers Program | DN9K |
| DN9R | New/Existing Customers Program | DN9K |
| DN9R | New/Existing Customers Program | DN9K |
| DN9R | New/Existing Customers Program | DN9L |
| DN9R | New/Existing Customers Program | DN9L |
| DN9R | New/Existing Customers Program | DN9L |
| DN9R | New/Existing Customers Program | DN9L |
| DN9R | New/Existing Customers Program | DN9L |
| DN9R | New/Existing Customers Program | DN9M |

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| DN9R | New/Existing Customers Program | DN9M |
| DN9R | New/Existing Customers Program | DN9M |
| DN9R | New/Existing Customers Program | DN9M |
| DN9R | New/Existing Customers Program | DN9M |
| DN9R | New/Existing Customers Program | DN9N |
| DN9R | New/Existing Customers Program | DN9N |
| DN9R | New/Existing Customers Program | DN9N |
| DN9R | New/Existing Customers Program | DN9N |
| DN9R | New/Existing Customers Program | DN9N |
| DN9R | New/Existing Customers Program | DN9P |
| DN9R | New/Existing Customers Program | DN9P |
| DN9R | New/Existing Customers Program | DN9P |
| DN9R | New/Existing Customers Program | DN9P |
| DN9R | New/Existing Customers Program | DN9P |
| DN9R | New/Existing Customers Program | DN9R |
| DN9R | New/Existing Customers Program | DN9R |
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| DN9R | New/Existing Customers Program | DN9R |
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| DN9R | New/Existing Customers Program | DN9R |
| DN9R | New/Existing Customers Program | DN9R |
| DN9R | New/Existing Customers Program | DN9S |
| DN9R | New/Existing Customers Program | DN9S |
| DN9R | New/Existing Customers Program | DN9S |
| DN9R | New/Existing Customers Program | DN9S |
| DN9R | New/Existing Customers Program | DN9S |
| DN9R | New/Existing Customers Program | DN9W |
| DN9R | New/Existing Customers Program | DN9W |
| DN9R | New/Existing Customers Program | DN9W |
| DN9R | New/Existing Customers Program | DN9W |
| DN9R | New/Existing Customers Program | DN9W |
| DN9R | New/Existing Customers Program | DN9Y |
| DN9R | New/Existing Customers Program | DN9Y |
| DN9R | New/Existing Customers Program | DN9Y |
| DN9R | New/Existing Customers Program | DN9Y |
| DN9R | New/Existing Customers Program | DN9Y |
| DN9R | New/Existing Customers Program | DN9Z |
| DN9R | New/Existing Customers Program | DN9Z |
| DN9R | New/Existing Customers Program | DN9Z |
| DN9R | New/Existing Customers Program | DN9Z |
| DN9R | New/Existing Customers Program | DN9Z |
| DV9R | Services Annual | DV9A |
| DV9R | Services Annual | DV9A |
| DV9R | Services Annual | DV9A |
| DV9R | Services Annual | DV9A |
| DV9R | Services Annual | DV9A |
| DV9R | Services Annual | DV9B |

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| DV9R | Services Annual | DV9B |
| DV9R | Services Annual | DV9B |
| DV9R | Services Annual | DV9B |
| DV9R | Services Annual | DV9B |
| DV9R | Services Annual | DV9C |
| DV9R | Services Annual | DV9C |
| DV9R | Services Annual | DV9C |
| DV9R | Services Annual | DV9C |
| DV9R | Services Annual | DV9C |
| DV9R | Services Annual | DV9D |
| DV9R | Services Annual | DV9D |
| DV9R | Services Annual | DV9D |
| DV9R | Services Annual | DV9D |
| DV9R | Services Annual | DV9D |
| DV9R | Services Annual | DV9E |
| DV9R | Services Annual | DV9E |
| DV9R | Services Annual | DV9E |
| DV9R | Services Annual | DV9E |
| DV9R | Services Annual | DV9E |
| DV9R | Services Annual | DV9K |
| DV9R | Services Annual | DV9K |
| DV9R | Services Annual | DV9K |
| DV9R | Services Annual | DV9K |
| DV9R | Services Annual | DV9K |
| DV9R | Services Annual | DV9L |
| DV9R | Services Annual | DV9L |
| DV9R | Services Annual | DV9L |
| DV9R | Services Annual | DV9L |
| DV9R | Services Annual | DV9L |
| DV9R | Services Annual | DV9N |
| DV9R | Services Annual | DV9N |
| DV9R | Services Annual | DV9N |
| DV9R | Services Annual | DV9N |
| DV9R | Services Annual | DV9N |
| DV9R | Services Annual | DV9P |
| DV9R | Services Annual | DV9P |
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| DV9R | Services Annual | DV9R |
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| DV9R | Services Annual | DV9R |
| DV9R | Services Annual | DV9R |

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| DV9R | Services Annual | DV9R |
| DV9R | Services Annual | DV9R |
| DV9R | Services Annual | DV9S |
| DV9R | Services Annual | DV9S |
| DV9R | Services Annual | DV9S |
| DV9R | Services Annual | DV9S |
| DV9R | Services Annual | DV9S |
| DV9R | Services Annual | DV9W |
| DV9R | Services Annual | DV9W |
| DV9R | Services Annual | DV9W |
| DV9R | Services Annual | DV9W |
| DV9R | Services Annual | DV9W |
| DV9R | Services Annual | DV9Y |
| DV9R | Services Annual | DV9Y |
| DV9R | Services Annual | DV9Y |
| DV9R | Services Annual | DV9Y |
| DV9R | Services Annual | DV9Y |
| DV9R | Services Annual | DV9Z |
| DV9R | Services Annual | DV9Z |
| DV9R | Services Annual | DV9Z |
| DV9R | Services Annual | DV9Z |
| DV9R | Services Annual | DV9Z |
| A21C52 | T2504 MANCHESTER LANDFILL PV | A21C52 |
| A21C52 | T2504 MANCHESTER LANDFILL PV | A21C52 |
| A21N88 | #T1213 LOUDON PLEASANT STREET PV | A21N88 |
| A21N88 | #T1213 LOUDON PLEASANT STREET PV | A21N88 |
| A21N88 | #T1213 LOUDON PLEASANT STREET PV | A21N88 |
| A21N90 | #T1193 CONWAY LAKE PV | A21N90 |
| A21N90 | #T1193 CONWAY LAKE PV | A21N90 |
| A21S89 | T1402 & T2007 NASHUA PENNICHUCK PV | A21S89 |
| A21S89 | T1402 & T2007 NASHUA PENNICHUCK PV | A21S89 |
| A21S89 | T1402 & T2007 NASHUA PENNICHUCK PV | A21S89 |
| A21X18 | ADD SCADA RECLOSERS TO DG SITES | A21X18 |
| A21X18 | ADD SCADA RECLOSERS TO DG SITES | A21X18 |
| A21X18 | ADD SCADA RECLOSERS TO DG SITES | A21X18 |
| A21X18 | ADD SCADA RECLOSERS TO DG SITES | A21X18 |
| A22C31 | BEDFORD TRANSFER STATION PV (#T2942) | A22C31 |
| A22C31 | BEDFORD TRANSFER STATION PV (#T2942) | A22C31 |
| A22C31 | BEDFORD TRANSFER STATION PV (#T2942) | A22C31 |
| A22C73 | Pembroke Solar Interconnection | A22C73 |
| A22C73 | Pembroke Solar Interconnection | A22C73 |
| A22W32 | KEENE WWTF PV (#T2797A) | A22W32 |
| A22W32 | KEENE WWTF PV (#T2797A) | A22W32 |
| A22W32 | KEENE WWTF PV (#T2797A) | A22W32 |
| A22W70 | Nellie Solar Interconnection | A22W70 |
| A22W70 | Nellie Solar Interconnection | A22W70 |
| A22W70 | Nellie Solar Interconnection | A22W70 |

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|---|---|---|
| DG9R | DG FIELD DESIGN & CONSTR- REIMBURSE | DG9R |
| DG9R | DG FIELD DESIGN & CONSTR- REIMBURSE | DG9R |
| DG9R | DG FIELD DESIGN & CONSTR- REIMBURSE | DG9R |
| DG9R | DG FIELD DESIGN & CONSTR- REIMBURSE | DG9R |
| DG9R | DG FIELD DESIGN & CONSTR- REIMBURSE | DG9R |
| DSPP8001 | DG ENG DESIGN & CONSTR | DSPP8001 |
| DSPP8001 | DG ENG DESIGN & CONSTR | DSPP8001 |
| DSPP8001 | DG ENG DESIGN & CONSTR | DSPP8001 |
| DSPP8001 | DG ENG DESIGN & CONSTR | DSPP8001 |
| DSPP8001 | DG ENG DESIGN & CONSTR | DSPP8001 |
| A19C25 | Reconductor Bedford Road, 360X7 | A19C25 |
| A19C25 | Reconductor Bedford Road, 360X7 | A19C25 |
| A19C25 | Reconductor Bedford Road, 360X7 | A19C25 |
| A19E26 | Convert Four Rod Road in Rochester | A19E26 |
| A19E26 | Convert Four Rod Road in Rochester | A19E26 |
| A19E26 | Convert Four Rod Road in Rochester | A19E26 |
| A19X31 | ROW Peak Load Plug | A19X31 |
| A06N30A | 386/386A/340 LINES REBUILD FOR Y-17 | A06N30A |
| A06N30A | 386/386A/340 LINES REBUILD FOR Y-17 | A06N30A |
| A06W42 | RETROFIT CAPACITOR BANK CONTROLS | A06W42 |
| A16C05 | Valley St Area Solution | A16C05 |
| A16C05 | Valley St Area Solution | A16C05 |
| A18E16 | West Rd Overloaded Steps | A18E16 |
| A19S46 | SOUTH AVE DERRY STEP OVERLOAD | A19S46 |
| A19S46 | SOUTH AVE DERRY STEP OVERLOAD | A19S46 |
| A19S46 | SOUTH AVE DERRY STEP OVERLOAD | A19S46 |
| A20C23 | 335X1 EXTEND 19.9kV 1P TO S. BOW RD | A20C23 |
| A20C23 | 335X1 EXTEND 19.9kV 1P TO S. BOW RD | A20C23 |
| A20C23 | 335X1 EXTEND 19.9kV 1P TO S. BOW RD | A20C23 |
| A20C23 | 335X1 EXTEND 19.9kV 1P TO S. BOW RD | A20C23 |
| A20C24 | INSTALL PM STEP TRNSF RTE 13 GOFFS | A20C24 |
| A20C24 | INSTALL PM STEP TRNSF RTE 13 GOFFS | A20C24 |
| A20C24 | INSTALL PM STEP TRNSF RTE 13 GOFFS | A20C24 |
| A20C24 | INSTALL PM STEP TRNSF RTE 13 GOFFS | A20C24 |
| A20C24 | INSTALL PM STEP TRNSF RTE 13 GOFFS | A20C24 |
| A20C24 | INSTALL PM STEP TRNSF RTE 13 GOFFS | A20C24 |
| A20E25 | OFFLOAD 63W1 AT E. NORTHWOOD | A20E25 |
| A20E25 | OFFLOAD 63W1 AT E. NORTHWOOD | A20E25 |
| A20E25 | OFFLOAD 63W1 AT E. NORTHWOOD | A20E25 |
| A20E25 | OFFLOAD 63W1 AT E. NORTHWOOD | A20E25 |
| A20S22 | RANGE RD WINDHAM CONVERSION | A20S22 |
| A20S22 | RANGE RD WINDHAM CONVERSION | A20S22 |
| A20S22 | RANGE RD WINDHAM CONVERSION | A20S22 |
| A21C19 | MEETINGHOUSE RD SS OFF- LOAD | A21C19 |
| A21C19 | MEETINGHOUSE RD SS OFF- LOAD | A21C19 |
| A21C19 | MEETINGHOUSE RD SS OFF- LOAD | A21C19 |
| A21C19 | MEETINGHOUSE RD SS OFF- LOAD | A21C19 |

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| A21C20 | 322X14 CIRCUIT OFFLOAD | A21C20 |
| A21C20 | 322X14 CIRCUIT OFFLOAD | A21C20 |
| A21C20 | 322X14 CIRCUIT OFFLOAD | A21C20 |
| A21C20 | 322X14 CIRCUIT OFFLOAD | A21C20 |
| A21C25 | ADD PHASES ON NEW BOSTON RD | A21C25 |
| A21C25 | ADD PHASES ON NEW BOSTON RD | A21C25 |
| A21C25 | ADD PHASES ON NEW BOSTON RD | A21C25 |
| A21C42 | WESTLAND AVE CONVERSION | A21C42 |
| A21C42 | WESTLAND AVE CONVERSION | A21C42 |
| A21C73 | LINE 321/3182 LAM WOOD STR REPL | A21C73 |
| A21C73 | LINE 321/3182 LAM WOOD STR REPL | A21C73 |
| A21E21 | RECONDUCTOR 1.06 MI DRAKE HILL RD | A21E21 |
| A21E21 | RECONDUCTOR 1.06 MI DRAKE HILL RD | A21E21 |
| A21E21 | RECONDUCTOR 1.06 MI DRAKE HILL RD | A21E21 |
| A21E21 | RECONDUCTOR 1.06 MI DRAKE HILL RD | A21E21 |
| A21E22 | PISCASSIC RD CONVERSION | A21E22 |
| A21E22 | PISCASSIC RD CONVERSION | A21E22 |
| A21E22 | PISCASSIC RD CONVERSION | A21E22 |
| A21E22 | PISCASSIC RD CONVERSION | A21E22 |
| A21E23 | FOGG RD CONVERSION | A21E23 |
| A21E23 | FOGG RD CONVERSION | A21E23 |
| A21E23 | FOGG RD CONVERSION | A21E23 |
| A21E23 | FOGG RD CONVERSION | A21E23 |
| A21E24 | BEAUTY HILL RD CONVERSION | A21E24 |
| A21E24 | BEAUTY HILL RD CONVERSION | A21E24 |
| A21E24 | BEAUTY HILL RD CONVERSION | A21E24 |
| A21E24 | BEAUTY HILL RD CONVERSION | A21E24 |
| A21N26 | CONVERT RTE 132 IN NORTHFIELD | A21N26 |
| A21N26 | CONVERT RTE 132 IN NORTHFIELD | A21N26 |
| A21S27 | DAMREN RD CONVERSION | A21S27 |
| A21S27 | DAMREN RD CONVERSION | A21S27 |
| A21S27 | DAMREN RD CONVERSION | A21S27 |
| A21W37 | EXTEND THREE PHASE ROUTE 202 RINDGE | A21W37 |
| A21W37 | EXTEND THREE PHASE ROUTE 202 RINDGE | A21W37 |
| A21W37 | EXTEND THREE PHASE ROUTE 202 RINDGE | A21W37 |
| A22C05 | 3108 PARALLEL STEP OVERLOAD | A22C05 |
| A22C05 | 3108 PARALLEL STEP OVERLOAD | A22C05 |
| A22C05 | 3108 PARALLEL STEP OVERLOAD | A22C05 |
| A22E22 | 15W4 RUSSELL ST SWITCHGEAR PORTSMTH | A22E22 |
| A22E23 | 3115X7 MAIN ST RAYMOND CONVERSION | A22E23 |
| A22E23 | 3115X7 MAIN ST RAYMOND CONVERSION | A22E23 |
| A22E23 | 3115X7 MAIN ST RAYMOND CONVERSION | A22E23 |
| A22E23 | 3115X7 MAIN ST RAYMOND CONVERSION | A22E23 |
| A22E24 | 377X20 MAIN ST EPPING CONVERSION | A22E24 |
| A22E24 | 377X20 MAIN ST EPPING CONVERSION | A22E24 |
| A22E24 | 377X20 MAIN ST EPPING CONVERSION | A22E24 |
| A22E24 | 377X20 MAIN ST EPPING CONVERSION | A22E24 |

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| A22E25 | 6H2 CONVERSION OFFLOAD TO 67W2 | A22E25 |
| A22E25 | 6H2 CONVERSION OFFLOAD TO 67W2 | A22E25 |
| A22E25 | 6H2 CONVERSION OFFLOAD TO 67W2 | A22E25 |
| A22E25 | 6H2 CONVERSION OFFLOAD TO 67W2 | A22E25 |
| A22E59 | 15W4 Market Street U/G Service | A22E59 |
| A22E59 | 15W4 Market Street U/G Service | A22E59 |
| A22N19 | 3525X5 E SIDE RD, ERROL CONVERSION | A22N19 |
| A22N19 | 3525X5 E SIDE RD, ERROL CONVERSION | A22N19 |
| A22N19 | 3525X5 E SIDE RD, ERROL CONVERSION | A22N19 |
| A22W20 | 42X3/44H1 EXTEND 34.5KV | A22W20 |
| A22W20 | 42X3/44H1 EXTEND 34.5KV | A22W20 |
| A22W20 | 42X3/44H1 EXTEND 34.5KV | A22W20 |
| A22W20 | 42X3/44H1 EXTEND 34.5KV | A22W20 |
| A22W21 | 3410 LAKE SUNAPEE EXT 34.5KV SPACER | A22W21 |
| A22W21 | 3410 LAKE SUNAPEE EXT 34.5KV SPACER | A22W21 |
| A22W21 | 3410 LAKE SUNAPEE EXT 34.5KV SPACER | A22W21 |
| A23E14 | 377X20 Pleasant Street Conversion | A23E14 |
| A23E14 | 377X20 Pleasant Street Conversion | A23E14 |
| A23E36 | 3103X1 Beede Hill Road Conversion | A23E36 |
| A23IFR | 2023 Initial Funding Placeholder | A23IFR |
| A23N07 | 319X1 Conversion S Barnstead Rd | A23N07 |
| A23N07 | 319X1 Conversion S Barnstead Rd | A23N07 |
| A23N08 | 336X1 Conversion | A23N08 |
| A23N09 | 3114W1 Conversion Ragged Mt Hwy | A23N09 |
| A23S19 | 2H2 Line Extension | A23S19 |
| A23S19 | 2H2 Line Extension | A23S19 |
| A23S20 | 3155X Route 13 Conversion | A23S20 |
| A23S20 | 3155X Route 13 Conversion | A23S20 |
| A23S21 | 3211X Kimball Hill Rd Conversion | A23S21 |
| A23S21 | 3211X Kimball Hill Rd Conversion | A23S21 |
| A23S22 | 3217X Knowlton Rd Conversion | A23S22 |
| A23W01 | 3155X Install Padmounted Step Xfmr | A23W01 |
| A23W01 | 3155X Install Padmounted Step Xfmr | A23W01 |
| A24E07 | Pease Tradeport Upgrade | A24E07 |
| DK9R | Maintain Voltage Annual | DK9A |
| DK9R | Maintain Voltage Annual | DK9A |
| DK9R | Maintain Voltage Annual | DK9A |
| DK9R | Maintain Voltage Annual | DK9A |
| DK9R | Maintain Voltage Annual | DK9A |
| DK9R | Maintain Voltage Annual | DK9B |
| DK9R | Maintain Voltage Annual | DK9B |
| DK9R | Maintain Voltage Annual | DK9B |
| DK9R | Maintain Voltage Annual | DK9B |
| DK9R | Maintain Voltage Annual | DK9B |
| DK9R | Maintain Voltage Annual | DK9C |
| DK9R | Maintain Voltage Annual | DK9C |
| DK9R | Maintain Voltage Annual | DK9C |

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| DK9R | Maintain Voltage Annual | DK9C |
| DK9R | Maintain Voltage Annual | DK9C |
| DK9R | Maintain Voltage Annual | DK9D |
| DK9R | Maintain Voltage Annual | DK9D |
| DK9R | Maintain Voltage Annual | DK9D |
| DK9R | Maintain Voltage Annual | DK9D |
| DK9R | Maintain Voltage Annual | DK9D |
| DK9R | Maintain Voltage Annual | DK9E |
| DK9R | Maintain Voltage Annual | DK9E |
| DK9R | Maintain Voltage Annual | DK9E |
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| DK9R | Maintain Voltage Annual | DK9E |
| DK9R | Maintain Voltage Annual | DK9K |
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| DK9R | Maintain Voltage Annual | DK9N |
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| DK9R | Maintain Voltage Annual | DK9R |
| DK9R | Maintain Voltage Annual | DK9S |
| DK9R | Maintain Voltage Annual | DK9S |
| DK9R | Maintain Voltage Annual | DK9S |
| DK9R | Maintain Voltage Annual | DK9S |
| DK9R | Maintain Voltage Annual | DK9S |
| DK9R | Maintain Voltage Annual | DK9W |
| DK9R | Maintain Voltage Annual | DK9W |
| DK9R | Maintain Voltage Annual | DK9W |
| DK9R | Maintain Voltage Annual | DK9W |
| DK9R | Maintain Voltage Annual | DK9W |

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| DK9R | Maintain Voltage Annual | DK9Y |
| DK9R | Maintain Voltage Annual | DK9Y |
| DK9R | Maintain Voltage Annual | DK9Y |
| DK9R | Maintain Voltage Annual | DK9Y |
| DK9R | Maintain Voltage Annual | DK9Y |
| DK9R | Maintain Voltage Annual | DK9Z |
| DK9R | Maintain Voltage Annual | DK9Z |
| DK9R | Maintain Voltage Annual | DK9Z |
| DK9R | Maintain Voltage Annual | DK9Z |
| DK9R | Maintain Voltage Annual | DK9Z |
| UB0836 | SO. ST. MILFORD REPL OH WITH UNDERG | UB0836 |
| A13S01 | RIMMON S/S ADD 2ND 115-34.5KV 44.8M | A13S01 |
| A15N03 | 310/29X1 Survey & Purchase Land | A15N03 |
| A15N06 | White Lake S/S - replace TB82 | A15N06 |
| A17W06 | RIVER ROAD SS | A17W06 |
| A18E09 | REPLACE 386 RELAY AT ROCHESTER SS | A18E09 |
| A18E09 | REPLACE 386 RELAY AT ROCHESTER SS | A18E09 |
| A18N05 | Pemi SS Upgrade | A18N05 |
| A18N05 | Pemi SS Upgrade | A18N05 |
| A18N05 | Pemi SS Upgrade | A18N05 |
| A18N05 | Pemi SS Upgrade | A18N05 |
| A18N05 | Pemi SS Upgrade | A18N05 |
| A18N05 | Pemi SS Upgrade | A18N05 |
| A18N05 | Pemi SS Upgrade | A18N05 |
| A18N05 | Pemi SS Upgrade | A18N05 |
| A20S19 | SOUTH MILFORD SUBSTATION | A20S19 |
| A20S19 | SOUTH MILFORD SUBSTATION | A20S19 |
| A20S19 | SOUTH MILFORD SUBSTATION | A20S19 |
| A20S19 | SOUTH MILFORD SUBSTATION | A20S19 |
| A20S19 | SOUTH MILFORD SUBSTATION | A20S19 |
| A21E71 | Salmon Falls SS Capactiy Project | A21E71 |
| A21E71L | Salmon Falls SS Capactiy (D-Line) | A21E71L |
| A21S85 | So Milford SS Distribution Line Wrk | A21S85 |
| A21S85 | So Milford SS Distribution Line Wrk | A21S85 |
| A21S85 | So Milford SS Distribution Line Wrk | A21S85 |
| A23N43 | Colebrook D Substsation | A23N43 |
| D1260C | Huse Road | D1260C |
| A07X98 | NESC CAPITAL REPAIRS | A07X98 |
| A07X98 | NESC CAPITAL REPAIRS | A07X98 |
| A07X98 | NESC CAPITAL REPAIRS | A07X98 |
| A07X98 | NESC CAPITAL REPAIRS | A07X98 |
| A07X98 | NESC CAPITAL REPAIRS | A07X98 |
| A19S23 | Miller State Park/Pack Monadnock | A19S23 |
| A19X24 | NESC CAPITAL REPAIRS | A19X24 |
| A19X24 | NESC CAPITAL REPAIRS | A19X24 |
| A19X24 | NESC CAPITAL REPAIRS | A19X24 |
| A22DA | 2022 POLE TOP DISTRIBUTION AUTOMATN | A22DA |

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|---|---|---|
| A22DA | 2022 POLE TOP DISTRIBUTION AUTOMATN | A22DA |
| A22DA | 2022 POLE TOP DISTRIBUTION AUTOMATN | A22DA |
| A22E43 | GREAT EAST LAKE POLE REPLACEMENT | A22E43 |
| A22E43 | GREAT EAST LAKE POLE REPLACEMENT | A22E43 |
| R15CDA | REP3 - 2015-2016 Central Region DA | R15CDA |
| R15CDA | REP3 - 2015-2016 Central Region DA | R15CDA |
| R15CDA | REP3 - 2015-2016 Central Region DA | R15CDA |
| R15CTC | Circuit Tie Construction | R15CTC |
| R15CTC | Circuit Tie Construction | R15CTC |
| R15CTC | Circuit Tie Construction | R15CTC |
| R15DBR | REP3 Direct Buried Cable Replace | R15DBR |
| R15DBR | REP3 Direct Buried Cable Replace | R15DBR |
| R15DBR | REP3 Direct Buried Cable Replace | R15DBR |
| R15EDA | REP 3 2015-2016 Eastern Region DA | R15EDA |
| R15EDA | REP 3 2015-2016 Eastern Region DA | R15EDA |
| R15HLDR | Hit List Reliability Enhancements | R15HLDR |
| R15HLDR | Hit List Reliability Enhancements | R15HLDR |
| R15HLR | Heather-Lite Replacement | R15HLR |
| R15HLR | Heather-Lite Replacement | R15HLR |
| R15HLR | Heather-Lite Replacement | R15HLR |
| R15NDA | REP3 - 2015-2016 Northern Region D | R15NDA |
| R15NDA | REP3 - 2015-2016 Northern Region D | R15NDA |
| R15NESC | NESC CAPITAL REPAIRS | R15NESC |
| R15NESC | NESC CAPITAL REPAIRS | R15NESC |
| R15NESC | NESC CAPITAL REPAIRS | R15NESC |
| R15POR | Porcelain Change-out | R15POR |
| R15POR | Porcelain Change-out | R15POR |
| R15POR | Porcelain Change-out | R15POR |
| R15RPR | REJECT POLE REPLACEMENT | R15RPR |
| R15RPR | REJECT POLE REPLACEMENT | R15RPR |
| R15RPR | REJECT POLE REPLACEMENT | R15RPR |
| R15RPR | REJECT POLE REPLACEMENT | R15RPR |
| R15RWM | ROW System Hardening | R15RWM |
| R15RWM | ROW System Hardening | R15RWM |
| R15SDA | REP3 - 2015-2016 Southern Re | R15SDA |
| R15SDA | REP3 - 2015-2016 Southern Re | R15SDA |
| R15SDA | REP3 - 2015-2016 Southern Re | R15SDA |
| R15SDA | REP3 - 2015-2017 Southern Re | R15SDA |
| R15SSAI | 4 & 12 kV Substations | R15SSAI |
| R15TDA | TELECOM EXPANSION TO SUPPORT DA | R15TDA |
| R15TDA | TELECOM EXPANSION TO SUPPORT DA | R15TDA |
| R15WDA | REP3 - 2015-2016 Western Region DA | R15WDA |
| R15WDA | REP3 - 2015-2016 Western Region DA | R15WDA |
| R15WDA | REP3 - 2015-2016 Western Region DA | R15WDA |
| R16LS | 2016 Line Sensor Project | R16LS |
| R16LS | 2016 Line Sensor Project | R16LS |
| R17CTC | REP 4 CIRCUIT TIES | R17CTC |

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|---|---|---|
| R17CTC | REP 4 CIRCUIT TIES | R17CTC |
| R17CTC | REP 4 CIRCUIT TIES | R17CTC |
| R17DA | REP 4 POLE TOP DA | R17DA |
| R17DA | REP 4 POLE TOP DA | R17DA |
| R17HLDR | REP 4 CIRCUIT RELIABILITY IMPROVE | R17HLDR |
| R17HLDR | REP 4 CIRCUIT RELIABILITY IMPROVE | R17HLDR |
| R17HLDR | REP 4 CIRCUIT RELIABILITY IMPROVE | R17HLDR |
| R17RWH | REP 4 ROW SYSTEM HARDENING | R17RWH |
| R18CTC01 | W185 - 4W1 CIRCUIT TIE | R18CTC01 |
| R18CTC01 | W185 - 4W1 CIRCUIT TIE | R18CTC01 |
| R18CTC01 | W185 - 4W1 CIRCUIT TIE | R18CTC01 |
| R18CTC02 | 3178X CIRCUIT TIE HINSDALE | R18CTC02 |
| R18CTC02 | 3178X CIRCUIT TIE HINSDALE | R18CTC02 |
| R18CTC02 | 3178X CIRCUIT TIE HINSDALE | R18CTC02 |
| 6DCIP | Avigilon Security Upgrades | 6DCIP |
| 6DCIP | Avigilon Security Upgrades | 6DCIP |
| 6DCIP | Avigilon Security Upgrades | 6DCIP |
| 6DCIP | Avigilon Security Upgrades | 6DCIP |
| A19E63 | JACKSON HILL SS FNCE & GRDNG REPLAC | A19E63 |
| A19X64 | SS SECURITY UPGRADES | A19X64 |
| A19X64 | SS SECURITY UPGRADES | A19X64 |
| A20X21 | NH DMS | A20X21 |
| A20X21 | NH DMS | A20X21 |
| A20X21 | NH DMS | A20X21 |
| A20X21 | NH DMS | A20X21 |
| A20X21 | NH DMS | A20X21 |
| A20X21 | NH DMS | A20X21 |
| A21C14 | GARVINS SS OCB REPLACEMENT | A21C14 |
| A21C14 | GARVINS SS OCB REPLACEMENT | A21C14 |
| A21W53 | 316 LINE DAVIT ARM & STRUCTURE REPL | A21W53 |
| A21W53 | 316 LINE DAVIT ARM & STRUCTURE REPL | A21W53 |
| A17E01 | RYE AREA 4KV STUDY | A17E01 |
| A17E01 | RYE AREA 4KV STUDY | A17E01 |
| A17E01 | RYE AREA 4KV STUDY | A17E01 |
| A17E01 | RYE AREA 4KV STUDY | A17E01 |
| A17E01 | RYE AREA 4KV STUDY | A17E01 |
| A17E09 | ROCHESTER 4KV CONVERSION | A17E09 |
| A17E09 | ROCHESTER 4KV CONVERSION | A17E09 |
| A17E09 | ROCHESTER 4KV CONVERSION | A17E09 |
| A17E09 | ROCHESTER 4KV CONVERSION | A17E09 |
| A17E09 | ROCHESTER 4KV CONVERSION | A17E09 |
| A17E09 | ROCHESTER 4KV CONVERSION | A17E09 |
| A17E09 | ROCHESTER 4KV CONVERSION | A17E09 |
| A17E09 | ROCHESTER 4KV CONVERSION | A17E09 |
| A17E09 | ROCHESTER 4KV CONVERSION | A17E09 |
| A20E04 | Ham St Conversion, Dover | A20E04 |
| A20E04 | Ham St Conversion, Dover | A20E04 |

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| A20E04 | Ham St Conversion, Dover | A20E04 |
| A21C04 | GOFFSTOWN SS CONVERSION | A21C04 |
| A21C04 | GOFFSTOWN SS CONVERSION | A21C04 |
| A21C04 | GOFFSTOWN SS CONVERSION | A21C04 |
| A21C04 | GOFFSTOWN SS CONVERSION | A21C04 |
| A22C03 | GOFFSTOWN SS ELIM PHASE 2 27W2 CONV | A22C03 |
| A22C03 | GOFFSTOWN SS ELIM PHASE 2 27W2 CONV | A22C03 |
| A22N11 | 36W1 CONVERSION/VEC TIE STRAFFORD | A22N11 |
| A15CDA | CENTRAL REGION 2015 DA | A15CDA |
| A15CDA | CENTRAL REGION 2015 DA | A15CDA |
| A15CDA | CENTRAL REGION 2015 DA | A15CDA |
| A15EDA | EASTERN REGION 2015 DA | A15EDA |
| A15EDA | EASTERN REGION 2015 DA | A15EDA |
| A15EDA | EASTERN REGION 2015 DA | A15EDA |
| A15EDA | EASTERN REGION 2015 DA | A15EDA |
| A15NDA | NORTHERN REGION 2015 DA | A15NDA |
| A15NDA | NORTHERN REGION 2015 DA | A15NDA |
| A15NDA | NORTHERN REGION 2015 DA | A15NDA |
| A15SDA | SOUTHERN REGION 2015 DA | A15SDA |
| A15SDA | SOUTHERN REGION 2015 DA | A15SDA |
| A15SDA | SOUTHERN REGION 2015 DA | A15SDA |
| A15SDA | SOUTHERN REGION 2015 DA | A15SDA |
| A15TDA | TELECOM BUILDOUT AUTOMATION 2015 | A15TDA |
| A17VRP | G&W Viper Warranty Replacment | A17VRP |
| A17VRP | G&W Viper Warranty Replacment | A17VRP |
| A18DA | DISTRIBUTION AUTOMATION - POLE TOP | A18DA |
| A18DA | DISTRIBUTION AUTOMATION - POLE TOP | A18DA |
| A18DA | DISTRIBUTION AUTOMATION - POLE TOP | A18DA |
| A18DA | DISTRIBUTION AUTOMATION - POLE TOP | A18DA |
| A18VRP | Viper Replacement Project-Bettermnt | A18VRP |
| A18VRP | Viper Replacement Project-Bettermnt | A18VRP |
| A19DA | DISTRIBUTION AUTOMATION - POLE TOP | A19DA |
| A19DA | DISTRIBUTION AUTOMATION - POLE TOP | A19DA |
| A19DA | DISTRIBUTION AUTOMATION - POLE TOP | A19DA |
| A19DA | DISTRIBUTION AUTOMATION - POLE TOP | A19DA |
| A19DA | DISTRIBUTION AUTOMATION - POLE TOP | A19DA |
| A19LS | Distribution Automation - Line Sens | A19LS |
| A19LS | Distribution Automation - Line Sens | A19LS |
| A19LS | Distribution Automation - Line Sens | A19LS |
| A19LS | Distribution Automation - Line Sens | A19LS |
| A19TDA | Distribution Automation - Telecom | A19TDA |
| A19XDA | Distribution Automation - Substatio | A19XDA |
| A19XDA | Distribution Automation - Substatio | A19XDA |
| A20DA | DISTRIBUTION AUTOMATION POLE TOP | A20DA |
| A20DA | DISTRIBUTION AUTOMATION POLE TOP | A20DA |
| A20DA | DISTRIBUTION AUTOMATION POLE TOP | A20DA |
| A20DA | DISTRIBUTION AUTOMATION POLE TOP | A20DA |

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| A20DA | DISTRIBUTION AUTOMATION POLE TOP | A20DA |
| A20LS | DISTRIBUTION AUTOMATION LINE SENSOR | A20LS |
| A20LS | DISTRIBUTION AUTOMATION LINE SENSOR | A20LS |
| A20LS | DISTRIBUTION AUTOMATION LINE SENSOR | A20LS |
| A20TDA | DISTRIBUTION AUTOMATION TELECOM | A20TDA |
| A20XDA | DISTRIBUTION AUTOMATION SUBSTATION | A20XDA |
| A21DA | DISTRIBUTION AUTOMATION POLE TOP | A21DA |
| A21DA | DISTRIBUTION AUTOMATION POLE TOP | A21DA |
| A21DA | DISTRIBUTION AUTOMATION POLE TOP | A21DA |
| A21DA | DISTRIBUTION AUTOMATION POLE TOP | A21DA |
| A21LS | DISTRIBUTION AUTOMATION LINE SENSOR | A21LS |
| A21LS | DISTRIBUTION AUTOMATION LINE SENSOR | A21LS |
| A21LS | DISTRIBUTION AUTOMATION LINE SENSOR | A21LS |
| A21LS | DISTRIBUTION AUTOMATION LINE SENSOR | A21LS |
| A21TDA | DISTRIBUTION AUTOMATION TELECOM | A21TDA |
| A21XDA | DISTRIBUTION AUTOMATION SUBSTATION | A21XDA |
| A22LS | 2022 Distr Automation - Line Sensor | A22LS |
| A22LS | 2022 Distr Automation - Line Sensor | A22LS |
| A22LS | 2022 Distr Automation - Line Sensor | A22LS |
| A22TDA | DISTRIBUTION AUTOMATION TELECOM | A22TDA |
| A22XDA | DISTRIBUTION AUTOMATION SUBSTATION | A22XDA |
| A23DA | 2023 Distr Automation - Pole Top | A23DA |
| A23DA | 2023 Distr Automation - Pole Top | A23DA |
| A23LS | Distr Automation - Line Sensors | A23LS |
| A23LS | Distr Automation - Line Sensors | A23LS |
| A23X26 | SCADA Reclosers at DG Sites | A23X26 |
| A23XDA | 2023 Distribution Automation - SS | A23XDA |
| UB1412 | 2014 DA DEPLOYMENT | UB1412 |
| A07X45 | REJECT POLE REPLACEMENT | A07X45 |
| A07X45 | REJECT POLE REPLACEMENT | A07X45 |
| A07X45 | REJECT POLE REPLACEMENT | A07X45 |
| A07X45 | REJECT POLE REPLACEMENT | A07X45 |
| A07X45 | REJECT POLE REPLACEMENT | A07X45 |
| A07X45 | REJECT POLE REPLACEMENT | A07X45 |
| A07X45 | REJECT POLE REPLACEMENT | A07X45 |
| A08X45 | REPLACE STEEL TOWERS | A08X45 |
| A08X45 | REPLACE STEEL TOWERS | A08X45 |
| A08X45 | REPLACE STEEL TOWERS | A08X45 |
| A08X45 | REPLACE STEEL TOWERS | A08X45 |
| A12W05 | REPL LACONIA UNDRGRD SWITCHGEAR 70W | A12W05 |
| A14CRL | Northern COOS Reliability Loop | A14CRL |
| A14S14 | 3818 NEW 34.5KV LINE 1.6 MI ON RTE | A14S14 |
| A16C02 | 12H4 West Side Conversion | A16C02 |
| A16C06 | 324 LINE, REBUILD AT INDUSTRIAL AVE | A16C06 |
| A16C06 | 324 LINE, REBUILD AT INDUSTRIAL AVE | A16C06 |
| A16N01 | 11W1 - Replace Submarine Cable | A16N01 |
| A16N01 | 11W1 - Replace Submarine Cable | A16N01 |

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| A16N01 | 11W1 - Replace Submarine Cable | A16N01 |
| A16N01 | 11W1 - Replace Submarine Cable | A16N01 |
| A16X02 | Circuit Tie 3271x2/311x1 | A16X02 |
| A16X04 | CAIDI IMPROVEMENT | A16X04 |
| A16X04 | CAIDI IMPROVEMENT | A16X04 |
| A16X04 | CAIDI IMPROVEMENT | A16X04 |
| A16X04 | CAIDI IMPROVEMENT | A16X04 |
| A17C10 | BROOK ST REPLACE G&W SWITCHGEAR | A17C10 |
| A17C10 | BROOK ST REPLACE G&W SWITCHGEAR | A17C10 |
| A17C10 | BROOK ST REPLACE G&W SWITCHGEAR | A17C10 |
| A17C10 | BROOK ST REPLACE G&W SWITCHGEAR | A17C10 |
| A17C12 | 3.74 PRI VOLT CONV NAVIGATOR RD | A17C12 |
| A17C12 | 3.74 PRI VOLT CONV NAVIGATOR RD | A17C12 |
| A17C13 | BLAINE ST SUBSTATION LINE WORK | A17C13 |
| A17C13 | BLAINE ST SUBSTATION LINE WORK | A17C13 |
| A17C17 | CIRCUIT TIE 3115X12 TO 3615X1 | A17C17 |
| A17C17 | CIRCUIT TIE 3115X12 TO 3615X1 | A17C17 |
| A17C17 | CIRCUIT TIE 3115X12 TO 3615X1 | A17C17 |
| A17C26 | 328 LINE RECONDUCTOR | A17C26 |
| A17C26 | 328 LINE RECONDUCTOR | A17C26 |
| A17C26 | 328 LINE RECONDUCTOR | A17C26 |
| A17C26 | 328 LINE RECONDUCTOR | A17C26 |
| A17C26 | 328 LINE RECONDUCTOR | A17C26 |
| A17E16 | 380 LINE BETTERMENT | A17E16 |
| A18X18 | ROW Hardening/Reconductoring | A18X18 |
| A18X18 | ROW Hardening/Reconductoring | A18X18 |
| A18X20 | CAIDI IMPROVEMENTS | A18X20 |
| A19C05 | Reconductor copper St Anselm Drive | A19C05 |
| A19C05 | Reconductor copper St Anselm Drive | A19C05 |
| A19C05 | Reconductor copper St Anselm Drive | A19C05 |
| A19E07 | Downtown Portsmouth UG System Impro | A19E07 |
| A19E07 | Downtown Portsmouth UG System Impro | A19E07 |
| A19E07 | Downtown Portsmouth UG System Impro | A19E07 |
| A19E07 | Downtown Portsmouth UG System Impro | A19E07 |
| A19E07 | Downtown Portsmouth UG System Impro | A19E07 |
| A19E07 | Downtown Portsmouth UG System Impro | A19E07 |
| A19E07 | Downtown Portsmouth UG System Impro | A19E07 |
| A19E07 | Downtown Portsmouth UG System Impro | A19E07 |
| A19E07 | Downtown Portsmouth UG System Impro | A19E07 |
| A19E11 | Circuit Ties-Wakefield 362 to 3157 | A19E11 |
| A19E11 | Circuit Ties-Wakefield 362 to 3157 | A19E11 |
| A19E11 | Circuit Ties-Wakefield 362 to 3157 | A19E11 |
| A19E11 | Circuit Ties-Wakefield 362 to 3157 | A19E11 |
| A19E11 | Circuit Ties-Wakefield 362 to 3157 | A19E11 |
| A19E11 | Circuit Ties-Wakefield 362 to 3157 | A19E11 |
| A19E52 | DOVER UNDERGROUND BACKFEED RELOCATI | A19E52 |
| A19E52 | DOVER UNDERGROUND BACKFEED RELOCATI | A19E52 |

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| A19E52 | DOVER UNDERGROUND BACKFEED RELOCATI | A19E52 |
| A19E52 | DOVER UNDERGROUND BACKFEED RELOCATI | A19E52 |
| A19N09 | Relocate 1W1 Main Line onto Route 3 | A19N09 |
| A19N09 | Relocate 1W1 Main Line onto Route 3 | A19N09 |
| A19N09 | Relocate 1W1 Main Line onto Route 3 | A19N09 |
| A19N09 | Relocate 1W1 Main Line onto Route 3 | A19N09 |
| A19N12 | Circuit Ties - Laconia 310 to 345 | A19N12 |
| A19N12 | Circuit Ties - Laconia 310 to 345 | A19N12 |
| A19N12 | Circuit Ties - Laconia 310 to 345 | A19N12 |
| A19N12 | Circuit Ties - Laconia 310 to 345 | A19N12 |
| A19N12 | Circuit Ties - Laconia 310 to 345 | A19N12 |
| A19N50 | 346X1 DEFECTIVE SPCA REPLACEMENT | A19N50 |
| A19N50 | 346X1 DEFECTIVE SPCA REPLACEMENT | A19N50 |
| A19S04 | Reconductor #6 Copper @ Fordway Ext | A19S04 |
| A19S06 | Replace Conductor Route 13 Amherst | A19S06 |
| A19S06 | Replace Conductor Route 13 Amherst | A19S06 |
| A19S06 | Replace Conductor Route 13 Amherst | A19S06 |
| A19S06 | Replace Conductor Route 13 Amherst | A19S06 |
| A19S06 | Replace Conductor Route 13 Amherst | A19S06 |
| A19S06 | Replace Conductor Route 13 Amherst | A19S06 |
| A19S08 | Relocate 3168X Bridge St S/S | A19S08 |
| A19S08 | Relocate 3168X Bridge St S/S | A19S08 |
| A19S08 | Relocate 3168X Bridge St S/S | A19S08 |
| A19S27 | Relocate 314 Line around Heron Pond | A19S27 |
| A19S27 | Relocate 314 Line around Heron Pond | A19S27 |
| A19S27 | Relocate 314 Line around Heron Pond | A19S27 |
| A19W03 | Repl open wire w/ Spacer cble Rt 63 | A19W03 |
| A19W03 | Repl open wire w/ Spacer cble Rt 63 | A19W03 |
| A19W03 | Repl open wire w/ Spacer cble Rt 63 | A19W03 |
| A19W03 | Repl open wire w/ Spacer cble Rt 63 | A19W03 |
| A19W03 | Repl open wire w/ Spacer cble Rt 63 | A19W03 |
| A19W10 | Relocate feed to Hinsdale Wastewat | A19W10 |
| A19W10 | Relocate feed to Hinsdale Wastewat | A19W10 |
| A19W10 | Relocate feed to Hinsdale Wastewat | A19W10 |
| A19W10 | Relocate feed to Hinsdale Wastewat | A19W10 |
| A19W10 | Relocate feed to Hinsdale Wastewat | A19W10 |
| A19W49 | DIST LINE WORK FOR MONADNOCK SS REB | A19W49 |
| A19W49 | DIST LINE WORK FOR MONADNOCK SS REB | A19W49 |
| A19W49 | DIST LINE WORK FOR MONADNOCK SS REB | A19W49 |
| A19W49 | DIST LINE WORK FOR MONADNOCK SS REB | A19W49 |
| A19W49 | DIST LINE WORK FOR MONADNOCK SS REB | A19W49 |
| A19W49 | DIST LINE WORK FOR MONADNOCK SS REB | A19W49 |
| A19W49 | DIST LINE WORK FOR MONADNOCK SS REB | A19W49 |
| A19W56 | 317 Line Reconstruction | A19W56 |
| A19W56 | 317 Line Reconstruction | A19W56 |
| A19X20 | Replace Lattice Steel Towers | A19X20 |
| A19X20 | Replace Lattice Steel Towers | A19X20 |

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| A19X20 | Replace Lattice Steel Towers | A19X20 |
| A19X20 | Replace Lattice Steel Towers | A19X20 |
| A19X20 | Replace Lattice Steel Towers | A19X20 |
| A19X20 | Replace Lattice Steel Towers | A19X20 |
| A19X58 | Replace Lattice Steel Towers | A19X58 |
| A19X58 | Replace Lattice Steel Towers | A19X58 |
| A20C46 | 317 Line ROW section rebuild | A20C46 |
| A20C46 | 317 Line ROW section rebuild | A20C46 |
| A20C46 | 317 Line ROW section rebuild | A20C46 |
| A20C46 | 317 Line ROW Section Rebuild | A20C46 |
| A20N05 | Reconductor Strafford St in Lacona | A20N05 |
| A20N10 | Relo 3200' main li fr ROW to roadsi | A20N10 |
| A20N11 | Voltage Conversion Lost Nation Rd a | A20N11 |
| A20N15 | 43W1 (13W1) Construct Circuit Tie | A20N15 |
| A20N15 | 43W1 (13W1) Construct Circuit Tie | A20N15 |
| A20N15 | 43W1 (13W1) Construct Circuit Tie | A20N15 |
| A20N15 | 43W1 (13W1) Construct Circuit Tie | A20N15 |
| A20S02 | Millyard SS Distribution Line Work | A20S02 |
| A20S02 | Millyard SS Distribution Line Work | A20S02 |
| A20S02 | Millyard SS Distribution Line Work | A20S02 |
| A20S02 | Millyard SS Distribution Line Work | A20S02 |
| A20S02 | Millyard SS Distribution Line Work | A20S02 |
| A20S02 | Millyard SS Distribution Line Work | A20S02 |
| A20S02 | Millyard SS Distribution Line Work | A20S02 |
| A20S06 | 3159X Extend 3 Phase Boston Post Rd | A20S06 |
| A20S06 | 3159X Extend 3 Phase Boston Post Rd | A20S06 |
| A20S06 | 3159X Extend 3 Phase Boston Post Rd | A20S06 |
| A20S12 | Replace 3891X cable along raiload t | A20S12 |
| A20S12 | Replace 3891X cable along raiload t | A20S12 |
| A20S12 | Replace 3891X cable along raiload t | A20S12 |
| A20S12 | Replace 3891X cable along raiload t | A20S12 |
| A20S12 | Replace 3891X cable along raiload t | A20S12 |
| A20S12 | Replace 3891X cable along raiload t | A20S12 |
| A20W07 | Mason Rd Relo 1500' main li to road | A20W07 |
| A20W07 | Mason Rd Relo 1500' main li to road | A20W07 |
| A20W07 | Mason Rd Relo 1500' main li to road | A20W07 |
| A20W07 | Mason Rd Relo 1500' main li to road | A20W07 |
| A20W08 | 3155X6 feed from the 3155X9 | A20W08 |
| A20W08 | 3155X6 feed from the 3155X9 | A20W08 |
| A20W08 | 3155X6 feed from the 3155X9 | A20W08 |
| A20W08 | 3155X6 feed from the 3155X9 | A20W08 |
| A20W09 | Rte 9 Relo 2800' main li to roadsid | A20W09 |
| A20W09 | Rte 9 Relo 2800' main li to roadsid | A20W09 |
| A20W09 | Rte 9 Relo 2800' main li to roadsid | A20W09 |
| A20W09 | Rte 9 Relo 2800' main li to roadsid | A20W09 |
| A20W13 | 3410 and 315 Circuit Tie | A20W13 |
| A20W13 | 3410 and 315 Circuit Tie | A20W13 |

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| A20W13 | 3410 and 315 Circuit Tie | A20W13 |
| A20W13 | 3410 and 315 Circuit Tie | A20W13 |
| A20W14 | 24X1 and 313X1 Circuit Tie | A20W14 |
| A20W14 | 24X1 and 313X1 Circuit Tie | A20W14 |
| A20W14 | 24X1 and 313X1 Circuit Tie | A20W14 |
| A20W14 | 24X1 and 313X1 Circuit Tie | A20W14 |
| A20W18 | 317/3410 RECON BRADFORD TO WARNER | A20W18 |
| A20W18 | 317/3410 RECON BRADFORD TO WARNER | A20W18 |
| A20W18 | 317/3410 RECON BRADFORD TO WARNER | A20W18 |
| A20W18 | 317/3410 RECON BRADFORD TO WARNER | A20W18 |
| A20X38 | 2020 CIRCUIT PATROL REPAIRS | A20X38 |
| A20X38 | 2020 CIRCUIT PATROL REPAIRS | A20X38 |
| A20X38 | 2020 CIRCUIT PATROL REPAIRS | A20X38 |
| A20X38 | 2020 CIRCUIT PATROL REPAIRS | A20X38 |
| A21C05 | RECONDUCTOR ACADEMY RD PEMBROKE SPA | A21C05 |
| A21C07 | MALVERN VALLEY HANOVER CIRCUIT TIE | A21C07 |
| A21C07 | MALVERN VALLEY HANOVER CIRCUIT TIE | A21C07 |
| A21C07 | MALVERN VALLEY HANOVER CIRCUIT TIE | A21C07 |
| A21C11 | CIRCUIT TIE 14X188 TO 3248 | A21C11 |
| A21C11 | CIRCUIT TIE 14X188 TO 3248 | A21C11 |
| A21C11 | CIRCUIT TIE 14X188 TO 3248 | A21C11 |
| A21C74 | LINE M164 LAMINATED WOOD SYS STR REPL | A21C74 |
| A21C74 | LINE M164 LAMINATED WOOD SYS STR REPL | A21C74 |
| A21C91 | 393 LINE ROW SECTION REBUILD | A21C91 |
| A21C91 | 393 LINE ROW SECTION REBUILD | A21C91 |
| A21C91 | 393 LINE ROW SECTION REBUILD | A21C91 |
| A21C91 | 393 LINE ROW SECTION REBUILD | A21C91 |
| A21E08 | CIRCUIT TIE 3191X1B TO 377X2 | A21E08 |
| A21E08 | CIRCUIT TIE 3191X1B TO 377X2 | A21E08 |
| A21E08 | CIRCUIT TIE 3191X1B TO 377X2 | A21E08 |
| A21E08 | CIRCUIT TIE 3191X1B TO 377X2 | A21E08 |
| A21E09 | CIRCUIT TIE 3191X3 TO 3191X | A21E09 |
| A21E09 | CIRCUIT TIE 3191X3 TO 3191X | A21E09 |
| A21E09 | CIRCUIT TIE 3191X3 TO 3191X | A21E09 |
| A21E09 | CIRCUIT TIE 3191X3 TO 3191X | A21E09 |
| A21E92 | 3174X4 ROUTE 11 OFF ROAD SHUNT | A21E92 |
| A21E92 | 3174X4 ROUTE 11 OFF ROAD SHUNT | A21E92 |
| A21RPR | ROADSIDE REJECT POLE REPLACEMENT | A21RPR |
| A21RPR | ROADSIDE REJECT POLE REPLACEMENT | A21RPR |
| A21RPR | ROADSIDE REJECT POLE REPLACEMENT | A21RPR |
| A21RPR | Roadside Reject Pole Replacement | A21RPR |
| A21S06 | CONSTRUCT NEW FEED FOR RTE 122 | A21S06 |
| A21S06 | CONSTRUCT NEW FEED FOR RTE 122 | A21S06 |
| A21S06 | CONSTRUCT NEW FEED FOR RTE 122 | A21S06 |
| A21S06 | CONSTRUCT NEW FEED FOR RTE 122 | A21S06 |
| A21X79 | 2021 WOOD POLE TREATMENT | A21X79 |
| A21X79 | 2021 WOOD POLE TREATMENT | A21X79 |

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| A21X79 | 2021 WOOD POLE TREATMENT | A21X79 |
| A21X93 | 2021 CIRCUIT PATROL REPAIRS PHASE 2 | A21X93 |
| A21X93 | 2021 CIRCUIT PATROL REPAIRS PHASE 2 | A21X93 |
| A21X93 | 2021 CIRCUIT PATROL REPAIRS PHASE 2 | A21X93 |
| A21X95 | Mobile Utility & Mobile Pole Assemb | A21X95 |
| A21X95 | Mobile Utility & Mobile Pole Assemb | A21X95 |
| A22C03 | GOFFSTOWN SS ELIM PHASE 2 27W2 CONV | A22C03 |
| A22C03 | GOFFSTOWN SS ELIM PHASE 2 27W2 CONV | A22C03 |
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| A22E56 | 32 Line Pole Replacement | A22E56 |
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| A22E57 | 371 Line Pole Replacements | A22E57 |
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| A22N71 | 355 Line Pole Replacement | A22N71 |
| A22N71 | 355 Line Pole Replacement | A22N71 |
| A22N71 | 355 Line Pole Replacement | A22N71 |
| A22RPR | 2022 Roadside Reject Pole Repl | A22RPR |
| A22RPR | 2022 Roadside Reject Pole Repl | A22RPR |
| A22RPR | 2022 Roadside Reject Pole Repl | A22RPR |
| A22S09 | 3154X2 - 377X1  CIRCUIT TIE | A22S09 |
| A22S09 | 3154X2 - 377X1  CIRCUIT TIE | A22S09 |
| A22S09 | 3154X2 - 377X1  CIRCUIT TIE | A22S09 |
| A22S10 | 3217X ROCKY POND RD BACKFEED | A22S10 |
| A22S10 | 3217X ROCKY POND RD BACKFEED | A22S10 |
| A22S10 | 3217X ROCKY POND RD BACKFEED | A22S10 |
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| A22S50 | GRIFFIN ROAD CONVERSION LONDONDERRY | A22S50 |
| A22S64 | 389X8 Line Relocation | A22S64 |
| A22S64 | 389X8 Line Relocation | A22S64 |
| A22W02 | 3120X2 RT 119 CONVERSION | A22W02 |
| A22W02 | 3120X2 RT 119 CONVERSION | A22W02 |
| A22W02 | 3120X2 RT 119 CONVERSION | A22W02 |
| A22W02 | 3120X2 RT 119 CONVERSION | A22W02 |
| A22W07 | 3140X2 WASHINGTON RD SPACER CABLE | A22W07 |
| A22W07 | 3140X2 WASHINGTON RD SPACER CABLE | A22W07 |
| A22W07 | 3140X2 WASHINGTON RD SPACER CABLE | A22W07 |
| A22W07 | 3140X2 WASHINGTON RD SPACER CABLE | A22W07 |
| A22W08 | 3139X SPOFFORD RD RECONDUCTOR | A22W08 |
| A22W08 | 3139X SPOFFORD RD RECONDUCTOR | A22W08 |
| A22W08 | 3139X SPOFFORD RD RECONDUCTOR | A22W08 |
| A22W26 | 317/3410 reconstr Roby Rd to Warner | A22W26 |
| A22W26 | 317/3410 reconstr Roby Rd to Warner | A22W26 |

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| A22W26 | 317/3410 reconstr Roby Rd to Warner | A22W26 |
| A22W26 | 317/3410 reconstr Roby Rd to Warner | A22W26 |
| A22W63 | 313X1 Riverview UG Replacement | A22W63 |
| A22W63 | 313X1 Riverview UG Replacement | A22W63 |
| A22W68 | 3140X Stoddard Rebuild | A22W68 |
| A22W68 | 3140X Stoddard Rebuild | A22W68 |
| A22X17 | 2022 WOOD POLE TREATMENT | A22X17 |
| A22X17 | 2022 WOOD POLE TREATMENT | A22X17 |
| A22X17 | 2022 WOOD POLE TREATMENT | A22X17 |
| A23C24 | Hampshire Plaza UG Reconfiguration | A23C24 |
| A23CCI | CCI Reject Pole Replacement | A23CCI |
| A23E11 | 399X15 Mcintosh Commons | A23E11 |
| A23E11 | 399X15 Mcintosh Commons | A23E11 |
| A23E12 | 392X1-392X2 Circuit Tie | A23E12 |
| A23E12 | 392X1-392X2 Circuit Tie | A23E12 |
| A23E15 | 3112X1 Reconductor | A23E15 |
| A23E15 | 3112X1 Reconductor | A23E15 |
| A23E16 | 3137X1-377X3 Circuit Tie | A23E16 |
| A23E16 | 3137X1-377X3 Circuit Tie | A23E16 |
| A23E25 | North Dover 4kV Conversion | A23E25 |
| A23E25 | North Dover 4kV Conversion | A23E25 |
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| A23N31 | 338 Line Reconstruction | A23N31 |
| A23N34 | 355 Line Reconstruction | A23N34 |
| A23N37 | 31W2 Transformer Repl | A23N37 |
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| A23RPR | Roadside Reject Pole Replacement 2023 | A23RPR |
| A23RPR | Roadside Reject Pole Replacement 2023 | A23RPR |
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| A23W01 | 3155X Install Padmounted Step Xfmr | A23W01 |
| A23W17 | 42X3-316X1 Circuit Tie Ph 1 | A23W17 |
| A23W17 | 42X3-316X1 Circuit Tie Ph 1 | A23W17 |
| A23W29 | 317 Roadway Rebuild | A23W29 |
| A23W29 | 317 Roadway Rebuild | A23W29 |
| A23W30 | 317 / 3410 Removal | A23W30 |
| A23W32 | 313 Line Lattice Tower Repl | A23W32 |
| A23W33 | 3178 Line - Lattice Tower Repl | A23W33 |
| A23W48 | 3139X-3178 Circuit Tie | A23W48 |
| A23X22 | Replace Degraded Manholes | A23X22 |
| A23X28 | 2023 Wood Pole Treatment | A23X28 |
| A23X28 | 2023 Wood Pole Treatment | A23X28 |
| A23X41 | 2023 Semi-annual Circuit Patrol | A23X41 |
| A24C35 | 322 Line Pole Repl | A24C35 |
| A24C36 | 3151 Line Pole Replacement | A24C36 |
| DL9R | DIST LINE ROW PROGRAM | DL9R |
| DL9R | DIST LINE ROW PROGRAM | DL9R |

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| DL9R | DIST LINE ROW PROGRAM | DL9R |
| DL9R | DIST LINE ROW PROGRAM | DL9R |
| DL9R | DIST LINE ROW PROGRAM | DL9R |
| DL9R | DIST LINE ROW PROGRAM | DL9R |
| DL9R | DIST LINE ROW PROGRAM | DL9R |
| DL9R | DIST LINE ROW PROGRAM | DL9R |
| DL9R | DIST LINE ROW PROGRAM | DL9R |
| DL9R | DIST LINE ROW PROGRAM | DL9R |
| DR9R | Reliability Improvements Annual | DR9A |
| DR9R | Reliability Improvements Annual | DR9A |
| DR9R | Reliability Improvements Annual | DR9A |
| DR9R | Reliability Improvements Annual | DR9A |
| DR9R | Reliability Improvements Annual | DR9A |
| DR9R | Reliability Improvements Annual | DR9B |
| DR9R | Reliability Improvements Annual | DR9B |
| DR9R | Reliability Improvements Annual | DR9B |
| DR9R | Reliability Improvements Annual | DR9B |
| DR9R | Reliability Improvements Annual | DR9B |
| DR9R | Reliability Improvements Annual | DR9C |
| DR9R | Reliability Improvements Annual | DR9C |
| DR9R | Reliability Improvements Annual | DR9C |
| DR9R | Reliability Improvements Annual | DR9C |
| DR9R | Reliability Improvements Annual | DR9C |
| DR9R | Reliability Improvements Annual | DR9D |
| DR9R | Reliability Improvements Annual | DR9D |
| DR9R | Reliability Improvements Annual | DR9D |
| DR9R | Reliability Improvements Annual | DR9D |
| DR9R | Reliability Improvements Annual | DR9D |
| DR9R | Reliability Improvements Annual | DR9E |
| DR9R | Reliability Improvements Annual | DR9E |
| DR9R | Reliability Improvements Annual | DR9E |
| DR9R | Reliability Improvements Annual | DR9E |
| DR9R | Reliability Improvements Annual | DR9E |
| DR9R | Reliability Improvements Annual | DR9K |
| DR9R | Reliability Improvements Annual | DR9K |
| DR9R | Reliability Improvements Annual | DR9K |
| DR9R | Reliability Improvements Annual | DR9K |
| DR9R | Reliability Improvements Annual | DR9K |
| DR9R | Reliability Improvements Annual | DR9L |
| DR9R | Reliability Improvements Annual | DR9L |
| DR9R | Reliability Improvements Annual | DR9L |
| DR9R | Reliability Improvements Annual | DR9L |
| DR9R | Reliability Improvements Annual | DR9L |
| DR9R | Reliability Improvements Annual | DR9N |
| DR9R | Reliability Improvements Annual | DR9N |
| DR9R | Reliability Improvements Annual | DR9N |
| DR9R | Reliability Improvements Annual | DR9N |

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| DR9R | Reliability Improvements Annual | DR9N |
| DR9R | Reliability Improvements Annual | DR9P |
| DR9R | Reliability Improvements Annual | DR9P |
| DR9R | Reliability Improvements Annual | DR9P |
| DR9R | Reliability Improvements Annual | DR9P |
| DR9R | Reliability Improvements Annual | DR9P |
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| DR9R | Reliability Improvements Annual | DR9R |
| DR9R | Reliability Improvements Annual | DR9R |
| DR9R | Reliability Improvements Annual | DR9S |
| DR9R | Reliability Improvements Annual | DR9S |
| DR9R | Reliability Improvements Annual | DR9S |
| DR9R | Reliability Improvements Annual | DR9S |
| DR9R | Reliability Improvements Annual | DR9S |
| DR9R | Reliability Improvements Annual | DR9W |
| DR9R | Reliability Improvements Annual | DR9W |
| DR9R | Reliability Improvements Annual | DR9W |
| DR9R | Reliability Improvements Annual | DR9W |
| DR9R | Reliability Improvements Annual | DR9W |
| DR9R | Reliability Improvements Annual | DR9Y |
| DR9R | Reliability Improvements Annual | DR9Y |
| DR9R | Reliability Improvements Annual | DR9Y |
| DR9R | Reliability Improvements Annual | DR9Y |
| DR9R | Reliability Improvements Annual | DR9Y |
| DR9R | Reliability Improvements Annual | DR9Z |
| DR9R | Reliability Improvements Annual | DR9Z |
| DR9R | Reliability Improvements Annual | DR9Z |
| DR9R | Reliability Improvements Annual | DR9Z |
| DR9R | Reliability Improvements Annual | DR9Z |
| UB1313 | CONSTRUCT NEW CIRCUIT-BRISTOL S/S | UB1313 |
| UB3CAD | Porcelain Change-out | UB3CAD |
| UB3CAD | Porcelain Change-out | UB3CAD |
| UB3CAD | Porcelain Change-out | UB3CAD |
| UB3CAD | Porcelain Change-out | UB3CAD |
| A03S13 | REPLACE VAULT TOPS | A03S13 |
| A08W49 | KEENE DOWNTOWN UG REPLACEMENT PROJ | A08W49 |
| A08W49 | KEENE DOWNTOWN UG REPLACEMENT PROJ | A08W49 |
| A08W49 | KEENE DOWNTOWN UG REPLACEMENT PROJ | A08W49 |
| A08W49 | KEENE DOWNTOWN UG REPLACEMENT PROJ | A08W49 |
| A08W49 | KEENE DOWNTOWN UG REPLACEMENT PROJ | A08W49 |
| A18X01 | DIRECT BURIED CABLE REPLACEMENT | A18X01 |

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| A18X01 | DIRECT BURIED CABLE REPLACEMENT | A18X01 |
| A18X01 | DIRECT BURIED CABLE REPLACEMENT | A18X01 |
| A19X01 | Replace Degraded Manholes | A19X01 |
| A19X01 | Replace Degraded Manholes | A19X01 |
| A19X01 | Replace Degraded Manholes | A19X01 |
| A20C40 | MANCHESTER NETWORK CABLE REPLACEMEN | A20C40 |
| A20C40 | MANCHESTER NETWORK CABLE REPLACEMEN | A20C40 |
| A20C40 | MANCHESTER NETWORK CABLE REPLACEMEN | A20C40 |
| A20C40 | MANCHESTER NETWORK CABLE REPLACEMEN | A20C40 |
| A20C40 | MANCHESTER NETWORK CABLE REPLACEMEN | A20C40 |
| A20E47 | CODFISH CORNER ROAD LOOP | A20E47 |
| A20E47 | CODFISH CORNER ROAD LOOP | A20E47 |
| A20E47 | CODFISH CORNER ROAD LOOP | A20E47 |
| A20N01 | Rebuild Berlin UG system | A20N01 |
| A20N01 | Rebuild Berlin UG system | A20N01 |
| A20N01 | Rebuild Berlin UG system | A20N01 |
| A20N01 | Rebuild Berlin UG system | A20N01 |
| A21E94 | TIDEWATER FARM URD LOOP | A21E94 |
| A21E94 | TIDEWATER FARM URD LOOP | A21E94 |
| A21W99 | Monadnock Trailer Park Underground | A21W99 |
| A21W99 | Monadnock Trailer Park Underground | A21W99 |
| A14W18 | N KEENE S/S NEW DIST CIRC | A14W18 |
| A16S02 | RECON LINES 3110, 353, 3445X | A16S02 |
| A20W33 | PACK MONADNOCK SUMMIT SOLUTION | A20W33 |
| A20W33 | PACK MONADNOCK SUMMIT SOLUTION | A20W33 |
| A20W33 | PACK MONADNOCK SUMMIT SOLUTION | A20W33 |
| A21C01 | REPLACE DEGRADED MANHOLE ROOFS | A21C01 |
| A21C01 | REPLACE DEGRADED MANHOLE ROOFS | A21C01 |
| A21E87 | 49W1 TIMCO ROW TAP REMOVAL | A21E87 |
| A21E87 | 49W1 TIMCO ROW TAP REMOVAL | A21E87 |
| A14N10 | SOMERSWORTH 34.5 KV OCB REPLACEMENT | A14N10 |
| A16C10 | JACKMAN - REPLACE OBSOLETE EQUIPMEN | A16C10 |
| A16C10 | JACKMAN - REPLACE OBSOLETE EQUIPMEN | A16C10 |
| A16C10 | JACKMAN - REPLACE OBSOLETE EQUIPMEN | A16C10 |
| A16C10 | JACKMAN - REPLACE OBSOLETE EQUIPMEN | A16C10 |
| A16C10 | JACKMAN - REPLACE OBSOLETE EQUIPMEN | A16C10 |
| A17N18 | LACONIA SS EQUIPMENT REPLACEMENT | A17N18 |
| A17N18 | LACONIA SS EQUIPMENT REPLACEMENT | A17N18 |
| A17N18 | LACONIA SS EQUIPMENT REPLACEMENT | A17N18 |
| A17N18 | LACONIA SS EQUIPMENT REPLACEMENT | A17N18 |
| A17N18 | LACONIA SS EQUIPMENT REPLACEMENT | A17N18 |
| A17N24 | LACONIA SS 24 VDC CNTRL SYS & RELAY | A17N24 |
| A19S40 | AMHERST S/S - PLC AUTOMATION REPLAC | A19S40 |
| A19S40 | AMHERST S/S - PLC AUTOMATION REPLAC | A19S40 |
| A19W55 | JACKMAN SS LTC CONTROL REPLACEMENT | A19W55 |
| A19W55 | JACKMAN SS LTC CONTROL REPLACEMENT | A19W55 |
| A19W55 | JACKMAN SS LTC CONTROL REPLACEMENT | A19W55 |

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| A19X35 | CAPACITOR SWITCH REPLACEMENTS | A19X35 |
| A19X351 | LONG HILL SS 34.5kV CAP BANK SWITCH | A19X351 |
| A19X351 | LONG HILL SS 34.5kV CAP BANK SWITCH | A19X351 |
| A19X351 | LONG HILL SS 34.5kV CAP BANK SWITCH | A19X351 |
| A19X351 | LONG HILL SS 34.5kV CAP BANK SWITCH | A19X351 |
| A20W37 | RIVER ROAD SS UPGRADES | A20W37 |
| A20W37 | RIVER ROAD SS UPGRADES | A20W37 |
| A20X36 | GARVINS S/S OCB REPLACEMENT | A20X36 |
| A21C14 | GARVINS SS OCB REPLACEMENT | A21C14 |
| A21C14 | GARVINS SS OCB REPLACEMENT | A21C14 |
| A21C76 | DUNBARTON RD SS EQUIP REPLACMNT | A21C76 |
| A21C76 | DUNBARTON RD SS EQUIP REPLACMNT | A21C76 |
| A21C76 | DUNBARTON RD SS EQUIP REPLACMNT | A21C76 |
| A21E16 | REPLACE ROCHESTER SS BUS TIE AUTOCL | A21E16 |
| A21E16 | REPLACE ROCHESTER SS BUS TIE AUTOCL | A21E16 |
| A21E16 | REPLACE ROCHESTER SS BUS TIE AUTOCL | A21E16 |
| A21E16 | REPLACE ROCHESTER SS BUS TIE AUTOCL | A21E16 |
| A21E16 | REPLACE ROCHESTER SS BUS TIE AUTOCL | A21E16 |
| A21N45 | ASHLAND S/S-PLC REPLCMNT& P&C UPGRD | A21N45 |
| A21N45 | ASHLAND S/S-PLC REPLCMNT& P&C UPGRD | A21N45 |
| A21N77 | SACO VALLEY 34.5kV OCB REPLACE | A21N77 |
| A21N96 | BEEBE RIVER SS TB70 REMOVAL | A21N96 |
| A21N96 | BEEBE RIVER SS TB70 REMOVAL | A21N96 |
| A21S17 | 34.5kV CAP BANK SWTCH REP BROAD ST | A21S17 |
| A21S17 | 34.5kV CAP BANK SWTCH REP BROAD ST | A21S17 |
| A21X15 | REPLACE 5 ABB TPU-2000R RELAYS | A21X15 |
| A21X15 | REPLACE 5 ABB TPU-2000R RELAYS | A21X15 |
| A21X15 | REPLACE 5 ABB TPU-2000R RELAYS | A21X15 |
| A21X15 | REPLACE 5 ABB TPU-2000R RELAYS | A21X15 |
| A21X15 | REPLACE 5 ABB TPU-2000R RELAYS | A21X15 |
| A22C52 | Contoocook SS Oil Recloser Replacement | A22C52 |
| A22C77 | Mammoth Rd SS TPU Relay Repl | A22C77 |
| A22C77 | Mammoth Rd SS TPU Relay Repl | A22C77 |
| A22E41 | RESISTANCE SS RETIREMENT | A22E41 |
| A22E41 | RESISTANCE SS RETIREMENT | A22E41 |
| A22E41 | RESISTANCE SS RETIREMENT | A22E41 |
| A22E76 | Tasker Farm SS TPU Relay Replacement | A22E76 |
| A22E76 | Tasker Farm SS TPU Relay Replacement | A22E76 |
| A22E76 | Tasker Farm SS TPU Relay Replacement | A22E76 |
| A22N51 | Colebrook SS Oil Recloser Replacement | A22N51 |
| A22X42 | SS OIL RECLOSER REPL PROGRAM | A22X42 |
| A22X42 | SS OIL RECLOSER REPL PROGRAM | A22X42 |
| A23E35 | Great Bay PLC Automation Scheme | A23E35 |
| UB1325 | RE-FEED 20H1 & RETIRE LISBON S/S | UB1325 |
| A17C30 | Pack Monadnock Rbld Single-Phase Li | A17C30 |
| A17C30 | Pack Monadnock Rbld Single-Phase Li | A17C30 |
| A17C30 | Pack Monadnock Rbld Single-Phase Li | A17C30 |

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| A17C30 | Pack Monadnock Rbld Single-Phase Li | A17C30 |
| A17C30 | Pack Monadnock Rbld Single-Phase Li | A17C30 |
| A17C30 | PACK MONADNOCK RBLD SINGLE-PHASE LI | A17C30 |
| A18E12 | CIRCUIT TIES 3172X1 - 3112X3 | A18E12 |
| A18E12 | CIRCUIT TIES 3172X1 - 3112X3 | A18E12 |
| A18E12 | CIRCUIT TIES 3172X1 - 3112X3 | A18E12 |
| A18W10 | 55H1 PETERBOROUGH URD | A18W10 |
| A18W11 | 316X1 CIRCUIT TIE EASTMAN DEVELOPME | A18W11 |
| A18W11 | 316X1 CIRCUIT TIE EASTMAN DEVELOPME | A18W11 |
| A18W11 | 316X1 CIRCUIT TIE EASTMAN DEVELOPME | A18W11 |
| A18W17 | EMERALD ST LINE WORK | A18W17 |
| A18W17 | EMERALD ST LINE WORK | A18W17 |
| A18W17 | EMERALD ST LINE WORK | A18W17 |
| A18W17 | EMERALD ST LINE WORK | A18W17 |
| A18X28 | 44 & 60 WEST PENN TELECOM | A18X28 |
| A18X28 | 44 & 60 WEST PENN TELECOM | A18X28 |
| A18X28 | 44 & 60 WEST PENN TELECOM | A18X28 |
| A18XDA | Distribution Automation - Substatio | A18XDA |
| A18XDA | Distribution Automation - Substatio | A18XDA |
| A19C54 | Pettingill Switchgear Reconfigurati | A19C54 |
| A19C54 | Pettingill Switchgear Reconfigurati | A19C54 |
| A19X28 | Advanced Load Flow Software | A19X28 |
| A19X29 | NH DMS Pilot Phase 2 | A19X29 |
| A19X32 | NH Lateral Initiative | A19X32 |
| A19X32 | NH Lateral Initiative | A19X32 |
| A19X32 | NH Lateral Initiative | A19X32 |
| A21S17 | 34.5kV CAP BANK SWTCH REP BROAD ST | A21S17 |
| A21S17 | 34.5kV CAP BANK SWTCH REP BROAD ST | A21S17 |
| A21S17 | 34.5kV CAP BANK SWTCH REP BROAD ST | A21S17 |
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| A21X44 | 2021 CIRCUIT PATROL REPAIRS | A21X44 |
| A21X44 | 2021 CIRCUIT PATROL REPAIRS | A21X44 |
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| A22C85 | 317 Line ROW Section Rebuild | A22C85 |
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| A22X35 | 2022 CIRCUIT PATROL REPAIRS | A22X35 |
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| A22X67 | NH Cutout Installation 2022 | A22X67 |
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| A22X74 | 2022 TripSaver Initiative | A22X74 |
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| A23X02 | 2023 DB Fault Indicator Repl | A23X02 |
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| D1328AH | Distribution Design P134 Line | D1328AH |
| D1328I | Distribution Design Y138 Line | D1328I |
| D1328I | Distribution Design Y138 Line | D1328I |
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| A08N10 | Portsmouth S/S - add transformer | A08N10 |
| A08N10 | Portsmouth S/S - add transformer | A08N10 |
| A08N10 | Portsmouth S/S - add transformer | A08N10 |
| A08N10 | Portsmouth S/S - add transformer | A08N10 |
| A08N10 | Portsmouth S/S - add transformer | A08N10 |
| A08N10 | Portsmouth S/S - add transformer | A08N10 |
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| A12X02 | SUBSTATION GROUND GRID UPGRADES | A12X02 |
| A12X02 | SUBSTATION GROUND GRID UPGRADES | A12X02 |
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| A14N08 | GORHAM SS-GENERATION DIVESTITURE | A14N08 |
| A14N08 | GORHAM SS-GENERATION DIVESTITURE | A14N08 |
| A14N08 | GORHAM SS-GENERATION DIVESTITURE | A14N08 |
| A14N08 | GORHAM SS-GENERATION DIVESTITURE | A14N08 |
| A14N08 | GORHAM SS-GENERATION DIVESTITURE | A14N08 |
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| A14S08 | GARVINS SUBSTATION REBUILD | A14S08 |
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| A14W01 | EMERALD STREET SUBSTATION | A14W01 |
| A14W01 | EMERALD STREET SUBSTATION | A14W01 |
| A14W01 | EMERALD STREET SUBSTATION | A14W01 |
| A14W01 | EMERALD STREET SUBSTATION | A14W01 |
| A14W01 | EMERALD STREET SUBSTATION | A14W01 |
| A14W01 | EMERALD STREET SUBSTATION | A14W01 |
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| A14W02 | DANIEL SS (WEBSTER)-34.5KV SS UPGRD | A14W02 |
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| A16C08 | Brook St S/S - 13TR1 Replacement | A16C08 |
| A16C08 | Brook St S/S - 13TR1 Replacement | A16C08 |
| A16C08 | Brook St S/S - 13TR1 Replacement | A16C08 |
| A16C08 | Brook St S/S - 13TR1 Replacement | A16C08 |

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| A16C08 | Brook St S/S - 13TR1 Replacement | A16C08 |
| A16C08 | Brook St S/S - 13TR1 Replacement | A16C08 |
| A16C08 | Brook St S/S - 13TR1 Replacement | A16C08 |
| A16C08 | Brook St S/S - 13TR1 Replacement | A16C08 |
| A16C08 | Brook St S/S - 13TR1 Replacement | A16C08 |
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| A16C09 | Blaine St SS add 34.5-12kV 10MVA tr | A16C09 |
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| A16E06 | West Rye S/S Re-build | A16E06 |
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| A16N02 | Second transformer at Lost Nation S | A16N02 |
| A16N02 | Second transformer at Lost Nation S | A16N02 |
| A16N02 | Second transformer at Lost Nation S | A16N02 |
| A16N02 | Second transformer at Lost Nation S | A16N02 |
| A16S01 | PLC AUTOMATION SCHEME REPLACEMENT | A16S01 |
| A16S01 | PLC AUTOMATION SCHEME REPLACEMENT | A16S01 |
| A16S01 | PLC AUTOMATION SCHEME REPLACEMENT | A16S01 |
| A16S01 | PLC AUTOMATION SCHEME REPLACEMENT | A16S01 |
| A16S01 | PLC AUTOMATION SCHEME REPLACEMENT | A16S01 |
| A16W01 | CLAREMONT AREA SUBSTATION UPGRADES | A16W01 |
| A16W01 | CLAREMONT AREA SUBSTATION UPGRADES | A16W01 |
| A16W01 | CLAREMONT AREA SUBSTATION UPGRADES | A16W01 |
| A16W01 | CLAREMONT AREA SUBSTATION UPGRADES | A16W01 |
| A16W01 | CLAREMONT AREA SUBSTATION UPGRADES | A16W01 |
| A16W01 | CLAREMONT AREA SUBSTATION UPGRADES | A16W01 |
| A16W01 | CLAREMONT AREA SUBSTATION UPGRADES | A16W01 |
| A16W01 | CLAREMONT AREA SUBSTATION UPGRADES | A16W01 |
| A17C04 | GREGGS SS REBUILD SS | A17C04 |
| A17C04 | GREGGS SS REBUILD SS | A17C04 |
| A17C04 | GREGGS SS REBUILD SS | A17C04 |
| A17C04 | GREGGS SS REBUILD SS | A17C04 |
| A17C21 | PINE HILL SS PLC AUTO SCH REPLACE | A17C21 |
| A17C21 | PINE HILL SS PLC AUTO SCH REPLACE | A17C21 |
| A17C21 | PINE HILL SS PLC AUTO SCH REPLACE | A17C21 |
| A17E05 | TWOMBLEY SS REBUILD | A17E05 |
| A17E05 | TWOMBLEY SS REBUILD | A17E05 |
| A17E05 | TWOMBLEY SS REBUILD | A17E05 |
| A17E05 | TWOMBLEY SS REBUILD | A17E05 |
| A17E05 | TWOMBLEY SS REBUILD | A17E05 |
| A17E05 | TWOMBLEY SS REBUILD | A17E05 |
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| A17E20 | OCEAN RD SS 34.5KV OCB REPLACE | A17E20 |
| A17E20 | OCEAN RD SS 34.5KV OCB REPLACE | A17E20 |
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| A17N02 | MESSER ST - REPLACE TB70 | A17N02 |
| A17N02 | MESSER ST - REPLACE TB70 | A17N02 |
| A17N22 | Beebe River SS Cap Switcher Replace | A17N22 |

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| A17N22 | Beebe River SS Cap Switcher Replace | A17N22 |
| A17N22 | Beebe River SS Cap Switcher Replace | A17N22 |
| A17S03 | MILLYARD SS REPLACEMENT | A17S03 |
| A17S03 | MILLYARD SS REPLACEMENT | A17S03 |
| A17S03 | MILLYARD SS REPLACEMENT | A17S03 |
| A17S03 | MILLYARD SS REPLACEMENT | A17S03 |
| A17S03 | MILLYARD SS REPLACEMENT | A17S03 |
| A17S03 | MILLYARD SS REPLACEMENT | A17S03 |
| A17S03 | MILLYARD SS REPLACEMENT | A17S03 |
| A17S03 | MILLYARD SS REPLACEMENT | A17S03 |
| A17S03 | MILLYARD SS REPLACEMENT | A17S03 |
| A17S03 | MILLYARD SS REPLACEMENT | A17S03 |
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| A17W19 | NORTH RD SS EQUIPMENT REPLACEMENT | A17W19 |
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| A17W23 | Monadnock SS Cap Switcher Replaceme | A17W23 |
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| A18C02 | BEDFORD SS PLC AUTOMATION SCHEME | A18C02 |
| A18C02 | BEDFORD SS PLC AUTOMATION SCHEME | A18C02 |
| A18C02 | BEDFORD SS PLC AUTOMATION SCHEME | A18C02 |
| A18C02 | BEDFORD SS PLC AUTOMATION SCHEME | A18C02 |
| A18C07 | EDDY SS CONTROL HOUSE | A18C07 |
| A18C07 | EDDY SS CONTROL HOUSE | A18C07 |
| A18C07 | EDDY SS CONTROL HOUSE | A18C07 |
| A18C07 | EDDY SS CONTROL HOUSE | A18C07 |
| A18C07 | EDDY SS CONTROL HOUSE | A18C07 |
| A18C07 | EDDY SS CONTROL HOUSE | A18C07 |
| A18C07 | EDDY SS CONTROL HOUSE | A18C07 |
| A18C07 | EDDY SS CONTROL HOUSE | A18C07 |
| A18C07 | EDDY SS CONTROL HOUSE | A18C07 |
| A18E04 | DOVER SUBSTATION REBUILD | A18E04 |
| A18E04 | DOVER SUBSTATION REBUILD | A18E04 |
| A18E04 | DOVER SUBSTATION REBUILD | A18E04 |
| A18E04 | DOVER SUBSTATION REBUILD | A18E04 |
| A18E04 | DOVER SUBSTATION REBUILD | A18E04 |
| A18E04 | DOVER SUBSTATION REBUILD | A18E04 |
| A18E04 | DOVER SUBSTATION REBUILD | A18E04 |
| A18E04 | DOVER SUBSTATION REBUILD | A18E04 |
| A18N03 | WHITE LAKE SS REBUILD | A18N03 |
| A18N03 | WHITE LAKE SS REBUILD | A18N03 |
| A18N03 | WHITE LAKE SS REBUILD | A18N03 |
| A18N03 | WHITE LAKE SS REBUILD | A18N03 |
| A18N03 | WHITE LAKE SS REBUILD | A18N03 |
| A18N03 | WHITE LAKE SS REBUILD | A18N03 |

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| A18N03 | WHITE LAKE SS REBUILD | A18N03 |
| A18N27 | Laconia SS Replace LTC Controls | A18N27 |
| A18N27 | Laconia SS Replace LTC Controls | A18N27 |
| A18W06 | MONADNOCK SS REPLACE TRANSFRMR TB40 | A18W06 |
| A18W06 | MONADNOCK SS REPLACE TRANSFRMR TB40 | A18W06 |
| A18W06 | MONADNOCK SS REPLACE TRANSFRMR TB40 | A18W06 |
| A18W06 | MONADNOCK SS REPLACE TRANSFRMR TB40 | A18W06 |
| A18W06 | MONADNOCK SS REPLACE TRANSFRMR TB40 | A18W06 |
| A18W06 | MONADNOCK SS REPLACE TRANSFRMR TB40 | A18W06 |
| A18W06 | MONADNOCK SS REPLACE TRANSFRMR TB40 | A18W06 |
| A18W06 | MONADNOCK SS REPLACE TRANSFRMR TB40 | A18W06 |
| A18W06 | MONADNOCK SS REPLACE TRANSFRMR TB40 | A18W06 |
| A18W06 | MONADNOCK SS REPLACE TRANSFRMR TB40 | A18W06 |
| A18X08 | ELECTROMECHANICAL RELAY REPLACEMENT | A18X08 |
| A18X08 | ELECTROMECHANICAL RELAY REPLACEMENT | A18X08 |
| A18X08 | ELECTROMECHANICAL RELAY REPLACEMENT | A18X08 |
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| A18X26 | Mobile Substatn 46x34.5kV-12.47/7.2 | A18X26 |
| A18X26 | Mobile Substatn 46x34.5kV-12.47/7.2 | A18X26 |
| A18X26 | Mobile Substatn 46x34.5kV-12.47/7.2 | A18X26 |
| A18X26 | Mobile Substatn 46x34.5kV-12.47/7.2 | A18X26 |
| A18X26 | Mobile Substatn 46x34.5kV-12.47/7.2 | A18X26 |
| A18X26 | Mobile Substatn 46x34.5kV-12.47/7.2 | A18X26 |
| A18X26 | Mobile Substatn 46x34.5kV-12.47/7.2 | A18X26 |
| A18X26 | Mobile Substatn 46x34.5kV-12.47/7.2 | A18X26 |
| A18X26 | Mobile Substatn 46x34.5kV-12.47/7.2 | A18X26 |
| A19C33 | Animal Protection at Rimmon SS | A19C33 |
| A19C33 | Animal Protection at Rimmon SS | A19C33 |
| A19C33 | Animal Protection at Rimmon SS | A19C33 |
| A19C33 | Animal Protection at Rimmon SS | A19C33 |
| A19C33 | Animal Protection at Rimmon SS | A19C33 |
| A19C33 | Animal Protection at Rimmon SS | A19C33 |
| A19C33 | Animal Protection at Rimmon SS | A19C33 |
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| A19E41 | REPLACE LTC CONTROLS AT MADBURY SS | A19E41 |
| A19E41 | REPLACE LTC CONTROLS AT MADBURY SS | A19E41 |
| A19E41 | REPLACE LTC CONTROLS AT MADBURY SS | A19E41 |
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| A19S40 | AMHERST S/S - PLC AUTOMATION REPLAC | A19S40 |
| A19S40 | AMHERST S/S - PLC AUTOMATION REPLAC | A19S40 |
| A19S40 | AMHERST S/S - PLC AUTOMATION REPLAC | A19S40 |
| A19S40 | AMHERST S/S - PLC AUTOMATION REPLAC | A19S40 |
| A19S40 | AMHERST S/S - PLC AUTOMATION REPLAC | A19S40 |
| A19S40 | AMHERST S/S - PLC AUTOMATION REPLAC | A19S40 |
| A19X22 | Install animal protection | A19X22 |

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| A19X22 | Install animal protection | A19X22 |
| A19X22 | Install animal protection | A19X22 |
| A19X22 | Install animal protection | A19X22 |
| A19X220 | Animal Protection at Tasker Farm SS | A19X220 |
| A19X220 | Animal Protection at Tasker Farm SS | A19X220 |
| A19X220 | Animal Protection at Tasker Farm SS | A19X220 |
| A19X220 | Animal Protection at Tasker Farm SS | A19X220 |
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| A19X222 | ANIMAL PROTECTION AT AMHERST SS | A19X222 |
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| A19X223 | ANIMAL PROTECTION AT VALLEY ST SS | A19X223 |
| A19X223 | ANIMAL PROTECTION AT VALLEY ST SS | A19X223 |
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| A19X36 | 34.5kV OCB BREAKER AND ANCILLARY EQ | A19X36 |
| A19X36 | 34.5kV OCB BREAKER AND ANCILLARY EQ | A19X36 |
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| A19X3601 | REEDS FERRY SS OCB REPLACEMENT | A19X3601 |
| A19X3601 | REEDS FERRY SS OCB REPLACEMENT | A19X3601 |
| A19X3601 | REEDS FERRY SS OCB REPLACEMENT | A19X3601 |
| A19X3601 | REEDS FERRY SS OCB REPLACEMENT | A19X3601 |
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| A19X61 | HIGH IMPEDANCE GND FLT DETECT NH | A19X61 |
| A19X61 | HIGH IMPEDANCE GND FLT DETECT NH | A19X61 |
| A19X61 | HIGH IMPEDANCE GND FLT DETECT NH | A19X61 |
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| A20E43 | East Northwood SS Regulator Replace | A20E43 |
| A20E43 | East Northwood SS Regulator Replace | A20E43 |
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| A20N45 | REPLACE CT TRNSF BERLIN ES SS | A20N45 |
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| A20W34 | BYRD AVE SS UPGRADES | A20W34 |
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| A20W35 | SPRING STREET SS UPGRADES | A20W35 |
| A20W35 | SPRING STREET SS UPGRADES | A20W35 |
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| A20W36 | SUGAR RIVER SS UPGRADES | A20W36 |
| A20W36 | SUGAR RIVER SS UPGRADES | A20W36 |
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| A20W37 | RIVER ROAD SS UPGRADES | A20W37 |
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| A20W44 | NEWPORT SS RECLOSER PROJECT | A20W44 |
| A20W44 | NEWPORT SS RECLOSER PROJECT | A20W44 |
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| A20X220 | ANIMAL PROTECTION AT BEDFORD SS | A20X220 |
| A20X220 | ANIMAL PROTECTION AT BEDFORD SS | A20X220 |

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| A20X221 | ANIMAL PROTECTION AT MAMMOTH SS | A20X221 |
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| A20X222 | ANIMAL PROTECTION AT WEARE SS | A20X222 |
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| A20X26 | SPARE 345-34.5kV TRANSFORMER | A20X26 |
| A20X26 | SPARE 345-34.5kV TRANSFORMER | A20X26 |
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| A21C04 | GOFFSTOWN SS CONVERSION | A21C04 |
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| A21E70 | PORTSMOUTH 12KV RELIABILITY (CUTT S | A21E70 |
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| A21N02 | WEIRS SUBSTATION REBUILD | A21N02 |
| A21N02 | WEIRS SUBSTATION REBUILD | A21N02 |
| A21N02 | WEIRS SUBSTATION REBUILD | A21N02 |
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| A21N55 | ASHLAND RELIABILITY SS WORK | A21N55 |
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| A21S64 | LAWRENCE RD TRANSFORMER BREAKER | A21S64 |
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| A21W69 | North Road SS Reliability | A21W69 |
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| A21X29 | SUBSTATION RTU UPGRADE/REPLACE PROG | A21X29 |
| A22E79 | Animal Protection Brentwood SS | A22E79 |
| A22N80 | ANIMAL PROTECTION OAK HILL SS | A22N80 |
| A22S81 | Animal Protection Hudson SS | A22S81 |
| A22S82 | Animal Protection Reeds Ferry SS | A22S82 |
| A22W78 | Swanzey TB8S Xfmr SCADA Upgrade | A22W78 |
| A22X38 | BATTERY REPLACEMENT PROGRAM | A22X38 |
| A22X38 | BATTERY REPLACEMENT PROGRAM | A22X38 |
| A22X38 | BATTERY REPLACEMENT PROGRAM | A22X38 |
| A22X48 | SS Station Service Transformer Repl Program | A22X48 |
| A23C39 | Jackman Transformer TB61 Replacement | A23C39 |
| A23C50 | Brook Street Switchgear & Transformer Replacement | A23C50 |
| D1249A | WEBSTR SS EXPN/CAP BNK SHRD ASTS-CE | D1249A |
| D1276A | Distribution Design for F107 Projec | D1276A |
| D1276A | Distribution Design for F107 Projec | D1276A |
| D1276A | Distribution Design for F107 Projec | D1276A |
| D1276A | Distribution Design for F107 Projec | D1276A |
| D1276A | Distribution Design for F107 Projec | D1276A |
| D1276A | Distribution Design for F107 Projec | D1276A |
| D1338A | DISTRIBUTION DESIGN L176 LINE REPLA | D1338A |

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|---|---|---|
| D1338A | DISTRIBUTION DESIGN L176 LINE REPLA | D1338A |
| DS9RD | DIST. S/S ANNUAL - DM | DS9RD |
| DS9RD | DIST. S/S ANNUAL - DM | DS9RD |
| DS9RD | DIST. S/S ANNUAL - DM | DS9RD |
| DS9RD | DIST. S/S ANNUAL - DM | DS9RD |
| DS9RD | DIST. S/S ANNUAL - DM | DS9RD |
| DS9RD | DIST. S/S ANNUAL - DM | DS9RD |
| DS9RD | DIST. S/S ANNUAL - DM | DS9RD |
| DS9RD | DIST. S/S ANNUAL - DM | DS9RD |
| DS9RD1 | DIST. S/S ANNUAL - DM | DS9RD1 |
| DS9RD1 | DIST. S/S ANNUAL - DM | DS9RD1 |
| DS9RD1 | DIST. S/S ANNUAL - DM | DS9RD1 |
| DS9RD1 | DIST. S/S ANNUAL - DM | DS9RD1 |
| DS9RP | DIST S/S ANNUAL - P&C | DS9RP |
| DS9RP | DIST S/S ANNUAL - P&C | DS9RP |
| DS9RS | SUBSTATION ANNUAL-SUBSTATION | DS9RS |
| DS9RS | SUBSTATION ANNUAL-SUBSTATION | DS9RS |
| DS9RS | SUBSTATION ANNUAL-SUBSTATION | DS9RS |
| DS9RS | SUBSTATION ANNUAL-SUBSTATION | DS9RS |
| DS9RS | SUBSTATION ANNUAL-SUBSTATION | DS9RS |
| DS9RS | SUBSTATION ANNUAL-SUBSTATION | DS9RS |
| DS9RS | SUBSTATION ANNUAL-SUBSTATION | DS9RS |
| DS9RS | SUBSTATION ANNUAL-SUBSTATION | DS9RS |
| DS9RS1 | SUBSTATION ANNUAL-SUBSTATION | DS9RS1 |
| DS9RS1 | SUBSTATION ANNUAL-SUBSTATION | DS9RS1 |
| DS9RS1 | SUBSTATION ANNUAL-SUBSTATION | DS9RS1 |
| DS9RS1 | SUBSTATION ANNUAL-SUBSTATION | DS9RS1 |
| DS9RS2 | 2022 NH D SS Planned Annual (Eng.) | DS9RS2 |
| DS9RS2 | 2022 NH D SS Planned Annual (Eng.) | DS9RS2 |
| DS9RS2 | 2022 NH D SS Planned Annual (Eng.) | DS9RS2 |
| DS9RS3 | 2023 NH D SS Planned Annual (Eng) | DS9RS3 |
| DS9RS3 | 2023 NH D SS Planned Annual (Eng) | DS9RS3 |
| DSNP22 | 2022 NH D SS Planned Annual (Ops) | DSNP22 |
| DSNP22 | 2022 NH D SS Planned Annual (Ops) | DSNP22 |
| DSNP22 | 2022 NH D SS Planned Annual (Ops) | DSNP22 |
| DSNP23 | 2023 NH D SS Planned Annual (Ops) | DSNP23 |
| DSNP23 | 2023 NH D SS Planned Annual (Ops) | DSNP23 |
| EMRELAY | Electromechanical Relay Replacement | EMRELAY |
| NS00002 | BES BATTERY MONITOR INSTALL PROGRAM | NS00002 |
| NS00002 | BES BATTERY MONITOR INSTALL PROGRAM | NS00002 |
| NS00002 | BES BATTERY MONITOR INSTALL PROGRAM | NS00002 |
| NS00002-1 | BES Battery Monitoring Madbury SS | NS00002-1 |
| NS00002-1 | BES Battery Monitoring Madbury SS | NS00002-1 |
| NS00002-10 | BES Battery Monitor Ocean Rd SS | NS00002-10 |
| NS00002-10 | BES Battery Monitor Ocean Rd SS | NS00002-10 |
| NS00002-3 | BES Battery Monitor Installation | NS00002-3 |
| NS00002-3 | BES Battery Monitor Installation | NS00002-3 |

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|---|---|---|
| NS00002-4 | BES Battery Monitor Lawrence Rd SS | NS00002-4 |
| NS00002-4 | BES Battery Monitor Lawrence Rd SS | NS00002-4 |
| NS00002-8 | BES Battery Monitor Oak Hill SS | NS00002-8 |
| UB0830 | CAPSWITCHER REPLACEMENT | UB0830 |
| A20X21 | NH DMS | A20X21 |
| A20X21 | NH DMS | A20X21 |
| A21W53 | 316 LINE DAVIT ARM & STRUCTURE REPL | A21W53 |
| A04S34 | DIRECT BURIED CABLE REPLACEMENT | A04S34 |
| A04S34 | DIRECT BURIED CABLE REPLACEMENT | A04S34 |
| A04S34 | DIRECT BURIED CABLE REPLACEMENT | A04S34 |
| A04S34 | DIRECT BURIED CABLE REPLACEMENT | A04S34 |
| A09S12 | REPLACED FAILED CABLE - POST TESTED | A09S12 |
| A09S12 | REPLACED FAILED CABLE - POST TESTED | A09S12 |
| A09S12 | REPLACED FAILED CABLE - POST TESTED | A09S12 |
| A10X04 | DIRECT BURIED CABLE INJECTION | A10X04 |
| A10X04 | DIRECT BURIED CABLE INJECTION | A10X04 |
| A10X04 | DIRECT BURIED CABLE INJECTION | A10X04 |
| A20C16 | BOUCHARD ST RPL CBL & SWTCHGR | A20C16 |
| A20C16 | BOUCHARD ST RPL CBL & SWTCHGR | A20C16 |
| A20C16 | BOUCHARD ST RPL CBL & SWTCHGR | A20C16 |
| A20C16 | BOUCHARD ST RPL CBL & SWTCHGR | A20C16 |
| A20C40 | Manchester Network Cable Replacemen | A20C40 |
| A20E48 | FOUNDRY PLACE SWITCHGEAR | A20E48 |
| A20E48 | FOUNDRY PLACE SWITCHGEAR | A20E48 |
| A20E48 | FOUNDRY PLACE SWITCHGEAR | A20E48 |
| A20S17 | DB CBLE REPLACE MAPLE HILL ACREA | A20S17 |
| A20S17 | DB CBLE REPLACE MAPLE HILL ACREA | A20S17 |
| A20S17 | DB CBLE REPLACE MAPLE HILL ACREA | A20S17 |
| A20S17 | DB CBLE REPLACE MAPLE HILL ACREA | A20S17 |
| A21C82 | CIRCUIT 3138 RIVERWAY PL CABLE REPL | A21C82 |
| A21C82 | CIRCUIT 3138 RIVERWAY PL CABLE REPL | A21C82 |
| A21E47 | 1275 MAPLEWOOD AVE DB CABLE REPL | A21E47 |
| A21E47 | 1275 MAPLEWOOD AVE DB CABLE REPL | A21E47 |
| A21S12 | REBUILD APPLE TREE CINEMA URD | A21S12 |
| A21S12 | REBUILD APPLE TREE CINEMA URD | A21S12 |
| A21S12 | REBUILD APPLE TREE CINEMA URD | A21S12 |
| A21S13 | REPLACE PINE ISLE DRIVE URD | A21S13 |
| A21S13 | REPLACE PINE ISLE DRIVE URD | A21S13 |
| A21S13 | REPLACE PINE ISLE DRIVE URD | A21S13 |
| A21S13 | REPLACE PINE ISLE DRIVE URD | A21S13 |
| A22C01 | Manchester NetworK Cable Repl Ph 2 | A22C01 |
| A22C01 | Manchester NetworK Cable Repl Ph 2 | A22C01 |
| A22C01 | Manchester NetworK Cable Repl Ph 2 | A22C01 |
| A22C01 | Manchester NetworK Cable Repl Ph 2 | A22C01 |
| A22C83 | Manchester Network Cable Repl Ph 3 | A22C83 |
| A23X23 | Submarine Cable Repair | A23X23 |
| A24C01 | Manchester Network Cable Ph 4 | A24C01 |

| Project Description | Period | Amount |
|---|---|---|
| COMCAST NON-BILLABLE LACONIA | 2023 FY Actual | (134,051.95) |
| COMCAST NON-BILLABLE LACONIA | 2023 FY Budget | 26,516.00 |
| COMCAST BILLABLE LACONIA | 2023 FY Actual | 51,892.43 |
| COMCAST BILLABLE LACONIA | 2023 FY Budget | (29.90) |
| JOINT POLES PURCHASE & SALE | 2019 FY Actual | 108,060.62 |
| JOINT POLES PURCHASE & SALE | 2019 FY Budget | 199,985.24 |
| JOINT POLES PURCHASE & SALE | 2020 FY Actual | 232,661.42 |
| JOINT POLES PURCHASE & SALE | 2020 FY Budget | 150,649.86 |
| JOINT POLES PURCHASE & SALE | 2021 FY Actual | (40,911.70) |
| JOINT POLES PURCHASE & SALE | 2021 FY Budget | 152,999.88 |
| JOINT POLES PURCHASE & SALE | 2022 FY Actual | 51,323.16 |
| JOINT POLES PURCHASE & SALE | 2022 FY Budget | 191,079.46 |
| JOINT POLES PURCHASE & SALE | 2023 FY Budget | 100,000.00 |
| CABLE TV PROJECTS ANNUAL | 2023 FY Actual | 5,408,590.10 |
| CABLE TV PROJECTS ANNUAL | 2023 FY Budget | 724,200.00 |
| TELEPHONE PROJECTS ANNUAL | 2019 FY Actual | 236,438.04 |
| TELEPHONE PROJECTS ANNUAL | 2019 FY Budget | 200,347.72 |
| TELEPHONE PROJECTS ANNUAL | 2020 FY Actual | 605,037.87 |
| TELEPHONE PROJECTS ANNUAL | 2020 FY Budget | 200,000.42 |
| TELEPHONE PROJECTS ANNUAL | 2021 FY Actual | 231,370.77 |
| TELEPHONE PROJECTS ANNUAL | 2021 FY Budget | 304,000.26 |
| TELEPHONE PROJECTS ANNUAL | 2022 FY Actual | 91,062.16 |
| TELEPHONE PROJECTS ANNUAL | 2022 FY Budget | 386,168.99 |
| TELEPHONE PROJECTS ANNUAL | 2023 FY Actual | (6,057.65) |
| TELEPHONE PROJECTS ANNUAL | 2023 FY Budget | 200,000.00 |
| ESCC control of Generation | 2019 FY Actual | 37,449.91 |
| ESCC control of Generation | 2019 FY Budget | 29,580.88 |
| ESCC control of Generation | 2020 FY Actual | 8,524.17 |
| ESCC control of Generation | 2022 FY Actual | (2,027.24) |
| ESCC control of Generation | 2023 FY Actual | (5,359.19) |
| NH Energy Park: audio visual equip | 2019 FY Actual | 67.91 |
| NH SOC/ESCC Backup | 2019 FY Actual | 114,540.49 |
| 1250 Hooksett Rd - AV Project | 2019 FY Actual | (114,540.49) |
| Peterborough Roadway and Bridge Pro | 2019 FY Actual | 515,184.09 |
| Peterborough Roadway and Bridge Pro | 2019 FY Budget | 150,000.16 |
| Peterborough Roadway and Bridge Pro | 2020 FY Actual | 3,769.95 |
| Peterborough Roadway and Bridge Pro | 2021 FY Actual | (6,373.60) |
| Peterborough Roadway and Bridge Pro | 2022 FY Actual | (12,957.89) |
| ANIMAL PROTECTION AT BROOK ST SS | 2021 FY Actual | 13,103.39 |
| ANIMAL PROTECTION AT EDDY SS | 2021 FY Actual | 14,859.02 |
| ANIMAL PROTECTION AT EDDY SS | 2023 FY Actual | (14,859.02) |
| Animal Protection Madbury SS | 2022 FY Actual | 71.06 |
| 3271X Sound Barrier Pad-Mount Step | 2022 FY Actual | 876.72 |
| 3271X Sound Barrier Pad-Mount Step | 2023 FY Actual | 20,619.77 |
| Animal Protection Brentwood SS | 2022 FY Actual | 71.06 |
| ANIMAL PROTECTION OAK HILL SS | 2022 FY Actual | 71.06 |

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|---|---|---|
| Animal Protection Hudson SS | 2022 FY Actual | 71.06 |
| Animal Protection Reeds Ferry SS | 2022 FY Actual | 71.06 |
| 15W4 Commercial Alley | 2023 FY Actual | 642,624.49 |
| W15 Lattice Tower Removal | 2023 FY Budget | 250,000.00 |
| NH Rubber Goods Lab Rebuild | 2023 FY Actual | 104,492.26 |
| 2022 Elec Sys Ops Equip Annual | 2022 FY Actual | 30,294.07 |
| 2022 Elec Sys Ops Equip Annual | 2023 FY Budget | 100,000.00 |
| Misc office equipment | 2019 FY Actual | 3,328.83 |
| Misc office equipment | 2019 FY Budget | 100,209.35 |
| Misc office equipment | 2020 FY Budget | 100,000.00 |
| Misc office equipment | 2021 FY Budget | 102,000.00 |
| Misc office equipment | 2022 FY Budget | 104,000.00 |
| Misc office equipment | 2023 FY Actual | 6,111.00 |
| Misc office equipment | 2023 FY Budget | 100,000.00 |
| TEMPORARY WORK - LANCASTER | 2021 FY Actual | 22,224.32 |
| TEMPORARY WORK - LANCASTER | 2022 FY Actual | 46,401.50 |
| TEMPORARY WORK - LANCASTER | 2023 FY Actual | 12,456.62 |
| TEMPORARY WORK - BERLIN | 2021 FY Actual | 3,336.11 |
| TEMPORARY WORK - BERLIN | 2022 FY Actual | 27,510.65 |
| TEMPORARY WORK - BERLIN | 2023 FY Actual | (2,076.85) |
| TEMPORARY WORK - CHOCORUA | 2021 FY Actual | 8,611.62 |
| TEMPORARY WORK - CHOCORUA | 2022 FY Actual | 33,515.79 |
| TEMPORARY WORK - CHOCORUA | 2023 FY Actual | 42,875.82 |
| TEMPORARY WORK - DERRY | 2021 FY Actual | 16,235.44 |
| TEMPORARY WORK - DERRY | 2022 FY Actual | 17,299.65 |
| TEMPORARY WORK - DERRY | 2023 FY Actual | 4,912.56 |
| TEMPORARY WORK - EPPING | 2021 FY Actual | 7,610.99 |
| TEMPORARY WORK - EPPING | 2022 FY Actual | 4,496.29 |
| TEMPORARY WORK - EPPING | 2023 FY Actual | 10,258.56 |
| TEMPORARY WORK - KEENE | 2021 FY Actual | 9,305.79 |
| TEMPORARY WORK - KEENE | 2022 FY Actual | 49,469.00 |
| TEMPORARY WORK - KEENE | 2023 FY Actual | 44,735.99 |
| TEMPORARY WORK - HOOKSETT | 2021 FY Actual | 16,437.97 |
| TEMPORARY WORK - HOOKSETT | 2022 FY Actual | 46,612.59 |
| TEMPORARY WORK - HOOKSETT | 2023 FY Actual | 27,275.08 |
| TEMPORARY WORK - LACONIA | 2020 FY Actual | (1,671.40) |
| TEMPORARY WORK - LACONIA | 2021 FY Actual | 20,596.41 |
| TEMPORARY WORK - LACONIA | 2022 FY Actual | 55,072.85 |
| TEMPORARY WORK - LACONIA | 2023 FY Actual | 90,509.44 |
| TEMPORARY WORK - NASHUA | 2019 FY Actual | (230.40) |
| TEMPORARY WORK - NASHUA | 2022 FY Actual | (988.00) |
| TEMPORARY WORK - NASHUA | 2023 FY Actual | 642.09 |
| TEMPORARY WORK - PORTSMOUTH | 2021 FY Actual | 6,994.23 |
| TEMPORARY WORK - PORTSMOUTH | 2022 FY Actual | 33,413.74 |
| TEMPORARY WORK - PORTSMOUTH | 2023 FY Actual | 25,934.48 |
| TEMPORARY WORK - NH | 2023 FY Budget | 300,000.00 |
| TEMPORARY WORK - ROCHESTER | 2021 FY Actual | 8,909.99 |

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| TEMPORARY WORK - ROCHESTER | 2022 FY Actual | 14,692.94 |
| TEMPORARY WORK - ROCHESTER | 2023 FY Actual | 29,375.33 |
| TEMPORARY WORK - NEWPORT | 2021 FY Actual | 8,305.26 |
| TEMPORARY WORK - NEWPORT | 2022 FY Actual | 9,370.39 |
| TEMPORARY WORK - NEWPORT | 2023 FY Actual | 8,415.11 |
| TEMPORARY WORK - MANCHESTER EAST | 2021 FY Actual | 6,053.21 |
| TEMPORARY WORK - MANCHESTER EAST | 2022 FY Actual | 5,551.15 |
| TEMPORARY WORK - MANCHESTER EAST | 2023 FY Actual | 17,372.10 |
| TEMPORARY WORK - MANCHESTER WEST | 2021 FY Actual | 9,458.34 |
| TEMPORARY WORK - MANCHESTER WEST | 2022 FY Actual | 16,494.85 |
| TEMPORARY WORK - MANCHESTER WEST | 2023 FY Actual | 16,225.40 |
| PRIVATE WORK - LANCASTER | 2021 FY Actual | 12,256.36 |
| PRIVATE WORK - LANCASTER | 2022 FY Actual | 72,856.81 |
| PRIVATE WORK - LANCASTER | 2023 FY Actual | 5,911.78 |
| PRIVATE WORK - BERLIN | 2022 FY Actual | (14,772.16) |
| PRIVATE WORK - BERLIN | 2023 FY Actual | 8,348.27 |
| PRIVATE WORK - CHOCORUA | 2021 FY Actual | 13,434.30 |
| PRIVATE WORK - CHOCORUA | 2022 FY Actual | 35,634.31 |
| PRIVATE WORK - CHOCORUA | 2023 FY Actual | 17,529.90 |
| PRIVATE WORK - DERRY | 2021 FY Actual | 667.12 |
| PRIVATE WORK - DERRY | 2022 FY Actual | 45.58 |
| PRIVATE WORK - DERRY | 2023 FY Actual | (10,253.41) |
| PRIVATE WORK - EPPING | 2021 FY Actual | 3,734.77 |
| PRIVATE WORK - EPPING | 2022 FY Actual | 15,237.73 |
| PRIVATE WORK - EPPING | 2023 FY Actual | 51,593.43 |
| PRIVATE WORK - KEENE | 2021 FY Actual | 19,615.86 |
| PRIVATE WORK - KEENE | 2022 FY Actual | 8,897.25 |
| PRIVATE WORK - KEENE | 2023 FY Actual | 18,970.30 |
| PRIVATE WORK - LACONIA | 2021 FY Actual | 4,500.18 |
| PRIVATE WORK - LACONIA | 2022 FY Actual | 33,999.48 |
| PRIVATE WORK - LACONIA | 2023 FY Actual | 58,984.01 |
| PRIVATE WORK - NASHUA | 2021 FY Actual | 3,905.15 |
| PRIVATE WORK - NASHUA | 2022 FY Actual | 30,805.53 |
| PRIVATE WORK - NASHUA | 2023 FY Actual | 194,731.41 |
| PRIVATE WORK - PORTSMOUTH | 2021 FY Actual | 129,832.41 |
| PRIVATE WORK - PORTSMOUTH | 2022 FY Actual | (51,542.60) |
| PRIVATE WORK - PORTSMOUTH | 2023 FY Actual | 135,354.50 |
| PRIVATE WORK - NH | 2023 FY Budget | 100,000.00 |
| PRIVATE WORK - ROCHESTER | 2021 FY Actual | 11,368.93 |
| PRIVATE WORK - ROCHESTER | 2022 FY Actual | 112,431.95 |
| PRIVATE WORK - ROCHESTER | 2023 FY Actual | 95,048.04 |
| PRIVATE WORK - NEWPORT | 2021 FY Actual | 3,449.84 |
| PRIVATE WORK - NEWPORT | 2022 FY Actual | 5,327.68 |
| PRIVATE WORK - HOOKSETT | 2019 FY Actual | 4,629.11 |
| PRIVATE WORK - HOOKSETT | 2021 FY Actual | 5,151.80 |
| PRIVATE WORK - HOOKSETT | 2022 FY Actual | 40,425.90 |
| PRIVATE WORK - HOOKSETT | 2023 FY Actual | (25,121.39) |

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| PRIVATE WORK - MANCHESTER WEST | 2021 FY Actual | 38,681.07 |
| PRIVATE WORK - MANCHESTER WEST | 2022 FY Actual | 13,432.57 |
| PRIVATE WORK - MANCHESTER WEST | 2023 FY Actual | 4,985.51 |
| Tools and Equipment - Engineering | 2019 FY Actual | 70,463.91 |
| Tools and Equipment - Engineering | 2019 FY Budget | 75,000.00 |
| Tools and Equipment - Engineering | 2020 FY Actual | 238.41 |
| Tools and Equipment - Engineering | 2020 FY Budget | 75,000.00 |
| Tools and Equipment - Engineering | 2021 FY Actual | 142,096.34 |
| Tools and Equipment - Engineering | 2021 FY Budget | 75,000.00 |
| Tools and Equipment - Engineering | 2022 FY Actual | 34,466.30 |
| Tools and Equipment - Engineering | 2022 FY Budget | 75,000.00 |
| Tools and Equipment - Engineering | 2023 FY Actual | 24,356.39 |
| Tools and Equipment - Engineering | 2023 FY Budget | 75,000.00 |
| Tools/equipment - S/S Operations | 2019 FY Actual | 109,385.96 |
| Tools/equipment - S/S Operations | 2019 FY Budget | 160,000.00 |
| Tools/equipment - S/S Operations | 2020 FY Actual | 339,180.20 |
| Tools/equipment - S/S Operations | 2020 FY Budget | 159,882.28 |
| Tools/equipment - S/S Operations | 2021 FY Actual | 74,331.83 |
| Tools/equipment - S/S Operations | 2021 FY Budget | 163,000.00 |
| 2021 NH D SS Capital Tool Annual | 2021 FY Actual | 622,168.92 |
| 2021 NH D SS Capital Tool Annual | 2022 FY Actual | 84,264.32 |
| 2021 NH D SS Capital Tool Annual | 2023 FY Actual | 1,601.58 |
| 2022 NH D SS Capital Tool Annual | 2022 FY Actual | 317,007.17 |
| 2022 NH D SS Capital Tool Annual | 2022 FY Budget | 166,000.00 |
| 2022 NH D SS Capital Tool Annual | 2023 FY Actual | 66,479.64 |
| 2023 NH D SS Capital Tool Annual | 2023 FY Actual | 23,684.97 |
| 2023 NH D SS Capital Tool Annual | 2023 FY Budget | 200,000.00 |
| Tools and Equipment- Troubleshooter | 2019 FY Actual | 148,169.24 |
| Tools and Equipment- Troubleshooter | 2019 FY Budget | 560,000.00 |
| Tools and Equipment- Troubleshooter | 2020 FY Actual | 412,049.90 |
| Tools and Equipment- Troubleshooter | 2020 FY Budget | 60,000.00 |
| Tools and Equipment- Troubleshooter | 2021 FY Actual | 490,996.62 |
| Tools and Equipment- Troubleshooter | 2021 FY Budget | 60,000.00 |
| Tools and Equipment- Troubleshooter | 2022 FY Actual | 179,692.01 |
| Tools and Equipment- Troubleshooter | 2022 FY Budget | 60,000.00 |
| Tools and Equipment- Troubleshooter | 2023 FY Actual | 290,082.15 |
| Tools and Equipment- Troubleshooter | 2023 FY Budget | 500,000.00 |
| Tools/equipment - Field Operations | 2019 FY Actual | 1,049,496.32 |
| Tools/equipment - Field Operations | 2019 FY Budget | 1,100,000.00 |
| Tools/equipment - Field Operations | 2020 FY Actual | 846,887.63 |
| Tools/equipment - Field Operations | 2020 FY Budget | 1,100,000.00 |
| Tools/equipment - Field Operations | 2021 FY Actual | 795,314.30 |
| Tools/equipment - Field Operations | 2021 FY Budget | 1,122,000.00 |
| Tools/equipment - Field Operations | 2022 FY Actual | 915,825.98 |
| Tools/equipment - Field Operations | 2022 FY Budget | 1,122,000.00 |
| Tools/equipment - Field Operations | 2023 FY Actual | 925,718.37 |
| Tools/equipment - Field Operations | 2023 FY Budget | 1,064,880.00 |

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|---|---|---|
| REPLACE FAILED CABLE SPRING RD RYE | 2019 FY Actual | 232,949.36 |
| Mobile Utility & Mobile Pole Assemb | 2023 FY Actual | 2,672.78 |
| Mobile Utility & Mobile Pole Assemb | 2023 FY Budget | 385,000.00 |
| DB PLANNED OBS ANNUAL - LANCASTER | 2019 FY Actual | 1,099.49 |
| DB PLANNED OBS ANNUAL - LANCASTER | 2020 FY Actual | 1,884.79 |
| DB PLANNED OBS ANNUAL - LANCASTER | 2022 FY Actual | (1,252.92) |
| DB PLANNED OBS ANNUAL - BERLIN | 2019 FY Actual | 958.21 |
| DB PLANNED OBS ANNUAL - BERLIN | 2020 FY Actual | 1,634.55 |
| DB PLANNED OBS ANNUAL - BERLIN | 2023 FY Actual | 767.36 |
| DB PLANNED OBS ANNUAL - CHOCORUA | 2019 FY Actual | (6,286.01) |
| DB PLANNED OBS ANNUAL - CHOCORUA | 2020 FY Actual | 1,974.29 |
| DB PLANNED OBS ANNUAL - CHOCORUA | 2021 FY Actual | 11,824.72 |
| DB PLANNED OBS ANNUAL - CHOCORUA | 2022 FY Actual | (414.64) |
| DB PLANNED OBS ANNUAL - DERRY | 2019 FY Actual | 120,802.28 |
| DB PLANNED OBS ANNUAL - DERRY | 2020 FY Actual | (1,902.38) |
| DB PLANNED OBS ANNUAL - DERRY | 2021 FY Actual | 72,785.97 |
| DB PLANNED OBS ANNUAL - DERRY | 2022 FY Actual | 378,978.97 |
| DB PLANNED OBS ANNUAL - DERRY | 2023 FY Actual | 17,757.40 |
| DB PLANNED OBS ANNUAL - EPPING | 2019 FY Actual | 36,138.32 |
| DB PLANNED OBS ANNUAL - EPPING | 2020 FY Actual | 15,979.19 |
| DB PLANNED OBS ANNUAL - EPPING | 2021 FY Actual | (963.95) |
| DB PLANNED OBS ANNUAL - EPPING | 2022 FY Actual | 1,140.92 |
| DB PLANNED OBS ANNUAL - KEENE | 2019 FY Actual | 196,646.23 |
| DB PLANNED OBS ANNUAL - KEENE | 2020 FY Actual | 8,838.91 |
| DB PLANNED OBS ANNUAL - KEENE | 2021 FY Actual | 3,505.14 |
| DB PLANNED OBS ANNUAL - KEENE | 2022 FY Actual | 2,017.34 |
| DB PLANNED OBS ANNUAL - KEENE | 2023 FY Actual | 3,183.43 |
| DB PLANNED OBS ANNUAL - TILTON | 2019 FY Actual | 5,429.57 |
| DB PLANNED OBS ANNUAL - TILTON | 2020 FY Actual | 32,933.02 |
| DB PLANNED OBS ANNUAL - TILTON | 2021 FY Actual | 34,485.76 |
| DB PLANNED OBS ANNUAL - TILTON | 2022 FY Actual | 6,135.51 |
| DB PLANNED OBS ANNUAL - NASHUA | 2019 FY Actual | 529,442.74 |
| DB PLANNED OBS ANNUAL - NASHUA | 2020 FY Actual | 133,930.59 |
| DB PLANNED OBS ANNUAL - NASHUA | 2021 FY Actual | (11,445.29) |
| DB PLANNED OBS ANNUAL - NASHUA | 2022 FY Actual | (1,304.86) |
| DB PLANNED OBS ANNUAL - NASHUA | 2023 FY Actual | 74,800.09 |
| DB PLANNED OBS ANNUAL - PORTSMOUTH | 2019 FY Actual | 51,894.96 |
| DB PLANNED OBS ANNUAL - PORTSMOUTH | 2020 FY Actual | 212,356.65 |
| DB PLANNED OBS ANNUAL - PORTSMOUTH | 2021 FY Actual | (33,106.96) |
| DB PLANNED OBS ANNUAL - PORTSMOUTH | 2022 FY Actual | (12,435.61) |
| DB PLANNED OBS ANNUAL - PORTSMOUTH | 2023 FY Actual | (5.40) |
| DB PLANNED OBS ANNUAL - ROCHESTER | 2019 FY Actual | 278,640.09 |
| DB PLANNED OBS ANNUAL - ROCHESTER | 2020 FY Actual | 175,234.33 |
| DB PLANNED OBS ANNUAL - ROCHESTER | 2021 FY Actual | 6,091.31 |
| DB PLANNED OBS ANNUAL - ROCHESTER | 2022 FY Actual | (1,163.49) |
| DB PLANNED OBS ANNUAL - ROCHESTER | 2023 FY Actual | 208.82 |
| DB PLANNED OBS ANNUAL - NEWPORT | 2019 FY Actual | 27,643.95 |

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| DB PLANNED OBS ANNUAL - NEWPORT | 2020 FY Actual | 194,296.69 |
| DB PLANNED OBS ANNUAL - NEWPORT | 2021 FY Actual | 2,697.90 |
| DB PLANNED OBS ANNUAL - NEWPORT | 2022 FY Actual | (3,407.04) |
| DB PLANNED OBS ANNUAL - HOOKSETT | 2019 FY Actual | 193.07 |
| DB PLANNED OBS ANNUAL - HOOKSETT | 2020 FY Actual | 118,898.32 |
| DB PLANNED OBS ANNUAL - HOOKSETT | 2021 FY Actual | 29,844.34 |
| DB PLANNED OBS ANNUAL - HOOKSETT | 2022 FY Actual | 30,285.56 |
| DB PLANNED OBS ANNUAL - BEDFORD | 2019 FY Actual | 113,919.64 |
| DB PLANNED OBS ANNUAL - BEDFORD | 2020 FY Actual | 41,453.22 |
| DB PLANNED OBS ANNUAL - BEDFORD | 2021 FY Actual | 2,864.57 |
| DB PLANNED OBS ANNUAL - BEDFORD | 2022 FY Actual | 11,057.86 |
| DB PLANNED OBS ANNUAL - BEDFORD | 2023 FY Actual | 4,366.21 |
| OH PLANNED OBS ANNUAL LANCASTER | 2019 FY Actual | 74,420.08 |
| OH PLANNED OBS ANNUAL LANCASTER | 2020 FY Actual | 407,183.40 |
| OH PLANNED OBS ANNUAL LANCASTER | 2021 FY Actual | 260,729.39 |
| OH PLANNED OBS ANNUAL LANCASTER | 2022 FY Actual | 143,094.39 |
| OH PLANNED OBS ANNUAL LANCASTER | 2023 FY Actual | 475,733.21 |
| OH PLANNED OBS ANNUAL BERLIN | 2019 FY Actual | 103,449.79 |
| OH PLANNED OBS ANNUAL BERLIN | 2020 FY Actual | 96,416.33 |
| OH PLANNED OBS ANNUAL BERLIN | 2021 FY Actual | 167,883.36 |
| OH PLANNED OBS ANNUAL BERLIN | 2022 FY Actual | 322,255.61 |
| OH PLANNED OBS ANNUAL BERLIN | 2023 FY Actual | 14,598.47 |
| OH PLANNED OBS ANNUAL CHOCORUA | 2019 FY Actual | 137,022.03 |
| OH PLANNED OBS ANNUAL CHOCORUA | 2020 FY Actual | 181,992.49 |
| OH PLANNED OBS ANNUAL CHOCORUA | 2021 FY Actual | 76,147.79 |
| OH PLANNED OBS ANNUAL CHOCORUA | 2022 FY Actual | 88,224.23 |
| OH PLANNED OBS ANNUAL CHOCORUA | 2023 FY Actual | 115,617.08 |
| OH PLANNED OBS ANNUAL DERRY | 2019 FY Actual | 240,154.02 |
| OH PLANNED OBS ANNUAL DERRY | 2020 FY Actual | 276,544.92 |
| OH PLANNED OBS ANNUAL DERRY | 2021 FY Actual | 409,703.20 |
| OH PLANNED OBS ANNUAL DERRY | 2022 FY Actual | 669,301.68 |
| OH PLANNED OBS ANNUAL DERRY | 2023 FY Actual | 504,404.42 |
| OH PLANNED OBS ANNUAL EPPING | 2019 FY Actual | 584,733.25 |
| OH PLANNED OBS ANNUAL EPPING | 2020 FY Actual | 568,604.56 |
| OH PLANNED OBS ANNUAL EPPING | 2021 FY Actual | 314,888.77 |
| OH PLANNED OBS ANNUAL EPPING | 2022 FY Actual | 408,141.01 |
| OH PLANNED OBS ANNUAL EPPING | 2023 FY Actual | 235,294.01 |
| OH PLANNED OBS ANNUAL KEENE | 2019 FY Actual | 1,016,681.91 |
| OH PLANNED OBS ANNUAL KEENE | 2020 FY Actual | 784,411.51 |
| OH PLANNED OBS ANNUAL KEENE | 2021 FY Actual | 643,073.25 |
| OH PLANNED OBS ANNUAL KEENE | 2022 FY Actual | 522,775.31 |
| OH PLANNED OBS ANNUAL KEENE | 2023 FY Actual | 1,643,740.31 |
| OH PLANNED OBS ANNUAL TILTON | 2019 FY Actual | 963,388.91 |
| OH PLANNED OBS ANNUAL TILTON | 2020 FY Actual | 328,225.17 |
| OH PLANNED OBS ANNUAL TILTON | 2021 FY Actual | 257,189.67 |
| OH PLANNED OBS ANNUAL TILTON | 2022 FY Actual | 472,433.06 |
| OH PLANNED OBS ANNUAL TILTON | 2023 FY Actual | 434,505.10 |

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| OH PLANNED OBS ANNUAL MILFORD | 2019 FY Actual | (1,307.44) |
| OH PLANNED OBS ANNUAL MILFORD | 2020 FY Actual | 7,258.52 |
| OH PLANNED OBS ANNUAL MILFORD | 2021 FY Actual | (3,027.53) |
| OH PLANNED OBS ANNUAL MILFORD | 2023 FY Actual | (108.35) |
| OH PLANNED OBS ANNUAL NASHUA | 2019 FY Actual | 437,473.23 |
| OH PLANNED OBS ANNUAL NASHUA | 2020 FY Actual | 475,847.56 |
| OH PLANNED OBS ANNUAL NASHUA | 2021 FY Actual | 593,221.91 |
| OH PLANNED OBS ANNUAL NASHUA | 2022 FY Actual | 880,512.71 |
| OH PLANNED OBS ANNUAL NASHUA | 2023 FY Actual | 1,093,934.41 |
| OH PLANNED OBS ANNUAL PORTSMOUTH | 2019 FY Actual | 163,746.89 |
| OH PLANNED OBS ANNUAL PORTSMOUTH | 2020 FY Actual | 637,681.47 |
| OH PLANNED OBS ANNUAL PORTSMOUTH | 2021 FY Actual | 497,764.24 |
| OH PLANNED OBS ANNUAL PORTSMOUTH | 2022 FY Actual | 329,746.54 |
| OH PLANNED OBS ANNUAL PORTSMOUTH | 2023 FY Actual | 276,558.01 |
| OH PLANNED OBS ANNUAL ROCHESTER | 2019 FY Actual | 436,121.02 |
| OH PLANNED OBS ANNUAL ROCHESTER | 2020 FY Actual | 721,102.13 |
| OH PLANNED OBS ANNUAL ROCHESTER | 2021 FY Actual | 539,339.70 |
| OH PLANNED OBS ANNUAL ROCHESTER | 2022 FY Actual | 211,458.33 |
| OH PLANNED OBS ANNUAL ROCHESTER | 2023 FY Actual | 316,302.74 |
| OH PLANNED OBS ANNUAL NEWPORT | 2019 FY Actual | 511,878.50 |
| OH PLANNED OBS ANNUAL NEWPORT | 2020 FY Actual | 488,348.66 |
| OH PLANNED OBS ANNUAL NEWPORT | 2021 FY Actual | 233,476.59 |
| OH PLANNED OBS ANNUAL NEWPORT | 2022 FY Actual | 284,398.74 |
| OH PLANNED OBS ANNUAL NEWPORT | 2023 FY Actual | 536,027.38 |
| OH PLANNED OBS ANNUAL HOOKSETT | 2019 FY Actual | 183,505.38 |
| OH PLANNED OBS ANNUAL HOOKSETT | 2020 FY Actual | 465,703.56 |
| OH PLANNED OBS ANNUAL HOOKSETT | 2021 FY Actual | 266,722.19 |
| OH PLANNED OBS ANNUAL HOOKSETT | 2022 FY Actual | 104,272.48 |
| OH PLANNED OBS ANNUAL HOOKSETT | 2023 FY Actual | 142,016.63 |
| OH PLANNED OBS ANNUAL BEDFORD | 2019 FY Actual | 399,293.35 |
| OH PLANNED OBS ANNUAL BEDFORD | 2020 FY Actual | 614,157.50 |
| OH PLANNED OBS ANNUAL BEDFORD | 2021 FY Actual | 436,539.59 |
| OH PLANNED OBS ANNUAL BEDFORD | 2022 FY Actual | 724,564.20 |
| OH PLANNED OBS ANNUAL BEDFORD | 2023 FY Actual | 1,204,365.55 |
| UG PLANNED OBS ANNUAL LANCASTER | 2022 FY Actual | 13,117.60 |
| UG PLANNED OBS ANNUAL BERLIN | 2023 FY Actual | 7,242.64 |
| UG PLANNED OBS ANNUAL CHOCORUA | 2022 FY Actual | 654.88 |
| UG PLANNED OBS ANNUAL CHOCORUA | 2023 FY Actual | (654.88) |
| UG PLANNED OBS ANNUAL DERRY | 2021 FY Actual | 174,634.38 |
| UG PLANNED OBS ANNUAL DERRY | 2022 FY Actual | 211,405.32 |
| UG PLANNED OBS ANNUAL DERRY | 2023 FY Actual | 252,906.21 |
| UG PLANNED OBS ANNUAL EPPING | 2021 FY Actual | 53,580.36 |
| UG PLANNED OBS ANNUAL EPPING | 2022 FY Actual | 79,648.26 |
| UG PLANNED OBS ANNUAL EPPING | 2023 FY Actual | 139,868.36 |
| UG PLANNED OBS ANNUAL KEENE | 2019 FY Actual | 2,243.54 |
| UG PLANNED OBS ANNUAL KEENE | 2020 FY Actual | 69,806.57 |
| UG PLANNED OBS ANNUAL KEENE | 2021 FY Actual | 1,450.09 |

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| UG PLANNED OBS ANNUAL KEENE | 2022 FY Actual | (1,316.84) |
| UG PLANNED OBS ANNUAL KEENE | 2023 FY Actual | 2,757.05 |
| UG PLANNED OBS ANNUAL TILTON | 2021 FY Actual | 1,193.11 |
| UG PLANNED OBS ANNUAL TILTON | 2022 FY Actual | 7,586.37 |
| UG PLANNED OBS ANNUAL TILTON | 2023 FY Actual | 4,699.08 |
| UG PLANNED OBS ANNUAL NASHUA | 2021 FY Actual | 64,734.77 |
| UG PLANNED OBS ANNUAL NASHUA | 2022 FY Actual | 3,917.26 |
| UG PLANNED OBS ANNUAL NASHUA | 2023 FY Actual | 4,520.54 |
| UG PLANNED OBS ANNUAL PORTSMOUTH | 2021 FY Actual | 70,509.54 |
| UG PLANNED OBS ANNUAL PORTSMOUTH | 2022 FY Actual | 58,575.03 |
| UG PLANNED OBS ANNUAL PORTSMOUTH | 2023 FY Actual | 66,662.61 |
| UG PLANNED OBS ANNUAL ROCHESTER | 2021 FY Actual | 84,429.89 |
| UG PLANNED OBS ANNUAL ROCHESTER | 2022 FY Actual | 150,078.44 |
| UG PLANNED OBS ANNUAL ROCHESTER | 2023 FY Actual | 303,233.62 |
| UG PLANNED OBS ANNUAL HOOKSETT | 2019 FY Actual | 1,152.74 |
| UG PLANNED OBS ANNUAL HOOKSETT | 2020 FY Actual | 90,399.11 |
| UG PLANNED OBS ANNUAL HOOKSETT | 2021 FY Actual | (68,566.13) |
| UG PLANNED OBS ANNUAL HOOKSETT | 2023 FY Actual | (2,085.76) |
| UG PLANNED OBS ANNUAL BEDFORD | 2021 FY Actual | 3,630.07 |
| UG PLANNED OBS ANNUAL BEDFORD | 2022 FY Actual | 315,548.99 |
| UG PLANNED OBS ANNUAL BEDFORD | 2023 FY Actual | 77,206.82 |
| SYSTEM REPAIRS/OBSOLETE - LANCASTER | 2019 FY Actual | 73,287.06 |
| SYSTEM REPAIRS/OBSOLETE - LANCASTER | 2020 FY Actual | 18,248.82 |
| SYSTEM REPAIRS/OBSOLETE - LANCASTER | 2021 FY Actual | (3,006.39) |
| SYSTEM REPAIRS/OBSOLETE - LANCASTER | 2022 FY Actual | 3,844.72 |
| SYSTEM REPAIRS/OBSOLETE - BERLIN | 2019 FY Actual | 51,693.77 |
| SYSTEM REPAIRS/OBSOLETE - BERLIN | 2020 FY Actual | 35,566.53 |
| SYSTEM REPAIRS/OBSOLETE - BERLIN | 2022 FY Actual | 217,526.46 |
| SYSTEM REPAIRS/OBSOLETE - BERLIN | 2023 FY Actual | (12,883.65) |
| SYSTEM REPAIRS/OBSOLETE - BERLIN | 2023 FY Budget | 2,947,661.16 |
| SYSTEM REPAIRS/OBSOLETE - CHOCORUA | 2019 FY Actual | 32,756.00 |
| SYSTEM REPAIRS/OBSOLETE - CHOCORUA | 2020 FY Actual | 108,769.57 |
| SYSTEM REPAIRS/OBSOLETE - CHOCORUA | 2021 FY Actual | 30,842.79 |
| SYSTEM REPAIRS/OBSOLETE - CHOCORUA | 2022 FY Actual | 30,727.44 |
| SYSTEM REPAIRS/OBSOLETE - CHOCORUA | 2023 FY Actual | 79,622.01 |
| SYSTEM REPAIRS/OBSOLETE - DERRY | 2019 FY Actual | 30,707.50 |
| SYSTEM REPAIRS/OBSOLETE - DERRY | 2020 FY Actual | 11,055.72 |
| SYSTEM REPAIRS/OBSOLETE - DERRY | 2021 FY Actual | 11,663.01 |
| SYSTEM REPAIRS/OBSOLETE - DERRY | 2022 FY Actual | 65.57 |
| SYSTEM REPAIRS/OBSOLETE - EPPING | 2019 FY Actual | 9,051.56 |
| SYSTEM REPAIRS/OBSOLETE - EPPING | 2020 FY Actual | 6,869.62 |
| SYSTEM REPAIRS/OBSOLETE - EPPING | 2021 FY Actual | 225,727.69 |
| SYSTEM REPAIRS/OBSOLETE - EPPING | 2022 FY Actual | 571,504.05 |
| SYSTEM REPAIRS/OBSOLETE - EPPING | 2023 FY Actual | 649,668.59 |
| SYSTEM REPAIRS/OBSOLETE - HILLSBORO | 2019 FY Actual | (205.00) |
| SYSTEM REPAIRS/OBSOLETE - KEENE | 2019 FY Actual | (1,947.92) |
| SYSTEM REPAIRS/OBSOLETE - KEENE | 2020 FY Actual | 28,399.22 |

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| SYSTEM REPAIRS/OBSOLETE - KEENE | 2021 FY Actual | 284,998.88 |
| SYSTEM REPAIRS/OBSOLETE - KEENE | 2022 FY Actual | 447,283.12 |
| SYSTEM REPAIRS/OBSOLETE - KEENE | 2023 FY Actual | 780,874.69 |
| SYSTEM REPAIRS/OBSOLETE- LACONIA | 2019 FY Actual | 231,923.29 |
| SYSTEM REPAIRS/OBSOLETE- LACONIA | 2020 FY Actual | 128,509.53 |
| SYSTEM REPAIRS/OBSOLETE- LACONIA | 2021 FY Actual | (27,494.41) |
| SYSTEM REPAIRS/OBSOLETE- LACONIA | 2022 FY Actual | 349,132.89 |
| SYSTEM REPAIRS/OBSOLETE- LACONIA | 2023 FY Actual | 389,009.61 |
| SYSTEM REPAIRS/OBSOLETE - MILFORD | 2019 FY Actual | (1,025.00) |
| SYSTEM REPAIRS/OBSOLETE - MILFORD | 2022 FY Actual | (3.32) |
| SYSTEM REPAIRS/OBSOLETE - NASHUA | 2019 FY Actual | 24,101.13 |
| SYSTEM REPAIRS/OBSOLETE - NASHUA | 2020 FY Actual | 32,995.06 |
| SYSTEM REPAIRS/OBSOLETE - NASHUA | 2021 FY Actual | 1,456.57 |
| SYSTEM REPAIRS/OBSOLETE - NASHUA | 2022 FY Actual | 72,456.47 |
| SYSTEM REPAIRS/OBSOLETE - NASHUA | 2023 FY Actual | 91,288.70 |
| SYSTEM REPAIRS/OBSOLETE - NASHUA | 2023 FY Budget | 3,821,256.96 |
| SYSTEM REPAIRS/OBSOLETE - PORTSMOUT | 2019 FY Actual | 28,541.02 |
| SYSTEM REPAIRS/OBSOLETE - PORTSMOUT | 2020 FY Actual | 40,158.48 |
| SYSTEM REPAIRS/OBSOLETE - PORTSMOUT | 2021 FY Actual | 69,711.10 |
| SYSTEM REPAIRS/OBSOLETE - PORTSMOUT | 2022 FY Actual | 111,126.26 |
| SYSTEM REPAIRS/OBSOLETE - PORTSMOUT | 2023 FY Actual | 98,547.87 |
| SYSTEM REPAIRS/OBSOLETE | 2019 FY Budget | 9,506,168.31 |
| SYSTEM REPAIRS/OBSOLETE | 2020 FY Budget | 9,999,634.65 |
| SYSTEM REPAIRS/OBSOLETE | 2021 FY Actual | 1,507,569.85 |
| SYSTEM REPAIRS/OBSOLETE | 2021 FY Budget | 10,253,999.99 |
| SYSTEM REPAIRS/OBSOLETE | 2022 FY Actual | 1,913,114.78 |
| SYSTEM REPAIRS/OBSOLETE | 2022 FY Budget | 5,948,915.17 |
| SYSTEM REPAIRS/OBSOLETE | 2023 FY Actual | 1,190,128.20 |
| SYSTEM REPAIRS/OBSOLETE | 2023 FY Budget | 2,146,509.24 |
| SYSTEM REPAIRS/OBSOLETE - ROCHESTER | 2019 FY Actual | 47,117.09 |
| SYSTEM REPAIRS/OBSOLETE - ROCHESTER | 2020 FY Actual | 61,795.69 |
| SYSTEM REPAIRS/OBSOLETE - ROCHESTER | 2021 FY Actual | 238,180.55 |
| SYSTEM REPAIRS/OBSOLETE - ROCHESTER | 2022 FY Actual | 758,856.76 |
| SYSTEM REPAIRS/OBSOLETE - ROCHESTER | 2023 FY Actual | 390,572.18 |
| SYSTEM REPAIRS/OBSOLETE - ROCHESTER | 2023 FY Budget | 3,052,604.64 |
| SYSTEM REPAIRS/OBSOLETE - NEWPORT | 2019 FY Actual | 218,878.38 |
| SYSTEM REPAIRS/OBSOLETE - NEWPORT | 2020 FY Actual | 10,282.98 |
| SYSTEM REPAIRS/OBSOLETE - NEWPORT | 2021 FY Actual | 67,313.29 |
| SYSTEM REPAIRS/OBSOLETE - NEWPORT | 2022 FY Actual | 49,954.52 |
| SYSTEM REPAIRS/OBSOLETE - NEWPORT | 2023 FY Actual | 189,959.84 |
| SYSTEM REPAIRS/OBSOLETE - NEWPORT | 2023 FY Budget | 2,045,480.40 |
| SYSTEM REPAIRS/OBSOLETE - HOOKSETT | 2019 FY Actual | 101,484.86 |
| SYSTEM REPAIRS/OBSOLETE - HOOKSETT | 2020 FY Actual | 191,533.71 |
| SYSTEM REPAIRS/OBSOLETE - HOOKSETT | 2021 FY Actual | 178,410.31 |
| SYSTEM REPAIRS/OBSOLETE - HOOKSETT | 2022 FY Actual | 195,457.57 |
| SYSTEM REPAIRS/OBSOLETE - HOOKSETT | 2023 FY Actual | 488,231.01 |
| SYSTEM REPAIRS/OBSOLETE - BEDFORD | 2019 FY Actual | 24,078.37 |

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| SYSTEM REPAIRS/OBSOLETE - BEDFORD | 2020 FY Actual | 28,430.96 |
| SYSTEM REPAIRS/OBSOLETE - BEDFORD | 2021 FY Actual | 75,666.70 |
| SYSTEM REPAIRS/OBSOLETE - BEDFORD | 2022 FY Actual | 124,883.74 |
| SYSTEM REPAIRS/OBSOLETE - BEDFORD | 2023 FY Actual | 75,301.26 |
| SYSTEM REPAIRS/OBSOLETE - BEDFORD | 2023 FY Budget | 2,941,487.52 |
| DB FAILED EQUIPMENT LANCASTER | 2019 FY Actual | 279,993.85 |
| DB FAILED EQUIPMENT LANCASTER | 2020 FY Actual | 258,042.68 |
| DB FAILED EQUIPMENT LANCASTER | 2021 FY Actual | 109,274.17 |
| DB FAILED EQUIPMENT LANCASTER | 2022 FY Actual | 17,110.29 |
| DB FAILED EQUIPMENT LANCASTER | 2023 FY Actual | 2,769.84 |
| DB FAILED EQUIPMENT BERLIN | 2019 FY Actual | 178,627.12 |
| DB FAILED EQUIPMENT BERLIN | 2020 FY Actual | 77,156.07 |
| DB FAILED EQUIPMENT BERLIN | 2021 FY Actual | 5,468.72 |
| DB FAILED EQUIPMENT BERLIN | 2022 FY Actual | 16,635.02 |
| DB FAILED EQUIPMENT BERLIN | 2023 FY Actual | 3,684.28 |
| DB FAILED EQUIPMENT CHOCORUA | 2019 FY Actual | 184,568.02 |
| DB FAILED EQUIPMENT CHOCORUA | 2020 FY Actual | 23,123.31 |
| DB FAILED EQUIPMENT CHOCORUA | 2021 FY Actual | 26,799.78 |
| DB FAILED EQUIPMENT CHOCORUA | 2022 FY Actual | 5,394.47 |
| DB FAILED EQUIPMENT CHOCORUA | 2023 FY Actual | 58,442.53 |
| DB FAILED EQUIPMENT DERRY | 2019 FY Actual | 798,120.97 |
| DB FAILED EQUIPMENT DERRY | 2020 FY Actual | 466,439.51 |
| DB FAILED EQUIPMENT DERRY | 2021 FY Actual | 190,456.91 |
| DB FAILED EQUIPMENT DERRY | 2022 FY Actual | 151,530.32 |
| DB FAILED EQUIPMENT DERRY | 2023 FY Actual | 1,617.56 |
| DB FAILED EQUIPMENT EPPING | 2019 FY Actual | 377.05 |
| DB FAILED EQUIPMENT EPPING | 2020 FY Actual | (207.21) |
| DB FAILED EQUIPMENT EPPING | 2021 FY Actual | 109,920.72 |
| DB FAILED EQUIPMENT EPPING | 2022 FY Actual | 7,486.42 |
| DB FAILED EQUIPMENT EPPING | 2023 FY Actual | 5,630.17 |
| DB FAILED EQUIPMENT KEENE | 2019 FY Actual | 27,731.87 |
| DB FAILED EQUIPMENT KEENE | 2020 FY Actual | 24,588.94 |
| DB FAILED EQUIPMENT KEENE | 2021 FY Actual | 88,881.25 |
| DB FAILED EQUIPMENT KEENE | 2022 FY Actual | 129,040.45 |
| DB FAILED EQUIPMENT KEENE | 2023 FY Actual | 154,606.14 |
| DB FAILED EQUIPMENT TILTON | 2019 FY Actual | 288,459.56 |
| DB FAILED EQUIPMENT TILTON | 2020 FY Actual | 306,464.64 |
| DB FAILED EQUIPMENT TILTON | 2021 FY Actual | 270,747.12 |
| DB FAILED EQUIPMENT TILTON | 2022 FY Actual | 219,891.36 |
| DB FAILED EQUIPMENT TILTON | 2023 FY Actual | 467,094.84 |
| DB FAILED EQUIPMENT NASHUA | 2019 FY Actual | 786,641.49 |
| DB FAILED EQUIPMENT NASHUA | 2020 FY Actual | 970,376.97 |
| DB FAILED EQUIPMENT NASHUA | 2021 FY Actual | 434,714.74 |
| DB FAILED EQUIPMENT NASHUA | 2022 FY Actual | 648,951.76 |
| DB FAILED EQUIPMENT NASHUA | 2023 FY Actual | 124,195.37 |
| DB FAILED EQUIPMENT PORTSMOUTH | 2019 FY Actual | 228,803.23 |
| DB FAILED EQUIPMENT PORTSMOUTH | 2020 FY Actual | 220,496.22 |

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| DB FAILED EQUIPMENT PORTSMOUTH | 2021 FY Actual | 156,267.01 |
| DB FAILED EQUIPMENT PORTSMOUTH | 2022 FY Actual | 9,478.53 |
| DB FAILED EQUIPMENT PORTSMOUTH | 2023 FY Actual | 105,974.35 |
| DB FAILED EQUIPMENT ROCHESTER | 2019 FY Actual | 63,806.89 |
| DB FAILED EQUIPMENT ROCHESTER | 2020 FY Actual | 48,850.90 |
| DB FAILED EQUIPMENT ROCHESTER | 2021 FY Actual | 123,695.24 |
| DB FAILED EQUIPMENT ROCHESTER | 2022 FY Actual | 201,583.61 |
| DB FAILED EQUIPMENT ROCHESTER | 2023 FY Actual | 123,004.33 |
| DB FAILED EQUIPMENT NEWPORT | 2019 FY Actual | 306,981.55 |
| DB FAILED EQUIPMENT NEWPORT | 2020 FY Actual | 204,770.82 |
| DB FAILED EQUIPMENT NEWPORT | 2021 FY Actual | 166,483.19 |
| DB FAILED EQUIPMENT NEWPORT | 2022 FY Actual | 296,412.85 |
| DB FAILED EQUIPMENT NEWPORT | 2023 FY Actual | 405,017.17 |
| DB FAILED EQUIPMENT HOOKSETT | 2019 FY Actual | 198,445.67 |
| DB FAILED EQUIPMENT HOOKSETT | 2020 FY Actual | 427,409.57 |
| DB FAILED EQUIPMENT HOOKSETT | 2021 FY Actual | 189,855.95 |
| DB FAILED EQUIPMENT HOOKSETT | 2022 FY Actual | 247,784.64 |
| DB FAILED EQUIPMENT HOOKSETT | 2023 FY Actual | 151,620.82 |
| DB FAILED EQUIPMENT BEDFORD | 2019 FY Actual | 769,704.41 |
| DB FAILED EQUIPMENT BEDFORD | 2020 FY Actual | 427,249.76 |
| DB FAILED EQUIPMENT BEDFORD | 2021 FY Actual | 295,183.52 |
| DB FAILED EQUIPMENT BEDFORD | 2022 FY Actual | 246,345.78 |
| DB FAILED EQUIPMENT BEDFORD | 2023 FY Actual | 393,658.66 |
| OH FAILED EQUIPMENT LANCASTER | 2019 FY Actual | 201,236.94 |
| OH FAILED EQUIPMENT LANCASTER | 2020 FY Actual | 167,747.22 |
| OH FAILED EQUIPMENT LANCASTER | 2021 FY Actual | 334,931.38 |
| OH FAILED EQUIPMENT LANCASTER | 2022 FY Actual | 146,701.36 |
| OH FAILED EQUIPMENT LANCASTER | 2023 FY Actual | 469,029.41 |
| OH FAILED EQUIPMENT BERLIN | 2019 FY Actual | 124,615.61 |
| OH FAILED EQUIPMENT BERLIN | 2020 FY Actual | 31,585.53 |
| OH FAILED EQUIPMENT BERLIN | 2021 FY Actual | 404,373.13 |
| OH FAILED EQUIPMENT BERLIN | 2022 FY Actual | 48,626.41 |
| OH FAILED EQUIPMENT BERLIN | 2023 FY Actual | 145,004.05 |
| OH FAILED EQUIPMENT CHOCORUA | 2019 FY Actual | 55,737.03 |
| OH FAILED EQUIPMENT CHOCORUA | 2020 FY Actual | 53,065.84 |
| OH FAILED EQUIPMENT CHOCORUA | 2021 FY Actual | 165,129.26 |
| OH FAILED EQUIPMENT CHOCORUA | 2022 FY Actual | 96,434.59 |
| OH FAILED EQUIPMENT CHOCORUA | 2023 FY Actual | 253,014.24 |
| OH FAILED EQUIPMENT DERRY | 2019 FY Actual | 195,997.65 |
| OH FAILED EQUIPMENT DERRY | 2020 FY Actual | 131,590.67 |
| OH FAILED EQUIPMENT DERRY | 2021 FY Actual | 180,932.59 |
| OH FAILED EQUIPMENT DERRY | 2022 FY Actual | 143,348.48 |
| OH FAILED EQUIPMENT DERRY | 2023 FY Actual | 202,803.33 |
| OH FAILED EQUIPMENT EPPING | 2019 FY Actual | 665.87 |
| OH FAILED EQUIPMENT EPPING | 2020 FY Actual | (214.65) |
| OH FAILED EQUIPMENT EPPING | 2021 FY Actual | 294,810.27 |
| OH FAILED EQUIPMENT EPPING | 2022 FY Actual | 47,330.10 |

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| OH FAILED EQUIPMENT EPPING | 2023 FY Actual | 28,056.02 |
| OH FAILED EQUIPMENT KEENE | 2019 FY Actual | 152,232.68 |
| OH FAILED EQUIPMENT KEENE | 2020 FY Actual | 355,910.96 |
| OH FAILED EQUIPMENT KEENE | 2021 FY Actual | 250,432.75 |
| OH FAILED EQUIPMENT KEENE | 2022 FY Actual | 105,926.80 |
| OH FAILED EQUIPMENT KEENE | 2023 FY Actual | 159,616.06 |
| OH FAILED EQUIPMENT TILTON | 2019 FY Actual | 389,033.67 |
| OH FAILED EQUIPMENT TILTON | 2020 FY Actual | 231,443.36 |
| OH FAILED EQUIPMENT TILTON | 2021 FY Actual | 525,653.82 |
| OH FAILED EQUIPMENT TILTON | 2022 FY Actual | 527,891.66 |
| OH FAILED EQUIPMENT TILTON | 2023 FY Actual | 899,423.67 |
| OH FAILED EQUIPMENT NASHUA | 2019 FY Actual | 173,598.14 |
| OH FAILED EQUIPMENT NASHUA | 2020 FY Actual | 335,906.56 |
| OH FAILED EQUIPMENT NASHUA | 2021 FY Actual | 405,443.86 |
| OH FAILED EQUIPMENT NASHUA | 2022 FY Actual | 500,213.61 |
| OH FAILED EQUIPMENT NASHUA | 2023 FY Actual | 803,676.74 |
| OH FAILED EQUIPMENT PORTSMOUTH | 2019 FY Actual | 93,053.93 |
| OH FAILED EQUIPMENT PORTSMOUTH | 2020 FY Actual | 63,733.10 |
| OH FAILED EQUIPMENT PORTSMOUTH | 2021 FY Actual | 168,038.71 |
| OH FAILED EQUIPMENT PORTSMOUTH | 2022 FY Actual | (51,632.43) |
| OH FAILED EQUIPMENT PORTSMOUTH | 2023 FY Actual | 117,604.09 |
| OH FAILED EQUIPMENT PSNH | 2019 FY Actual | (397,603.67) |
| OH FAILED EQUIPMENT PSNH | 2020 FY Actual | (279,730.39) |
| OH FAILED EQUIPMENT PSNH | 2021 FY Actual | (441,617.27) |
| OH FAILED EQUIPMENT PSNH | 2022 FY Actual | (277,750.81) |
| OH FAILED EQUIPMENT PSNH | 2023 FY Actual | (353,710.56) |
| OH FAILED EQUIPMENT ROCHESTER | 2019 FY Actual | 19,076.37 |
| OH FAILED EQUIPMENT ROCHESTER | 2020 FY Actual | 146,616.22 |
| OH FAILED EQUIPMENT ROCHESTER | 2021 FY Actual | 268,608.50 |
| OH FAILED EQUIPMENT ROCHESTER | 2022 FY Actual | 417,605.91 |
| OH FAILED EQUIPMENT ROCHESTER | 2023 FY Actual | 267,580.87 |
| OH FAILED EQUIPMENT NEWPORT | 2019 FY Actual | 55,571.10 |
| OH FAILED EQUIPMENT NEWPORT | 2020 FY Actual | 168,196.14 |
| OH FAILED EQUIPMENT NEWPORT | 2021 FY Actual | 129,675.59 |
| OH FAILED EQUIPMENT NEWPORT | 2022 FY Actual | 120,997.86 |
| OH FAILED EQUIPMENT NEWPORT | 2023 FY Actual | 197,975.69 |
| OH FAILED EQUIPMENT HOOKSETT | 2019 FY Actual | 236,438.22 |
| OH FAILED EQUIPMENT HOOKSETT | 2020 FY Actual | 287,133.11 |
| OH FAILED EQUIPMENT HOOKSETT | 2021 FY Actual | 248,485.13 |
| OH FAILED EQUIPMENT HOOKSETT | 2022 FY Actual | 455,485.58 |
| OH FAILED EQUIPMENT HOOKSETT | 2023 FY Actual | 874,605.79 |
| OH FAILED EQUIPMENT BEDFORD | 2019 FY Actual | 179,537.85 |
| OH FAILED EQUIPMENT BEDFORD | 2020 FY Actual | 102,235.30 |
| OH FAILED EQUIPMENT BEDFORD | 2021 FY Actual | 439,745.69 |
| OH FAILED EQUIPMENT BEDFORD | 2022 FY Actual | 480,591.39 |
| OH FAILED EQUIPMENT BEDFORD | 2023 FY Actual | 693,410.80 |
| UG FAILED EQUIPMENT LANCASTER | 2022 FY Actual | 929.89 |

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| UG FAILED EQUIPMENT LANCASTER | 2023 FY Actual | 135,647.29 |
| UG FAILED EQUIPMENT BERLIN | 2023 FY Actual | 4,924.61 |
| UG FAILED EQUIPMENT CHOCORUA | 2021 FY Actual | 475.63 |
| UG FAILED EQUIPMENT DERRY | 2021 FY Actual | 5,834.92 |
| UG FAILED EQUIPMENT DERRY | 2022 FY Actual | (2,528.25) |
| UG FAILED EQUIPMENT DERRY | 2023 FY Actual | (2,634.80) |
| UG FAILED EQUIPMENT EPPING | 2021 FY Actual | 81,238.30 |
| UG FAILED EQUIPMENT EPPING | 2022 FY Actual | 7,181.50 |
| UG FAILED EQUIPMENT EPPING | 2023 FY Actual | (385.75) |
| UG FAILED EQUIPMENT KEENE | 2019 FY Actual | 120,010.69 |
| UG FAILED EQUIPMENT KEENE | 2020 FY Actual | 16,268.54 |
| UG FAILED EQUIPMENT KEENE | 2021 FY Actual | 20,507.93 |
| UG FAILED EQUIPMENT KEENE | 2022 FY Actual | (5,042.79) |
| UG FAILED EQUIPMENT KEENE | 2023 FY Actual | 79,158.29 |
| UG FAILED EQUIPMENT TILTON | 2019 FY Actual | 38,444.79 |
| UG FAILED EQUIPMENT TILTON | 2020 FY Actual | (7,267.54) |
| UG FAILED EQUIPMENT TILTON | 2021 FY Actual | 4,582.89 |
| UG FAILED EQUIPMENT TILTON | 2022 FY Actual | 177,723.04 |
| UG FAILED EQUIPMENT TILTON | 2023 FY Actual | 456,945.33 |
| UG FAILED EQUIPMENT NASHUA | 2021 FY Actual | 307,513.15 |
| UG FAILED EQUIPMENT NASHUA | 2022 FY Actual | 29,213.12 |
| UG FAILED EQUIPMENT NASHUA | 2023 FY Actual | 545,669.39 |
| UG FAILED EQUIPMENT PORTSMOUTH | 2021 FY Actual | 150,428.68 |
| UG FAILED EQUIPMENT PORTSMOUTH | 2022 FY Actual | 29,178.88 |
| UG FAILED EQUIPMENT PORTSMOUTH | 2023 FY Actual | 156,838.49 |
| UG FAILED EQUIPMENT ROCHESTER | 2021 FY Actual | 25,530.19 |
| UG FAILED EQUIPMENT ROCHESTER | 2022 FY Actual | 22,753.99 |
| UG FAILED EQUIPMENT ROCHESTER | 2023 FY Actual | 101,878.26 |
| UG FAILED EQUIPMENT NEWPORT | 2021 FY Actual | 20,936.26 |
| UG FAILED EQUIPMENT NEWPORT | 2022 FY Actual | (2,506.36) |
| UG FAILED EQUIPMENT NEWPORT | 2023 FY Actual | 58,462.47 |
| UG FAILED EQUIMENT HOOKSETT | 2019 FY Actual | 335,715.52 |
| UG FAILED EQUIMENT HOOKSETT | 2020 FY Actual | 206,217.60 |
| UG FAILED EQUIMENT HOOKSETT | 2021 FY Actual | 6,344.54 |
| UG FAILED EQUIMENT HOOKSETT | 2022 FY Actual | 30,730.21 |
| UG FAILED EQUIMENT HOOKSETT | 2023 FY Actual | 41,023.46 |
| UG FAILED EQUIPMENT BEDFORD | 2021 FY Actual | 235,727.38 |
| UG FAILED EQUIPMENT BEDFORD | 2022 FY Actual | 47,676.76 |
| UG FAILED EQUIPMENT BEDFORD | 2023 FY Actual | 307,802.78 |
| DB INSPECTION FAILED EQUIPMENT MILF | 2020 FY Actual | 90.41 |
| DB INSPECTION FAILED EQUIPMENT NASH | 2019 FY Actual | (348.66) |
| DB INSPECTION FAILED EQUIPMENT ROCH | 2019 FY Actual | 106.85 |
| DB INSPECTION FAILED EQUIPMENT ROCH | 2020 FY Actual | (1,358.94) |
| DB INSPECTION FAILED EQUIPMENT HOOK | 2019 FY Actual | 157.96 |
| DB INSPECTION FAILED EQUIPMENT BEDF | 2019 FY Actual | (349.04) |
| DB INSPECTION FAILED EQUIPMENT BEDF | 2020 FY Actual | 14,334.71 |
| DB INSPECTION FAILED EQUIPMENT BEDF | 2021 FY Actual | 148.02 |

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| DB INSPECTION FAILED EQUIPMENT BEDF | 2023 FY Actual | (15,071.56) |
| OH INSPECTION FAILED EQUIPMENT-LANC | 2019 FY Actual | (88.97) |
| OH INSPECTION FAILED EQUIPMENT-LANC | 2022 FY Actual | (70.18) |
| OH INSPECTION FAILED EQUIPMENT-LANC | 2023 FY Actual | 3,491.35 |
| OH INSPECTION FAILED EQUIPMENT-CHOC | 2021 FY Actual | 3,053.93 |
| OH INSPECTION FAILED EQUIPMENT - DE | 2021 FY Actual | 14,272.18 |
| OH INSPECTION FAILED EQUIPMENT - DE | 2022 FY Actual | (7,415.24) |
| OH INSPECTION FAILED EQUIPMENT - DE | 2023 FY Actual | 9,877.36 |
| OH INSPECTION FAILED EQUIPMENT - EP | 2021 FY Actual | 195,101.44 |
| OH INSPECTION FAILED EQUIPMENT - EP | 2022 FY Actual | 115,259.38 |
| OH INSPECTION FAILED EQUIPMENT - EP | 2023 FY Actual | 20,613.68 |
| OH INSPECTION FAILED EQUIPMENT - KE | 2019 FY Actual | 2.84 |
| OH INSPECTION FAILED EQUIPMENT - KE | 2021 FY Actual | 43,138.35 |
| OH INSPECTION FAILED EQUIPMENT - KE | 2022 FY Actual | 8,755.31 |
| OH INSPECTION FAILED EQUIPMENT - KE | 2023 FY Actual | 67,803.55 |
| OH INSPECTION FAILED EQUIPMENT - NA | 2021 FY Actual | 6,557.70 |
| OH INSPECTION FAILED EQUIPMENT - NA | 2022 FY Actual | 5,704.62 |
| OH INSPECTION FAILED EQUIP - PORTSM | 2019 FY Actual | 3,262.65 |
| OH INSPECTION FAILED EQUIP - PORTSM | 2020 FY Actual | 1,634.08 |
| OH INSPECTION FAILED EQUIP - PORTSM | 2021 FY Actual | 1.08 |
| OH INSPECTION FAILED EQUIP - PORTSM | 2023 FY Actual | 5,819.94 |
| OH INSPECTION FAILED EQUIPMENT-ROCH | 2019 FY Actual | 5,702.61 |
| OH INSPECTION FAILED EQUIPMENT-ROCH | 2021 FY Actual | 5,270.01 |
| OH INSPECTION FAILED EQUIPMENT-ROCH | 2022 FY Actual | (162.32) |
| OH INSPECTION FAILED EQUIPMENT-ROCH | 2023 FY Actual | (148.43) |
| OH INSPECTION FAILED EQUIPMENT - NE | 2022 FY Actual | 20,835.43 |
| OH INSPECTION FAILED EQUIPMENT - NE | 2023 FY Actual | 83,071.04 |
| OH INSPECTION FAILED EQUIPMENT-HOOK | 2019 FY Actual | 110,696.50 |
| OH INSPECTION FAILED EQUIPMENT-HOOK | 2020 FY Actual | 31,452.82 |
| OH INSPECTION FAILED EQUIPMENT-HOOK | 2021 FY Actual | (974.60) |
| OH INSPECTION FAILED EQUIPMENT-HOOK | 2022 FY Actual | (10,937.52) |
| OH INSPECTION FAILED EQUIPMENT-HOOK | 2023 FY Actual | (2,088.60) |
| OH INSPECTION FAILED EQUIPMENT - BE | 2019 FY Actual | 21,804.15 |
| OH INSPECTION FAILED EQUIPMENT - BE | 2020 FY Actual | 34,922.71 |
| OH INSPECTION FAILED EQUIPMENT - BE | 2021 FY Actual | 210.91 |
| ROW REPLACE FAILED EQUIPMENT-ANNUA | 2019 FY Actual | 1,038,875 |
| ROW REPLACE FAILED EQUIPMENT-ANNUA | 2019 FY Budget | 1,199,925 |
| ROW REPLACE FAILED EQUIPMENT-ANNUA | 2020 FY Actual | 562,288 |
| ROW REPLACE FAILED EQUIPMENT-ANNUA | 2020 FY Budget | 1,091,993 |
| ROW REPLACE FAILED EQUIPMENT-ANNUA | 2021 FY Actual | 1,082,002 |
| ROW REPLACE FAILED EQUIPMENT-ANNUA | 2021 FY Budget | 1,122,000 |
| ROW REPLACE FAILED EQUIPMENT-ANNUA | 2022 FY Actual | 1,023,660 |
| ROW REPLACE FAILED EQUIPMENT-ANNUA | 2022 FY Budget | 1,113,581 |
| ROW REPLACE FAILED EQUIPMENT-ANNUA | 2023 FY Actual | 1,119,642 |
| ROW REPLACE FAILED EQUIPMENT-ANNUA | 2023 FY Budget | 1,250,000 |
| MINOR STORMS CAPITAL - LANCASTER AW | 2022 FY Actual | 47,888.01 |
| MINOR STORMS CAPITAL - LANCASTER AW | 2023 FY Actual | 57,527.83 |

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| Minor Storms Capital - Berlin AWC | 2023 FY Actual | 5,928.97 |
| MINOR STORMS CAPITAL - CHOCORUA AWC | 2021 FY Actual | 8,703.09 |
| MINOR STORMS CAPITAL - CHOCORUA AWC | 2022 FY Actual | 27,156.34 |
| MINOR STORMS CAPITAL - CHOCORUA AWC | 2023 FY Actual | 107,672.23 |
| MINOR STORMS CAPITAL - DERRY AWC | 2021 FY Actual | 12,416.78 |
| MINOR STORMS CAPITAL - DERRY AWC | 2022 FY Actual | 206,996.64 |
| MINOR STORMS CAPITAL - DERRY AWC | 2023 FY Actual | 31,278.80 |
| MINOR STORMS CAPITAL - EPPING AWC | 2019 FY Actual | 63.69 |
| MINOR STORMS CAPITAL - EPPING AWC | 2021 FY Actual | 7,873.16 |
| MINOR STORMS CAPITAL - EPPING AWC | 2022 FY Actual | (4,310.08) |
| MINOR STORMS CAPITAL - KEENE AWC | 2019 FY Actual | 1,360.66 |
| MINOR STORMS CAPITAL - KEENE AWC | 2020 FY Actual | 23,944.77 |
| MINOR STORMS CAPITAL - KEENE AWC | 2021 FY Actual | 36,967.40 |
| MINOR STORMS CAPITAL - KEENE AWC | 2022 FY Actual | 36,449.98 |
| MINOR STORMS CAPITAL - KEENE AWC | 2023 FY Actual | 32,877.30 |
| MINOR STORMS CAPITAL - TILTON AWC | 2019 FY Actual | 6,569.68 |
| MINOR STORMS CAPITAL - TILTON AWC | 2020 FY Actual | (1,221.72) |
| MINOR STORMS CAPITAL - TILTON AWC | 2021 FY Actual | 133,674.16 |
| MINOR STORMS CAPITAL - TILTON AWC | 2022 FY Actual | 194,290.59 |
| MINOR STORMS CAPITAL - TILTON AWC | 2023 FY Actual | 346,016.52 |
| MINOR STORMS CAPITAL - NASHUA AWC | 2019 FY Actual | 75.36 |
| MINOR STORMS CAPITAL - NASHUA AWC | 2021 FY Actual | 48,593.48 |
| MINOR STORMS CAPITAL - NASHUA AWC | 2022 FY Actual | 595,968.99 |
| MINOR STORMS CAPITAL - NASHUA AWC | 2023 FY Actual | 251,303.41 |
| MINOR STORMS CAPITAL - PORTSMOUTH A | 2021 FY Actual | 52,224.52 |
| MINOR STORMS CAPITAL - PORTSMOUTH A | 2022 FY Actual | 42,948.09 |
| MINOR STORMS CAPITAL - PORTSMOUTH A | 2023 FY Actual | 7,379.57 |
| Minor storms capital | 2019 FY Budget | 129,166.04 |
| Minor storms capital | 2020 FY Budget | 132,486.28 |
| Minor storms capital | 2021 FY Budget | 135,299.57 |
| Minor storms capital | 2022 FY Budget | 166,946.83 |
| Minor storms capital | 2023 FY Budget | 500,000.00 |
| MINOR STORMS CAPITAL - ROCHESTER AW | 2021 FY Actual | 7,779.42 |
| MINOR STORMS CAPITAL - ROCHESTER AW | 2022 FY Actual | 28,389.51 |
| MINOR STORMS CAPITAL - ROCHESTER AW | 2023 FY Actual | 159,930.14 |
| MINOR STORMS CAPITAL - NEWPORT AWC | 2020 FY Actual | 17,715.32 |
| MINOR STORMS CAPITAL - NEWPORT AWC | 2021 FY Actual | 73,445.70 |
| MINOR STORMS CAPITAL - NEWPORT AWC | 2022 FY Actual | 77,450.61 |
| MINOR STORMS CAPITAL - NEWPORT AWC | 2023 FY Actual | 133,039.61 |
| MINOR STORMS CAPITAL - HOOKSETT AWC | 2019 FY Actual | 313.62 |
| MINOR STORMS CAPITAL - HOOKSETT AWC | 2020 FY Actual | 123,585.23 |
| MINOR STORMS CAPITAL - HOOKSETT AWC | 2021 FY Actual | 88,468.78 |
| MINOR STORMS CAPITAL - HOOKSETT AWC | 2022 FY Actual | 160,723.76 |
| MINOR STORMS CAPITAL - HOOKSETT AWC | 2023 FY Actual | 81,809.11 |
| MINOR STORMS CAPITAL - BEDFORD AWC | 2019 FY Actual | (3,871.10) |
| MINOR STORMS CAPITAL - BEDFORD AWC | 2020 FY Actual | 1,814.92 |
| MINOR STORMS CAPITAL - BEDFORD AWC | 2021 FY Actual | 182,392.28 |

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| MINOR STORMS CAPITAL - BEDFORD AWC | 2022 FY Actual | 130,395.92 |
| MINOR STORMS CAPITAL - BEDFORD AWC | 2023 FY Actual | 554,603.68 |
| NH LINE CONTRACTORS | 2019 FY Actual | 82,378.03 |
| NH LINE CONTRACTORS | 2019 FY Budget | 300,092.40 |
| NH LINE CONTRACTORS | 2020 FY Actual | (319,556.68) |
| NH LINE CONTRACTORS | 2020 FY Budget | 299,905.20 |
| NH LINE CONTRACTORS | 2021 FY Actual | 1,149,950.41 |
| NH LINE CONTRACTORS | 2021 FY Budget | 306,000.00 |
| NH LINE CONTRACTORS | 2022 FY Actual | (510,209.49) |
| NH LINE CONTRACTORS | 2022 FY Budget | 299,488.70 |
| NH LINE CONTRACTORS | 2023 FY Actual | 387,129.90 |
| NH STORM CAPITALIZATION | 2019 FY Actual | (3,449.18) |
| NH STORM CAPITALIZATION | 2019 FY Budget | 605,109.72 |
| NH STORM CAPITALIZATION | 2020 FY Actual | 1,494,071.14 |
| NH STORM CAPITALIZATION | 2020 FY Budget | 611,268.99 |
| NH STORM CAPITALIZATION | 2021 FY Actual | 114,138.53 |
| NH STORM CAPITALIZATION | 2021 FY Budget | 624,199.99 |
| NH STORM CAPITALIZATION | 2022 FY Actual | 2,745,560.93 |
| NH STORM CAPITALIZATION | 2022 FY Budget | 597,995.66 |
| NH STORM CAPITALIZATION | 2023 FY Actual | 3,269,593.53 |
| NH STORM CAPITALIZATION | 2023 FY Budget | 2,550,000.00 |
| NH STORM CAP: Mar 2, 2017 event | 2019 FY Actual | (2,885.33) |
| NH STORM CAP: Oct 29, 2017 event | 2019 FY Actual | (10,107.67) |
| NH STORM CAP: Oct 29, 2017 event | 2020 FY Actual | (8,891.00) |
| NH STORM CAP: Oct 29, 2017 event | 2021 FY Actual | (2,658.84) |
| NH STORM CAP: Mar 7-8, 2018 event | 2019 FY Actual | 50,651.43 |
| NH STORM CAP: Apr 4-5, 2018 event | 2019 FY Actual | 83.34 |
| NH STORM CAP: Apr 4-5, 2018 event | 2021 FY Actual | (529.40) |
| BERLIN 4KV SYSTEM RECONFIGURATION | 2019 FY Actual | 1,849.50 |
| BERLIN EASTSIDE 34.5KV LINE BREAKER | 2019 FY Actual | (5,563.38) |
| BERLIN EASTSIDE 34.5KV LINE BREAKER | 2020 FY Actual | (5,286.59) |
| BERLIN EASTSIDE 34.5KV LINE BREAKER | 2022 FY Actual | 10,605.00 |
| REPLACE LTC CONTROLS EDDY SS | 2021 FY Actual | 88,631.00 |
| REPLACE LTC CONTROLS EDDY SS | 2022 FY Actual | 515,630.18 |
| REPLACE LTC CONTROLS EDDY SS | 2022 FY Budget | 82,335.40 |
| REPLACE LTC CONTROLS EDDY SS | 2023 FY Actual | 7,559.17 |
| BERLIN EAST SIDE SS REPLACE TRANSFO | 2021 FY Actual | 2,114,931.92 |
| BERLIN EAST SIDE SS REPLACE TRANSFO | 2022 FY Actual | 1,763,722.59 |
| BERLIN EAST SIDE SS REPLACE TRANSFO | 2022 FY Budget | 1,721,504.08 |
| BERLIN EAST SIDE SS REPLACE TRANSFO | 2023 FY Actual | 5,699.30 |
| 2022 NH D SS Emergent Annual | 2022 FY Actual | 265,305 |
| 2022 NH D SS Emergent Annual | 2022 FY Budget | 1,200,000 |
| 2022 NH D SS Emergent Annual | 2023 FY Actual | 474,806 |
| 2023 NH D SS Emergent Annual | 2023 FY Actual | 615,611 |
| 2023 NH D SS Emergent Annual | 2023 FY Budget | 846,600 |
| PCB TRANSFORMER CHANGEOUT PROGRAM | 2019 FY Actual | 52,324.78 |
| PCB TRANSFORMER CHANGEOUT PROGRAM | 2019 FY Budget | 75,049.13 |

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| PCB TRANSFORMER CHANGEOUT PROGRAM | 2020 FY Actual | 89,820.91 |
| PCB TRANSFORMER CHANGEOUT PROGRAM | 2020 FY Budget | 74,333.99 |
| PCB TRANSFORMER CHANGEOUT PROGRAM | 2021 FY Actual | 275,568.26 |
| PCB TRANSFORMER CHANGEOUT PROGRAM | 2021 FY Budget | 76,500.00 |
| PCB TRANSFORMER CHANGEOUT PROGRAM | 2022 FY Actual | 207,137.79 |
| PCB TRANSFORMER CHANGEOUT PROGRAM | 2022 FY Budget | 148,906.99 |
| PCB TRANSFORMER CHANGEOUT PROGRAM | 2023 FY Actual | 410,588.34 |
| PCB TRANSFORMER CHANGEOUT PROGRAM | 2023 FY Budget | 265,200.00 |
| DB INSURANCE CLAIM ANNUAL LANCASTER | 2019 FY Actual | 2,138.50 |
| DB INSURANCE CLAIM ANNUAL LANCASTER | 2020 FY Actual | 3,552.88 |
| DB INSURANCE CLAIM ANNUAL LANCASTER | 2021 FY Actual | 3,656.98 |
| DB INSURANCE CLAIM ANNUAL LANCASTER | 2022 FY Actual | 555.82 |
| DB INSURANCE CLAIM ANNUAL LANCASTER | 2023 FY Actual | (392.51) |
| DB INSURANCE CLAIM ANNUAL BERLIN | 2022 FY Actual | 448.06 |
| DB INSURANCE CLAIM ANNUAL BERLIN | 2023 FY Actual | 155.14 |
| DB INSURANCE CLAIM ANNUAL CHOCORUA | 2021 FY Actual | 1,816.85 |
| DB INSURANCE CLAIM ANNUAL CHOCORUA | 2022 FY Actual | (1,477.86) |
| DB INSURANCE CLAIM ANNUAL CHOCORUA | 2023 FY Actual | (114.75) |
| DB INSURANCE CLAIM ANNUAL - DERRY | 2019 FY Actual | (5,832.09) |
| DB INSURANCE CLAIM ANNUAL - DERRY | 2020 FY Actual | 28,827.21 |
| DB INSURANCE CLAIM ANNUAL - DERRY | 2021 FY Actual | (13,139.51) |
| DB INSURANCE CLAIM ANNUAL - DERRY | 2022 FY Actual | 5,732.66 |
| DB INSURANCE CLAIM ANNUAL - DERRY | 2023 FY Actual | 3,612.82 |
| DB INSURANCE CLAIM ANNUAL EPPING | 2019 FY Actual | (1,087.65) |
| DB INSURANCE CLAIM ANNUAL EPPING | 2021 FY Actual | 24,713.30 |
| DB INSURANCE CLAIM ANNUAL EPPING | 2022 FY Actual | 6.43 |
| DB INSURANCE CLAIM ANNUAL EPPING | 2023 FY Actual | (24,477.70) |
| DB INSURANCE CLAIM ANNUAL - KEENE | 2019 FY Actual | 2,744.94 |
| DB INSURANCE CLAIM ANNUAL - KEENE | 2020 FY Actual | 1,145.41 |
| DB INSURANCE CLAIM ANNUAL - KEENE | 2021 FY Actual | 8,078.54 |
| DB INSURANCE CLAIM ANNUAL - KEENE | 2022 FY Actual | 442.91 |
| DB INSURANCE CLAIM ANNUAL - KEENE | 2023 FY Actual | 19,348.42 |
| DB INSURANCE CLAIM ANNUAL TILTON | 2019 FY Actual | 460.95 |
| DB INSURANCE CLAIM ANNUAL TILTON | 2020 FY Actual | 2,820.07 |
| DB INSURANCE CLAIM ANNUAL TILTON | 2021 FY Actual | 17,866.65 |
| DB INSURANCE CLAIM ANNUAL TILTON | 2022 FY Actual | 90,629.90 |
| DB INSURANCE CLAIM ANNUAL TILTON | 2023 FY Actual | (21,606.56) |
| DB INSURANCE CLAIM ANNUAL - NASHUA | 2019 FY Actual | 91,348.58 |
| DB INSURANCE CLAIM ANNUAL - NASHUA | 2020 FY Actual | 170,807.02 |
| DB INSURANCE CLAIM ANNUAL - NASHUA | 2021 FY Actual | (18,674.57) |
| DB INSURANCE CLAIM ANNUAL - NASHUA | 2022 FY Actual | 8,911.57 |
| DB INSURANCE CLAIM ANNUAL - NASHUA | 2023 FY Actual | 14,518.90 |
| DB INSURANCE CLAIM ANNUAL PORTSMOUT | 2019 FY Actual | 34,465.51 |
| DB INSURANCE CLAIM ANNUAL PORTSMOUT | 2020 FY Actual | 66,816.21 |
| DB INSURANCE CLAIM ANNUAL PORTSMOUT | 2021 FY Actual | (44,684.67) |
| DB INSURANCE CLAIM ANNUAL PORTSMOUT | 2022 FY Actual | 7,113.66 |
| DB INSURANCE CLAIM ANNUAL PORTSMOUT | 2023 FY Actual | 147,018.22 |

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| DB INSURANCE CLAIM ANNUAL ROCHESTER | 2020 FY Actual | 103.51 |
| DB INSURANCE CLAIM ANNUAL ROCHESTER | 2021 FY Actual | 23,376.46 |
| DB INSURANCE CLAIM ANNUAL ROCHESTER | 2022 FY Actual | 5,168.93 |
| DB INSURANCE CLAIM ANNUAL ROCHESTER | 2023 FY Actual | 13,846.83 |
| DB INSURANCE CLAIM ANNUAL NEWPORT | 2019 FY Actual | 2,374.83 |
| DB INSURANCE CLAIM ANNUAL NEWPORT | 2020 FY Actual | 29,042.33 |
| DB INSURANCE CLAIM ANNUAL NEWPORT | 2021 FY Actual | 1,768.55 |
| DB INSURANCE CLAIM ANNUAL NEWPORT | 2022 FY Actual | 28,388.80 |
| DB INSURANCE CLAIM ANNUAL NEWPORT | 2023 FY Actual | (27,210.45) |
| DB INSURANCE CLAIM ANNUAL - HOOKSET | 2019 FY Actual | 7,123.94 |
| DB INSURANCE CLAIM ANNUAL - HOOKSET | 2020 FY Actual | (9,040.49) |
| DB INSURANCE CLAIM ANNUAL - HOOKSET | 2021 FY Actual | 53,954.97 |
| DB INSURANCE CLAIM ANNUAL - HOOKSET | 2022 FY Actual | (15,917.05) |
| DB INSURANCE CLAIM ANNUAL - HOOKSET | 2023 FY Actual | (4,320.89) |
| DB INSURANCE CLAIM ANNUAL BEDFORD | 2019 FY Actual | 10,705.17 |
| DB INSURANCE CLAIM ANNUAL BEDFORD | 2020 FY Actual | (6,365.77) |
| DB INSURANCE CLAIM ANNUAL BEDFORD | 2021 FY Actual | 20,422.15 |
| DB INSURANCE CLAIM ANNUAL BEDFORD | 2022 FY Actual | (10,434.77) |
| DB INSURANCE CLAIM ANNUAL BEDFORD | 2023 FY Actual | 603.22 |
| OH INSURANCE CLAIM LANCASTER | 2019 FY Actual | 8,657.36 |
| OH INSURANCE CLAIM LANCASTER | 2020 FY Actual | 29,928.62 |
| OH INSURANCE CLAIM LANCASTER | 2021 FY Actual | 148,952.53 |
| OH INSURANCE CLAIM LANCASTER | 2022 FY Actual | 20,341.58 |
| OH INSURANCE CLAIM LANCASTER | 2023 FY Actual | 60,953.38 |
| OH INSURANCE CLAIM BERLIN | 2019 FY Actual | 64,349.32 |
| OH INSURANCE CLAIM BERLIN | 2020 FY Actual | (13,180.31) |
| OH INSURANCE CLAIM BERLIN | 2021 FY Actual | (16,482.91) |
| OH INSURANCE CLAIM BERLIN | 2022 FY Actual | (7,652.51) |
| OH INSURANCE CLAIM BERLIN | 2023 FY Actual | 41,676.64 |
| OH INSURANCE CLAIM CHOCORUA | 2019 FY Actual | 15,809.76 |
| OH INSURANCE CLAIM CHOCORUA | 2020 FY Actual | 20,404.86 |
| OH INSURANCE CLAIM CHOCORUA | 2021 FY Actual | 117,407.45 |
| OH INSURANCE CLAIM CHOCORUA | 2022 FY Actual | (21,656.55) |
| OH INSURANCE CLAIM CHOCORUA | 2023 FY Actual | 92,507.99 |
| OH INSURANCE CLAIM DERRY | 2019 FY Actual | 164,604.31 |
| OH INSURANCE CLAIM DERRY | 2020 FY Actual | (61,462.09) |
| OH INSURANCE CLAIM DERRY | 2021 FY Actual | 303,774.23 |
| OH INSURANCE CLAIM DERRY | 2022 FY Actual | 138,362.04 |
| OH INSURANCE CLAIM DERRY | 2023 FY Actual | (42,208.50) |
| OH INSURANCE CLAIM EPPING | 2019 FY Actual | 38,989.24 |
| OH INSURANCE CLAIM EPPING | 2020 FY Actual | 35,014.83 |
| OH INSURANCE CLAIM EPPING | 2021 FY Actual | 129,065.89 |
| OH INSURANCE CLAIM EPPING | 2022 FY Actual | 102,322.71 |
| OH INSURANCE CLAIM EPPING | 2023 FY Actual | 67,981.52 |
| OH INSURANCE CLAIM KEENE | 2019 FY Actual | 83,825.25 |
| OH INSURANCE CLAIM KEENE | 2020 FY Actual | 134,681.16 |
| OH INSURANCE CLAIM KEENE | 2021 FY Actual | 254,277.74 |

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| OH INSURANCE CLAIM KEENE | 2022 FY Actual | 207,290.11 |
| OH INSURANCE CLAIM KEENE | 2023 FY Actual | (101,227.03) |
| OH INSURANCE CLAIM TILTON | 2019 FY Actual | 95,455.43 |
| OH INSURANCE CLAIM TILTON | 2020 FY Actual | 99,146.61 |
| OH INSURANCE CLAIM TILTON | 2021 FY Actual | 157,499.18 |
| OH INSURANCE CLAIM TILTON | 2022 FY Actual | 41,118.26 |
| OH INSURANCE CLAIM TILTON | 2023 FY Actual | 170,229.79 |
| OH INSURANCE CLAIM MILFORD | 2023 FY Actual | (211.11) |
| OH INSURANCE CLAIM NASHUA | 2019 FY Actual | 246,168.54 |
| OH INSURANCE CLAIM NASHUA | 2020 FY Actual | 33,269.36 |
| OH INSURANCE CLAIM NASHUA | 2021 FY Actual | 456,182.80 |
| OH INSURANCE CLAIM NASHUA | 2022 FY Actual | (193,900.08) |
| OH INSURANCE CLAIM NASHUA | 2023 FY Actual | 213,483.15 |
| OH INSURANCE CLAIM PORTSMOUTH | 2019 FY Actual | 11,038.41 |
| OH INSURANCE CLAIM PORTSMOUTH | 2020 FY Actual | 10,129.43 |
| OH INSURANCE CLAIM PORTSMOUTH | 2021 FY Actual | 147,577.50 |
| OH INSURANCE CLAIM PORTSMOUTH | 2022 FY Actual | 21,590.84 |
| OH INSURANCE CLAIM PORTSMOUTH | 2023 FY Actual | (25,709.12) |
| OH INSURANCE CLAIM PSNH | 2019 FY Budget | 600,190.46 |
| OH INSURANCE CLAIM PSNH | 2020 FY Budget | 600,001.30 |
| OH INSURANCE CLAIM PSNH | 2021 FY Budget | 611,999.95 |
| OH INSURANCE CLAIM PSNH | 2022 FY Budget | 1,435,299.96 |
| OH INSURANCE CLAIM PSNH | 2023 FY Budget | 1,770,720.00 |
| OH INSURANCE CLAIM ROCHESTER | 2019 FY Actual | 133,949.91 |
| OH INSURANCE CLAIM ROCHESTER | 2020 FY Actual | 62,803.30 |
| OH INSURANCE CLAIM ROCHESTER | 2021 FY Actual | 197,268.06 |
| OH INSURANCE CLAIM ROCHESTER | 2022 FY Actual | 140,247.67 |
| OH INSURANCE CLAIM ROCHESTER | 2023 FY Actual | 112,644.01 |
| OH INSURANCE CLAIM NEWPORT | 2019 FY Actual | 19,775.87 |
| OH INSURANCE CLAIM NEWPORT | 2020 FY Actual | 56,768.40 |
| OH INSURANCE CLAIM NEWPORT | 2021 FY Actual | 79,925.50 |
| OH INSURANCE CLAIM NEWPORT | 2022 FY Actual | (47,510.39) |
| OH INSURANCE CLAIM NEWPORT | 2023 FY Actual | 59,408.21 |
| OH INSURANCE CLAIM HOOKSETT | 2019 FY Actual | 29,415.19 |
| OH INSURANCE CLAIM HOOKSETT | 2020 FY Actual | 131,651.30 |
| OH INSURANCE CLAIM HOOKSETT | 2021 FY Actual | 342,010.15 |
| OH INSURANCE CLAIM HOOKSETT | 2022 FY Actual | 124,342.43 |
| OH INSURANCE CLAIM HOOKSETT | 2023 FY Actual | (57,693.93) |
| OH INSURANCE CLAIM BEDFORD | 2019 FY Actual | (81,497.23) |
| OH INSURANCE CLAIM BEDFORD | 2020 FY Actual | 96,306.53 |
| OH INSURANCE CLAIM BEDFORD | 2021 FY Actual | 315,959.39 |
| OH INSURANCE CLAIM BEDFORD | 2022 FY Actual | (146,717.84) |
| OH INSURANCE CLAIM BEDFORD | 2023 FY Actual | 86,720.75 |
| UG INSURANCE CLAIM LANCASTER | 2023 FY Actual | 414.46 |
| UG INSURANCE CLAIM BERLIN | 2021 FY Actual | 423.41 |
| UG INSURANCE CLAIM BERLIN | 2022 FY Actual | 111.27 |
| UG INSURANCE CLAIM BERLIN | 2023 FY Actual | 569.50 |

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| UG INSURANCE CLAIM CHOCORUA | 2021 FY Actual | 151.70 |
| UG INSURANCE CLAIM CHOCORUA | 2022 FY Actual | 539.98 |
| UG INSURANCE CLAIM CHOCORUA | 2023 FY Actual | 60.21 |
| UG INSURANCE CLAIM DERRY | 2021 FY Actual | 85.29 |
| UG INSURANCE CLAIM DERRY | 2022 FY Actual | 8,353.39 |
| UG INSURANCE CLAIM DERRY | 2023 FY Actual | 6,254.47 |
| UG INSURANCE CLAIM EPPING | 2023 FY Actual | 5,864.31 |
| UG INSURANCE CLAIM KEENE | 2019 FY Actual | (8,550.82) |
| UG INSURANCE CLAIM KEENE | 2020 FY Actual | 3,923.04 |
| UG INSURANCE CLAIM KEENE | 2021 FY Actual | 656.01 |
| UG INSURANCE CLAIM KEENE | 2022 FY Actual | 12,283.92 |
| UG INSURANCE CLAIM KEENE | 2023 FY Actual | (13,857.10) |
| UG INSURANCE CLAIM TILTON | 2021 FY Actual | 8,844.40 |
| UG INSURANCE CLAIM TILTON | 2022 FY Actual | 293.34 |
| UG INSURANCE CLAIM TILTON | 2023 FY Actual | 1,248.29 |
| UG INSURANCE CLAIM NASHUA | 2021 FY Actual | 425.84 |
| UG INSURANCE CLAIM NASHUA | 2022 FY Actual | 46,465.64 |
| UG INSURANCE CLAIM NASHUA | 2023 FY Actual | 14,326.00 |
| UG INSURANCE CLAIM PORTSMOUTH | 2021 FY Actual | 10,251.11 |
| UG INSURANCE CLAIM PORTSMOUTH | 2022 FY Actual | 6,538.88 |
| UG INSURANCE CLAIM PORTSMOUTH | 2023 FY Actual | 70,910.42 |
| UG INSURANCE CLAIM ROCHESTER | 2021 FY Actual | 11,947.29 |
| UG INSURANCE CLAIM ROCHESTER | 2022 FY Actual | 22,882.17 |
| UG INSURANCE CLAIM ROCHESTER | 2023 FY Actual | 7,548.55 |
| UG INSURANCE CLAIM NEWPORT | 2022 FY Actual | 870.49 |
| UG INSURANCE CLAIM NEWPORT | 2023 FY Actual | 6,004.30 |
| UG INSURANCE CLAIM HOOKSETT | 2020 FY Actual | 2,324.78 |
| UG INSURANCE CLAIM HOOKSETT | 2022 FY Actual | (1,151.24) |
| UG INSURANCE CLAIM HOOKSETT | 2023 FY Actual | 3,126.93 |
| UG INSURANCE CLAIM BEDFORD | 2021 FY Actual | 2,540.50 |
| UG INSURANCE CLAIM BEDFORD | 2022 FY Actual | 7,649.25 |
| UG INSURANCE CLAIM BEDFORD | 2023 FY Actual | 2,506.76 |
| NON-ROADWAY LIGHTING - LANCASTER | 2019 FY Actual | 30,523.58 |
| NON-ROADWAY LIGHTING - LANCASTER | 2020 FY Actual | 12,582.82 |
| NON-ROADWAY LIGHTING - LANCASTER | 2021 FY Actual | 12,179.64 |
| NON-ROADWAY LIGHTING - LANCASTER | 2022 FY Actual | 9,090.75 |
| NON-ROADWAY LIGHTING - LANCASTER | 2023 FY Actual | 8,108.90 |
| NON-ROADWAY LIGHTING - BERLIN | 2019 FY Actual | 3,937.34 |
| NON-ROADWAY LIGHTING - BERLIN | 2020 FY Actual | 7,257.73 |
| NON-ROADWAY LIGHTING - BERLIN | 2021 FY Actual | 12,697.33 |
| NON-ROADWAY LIGHTING - BERLIN | 2022 FY Actual | 14,610.27 |
| NON-ROADWAY LIGHTING - BERLIN | 2023 FY Actual | 1,777.01 |
| NON-ROADWAY LIGHTING - CHOCORUA | 2019 FY Actual | 15,870.57 |
| NON-ROADWAY LIGHTING - CHOCORUA | 2020 FY Actual | 8,175.75 |
| NON-ROADWAY LIGHTING - CHOCORUA | 2021 FY Actual | 5,520.78 |
| NON-ROADWAY LIGHTING - CHOCORUA | 2022 FY Actual | 52,005.41 |
| NON-ROADWAY LIGHTING - CHOCORUA | 2023 FY Actual | 20,257.05 |

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| NON-ROADWAY LIGHTING - DERRY | 2019 FY Actual | 41,144.59 |
| NON-ROADWAY LIGHTING - DERRY | 2020 FY Actual | 22,645.06 |
| NON-ROADWAY LIGHTING - DERRY | 2021 FY Actual | 38,835.90 |
| NON-ROADWAY LIGHTING - DERRY | 2022 FY Actual | 21,335.09 |
| NON-ROADWAY LIGHTING - DERRY | 2023 FY Actual | 55,556.67 |
| NON-ROADWAY LIGHTING - EPPING | 2019 FY Actual | 20,177.60 |
| NON-ROADWAY LIGHTING - EPPING | 2020 FY Actual | 13,897.60 |
| NON-ROADWAY LIGHTING - EPPING | 2021 FY Actual | 22,487.24 |
| NON-ROADWAY LIGHTING - EPPING | 2022 FY Actual | 27,797.04 |
| NON-ROADWAY LIGHTING - EPPING | 2023 FY Actual | 39,725.41 |
| NON-ROADWAY LIGHTING - KEENE | 2019 FY Actual | 37,899.12 |
| NON-ROADWAY LIGHTING - KEENE | 2020 FY Actual | 26,828.02 |
| NON-ROADWAY LIGHTING - KEENE | 2021 FY Actual | 34,801.03 |
| NON-ROADWAY LIGHTING - KEENE | 2022 FY Actual | 30,813.54 |
| NON-ROADWAY LIGHTING - KEENE | 2023 FY Actual | 80,360.81 |
| NON-ROADWAY LIGHTING LACONIA | 2019 FY Actual | 56,337.82 |
| NON-ROADWAY LIGHTING LACONIA | 2020 FY Actual | 30,340.52 |
| NON-ROADWAY LIGHTING LACONIA | 2021 FY Actual | 30,773.38 |
| NON-ROADWAY LIGHTING LACONIA | 2022 FY Actual | 92,840.73 |
| NON-ROADWAY LIGHTING LACONIA | 2023 FY Actual | 102,675.95 |
| NON-ROADWAY LIGHTING - NASHUA | 2019 FY Actual | 67,021.92 |
| NON-ROADWAY LIGHTING - NASHUA | 2020 FY Actual | 96,459.67 |
| NON-ROADWAY LIGHTING - NASHUA | 2021 FY Actual | 52,940.59 |
| NON-ROADWAY LIGHTING - NASHUA | 2022 FY Actual | 86,702.66 |
| NON-ROADWAY LIGHTING - NASHUA | 2023 FY Actual | 130,102.84 |
| NON-ROADWAY LIGHTING - PORTSMOUTH | 2019 FY Actual | 9,231.88 |
| NON-ROADWAY LIGHTING - PORTSMOUTH | 2020 FY Actual | 23,972.79 |
| NON-ROADWAY LIGHTING - PORTSMOUTH | 2021 FY Actual | 10,979.34 |
| NON-ROADWAY LIGHTING - PORTSMOUTH | 2022 FY Actual | 7,224.37 |
| NON-ROADWAY LIGHTING - PORTSMOUTH | 2023 FY Actual | 17,538.46 |
| NON-ROADWAY LIGHTING | 2019 FY Budget | 400,126.57 |
| NON-ROADWAY LIGHTING | 2020 FY Budget | 407,574.25 |
| NON-ROADWAY LIGHTING | 2021 FY Budget | 416,200.06 |
| NON-ROADWAY LIGHTING | 2022 FY Budget | 765,705.04 |
| NON-ROADWAY LIGHTING | 2023 FY Budget | 693,600.00 |
| NON-ROADWAY LIGHTING - ROCHESTER | 2019 FY Actual | 31,349.13 |
| NON-ROADWAY LIGHTING - ROCHESTER | 2020 FY Actual | 47,636.14 |
| NON-ROADWAY LIGHTING - ROCHESTER | 2021 FY Actual | 20,598.45 |
| NON-ROADWAY LIGHTING - ROCHESTER | 2022 FY Actual | 59,710.16 |
| NON-ROADWAY LIGHTING - ROCHESTER | 2023 FY Actual | 51,158.33 |
| NON-ROADWAY LIGHTING - NEWPORT | 2019 FY Actual | 20,676.46 |
| NON-ROADWAY LIGHTING - NEWPORT | 2020 FY Actual | 11,522.05 |
| NON-ROADWAY LIGHTING - NEWPORT | 2021 FY Actual | 8,929.37 |
| NON-ROADWAY LIGHTING - NEWPORT | 2022 FY Actual | 4,942.99 |
| NON-ROADWAY LIGHTING - NEWPORT | 2023 FY Actual | 17,698.47 |
| NON-ROADWAY LIGHTING - MANCHESTER E | 2019 FY Actual | 70,122.46 |
| NON-ROADWAY LIGHTING - MANCHESTER E | 2020 FY Actual | 25,692.21 |

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| NON-ROADWAY LIGHTING - MANCHESTER E | 2021 FY Actual | 24,031.08 |
| NON-ROADWAY LIGHTING - MANCHESTER E | 2022 FY Actual | 34,344.47 |
| NON-ROADWAY LIGHTING - MANCHESTER E | 2023 FY Actual | 264,739.05 |
| NON-ROADWAY LIGHTING - MANCHESTER W | 2019 FY Actual | 33,471.52 |
| NON-ROADWAY LIGHTING - MANCHESTER W | 2020 FY Actual | 25,336.83 |
| NON-ROADWAY LIGHTING - MANCHESTER W | 2021 FY Actual | 45,896.00 |
| NON-ROADWAY LIGHTING - MANCHESTER W | 2022 FY Actual | 28,313.21 |
| NON-ROADWAY LIGHTING - MANCHESTER W | 2023 FY Actual | 32,358.30 |
| ROADWAY LIGHTING - LANCASTER | 2019 FY Actual | (195.38) |
| ROADWAY LIGHTING - LANCASTER | 2020 FY Actual | 1,283.72 |
| ROADWAY LIGHTING - LANCASTER | 2021 FY Actual | 1,199.13 |
| ROADWAY LIGHTING - LANCASTER | 2022 FY Actual | 538.43 |
| ROADWAY LIGHTING - LANCASTER | 2023 FY Actual | 2,515.66 |
| ROADWAY LIGHTING - BERLIN | 2019 FY Actual | 2,252.72 |
| ROADWAY LIGHTING - BERLIN | 2020 FY Actual | (190.00) |
| ROADWAY LIGHTING - BERLIN | 2021 FY Actual | 369.65 |
| ROADWAY LIGHTING - BERLIN | 2022 FY Actual | 1,306.98 |
| ROADWAY LIGHTING - BERLIN | 2023 FY Actual | (8.38) |
| ROADWAY LIGHTING - CHOCORUA | 2019 FY Actual | 2,603.05 |
| ROADWAY LIGHTING - CHOCORUA | 2020 FY Actual | 2,572.20 |
| ROADWAY LIGHTING - CHOCORUA | 2021 FY Actual | 1,898.26 |
| ROADWAY LIGHTING - CHOCORUA | 2022 FY Actual | 7,350.82 |
| ROADWAY LIGHTING - CHOCORUA | 2023 FY Actual | 14,525.14 |
| ROADWAY LIGHTING - DERRY | 2019 FY Actual | 3,215.96 |
| ROADWAY LIGHTING - DERRY | 2020 FY Actual | 1,311.94 |
| ROADWAY LIGHTING - DERRY | 2021 FY Actual | 5,023.81 |
| ROADWAY LIGHTING - DERRY | 2022 FY Actual | 18,912.90 |
| ROADWAY LIGHTING - DERRY | 2023 FY Actual | 112,547.95 |
| ROADWAY LIGHTING - EPPING | 2019 FY Actual | 1,845.34 |
| ROADWAY LIGHTING - EPPING | 2020 FY Actual | 8,225.76 |
| ROADWAY LIGHTING - EPPING | 2021 FY Actual | 761.22 |
| ROADWAY LIGHTING - EPPING | 2022 FY Actual | 3,025.88 |
| ROADWAY LIGHTING - EPPING | 2023 FY Actual | 59,095.73 |
| ROADWAY LIGHTING - KEENE | 2019 FY Actual | (3,134.64) |
| ROADWAY LIGHTING - KEENE | 2020 FY Actual | 5,766.09 |
| ROADWAY LIGHTING - KEENE | 2021 FY Actual | 7,104.74 |
| ROADWAY LIGHTING - KEENE | 2022 FY Actual | 2,809.98 |
| ROADWAY LIGHTING - KEENE | 2023 FY Actual | 47,469.67 |
| ROADWAY LIGHTING - LACONIA | 2019 FY Actual | 25,080.03 |
| ROADWAY LIGHTING - LACONIA | 2020 FY Actual | 6,382.32 |
| ROADWAY LIGHTING - LACONIA | 2021 FY Actual | 5,003.93 |
| ROADWAY LIGHTING - LACONIA | 2022 FY Actual | 24,614.30 |
| ROADWAY LIGHTING - LACONIA | 2023 FY Actual | 108,147.73 |
| ROADWAY LIGHTING - NASHUA | 2019 FY Actual | 5,060.04 |
| ROADWAY LIGHTING - NASHUA | 2020 FY Actual | 9,549.52 |
| ROADWAY LIGHTING - NASHUA | 2021 FY Actual | 6,035.69 |
| ROADWAY LIGHTING - NASHUA | 2022 FY Actual | 10,431.15 |

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| ROADWAY LIGHTING - NASHUA | 2023 FY Actual | 53,570.83 |
| ROADWAY LIGHTING - PORTSMOUTH | 2019 FY Actual | 14,334.90 |
| ROADWAY LIGHTING - PORTSMOUTH | 2020 FY Actual | 5,242.46 |
| ROADWAY LIGHTING - PORTSMOUTH | 2021 FY Actual | 36,192.52 |
| ROADWAY LIGHTING - PORTSMOUTH | 2022 FY Actual | 4,065.26 |
| ROADWAY LIGHTING - PORTSMOUTH | 2023 FY Actual | 25,874.91 |
| ROADWAY LIGHTING - ROCHESTER | 2019 FY Actual | 12,761.33 |
| ROADWAY LIGHTING - ROCHESTER | 2020 FY Actual | 16,516.26 |
| ROADWAY LIGHTING - ROCHESTER | 2021 FY Actual | 35,932.59 |
| ROADWAY LIGHTING - ROCHESTER | 2022 FY Actual | (1,600.30) |
| ROADWAY LIGHTING - ROCHESTER | 2023 FY Actual | 77,148.66 |
| ROADWAY LIGHTING - NEWPORT | 2019 FY Actual | 1,118.86 |
| ROADWAY LIGHTING - NEWPORT | 2020 FY Actual | 612.62 |
| ROADWAY LIGHTING - NEWPORT | 2021 FY Actual | 263.40 |
| ROADWAY LIGHTING - NEWPORT | 2022 FY Actual | (66.09) |
| ROADWAY LIGHTING - NEWPORT | 2023 FY Actual | 11,291.97 |
| ROADWAY LIGHTING - MANCHESTER EAST | 2019 FY Actual | (4,816.99) |
| ROADWAY LIGHTING - MANCHESTER EAST | 2020 FY Actual | (9,862.70) |
| ROADWAY LIGHTING - MANCHESTER EAST | 2021 FY Actual | 12,213.54 |
| ROADWAY LIGHTING - MANCHESTER EAST | 2022 FY Actual | 18,889.33 |
| ROADWAY LIGHTING - MANCHESTER EAST | 2023 FY Actual | 34,085.52 |
| ROADWAY LIGHTING - BEDFORD | 2019 FY Actual | 12,784.45 |
| ROADWAY LIGHTING - BEDFORD | 2020 FY Actual | 465.94 |
| ROADWAY LIGHTING - BEDFORD | 2021 FY Actual | 11,939.27 |
| ROADWAY LIGHTING - BEDFORD | 2022 FY Actual | 5,601.39 |
| ROADWAY LIGHTING - BEDFORD | 2023 FY Actual | 12,438.64 |
| EOL (ENERGY EFFICIENT OUTDOOR LIGHT | 2019 FY Actual | (2,682.14) |
| EOL (ENERGY EFFICIENT OUTDOOR LIGHT | 2019 FY Budget | 119,925.77 |
| EOL (ENERGY EFFICIENT OUTDOOR LIGHT | 2020 FY Actual | (10,363.28) |
| EOL (ENERGY EFFICIENT OUTDOOR LIGHT | 2020 FY Budget | 120,000.06 |
| EOL (ENERGY EFFICIENT OUTDOOR LIGHT | 2021 FY Actual | (7,184.24) |
| EOL (ENERGY EFFICIENT OUTDOOR LIGHT | 2021 FY Budget | 122,399.85 |
| EOL (ENERGY EFFICIENT OUTDOOR LIGHT | 2022 FY Budget | 268,008.71 |
| EOL (ENERGY EFFICIENT OUTDOOR LIGHT | 2023 FY Budget | 224,400.00 |
| LINE RELOCATE EAST HOLLIS ST NASHUA | 2022 FY Actual | 1,194.99 |
| MANCHESTER AIRPORT DUCT RELOCATION | 2019 FY Actual | (7,630.04) |
| Rochester Comcast Make Ready | 2019 FY Actual | 772,086.46 |
| Rochester Comcast Make Ready | 2019 FY Budget | 535,877.48 |
| Rochester Comcast Make Ready | 2020 FY Actual | 38,004.96 |
| Rochester Comcast Make Ready | 2022 FY Actual | (52,552.22) |
| Route 9 Roxbury-Sullivan 10439 | 2019 FY Actual | (41,532.51) |
| Route 9 Roxbury-Sullivan 10439 | 2020 FY Actual | (2,183.36) |
| Route 9 Roxbury-Sullivan 10439 | 2021 FY Actual | 586.59 |
| Route 9 Roxbury-Sullivan 10439 | 2022 FY Actual | (1,598.85) |
| LACONIA COMCAST NON-BILLABLE 2020 | 2020 FY Actual | 279,259.91 |
| LACONIA COMCAST NON-BILLABLE 2020 | 2021 FY Actual | 226,679.67 |
| LACONIA COMCAST NON-BILLABLE 2020 | 2022 FY Actual | (31,723.88) |

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| LACONIA COMCAST BILLABLE 2020 | 2020 FY Actual | (106,529.57) |
| LACONIA COMCAST BILLABLE 2020 | 2021 FY Actual | (288,427.97) |
| LACONIA COMCAST BILLABLE 2020 | 2022 FY Actual | (2,369.25) |
| LACONIA COMCAST BILLABLE 2020 | 2023 FY Actual | (4,495.30) |
| GILFORD COMCAST NON-BILLABLE 2020 | 2020 FY Actual | 306,087.14 |
| GILFORD COMCAST NON-BILLABLE 2020 | 2021 FY Actual | 121,294.18 |
| GILFORD COMCAST NON-BILLABLE 2020 | 2022 FY Actual | (22,138.58) |
| GILFORD COMCAST BILLABLE 2020 | 2020 FY Actual | (216,470.72) |
| GILFORD COMCAST BILLABLE 2020 | 2021 FY Actual | 163,820.94 |
| GILFORD COMCAST BILLABLE 2020 | 2022 FY Actual | (48,704.17) |
| NHDOT LINE RELOC RTE 106 LOUDON | 2020 FY Actual | 121,095.34 |
| NHDOT LINE RELOC RTE 106 LOUDON | 2021 FY Actual | 259,789.63 |
| NHDOT LINE RELOC RTE 106 LOUDON | 2022 FY Actual | (27,810.29) |
| ROUTE 16 LINE RELOCATION NHDOT | 2021 FY Actual | 225,781.65 |
| ROUTE 16 LINE RELOCATION NHDOT | 2022 FY Actual | (3,370.96) |
| LACONIA COMCAST NONBILLABLE 2021 | 2021 FY Actual | 163,030.08 |
| LACONIA COMCAST NONBILLABLE 2021 | 2022 FY Actual | 161,237.08 |
| LACONIA COMCAST NONBILLABLE 2021 | 2022 FY Budget | 90,946.80 |
| LACONIA COMCAST NONBILLABLE 2021 | 2023 FY Actual | (472.78) |
| LACONIA COMCAST BILLABLE 2021 | 2021 FY Actual | 1,639.45 |
| LACONIA COMCAST BILLABLE 2021 | 2022 FY Actual | (179,001.05) |
| LACONIA COMCAST BILLABLE 2021 | 2023 FY Actual | 151,789.55 |
| GILFORD COMCAST NONBILLABLE 2021 | 2021 FY Actual | 181,744.44 |
| GILFORD COMCAST NONBILLABLE 2021 | 2022 FY Actual | 357,760.71 |
| GILFORD COMCAST NONBILLABLE 2021 | 2022 FY Budget | 94,378.53 |
| GILFORD COMCAST NONBILLABLE 2021 | 2023 FY Actual | 362.57 |
| GILFORD COMCAST BILLABLE 2021 | 2021 FY Actual | (237.62) |
| GILFORD COMCAST BILLABLE 2021 | 2022 FY Actual | (257,106.25) |
| GILFORD COMCAST BILLABLE 2021 | 2023 FY Actual | 184,584.95 |
| NHDOT PROJ #13065 - 365 Line | 2021 FY Actual | 49,970.92 |
| NHDOT PROJ #13065 - 365 Line | 2022 FY Actual | 1,022,344.83 |
| NHDOT PROJ #13065 - 365 Line | 2022 FY Budget | 402,816.51 |
| NHDOT PROJ #13065 - 365 Line | 2023 FY Actual | (1,007,422.62) |
| NHDOT PROJ #13761 3138/3151 LINES | 2021 FY Actual | 73,088.61 |
| NHDOT PROJ #13761 3138/3151 LINES | 2022 FY Actual | 838.72 |
| NHDOT PROJ #13761 3138/3151 LINES | 2022 FY Budget | (92,457.16) |
| NHDOT PROJ #13761 3138/3151 LINES | 2023 FY Actual | (108,923.99) |
| COMCAST NON-BILLABLE LACONIA | 2022 FY Actual | 256,938.43 |
| COMCAST NON-BILLABLE LACONIA | 2022 FY Budget | 299,992.09 |
| COMCAST BILLABLE LACONIA | 2022 FY Actual | (60,511.06) |
| COMCAST NON-BILLABLE GILFORD | 2022 FY Actual | 589,012.92 |
| COMCAST NON-BILLABLE GILFORD | 2022 FY Budget | 300,000.00 |
| COMCAST NON-BILLABLE GILFORD | 2023 FY Actual | (218,887.54) |
| COMCAST BILLABLE GILFORD | 2022 FY Actual | (100,397.30) |
| COMCAST BILLABLE GILFORD | 2023 FY Actual | 30,177.74 |
| COMCAST NON-BILLABLE BELMONT | 2023 FY Actual | 887,089.65 |
| COMCAST BILLABLE BELMONT | 2022 FY Actual | (103,808.28) |

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| COMCAST BILLABLE BELMONT | 2023 FY Actual | 173,415.65 |
| COMCAST NON-BILLABLE TILTON | 2023 FY Actual | 24,893.12 |
| COMCAST BILLABLE TILTON | 2023 FY Actual | (292,191.25) |
| CABLE TV PROJECTS ANNUAL | 2019 FY Actual | 188,908.23 |
| CABLE TV PROJECTS ANNUAL | 2019 FY Budget | 500,214.10 |
| CABLE TV PROJECTS ANNUAL | 2020 FY Actual | 267,199.10 |
| CABLE TV PROJECTS ANNUAL | 2020 FY Budget | 509,858.60 |
| CABLE TV PROJECTS ANNUAL | 2021 FY Actual | 434,606.28 |
| CABLE TV PROJECTS ANNUAL | 2021 FY Budget | 749,999.76 |
| CABLE TV PROJECTS ANNUAL | 2022 FY Actual | 1,929,573.45 |
| CABLE TV PROJECTS ANNUAL | 2022 FY Budget | 986,748.71 |
| NHDOT PROJECT PROGRAM | 2019 FY Actual | 2,286,844.69 |
| NHDOT PROJECT PROGRAM | 2019 FY Budget | 1,849,665.88 |
| NHDOT PROJECT PROGRAM | 2020 FY Actual | 1,411,585.99 |
| NHDOT PROJECT PROGRAM | 2020 FY Budget | 2,039,543.49 |
| NHDOT PROJECT PROGRAM | 2021 FY Actual | 329,366.86 |
| NHDOT PROJECT PROGRAM | 2021 FY Budget | 2,068,000.49 |
| NHDOT PROJECT PROGRAM | 2022 FY Actual | 84,324.91 |
| NHDOT PROJECT PROGRAM | 2022 FY Budget | 2,441,401.62 |
| NHDOT PROJECT PROGRAM | 2023 FY Actual | 842,935.69 |
| NHDOT PROJECT PROGRAM | 2023 FY Budget | 1,530,000.00 |
| LINE RELOCATIONS - LANCASTER | 2019 FY Actual | 283,168.18 |
| LINE RELOCATIONS - LANCASTER | 2020 FY Actual | 229,606.94 |
| LINE RELOCATIONS - LANCASTER | 2021 FY Actual | 306,740.52 |
| LINE RELOCATIONS - LANCASTER | 2022 FY Actual | 35,975.80 |
| LINE RELOCATIONS - LANCASTER | 2023 FY Actual | 65,005.93 |
| LINE RELOCATIONS - BERLIN | 2019 FY Actual | (10,207.16) |
| LINE RELOCATIONS - BERLIN | 2020 FY Actual | 17,381.55 |
| LINE RELOCATIONS - BERLIN | 2021 FY Actual | 7,855.67 |
| LINE RELOCATIONS - BERLIN | 2022 FY Actual | 3,478.47 |
| LINE RELOCATIONS - BERLIN | 2023 FY Actual | 3,717.14 |
| LINE RELOCATIONS - CHOCORUA | 2019 FY Actual | (377,158.56) |
| LINE RELOCATIONS - CHOCORUA | 2020 FY Actual | 24,197.08 |
| LINE RELOCATIONS - CHOCORUA | 2021 FY Actual | 27,425.98 |
| LINE RELOCATIONS - CHOCORUA | 2022 FY Actual | 21,333.20 |
| LINE RELOCATIONS - CHOCORUA | 2023 FY Actual | 780,854.54 |
| LINE RELOCATIONS - DERRY | 2019 FY Actual | (213,863.67) |
| LINE RELOCATIONS - DERRY | 2020 FY Actual | 72,286.89 |
| LINE RELOCATIONS - DERRY | 2021 FY Actual | 42,238.32 |
| LINE RELOCATIONS - DERRY | 2022 FY Actual | 119,807.85 |
| LINE RELOCATIONS - DERRY | 2023 FY Actual | 58,884.57 |
| LINE RELOCATIONS - EPPING | 2019 FY Actual | 44,284.76 |
| LINE RELOCATIONS - EPPING | 2020 FY Actual | 18,910.08 |
| LINE RELOCATIONS - EPPING | 2021 FY Actual | 18,072.80 |
| LINE RELOCATIONS - EPPING | 2022 FY Actual | 53,897.68 |
| LINE RELOCATIONS - EPPING | 2023 FY Actual | 159,039.72 |
| LINE RELOCATIONS - HILLSBORO | 2021 FY Actual | 59,077.36 |

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| LINE RELOCATIONS - HILLSBORO | 2022 FY Actual | 209,272.95 |
| LINE RELOCATIONS - HILLSBORO | 2023 FY Actual | 150,657.35 |
| LINE RELOCATIONS - KEENE | 2019 FY Actual | 10,547.69 |
| LINE RELOCATIONS - KEENE | 2020 FY Actual | 23,634.86 |
| LINE RELOCATIONS - KEENE | 2021 FY Actual | 245,609.05 |
| LINE RELOCATIONS - KEENE | 2022 FY Actual | 325,142.73 |
| LINE RELOCATIONS - KEENE | 2023 FY Actual | 193,283.55 |
| LINE RELOCATIONS - LACONIA | 2019 FY Actual | 378,223.97 |
| LINE RELOCATIONS - LACONIA | 2020 FY Actual | (23,640.43) |
| LINE RELOCATIONS - LACONIA | 2021 FY Actual | 64,212.19 |
| LINE RELOCATIONS - LACONIA | 2022 FY Actual | 115,157.26 |
| LINE RELOCATIONS - LACONIA | 2023 FY Actual | 112,521.15 |
| LINE RELOCATIONS - MILFORD | 2020 FY Actual | 99.32 |
| LINE RELOCATIONS - NASHUA | 2019 FY Actual | 63,204.64 |
| LINE RELOCATIONS - NASHUA | 2020 FY Actual | 127,821.01 |
| LINE RELOCATIONS - NASHUA | 2021 FY Actual | 247,751.94 |
| LINE RELOCATIONS - NASHUA | 2022 FY Actual | (9,582.76) |
| LINE RELOCATIONS - PORTSMOUTH | 2019 FY Actual | 143,020.12 |
| LINE RELOCATIONS - PORTSMOUTH | 2020 FY Actual | 120,151.38 |
| LINE RELOCATIONS - PORTSMOUTH | 2021 FY Actual | 105,466.35 |
| LINE RELOCATIONS - PORTSMOUTH | 2022 FY Actual | 116,878.71 |
| LINE RELOCATIONS - PORTSMOUTH | 2023 FY Actual | 386,799.30 |
| LINE RELOCATIONS | 2019 FY Budget | 1,000,013.58 |
| LINE RELOCATIONS | 2020 FY Budget | 1,019,623.52 |
| LINE RELOCATIONS | 2021 FY Budget | 1,040,400.44 |
| LINE RELOCATIONS | 2022 FY Budget | 1,341,131.08 |
| LINE RELOCATIONS | 2023 FY Budget | 1,275,000.00 |
| LINE RELOCATIONS - ROCHESTER | 2019 FY Actual | 151,788.00 |
| LINE RELOCATIONS - ROCHESTER | 2020 FY Actual | 176,400.98 |
| LINE RELOCATIONS - ROCHESTER | 2021 FY Actual | (12,993.25) |
| LINE RELOCATIONS - ROCHESTER | 2022 FY Actual | 104,984.19 |
| LINE RELOCATIONS - ROCHESTER | 2023 FY Actual | 659,623.32 |
| LINE RELOCATIONS - NEWPORT | 2019 FY Actual | 5,259.15 |
| LINE RELOCATIONS - NEWPORT | 2020 FY Actual | 22,180.19 |
| LINE RELOCATIONS - NEWPORT | 2021 FY Actual | 128,696.42 |
| LINE RELOCATIONS - NEWPORT | 2022 FY Actual | 402,828.33 |
| LINE RELOCATIONS - NEWPORT | 2023 FY Actual | 48,315.94 |
| LINE RELOCATIONS - HOOKSETT | 2019 FY Actual | 179,330.67 |
| LINE RELOCATIONS - HOOKSETT | 2020 FY Actual | 28,496.52 |
| LINE RELOCATIONS - HOOKSETT | 2021 FY Actual | 56,579.09 |
| LINE RELOCATIONS - HOOKSETT | 2022 FY Actual | 208,309.04 |
| LINE RELOCATIONS - HOOKSETT | 2023 FY Actual | 210,675.27 |
| LINE RELOCATIONS - BEDFORD | 2019 FY Actual | 84,155.91 |
| LINE RELOCATIONS - BEDFORD | 2020 FY Actual | 317,851.47 |
| LINE RELOCATIONS - BEDFORD | 2021 FY Actual | 192,391.10 |
| LINE RELOCATIONS - BEDFORD | 2022 FY Actual | 163,147.08 |
| LINE RELOCATIONS - BEDFORD | 2023 FY Actual | 182,509.31 |

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| EXPENSE PORTION OF CATV PROJECTS | 2019 FY Actual | (61,165.29) |
| EXPENSE PORTION OF CATV PROJECTS | 2020 FY Actual | (5,548.86) |
| EXPENSE PORTION OF CATV PROJECTS | 2021 FY Actual | 46,765.53 |
| EXPENSE PORTION OF CATV PROJECTS | 2022 FY Actual | 22,852.84 |
| EXPENSE PORTION OF CATV PROJECTS | 2023 FY Actual | 1,366.94 |
| ROW Relocations - Reimbursable | 2019 FY Budget | 2,741.57 |
| RELOCATE 12 SECTIONS LONDONDRY TPK | 2023 FY Actual | 3,341.40 |
| PURCHASE TRANSFORMERS AND REGULATOR | 2019 FY Actual | 11,072,349.31 |
| PURCHASE TRANSFORMERS AND REGULATOR | 2019 FY Budget | 10,189,950.47 |
| PURCHASE TRANSFORMERS AND REGULATOR | 2020 FY Actual | 12,024,594.95 |
| PURCHASE TRANSFORMERS AND REGULATOR | 2020 FY Budget | 9,999,426.42 |
| PURCHASE TRANSFORMERS AND REGULATOR | 2021 FY Actual | 14,624,957.54 |
| PURCHASE TRANSFORMERS AND REGULATOR | 2021 FY Budget | 11,499,999.95 |
| PURCHASE TRANSFORMERS AND REGULATOR | 2022 FY Actual | 15,328,045.59 |
| PURCHASE TRANSFORMERS AND REGULATOR | 2022 FY Budget | 11,504,443.96 |
| PURCHASE TRANSFORMERS AND REGULATOR | 2023 FY Actual | 21,976,565.59 |
| PURCHASE TRANSFORMERS AND REGULATOR | 2023 FY Budget | 11,066,455.65 |
| PSNH Overheads | 2023 FY Actual | 34.76 |
| 922 ELM ST DEVELOPMENT | 2019 FY Actual | 600,171.56 |
| 922 ELM ST DEVELOPMENT | 2020 FY Actual | (3,276.20) |
| 922 ELM ST DEVELOPMENT | 2021 FY Actual | (850.92) |
| 922 ELM ST DEVELOPMENT | 2022 FY Actual | 9,197.72 |
| SANBORN CROSSING APARTMENTS | 2019 FY Actual | 143,646.81 |
| SANBORN CROSSING APARTMENTS | 2020 FY Actual | (956.89) |
| SANBORN CROSSING APARTMENTS | 2022 FY Actual | 5,882.09 |
| PULPIT RD URD | 2019 FY Actual | 298.02 |
| PULPIT RD URD | 2020 FY Actual | (29,111.06) |
| PULPIT RD URD | 2021 FY Actual | 5,292.62 |
| MYRTLE SO. BK. CONV MANCHESTER | 2019 FY Actual | 136,730.67 |
| MYRTLE SO. BK. CONV MANCHESTER | 2020 FY Actual | (8,071.49) |
| BAE GOFFS FALLS RD SERVICE | 2019 FY Actual | 129,983.36 |
| BAE GOFFS FALLS RD SERVICE | 2020 FY Actual | 66,529.30 |
| BAE GOFFS FALLS RD SERVICE | 2021 FY Actual | 6,385.33 |
| 348X3 CUSTOMER LINE EXT | 2019 FY Actual | 3,601.67 |
| 348X3 CUSTOMER LINE EXT | 2020 FY Actual | 1,466.15 |
| 348X3 CUSTOMER LINE EXT | 2021 FY Actual | (237,152.91) |
| 348X3 CUSTOMER LINE EXT | 2022 FY Actual | 1,573.49 |
| 348X3 CUSTOMER LINE EXT | 2023 FY Actual | (25,018.40) |
| WOODMONT COMMONS PHASE 1A 2019 | 2019 FY Actual | (9,308.36) |
| WOODMONT COMMONS PHASE 1A 2019 | 2020 FY Actual | 23,455.06 |
| WOODMONT COMMONS PHASE 1A 2019 | 2021 FY Actual | 39,731.38 |
| WOODMONT COMMONS PHASE 1A 2019 | 2022 FY Actual | 77,342.00 |
| WOODMONT COMMONS PHASE 1A 2019 | 2023 FY Actual | 1,074.28 |
| WOODMONT COMMONS PHASE 1B 2019 | 2019 FY Actual | (165,607.16) |
| WOODMONT COMMONS PHASE 1B 2019 | 2020 FY Actual | 119,803.87 |
| WOODMONT COMMONS PHASE 1B 2019 | 2021 FY Actual | 45,803.29 |
| WOODMONT COMMONS PHASE 1B 2019 | 2022 FY Actual | 101,037.19 |

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| Service to new Nashua Perfoming Art | 2020 FY Budget | 199,028.84 |
| Service to new Nashua Perfoming Art | 2021 FY Actual | 344,728.87 |
| COLEBROOK LINE EXT AMER PERF POLYMR | 2021 FY Actual | 469,008.77 |
| COLEBROOK LINE EXT AMER PERF POLYMR | 2022 FY Actual | 96,048.67 |
| COLEBROOK LINE EXT AMER PERF POLYMR | 2023 FY Actual | 860.99 |
| Allenstown School Project | 2022 FY Actual | (86,130.62) |
| Allenstown School Project | 2023 FY Actual | 20,920.79 |
| 355 Upgrades and Rt 26 Line Extension | 2023 FY Actual | 397.35 |
| NEW BUSINESS SPECIFICS UNKNOWN | 2019 FY Actual | (3,478.50) |
| NEW BUSINESS SPECIFICS UNKNOWN | 2020 FY Budget | (132.72) |
| NEW BUSINESS SPECIFICS UNKNOWN | 2022 FY Actual | 363.90 |
| NEW/EXISTING CUSTOMERS - LANCASTER | 2019 FY Actual | 496,349.82 |
| NEW/EXISTING CUSTOMERS - LANCASTER | 2020 FY Actual | 595,655.92 |
| NEW/EXISTING CUSTOMERS - LANCASTER | 2021 FY Actual | 2,219,844.13 |
| NEW/EXISTING CUSTOMERS - LANCASTER | 2022 FY Actual | 1,377,013.96 |
| NEW/EXISTING CUSTOMERS - LANCASTER | 2023 FY Actual | 1,820,814.10 |
| NEW/EXISTING CUSTOMERS - BERLIN | 2019 FY Actual | 245,136.60 |
| NEW/EXISTING CUSTOMERS - BERLIN | 2020 FY Actual | 68,807.23 |
| NEW/EXISTING CUSTOMERS - BERLIN | 2021 FY Actual | 361,478.76 |
| NEW/EXISTING CUSTOMERS - BERLIN | 2022 FY Actual | 320,849.32 |
| NEW/EXISTING CUSTOMERS - BERLIN | 2023 FY Actual | 1,307,958.94 |
| NEW/EXISTING CUSTOMERS - CHOCORUA | 2019 FY Actual | 603,690.85 |
| NEW/EXISTING CUSTOMERS - CHOCORUA | 2020 FY Actual | 425,715.42 |
| NEW/EXISTING CUSTOMERS - CHOCORUA | 2021 FY Actual | 1,337,924.70 |
| NEW/EXISTING CUSTOMERS - CHOCORUA | 2022 FY Actual | 881,343.49 |
| NEW/EXISTING CUSTOMERS - CHOCORUA | 2023 FY Actual | 1,999,310.63 |
| NEW/EXISTING CUSTOMERS - DERRY | 2019 FY Actual | 243,691.55 |
| NEW/EXISTING CUSTOMERS - DERRY | 2020 FY Actual | 751,472.71 |
| NEW/EXISTING CUSTOMERS - DERRY | 2021 FY Actual | 1,197,245.70 |
| NEW/EXISTING CUSTOMERS - DERRY | 2022 FY Actual | 907,383.06 |
| NEW/EXISTING CUSTOMERS - DERRY | 2023 FY Actual | 1,414,199.06 |
| NEW/EXISTING CUSTOMERS - EPPING | 2019 FY Actual | 341,257.72 |
| NEW/EXISTING CUSTOMERS - EPPING | 2020 FY Actual | 337,930.22 |
| NEW/EXISTING CUSTOMERS - EPPING | 2021 FY Actual | 1,675,753.48 |
| NEW/EXISTING CUSTOMERS - EPPING | 2022 FY Actual | 1,952,420.17 |
| NEW/EXISTING CUSTOMERS - EPPING | 2023 FY Actual | 2,930,121.43 |
| NEW/EXISTING CUSTOMERS - KEENE | 2019 FY Actual | 1,520,056.81 |
| NEW/EXISTING CUSTOMERS - KEENE | 2020 FY Actual | 1,615,066.63 |
| NEW/EXISTING CUSTOMERS - KEENE | 2021 FY Actual | 3,680,905.55 |
| NEW/EXISTING CUSTOMERS - KEENE | 2022 FY Actual | 3,287,309.35 |
| NEW/EXISTING CUSTOMERS - KEENE | 2023 FY Actual | 2,244,524.08 |
| NEW/EXISTING CUSTOMERS - LACONIA | 2019 FY Actual | 927,262.86 |
| NEW/EXISTING CUSTOMERS - LACONIA | 2020 FY Actual | 940,191.46 |
| NEW/EXISTING CUSTOMERS - LACONIA | 2021 FY Actual | 3,267,591.82 |
| NEW/EXISTING CUSTOMERS - LACONIA | 2022 FY Actual | 4,401,067.16 |
| NEW/EXISTING CUSTOMERS - LACONIA | 2023 FY Actual | 5,650,962.09 |
| NEW/EXISTING CUSTOMERS - MILFORD | 2019 FY Actual | (1,409.05) |

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| NEW/EXISTING CUSTOMERS - MILFORD | 2020 FY Actual | (1,678.66) |
| NEW/EXISTING CUSTOMERS - MILFORD | 2021 FY Actual | (1,016.89) |
| NEW/EXISTING CUSTOMERS - MILFORD | 2022 FY Actual | (24.53) |
| NEW/EXISTING CUSTOMERS - MILFORD | 2023 FY Actual | 581.21 |
| NEW/EXISTING CUSTOMERS - NASHUA | 2019 FY Actual | 1,179,835.13 |
| NEW/EXISTING CUSTOMERS - NASHUA | 2020 FY Actual | 765,157.66 |
| NEW/EXISTING CUSTOMERS - NASHUA | 2021 FY Actual | 2,646,008.21 |
| NEW/EXISTING CUSTOMERS - NASHUA | 2022 FY Actual | 1,821,162.07 |
| NEW/EXISTING CUSTOMERS - NASHUA | 2023 FY Actual | 2,842,336.43 |
| NEW/EXISTING CUSTOMERS - PORTSMOUTH | 2019 FY Actual | 744,113.06 |
| NEW/EXISTING CUSTOMERS - PORTSMOUTH | 2020 FY Actual | 921,938.80 |
| NEW/EXISTING CUSTOMERS - PORTSMOUTH | 2021 FY Actual | 1,103,252.59 |
| NEW/EXISTING CUSTOMERS - PORTSMOUTH | 2022 FY Actual | 1,053,744.07 |
| NEW/EXISTING CUSTOMERS - PORTSMOUTH | 2023 FY Actual | 1,021,640.80 |
| NEW/EXISTING CUSTOMERS | 2019 FY Budget | 8,000,096.93 |
| NEW/EXISTING CUSTOMERS | 2020 FY Budget | 8,000,000.49 |
| NEW/EXISTING CUSTOMERS | 2021 FY Budget | 10,322,999.95 |
| NEW/EXISTING CUSTOMERS | 2022 FY Actual | (7,090.20) |
| NEW/EXISTING CUSTOMERS | 2022 FY Budget | 6,474,287.12 |
| NEW/EXISTING CUSTOMERS | 2023 FY Actual | 31,217.15 |
| NEW/EXISTING CUSTOMERS | 2023 FY Budget | 13,860,643.00 |
| NEW/EXISTING CUSTOMERS - ROCHESTER | 2019 FY Actual | 929,721.38 |
| NEW/EXISTING CUSTOMERS - ROCHESTER | 2020 FY Actual | 1,416,475.00 |
| NEW/EXISTING CUSTOMERS - ROCHESTER | 2021 FY Actual | 2,620,684.49 |
| NEW/EXISTING CUSTOMERS - ROCHESTER | 2022 FY Actual | 2,083,460.95 |
| NEW/EXISTING CUSTOMERS - ROCHESTER | 2023 FY Actual | 2,529,221.82 |
| NEW/EXISTING CUSTOMERS - NEWPORT | 2019 FY Actual | 526,164.76 |
| NEW/EXISTING CUSTOMERS - NEWPORT | 2020 FY Actual | 791,216.16 |
| NEW/EXISTING CUSTOMERS - NEWPORT | 2021 FY Actual | 1,930,073.83 |
| NEW/EXISTING CUSTOMERS - NEWPORT | 2022 FY Actual | 1,323,665.83 |
| NEW/EXISTING CUSTOMERS - NEWPORT | 2023 FY Actual | 1,690,252.57 |
| NEW/EXISTING CUSTOMERS - HOOKSETT | 2019 FY Actual | 577,528.15 |
| NEW/EXISTING CUSTOMERS - HOOKSETT | 2020 FY Actual | 392,163.71 |
| NEW/EXISTING CUSTOMERS - HOOKSETT | 2021 FY Actual | 1,596,482.30 |
| NEW/EXISTING CUSTOMERS - HOOKSETT | 2022 FY Actual | 1,388,262.37 |
| NEW/EXISTING CUSTOMERS - HOOKSETT | 2023 FY Actual | 1,592,459.53 |
| NEW/EXISTING CUSTOMERS - BEDFORD | 2019 FY Actual | 732,172.65 |
| NEW/EXISTING CUSTOMERS - BEDFORD | 2020 FY Actual | 837,902.59 |
| NEW/EXISTING CUSTOMERS - BEDFORD | 2021 FY Actual | 2,606,325.71 |
| NEW/EXISTING CUSTOMERS - BEDFORD | 2022 FY Actual | 1,842,544.96 |
| NEW/EXISTING CUSTOMERS - BEDFORD | 2023 FY Actual | 2,170,205.73 |
| SERVICES - LANCASTER | 2019 FY Actual | 124,782.04 |
| SERVICES - LANCASTER | 2020 FY Actual | 188,354.07 |
| SERVICES - LANCASTER | 2021 FY Actual | 42,379.48 |
| SERVICES - LANCASTER | 2022 FY Actual | 51,967.84 |
| SERVICES - LANCASTER | 2023 FY Actual | 58,162.05 |
| SERVICES - BERLIN | 2019 FY Actual | 113,243.60 |

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| SERVICES - BERLIN | 2020 FY Actual | 91,738.60 |
| SERVICES - BERLIN | 2021 FY Actual | 18,557.13 |
| SERVICES - BERLIN | 2022 FY Actual | 7,637.00 |
| SERVICES - BERLIN | 2023 FY Actual | 20,588.50 |
| SERVICES - CHOCORUA | 2019 FY Actual | 18,534.01 |
| SERVICES - CHOCORUA | 2020 FY Actual | 108,770.58 |
| SERVICES - CHOCORUA | 2021 FY Actual | 62,387.65 |
| SERVICES - CHOCORUA | 2022 FY Actual | 20,919.57 |
| SERVICES - CHOCORUA | 2023 FY Actual | 6,382.91 |
| SERVICES - DERRY | 2019 FY Actual | 291,743.88 |
| SERVICES - DERRY | 2020 FY Actual | 355,592.06 |
| SERVICES - DERRY | 2021 FY Actual | 875,230.83 |
| SERVICES - DERRY | 2022 FY Actual | 414,859.23 |
| SERVICES - DERRY | 2023 FY Actual | (387,791.67) |
| SERVICES - EPPING | 2019 FY Actual | 210,821.02 |
| SERVICES - EPPING | 2020 FY Actual | 291,649.05 |
| SERVICES - EPPING | 2021 FY Actual | 268,304.84 |
| SERVICES - EPPING | 2022 FY Actual | 143,761.78 |
| SERVICES - EPPING | 2023 FY Actual | 244,166.30 |
| SERVICES - KEENE | 2019 FY Actual | 294,804.05 |
| SERVICES - KEENE | 2020 FY Actual | 374,881.61 |
| SERVICES - KEENE | 2021 FY Actual | 98,256.35 |
| SERVICES - KEENE | 2022 FY Actual | 78,009.09 |
| SERVICES - KEENE | 2023 FY Actual | 374,523.39 |
| SERVICES - LACONIA | 2019 FY Actual | 432,541.99 |
| SERVICES - LACONIA | 2020 FY Actual | 475,234.34 |
| SERVICES - LACONIA | 2021 FY Actual | 281,075.02 |
| SERVICES - LACONIA | 2022 FY Actual | 467,848.28 |
| SERVICES - LACONIA | 2023 FY Actual | 561,961.19 |
| SERVICES - NASHUA | 2019 FY Actual | 466,276.85 |
| SERVICES - NASHUA | 2020 FY Actual | 558,862.94 |
| SERVICES - NASHUA | 2021 FY Actual | 724,665.64 |
| SERVICES - NASHUA | 2022 FY Actual | 889,381.11 |
| SERVICES - NASHUA | 2023 FY Actual | 1,190,034.48 |
| SERVICES - PORTSMOUTH | 2019 FY Actual | 200,782.71 |
| SERVICES - PORTSMOUTH | 2020 FY Actual | 217,927.83 |
| SERVICES - PORTSMOUTH | 2021 FY Actual | 135,315.78 |
| SERVICES - PORTSMOUTH | 2022 FY Actual | 55,456.01 |
| SERVICES - PORTSMOUTH | 2023 FY Actual | 75,737.33 |
| SERVICES - PSNH | 2019 FY Actual | 483,287.38 |
| SERVICES - PSNH | 2019 FY Budget | 3,250,311.28 |
| SERVICES - PSNH | 2020 FY Actual | (172,488.13) |
| SERVICES - PSNH | 2020 FY Budget | 3,309,393.21 |
| SERVICES - PSNH | 2021 FY Actual | (560,692.87) |
| SERVICES - PSNH | 2021 FY Budget | 3,414,999.53 |
| SERVICES - PSNH | 2022 FY Actual | (1,434,999.18) |
| SERVICES - PSNH | 2022 FY Budget | 4,295,634.14 |

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| SERVICES - PSNH | 2023 FY Actual | (1,096,766.51) |
| SERVICES - PSNH | 2023 FY Budget | 1,000,000.00 |
| SERVICES - ROCHESTER | 2019 FY Actual | 486,720.15 |
| SERVICES - ROCHESTER | 2020 FY Actual | 591,299.75 |
| SERVICES - ROCHESTER | 2021 FY Actual | 165,821.23 |
| SERVICES - ROCHESTER | 2022 FY Actual | 240,194.54 |
| SERVICES - ROCHESTER | 2023 FY Actual | 273,537.48 |
| SERVICES - NEWPORT | 2019 FY Actual | 83,303.17 |
| SERVICES - NEWPORT | 2020 FY Actual | 89,011.39 |
| SERVICES - NEWPORT | 2021 FY Actual | 45,720.26 |
| SERVICES - NEWPORT | 2022 FY Actual | 7,613.38 |
| SERVICES - NEWPORT | 2023 FY Actual | 48,053.56 |
| SERVICES - HOOKSETT | 2019 FY Actual | 277,218.11 |
| SERVICES - HOOKSETT | 2020 FY Actual | 377,431.15 |
| SERVICES - HOOKSETT | 2021 FY Actual | 109,121.56 |
| SERVICES - HOOKSETT | 2022 FY Actual | 129,694.91 |
| SERVICES - HOOKSETT | 2023 FY Actual | 165,799.56 |
| SERVICES - BEDFORD | 2019 FY Actual | 360,699.19 |
| SERVICES - BEDFORD | 2020 FY Actual | 328,273.93 |
| SERVICES - BEDFORD | 2021 FY Actual | 118,809.64 |
| SERVICES - BEDFORD | 2022 FY Actual | 163,708.68 |
| SERVICES - BEDFORD | 2023 FY Actual | 171,375.18 |
| T2504 MANCHESTER LANDFILL PV | 2021 FY Actual | 15,301.66 |
| T2504 MANCHESTER LANDFILL PV | 2022 FY Actual | (78,533.35) |
| #T1213 LOUDON PLEASANT STREET PV | 2021 FY Actual | 37,627.54 |
| #T1213 LOUDON PLEASANT STREET PV | 2022 FY Actual | 16,892.94 |
| #T1213 LOUDON PLEASANT STREET PV | 2023 FY Actual | 1,311.39 |
| #T1193 CONWAY LAKE PV | 2021 FY Actual | (19,862.69) |
| #T1193 CONWAY LAKE PV | 2022 FY Actual | (4,203.50) |
| T1402 & T2007 NASHUA PENNICHUCK PV | 2021 FY Actual | (9,095.11) |
| T1402 & T2007 NASHUA PENNICHUCK PV | 2022 FY Actual | (3,591.01) |
| T1402 & T2007 NASHUA PENNICHUCK PV | 2023 FY Actual | 12,230.78 |
| ADD SCADA RECLOSERS TO DG SITES | 2021 FY Actual | 297,000.13 |
| ADD SCADA RECLOSERS TO DG SITES | 2021 FY Budget | 1,000,000.23 |
| ADD SCADA RECLOSERS TO DG SITES | 2022 FY Actual | 24,561.64 |
| ADD SCADA RECLOSERS TO DG SITES | 2022 FY Budget | 500,000.00 |
| BEDFORD TRANSFER STATION PV (#T2942) | 2021 FY Actual | 787.90 |
| BEDFORD TRANSFER STATION PV (#T2942) | 2022 FY Actual | 23,920.90 |
| BEDFORD TRANSFER STATION PV (#T2942) | 2023 FY Actual | (298,701.80) |
| Pembroke Solar Interconnection | 2022 FY Actual | (125,290.06) |
| Pembroke Solar Interconnection | 2023 FY Actual | (317,246.71) |
| KEENE WWTF PV (#T2797A) | 2021 FY Actual | (43,087.26) |
| KEENE WWTF PV (#T2797A) | 2022 FY Actual | (77,607.82) |
| KEENE WWTF PV (#T2797A) | 2023 FY Actual | 163,024.31 |
| Nellie Solar Interconnection | 2022 FY Actual | (149,470.26) |
| Nellie Solar Interconnection | 2023 FY Actual | (594,830.34) |
| Nellie Solar Interconnection | 2023 FY Budget | 121,000.00 |

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| DG FIELD DESIGN & CONSTR- REIMBURSE | 2019 FY Actual | (134,773.77) |
| DG FIELD DESIGN & CONSTR- REIMBURSE | 2020 FY Actual | 274,788.18 |
| DG FIELD DESIGN & CONSTR- REIMBURSE | 2021 FY Actual | 95,535.82 |
| DG FIELD DESIGN & CONSTR- REIMBURSE | 2022 FY Actual | 130,213.44 |
| DG FIELD DESIGN & CONSTR- REIMBURSE | 2023 FY Actual | 142,469.38 |
| DG ENG DESIGN & CONSTR | 2019 FY Actual | 49,602.51 |
| DG ENG DESIGN & CONSTR | 2020 FY Actual | (236,272.25) |
| DG ENG DESIGN & CONSTR | 2021 FY Actual | (60,679.74) |
| DG ENG DESIGN & CONSTR | 2022 FY Actual | 194,375.18 |
| DG ENG DESIGN & CONSTR | 2023 FY Actual | (701,871.64) |
| Reconductor Bedford Road, 360X7 | 2019 FY Actual | 304,411.03 |
| Reconductor Bedford Road, 360X7 | 2019 FY Budget | 299,828.21 |
| Reconductor Bedford Road, 360X7 | 2020 FY Actual | (182.86) |
| Convert Four Rod Road in Rochester | 2019 FY Actual | 182,902.22 |
| Convert Four Rod Road in Rochester | 2019 FY Budget | 159,999.69 |
| Convert Four Rod Road in Rochester | 2020 FY Actual | (11,909.58) |
| ROW Peak Load Plug | 2019 FY Budget | 499,910.00 |
| 386/386A/340 LINES REBUILD FOR Y-17 | 2019 FY Actual | (680.84) |
| 386/386A/340 LINES REBUILD FOR Y-17 | 2022 FY Actual | 322.64 |
| RETROFIT CAPACITOR BANK CONTROLS | 2021 FY Actual | 14,799.67 |
| Valley St Area Solution | 2019 FY Actual | 1,495.72 |
| Valley St Area Solution | 2022 FY Actual | (2,388.02) |
| West Rd Overloaded Steps | 2019 FY Actual | (15,518.57) |
| SOUTH AVE DERRY STEP OVERLOAD | 2019 FY Actual | 274,631.46 |
| SOUTH AVE DERRY STEP OVERLOAD | 2020 FY Actual | 31.34 |
| SOUTH AVE DERRY STEP OVERLOAD | 2022 FY Actual | (10,063.34) |
| 335X1 EXTEND 19.9kV 1P TO S. BOW RD | 2020 FY Actual | 221,839.91 |
| 335X1 EXTEND 19.9kV 1P TO S. BOW RD | 2020 FY Budget | 319,448.65 |
| 335X1 EXTEND 19.9kV 1P TO S. BOW RD | 2021 FY Actual | 8,708.21 |
| 335X1 EXTEND 19.9kV 1P TO S. BOW RD | 2022 FY Actual | 31,960.14 |
| INSTALL PM STEP TRNSF RTE 13 GOFFS | 2020 FY Actual | 161,073.44 |
| INSTALL PM STEP TRNSF RTE 13 GOFFS | 2020 FY Budget | 674,681.00 |
| INSTALL PM STEP TRNSF RTE 13 GOFFS | 2021 FY Actual | 676,176.62 |
| INSTALL PM STEP TRNSF RTE 13 GOFFS | 2021 FY Budget | (553.67) |
| INSTALL PM STEP TRNSF RTE 13 GOFFS | 2022 FY Actual | 70,700.37 |
| INSTALL PM STEP TRNSF RTE 13 GOFFS | 2023 FY Actual | 496.32 |
| OFFLOAD 63W1 AT E. NORTHWOOD | 2020 FY Actual | 412,001.01 |
| OFFLOAD 63W1 AT E. NORTHWOOD | 2020 FY Budget | 200,000.49 |
| OFFLOAD 63W1 AT E. NORTHWOOD | 2021 FY Actual | 3,489.65 |
| OFFLOAD 63W1 AT E. NORTHWOOD | 2022 FY Actual | (6,940.98) |
| RANGE RD WINDHAM CONVERSION | 2020 FY Actual | 405,629.37 |
| RANGE RD WINDHAM CONVERSION | 2020 FY Budget | 249,971.34 |
| RANGE RD WINDHAM CONVERSION | 2022 FY Actual | (0.37) |
| MEETINGHOUSE RD SS OFF- LOAD | 2021 FY Actual | 1,189,092.41 |
| MEETINGHOUSE RD SS OFF- LOAD | 2021 FY Budget | 599,999.78 |
| MEETINGHOUSE RD SS OFF- LOAD | 2022 FY Actual | (389,470.86) |
| MEETINGHOUSE RD SS OFF- LOAD | 2023 FY Actual | 10,674.71 |

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| 322X14 CIRCUIT OFFLOAD | 2021 FY Actual | 38,995.88 |
| 322X14 CIRCUIT OFFLOAD | 2021 FY Budget | 125,000.16 |
| 322X14 CIRCUIT OFFLOAD | 2022 FY Actual | (9,123.15) |
| 322X14 CIRCUIT OFFLOAD | 2023 FY Actual | 1,346.21 |
| ADD PHASES ON NEW BOSTON RD | 2021 FY Actual | 479,471.37 |
| ADD PHASES ON NEW BOSTON RD | 2021 FY Budget | 759,999.60 |
| ADD PHASES ON NEW BOSTON RD | 2022 FY Actual | (20,814.24) |
| WESTLAND AVE CONVERSION | 2021 FY Actual | 120,903.48 |
| WESTLAND AVE CONVERSION | 2022 FY Actual | 534.09 |
| LINE 321/3182 LAM WOOD STR REPL | 2021 FY Actual | 137,825.14 |
| LINE 321/3182 LAM WOOD STR REPL | 2022 FY Actual | (19,646.76) |
| RECONDUCTOR 1.06 MI DRAKE HILL RD | 2021 FY Actual | 902,452.88 |
| RECONDUCTOR 1.06 MI DRAKE HILL RD | 2021 FY Budget | 899,999.92 |
| RECONDUCTOR 1.06 MI DRAKE HILL RD | 2022 FY Actual | (18,809.36) |
| RECONDUCTOR 1.06 MI DRAKE HILL RD | 2023 FY Actual | (7,153.97) |
| PISCASSIC RD CONVERSION | 2021 FY Actual | 26,313.81 |
| PISCASSIC RD CONVERSION | 2021 FY Budget | 446,000.34 |
| PISCASSIC RD CONVERSION | 2022 FY Actual | 168,643.82 |
| PISCASSIC RD CONVERSION | 2023 FY Actual | 510,756.21 |
| FOGG RD CONVERSION | 2021 FY Actual | 272,486.47 |
| FOGG RD CONVERSION | 2021 FY Budget | 451,999.72 |
| FOGG RD CONVERSION | 2022 FY Actual | 471,413.73 |
| FOGG RD CONVERSION | 2023 FY Actual | 60,607.70 |
| BEAUTY HILL RD CONVERSION | 2021 FY Actual | 907,714.59 |
| BEAUTY HILL RD CONVERSION | 2021 FY Budget | 491,000.44 |
| BEAUTY HILL RD CONVERSION | 2022 FY Actual | (85,456.16) |
| BEAUTY HILL RD CONVERSION | 2023 FY Actual | (28,585.06) |
| CONVERT RTE 132 IN NORTHFIELD | 2021 FY Budget | 340,000.49 |
| CONVERT RTE 132 IN NORTHFIELD | 2022 FY Actual | (83,511.72) |
| DAMREN RD CONVERSION | 2021 FY Actual | 111,838.55 |
| DAMREN RD CONVERSION | 2021 FY Budget | 282,999.87 |
| DAMREN RD CONVERSION | 2023 FY Actual | (12,182.61) |
| EXTEND THREE PHASE ROUTE 202 RINDGE | 2021 FY Actual | 271,565.80 |
| EXTEND THREE PHASE ROUTE 202 RINDGE | 2022 FY Actual | (8,496.02) |
| EXTEND THREE PHASE ROUTE 202 RINDGE | 2023 FY Actual | 1,583.79 |
| 3108 PARALLEL STEP OVERLOAD | 2022 FY Budget | 867,000.00 |
| 3108 PARALLEL STEP OVERLOAD | 2023 FY Actual | 123,838.17 |
| 3108 PARALLEL STEP OVERLOAD | 2023 FY Budget | 2,318,000.00 |
| 15W4 RUSSELL ST SWITCHGEAR PORTSMTH | 2023 FY Budget | 400,000.00 |
| 3115X7 MAIN ST RAYMOND CONVERSION | 2022 FY Actual | 978,909.71 |
| 3115X7 MAIN ST RAYMOND CONVERSION | 2022 FY Budget | 482,000.00 |
| 3115X7 MAIN ST RAYMOND CONVERSION | 2023 FY Actual | 347,772.83 |
| 3115X7 MAIN ST RAYMOND CONVERSION | 2023 FY Budget | 100,000.00 |
| 377X20 MAIN ST EPPING CONVERSION | 2022 FY Actual | 935,967.68 |
| 377X20 MAIN ST EPPING CONVERSION | 2022 FY Budget | 405,000.00 |
| 377X20 MAIN ST EPPING CONVERSION | 2023 FY Actual | 93,469.73 |
| 377X20 MAIN ST EPPING CONVERSION | 2023 FY Budget | 100,000.00 |

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| 6H2 CONVERSION OFFLOAD TO 67W2 | 2022 FY Actual | 896,921.92 |
| 6H2 CONVERSION OFFLOAD TO 67W2 | 2022 FY Budget | 140,000.00 |
| 6H2 CONVERSION OFFLOAD TO 67W2 | 2023 FY Actual | (218,615.51) |
| 6H2 CONVERSION OFFLOAD TO 67W2 | 2023 FY Budget | 50,000.00 |
| 15W4 Market Street U/G Service | 2022 FY Actual | 1,828,821.13 |
| 15W4 Market Street U/G Service | 2023 FY Actual | 16,298.83 |
| 3525X5 E SIDE RD, ERROL CONVERSION | 2022 FY Actual | 92,060.67 |
| 3525X5 E SIDE RD, ERROL CONVERSION | 2022 FY Budget | 312,000.00 |
| 3525X5 E SIDE RD, ERROL CONVERSION | 2023 FY Actual | 13,245.25 |
| 42X3/44H1 EXTEND 34.5KV | 2022 FY Actual | 896,847.75 |
| 42X3/44H1 EXTEND 34.5KV | 2022 FY Budget | 1,298,000.00 |
| 42X3/44H1 EXTEND 34.5KV | 2023 FY Actual | 871,935.01 |
| 42X3/44H1 EXTEND 34.5KV | 2023 FY Budget | 1,418,513.14 |
| 3410 LAKE SUNAPEE EXT 34.5KV SPACER | 2022 FY Actual | 359,418.53 |
| 3410 LAKE SUNAPEE EXT 34.5KV SPACER | 2022 FY Budget | 396,070.99 |
| 3410 LAKE SUNAPEE EXT 34.5KV SPACER | 2023 FY Actual | 51,787.49 |
| 377X20 Pleasant Street Conversion | 2023 FY Actual | 853,997.43 |
| 377X20 Pleasant Street Conversion | 2023 FY Budget | 1,100,500.00 |
| 3103X1 Beede Hill Road Conversion | 2023 FY Budget | 279,500.00 |
| 2023 Initial Funding Placeholder | 2023 FY Budget | 700,000.00 |
| 319X1 Conversion S Barnstead Rd | 2023 FY Actual | 129,551.07 |
| 319X1 Conversion S Barnstead Rd | 2023 FY Budget | 713,520.00 |
| 336X1 Conversion | 2023 FY Budget | 2,500,000.00 |
| 3114W1 Conversion Ragged Mt Hwy | 2023 FY Budget | 2,596,000.00 |
| 2H2 Line Extension | 2023 FY Actual | 825,668.03 |
| 2H2 Line Extension | 2023 FY Budget | 550,000.00 |
| 3155X Route 13 Conversion | 2023 FY Actual | 1,915,395.56 |
| 3155X Route 13 Conversion | 2023 FY Budget | 3,500,000.00 |
| 3211X Kimball Hill Rd Conversion | 2023 FY Actual | 450,939.22 |
| 3211X Kimball Hill Rd Conversion | 2023 FY Budget | 709,000.00 |
| 3217X Knowlton Rd Conversion | 2023 FY Budget | 600,000.00 |
| 3155X Install Padmounted Step Xfmr | 2023 FY Actual | 29,935.96 |
| 3155X Install Padmounted Step Xfmr | 2023 FY Budget | 600,000.00 |
| Pease Tradeport Upgrade | 2023 FY Actual | 10,582.72 |
| MAINTAIN VOLTAGE - LANCASTER | 2019 FY Actual | 178,408.81 |
| MAINTAIN VOLTAGE - LANCASTER | 2020 FY Actual | 6,585.73 |
| MAINTAIN VOLTAGE - LANCASTER | 2021 FY Actual | 252,568.45 |
| MAINTAIN VOLTAGE - LANCASTER | 2022 FY Actual | 253,655.42 |
| MAINTAIN VOLTAGE - LANCASTER | 2023 FY Actual | 99,204.09 |
| MAINTAIN VOLTAGE - BERLIN | 2019 FY Actual | 7,426.59 |
| MAINTAIN VOLTAGE - BERLIN | 2020 FY Actual | 2,967.57 |
| MAINTAIN VOLTAGE - BERLIN | 2021 FY Actual | 27,910.70 |
| MAINTAIN VOLTAGE - BERLIN | 2022 FY Actual | 1,277.35 |
| MAINTAIN VOLTAGE - BERLIN | 2023 FY Actual | 11,713.11 |
| MAINTAIN VOLTAGE - CHOCORUA | 2019 FY Actual | 4,424.15 |
| MAINTAIN VOLTAGE - CHOCORUA | 2020 FY Actual | 32,884.14 |
| MAINTAIN VOLTAGE - CHOCORUA | 2021 FY Actual | 64,536.46 |

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| MAINTAIN VOLTAGE - CHOCORUA | 2022 FY Actual | 48,143.74 |
| MAINTAIN VOLTAGE - CHOCORUA | 2023 FY Actual | 7,042.14 |
| MAINTAIN VOLTAGE - DERRY | 2019 FY Actual | 27,283.35 |
| MAINTAIN VOLTAGE - DERRY | 2020 FY Actual | 77,629.75 |
| MAINTAIN VOLTAGE - DERRY | 2021 FY Actual | 8,344.44 |
| MAINTAIN VOLTAGE - DERRY | 2022 FY Actual | 30,904.26 |
| MAINTAIN VOLTAGE - DERRY | 2023 FY Actual | 29,272.64 |
| MAINTAIN VOLTAGE - EPPING | 2019 FY Actual | 161,597.52 |
| MAINTAIN VOLTAGE - EPPING | 2020 FY Actual | 55,965.22 |
| MAINTAIN VOLTAGE - EPPING | 2021 FY Actual | 188,463.01 |
| MAINTAIN VOLTAGE - EPPING | 2022 FY Actual | 173,962.26 |
| MAINTAIN VOLTAGE - EPPING | 2023 FY Actual | 187,141.14 |
| MAINTAIN VOLTAGE - KEENE | 2019 FY Actual | 79,481.69 |
| MAINTAIN VOLTAGE - KEENE | 2020 FY Actual | 16,418.47 |
| MAINTAIN VOLTAGE - KEENE | 2021 FY Actual | 76,936.60 |
| MAINTAIN VOLTAGE - KEENE | 2022 FY Actual | (18,472.34) |
| MAINTAIN VOLTAGE - KEENE | 2023 FY Actual | 27,394.27 |
| MAINTAIN VOLTAGE - LACONIA | 2019 FY Actual | 100,449.48 |
| MAINTAIN VOLTAGE - LACONIA | 2020 FY Actual | 129,817.03 |
| MAINTAIN VOLTAGE - LACONIA | 2021 FY Actual | 627,371.59 |
| MAINTAIN VOLTAGE - LACONIA | 2022 FY Actual | 301,449.24 |
| MAINTAIN VOLTAGE - LACONIA | 2023 FY Actual | 97,333.19 |
| MAINTAIN VOLTAGE - NASHUA | 2019 FY Actual | 152,209.24 |
| MAINTAIN VOLTAGE - NASHUA | 2020 FY Actual | 174,974.23 |
| MAINTAIN VOLTAGE - NASHUA | 2021 FY Actual | 158,070.06 |
| MAINTAIN VOLTAGE - NASHUA | 2022 FY Actual | 124,056.33 |
| MAINTAIN VOLTAGE - NASHUA | 2023 FY Actual | 125,195.00 |
| MAINTAIN VOLTAGE - PORTSMOUTH | 2019 FY Actual | 42,827.02 |
| MAINTAIN VOLTAGE - PORTSMOUTH | 2020 FY Actual | (164,065.77) |
| MAINTAIN VOLTAGE - PORTSMOUTH | 2021 FY Actual | 375,232.95 |
| MAINTAIN VOLTAGE - PORTSMOUTH | 2022 FY Actual | 134,598.54 |
| MAINTAIN VOLTAGE - PORTSMOUTH | 2023 FY Actual | 161,275.23 |
| MAINTAIN VOLTAGE | 2019 FY Budget | 700,008.79 |
| MAINTAIN VOLTAGE | 2020 FY Budget | 699,851.98 |
| MAINTAIN VOLTAGE | 2021 FY Budget | 700,000.31 |
| MAINTAIN VOLTAGE | 2022 FY Budget | 826,107.37 |
| MAINTAIN VOLTAGE | 2023 FY Budget | 1,500,000.00 |
| MAINTAIN VOLTAGE - ROCHESTER | 2019 FY Actual | 35,740.27 |
| MAINTAIN VOLTAGE - ROCHESTER | 2020 FY Actual | 440,700.02 |
| MAINTAIN VOLTAGE - ROCHESTER | 2021 FY Actual | 433,735.21 |
| MAINTAIN VOLTAGE - ROCHESTER | 2022 FY Actual | 26,384.49 |
| MAINTAIN VOLTAGE - ROCHESTER | 2023 FY Actual | 347,212.97 |
| MAINTAIN VOLTAGE - NEWPORT | 2019 FY Actual | 9,543.01 |
| MAINTAIN VOLTAGE - NEWPORT | 2020 FY Actual | 10,169.57 |
| MAINTAIN VOLTAGE - NEWPORT | 2021 FY Actual | 1,804.35 |
| MAINTAIN VOLTAGE - NEWPORT | 2022 FY Actual | 52,099.55 |
| MAINTAIN VOLTAGE - NEWPORT | 2023 FY Actual | 25,948.40 |

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| MAINTAIN VOLTAGE - HOOKSETT | 2019 FY Actual | 32,660.23 |
| MAINTAIN VOLTAGE - HOOKSETT | 2020 FY Actual | 28,095.84 |
| MAINTAIN VOLTAGE - HOOKSETT | 2021 FY Actual | 9,511.22 |
| MAINTAIN VOLTAGE - HOOKSETT | 2022 FY Actual | 23,626.93 |
| MAINTAIN VOLTAGE - HOOKSETT | 2023 FY Actual | 108,523.42 |
| MAINTAIN VOLTAGE - BEDFORD | 2019 FY Actual | 55,814.56 |
| MAINTAIN VOLTAGE - BEDFORD | 2020 FY Actual | (9,681.66) |
| MAINTAIN VOLTAGE - BEDFORD | 2021 FY Actual | 145,980.21 |
| MAINTAIN VOLTAGE - BEDFORD | 2022 FY Actual | 47,599.79 |
| MAINTAIN VOLTAGE - BEDFORD | 2023 FY Actual | 151,451.42 |
| SO. ST. MILFORD REPL OH WITH UNDERG | 2021 FY Actual | (2,213.19) |
| RIMMON S/S ADD 2ND 115-34.5KV 44.8M | 2019 FY Actual | 414.16 |
| 310/29X1 Survey & Purchase Land | 2021 FY Actual | 175.11 |
| White Lake S/S - replace TB82 | 2019 FY Actual | (106.88) |
| RIVER ROAD SS | 2019 FY Budget | 2,000,000.23 |
| REPLACE 386 RELAY AT ROCHESTER SS | 2019 FY Actual | 168,394.42 |
| REPLACE 386 RELAY AT ROCHESTER SS | 2020 FY Actual | 292,169.11 |
| Pemi SS Upgrade | 2019 FY Actual | 1,335,055.79 |
| Pemi SS Upgrade | 2019 FY Budget | 3,270,891.79 |
| Pemi SS Upgrade | 2020 FY Actual | 5,068,385.24 |
| Pemi SS Upgrade | 2020 FY Budget | 3,748,102.41 |
| Pemi SS Upgrade | 2021 FY Actual | (27,521.69) |
| Pemi SS Upgrade | 2021 FY Budget | 0.18 |
| Pemi SS Upgrade | 2022 FY Actual | (55,459.82) |
| Pemi SS Upgrade | 2023 FY Actual | 197.14 |
| SOUTH MILFORD SUBSTATION | 2021 FY Budget | (0.05) |
| SOUTH MILFORD SUBSTATION | 2022 FY Actual | 38,985.88 |
| SOUTH MILFORD SUBSTATION | 2022 FY Budget | 1,783,269.92 |
| SOUTH MILFORD SUBSTATION | 2023 FY Actual | 72,883.39 |
| SOUTH MILFORD SUBSTATION | 2023 FY Budget | 2,506,647.01 |
| Salmon Falls SS Capactiy Project | 2023 FY Actual | 320.54 |
| Salmon Falls SS Capactiy (D-Line) | 2023 FY Actual | 427.52 |
| So Milford SS Distribution Line Wrk | 2022 FY Actual | 26,682.70 |
| So Milford SS Distribution Line Wrk | 2023 FY Actual | 26,594.98 |
| So Milford SS Distribution Line Wrk | 2023 FY Budget | 36,867.15 |
| Colebrook D Substsation | 2023 FY Actual | 275,017.20 |
| Huse Road | 2019 FY Actual | (5,014.25) |
| NESC CAPITAL REPAIRS | 2019 FY Actual | (15,243.47) |
| NESC CAPITAL REPAIRS | 2020 FY Actual | (24,693.88) |
| NESC CAPITAL REPAIRS | 2021 FY Actual | 794.84 |
| NESC CAPITAL REPAIRS | 2022 FY Actual | (4,136.53) |
| NESC CAPITAL REPAIRS | 2023 FY Actual | 25,419.22 |
| Miller State Park/Pack Monadnock | 2019 FY Budget | 1,049,933.07 |
| NESC CAPITAL REPAIRS | 2019 FY Budget | 100,009.37 |
| NESC CAPITAL REPAIRS | 2020 FY Budget | 98,856.49 |
| NESC CAPITAL REPAIRS | 2021 FY Budget | 100,000.00 |
| 2022 POLE TOP DISTRIBUTION AUTOMATN | 2021 FY Actual | 113.88 |

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| 2022 POLE TOP DISTRIBUTION AUTOMATN | 2022 FY Actual | 6,477,095.31 |
| 2022 POLE TOP DISTRIBUTION AUTOMATN | 2022 FY Budget | 5,977,688.37 |
| GREAT EAST LAKE POLE REPLACEMENT | 2022 FY Actual | 249,400.44 |
| GREAT EAST LAKE POLE REPLACEMENT | 2023 FY Actual | 14,357.40 |
| REP3 - 2015-2016 Central Region DA | 2019 FY Actual | 2,961.17 |
| REP3 - 2015-2016 Central Region DA | 2020 FY Actual | 91,864.84 |
| REP3 - 2015-2016 Central Region DA | 2022 FY Actual | (1,420.29) |
| Circuit Tie Construction | 2019 FY Actual | (50,243.58) |
| Circuit Tie Construction | 2021 FY Actual | 1,748.79 |
| Circuit Tie Construction | 2022 FY Actual | (3,317.19) |
| REP3 Direct Buried Cable Replace | 2019 FY Actual | (11,124.77) |
| REP3 Direct Buried Cable Replace | 2020 FY Actual | (1,897.53) |
| REP3 Direct Buried Cable Replace | 2022 FY Actual | (8,341.77) |
| REP 3 2015-2016 Eastern Region DA | 2019 FY Actual | (750.87) |
| REP 3 2015-2016 Eastern Region DA | 2022 FY Actual | (1,238.61) |
| Hit List Reliability Enhancements | 2019 FY Actual | (17,411.32) |
| Hit List Reliability Enhancements | 2022 FY Actual | (563.18) |
| Heather-Lite Replacement | 2019 FY Actual | 2,673.17 |
| Heather-Lite Replacement | 2021 FY Actual | (2,422.85) |
| Heather-Lite Replacement | 2022 FY Actual | (403.05) |
| REP3 - 2015-2016 Northern Region D | 2019 FY Actual | 79,523.55 |
| REP3 - 2015-2016 Northern Region D | 2020 FY Actual | 9.81 |
| NESC CAPITAL REPAIRS | 2019 FY Actual | (5,259.66) |
| NESC CAPITAL REPAIRS | 2022 FY Actual | (401.21) |
| NESC CAPITAL REPAIRS | 2023 FY Actual | 8,858.90 |
| Porcelain Change-out | 2019 FY Actual | 6,713.30 |
| Porcelain Change-out | 2020 FY Actual | (3,574.04) |
| Porcelain Change-out | 2022 FY Actual | 1,913.71 |
| REJECT POLE REPLACEMENT | 2019 FY Actual | (132,188.06) |
| REJECT POLE REPLACEMENT | 2020 FY Actual | (7,288.12) |
| REJECT POLE REPLACEMENT | 2021 FY Actual | (1,657.77) |
| REJECT POLE REPLACEMENT | 2022 FY Actual | (2,895.07) |
| ROW System Hardening | 2019 FY Actual | (96,013.00) |
| ROW System Hardening | 2020 FY Actual | 40,229.08 |
| REP3 - 2015-2017 Southern Re | 2019 FY Actual | 1,887.12 |
| REP3 - 2015-2017 Southern Re | 2020 FY Actual | (5,083.33) |
| REP3 - 2015-2017 Southern Re | 2021 FY Actual | (1,899.79) |
| REP3 - 2015-2017 Southern Re | 2022 FY Actual | (2,421.16) |
| 4 & 12 kV Substations | 2019 FY Actual | (2,309.05) |
| TELECOM EXPANSION TO SUPPORT DA | 2019 FY Actual | 157,193.25 |
| TELECOM EXPANSION TO SUPPORT DA | 2020 FY Actual | 3,929.16 |
| REP3 - 2015-2016 Western Region DA | 2019 FY Actual | 30,521.07 |
| REP3 - 2015-2016 Western Region DA | 2020 FY Actual | 10,462.88 |
| REP3 - 2015-2016 Western Region DA | 2022 FY Actual | (90.94) |
| 2016 Line Sensor Project | 2019 FY Actual | (21,768.39) |
| 2016 Line Sensor Project | 2021 FY Actual | 592.21 |
| REP 4 CIRCUIT TIES | 2019 FY Actual | (228,187.08) |

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| REP 4 CIRCUIT TIES | 2021 FY Actual | (2,302.07) |
| REP 4 CIRCUIT TIES | 2022 FY Actual | (33,051.55) |
| REP 4 POLE TOP DA | 2019 FY Actual | (40,483.10) |
| REP 4 POLE TOP DA | 2021 FY Actual | 272.51 |
| REP 4 CIRCUIT RELIABILITY IMPROVE | 2019 FY Actual | 8,194.00 |
| REP 4 CIRCUIT RELIABILITY IMPROVE | 2021 FY Actual | 217.44 |
| REP 4 CIRCUIT RELIABILITY IMPROVE | 2022 FY Actual | (6,781.74) |
| REP 4 ROW SYSTEM HARDENING | 2019 FY Actual | 5,814.44 |
| W185 - 4W1 CIRCUIT TIE | 2019 FY Actual | 150,482.90 |
| W185 - 4W1 CIRCUIT TIE | 2020 FY Actual | 12,739.98 |
| W185 - 4W1 CIRCUIT TIE | 2021 FY Actual | (51,698.82) |
| 3178X CIRCUIT TIE HINSDALE | 2019 FY Actual | 394,891.91 |
| 3178X CIRCUIT TIE HINSDALE | 2020 FY Actual | (11,781.51) |
| 3178X CIRCUIT TIE HINSDALE | 2021 FY Actual | (56,291.89) |
| NH Avigilon Intrusion Detection | 2019 FY Actual | 143,587.57 |
| NH Avigilon Intrusion Detection | 2019 FY Budget | 109,387.71 |
| NH Avigilon Intrusion Detection | 2020 FY Actual | 44,349.17 |
| NH Avigilon Intrusion Detection | 2021 FY Actual | 1,203.17 |
| JACKSON HILL SS FNCE & GRDNG REPLAC | 2020 FY Actual | 291,795.58 |
| SECURITY UPGRADES CIP5 NH | 2019 FY Actual | 26,889.92 |
| SECURITY UPGRADES CIP5 NH | 2020 FY Actual | 49,826.17 |
| NH DMS | 2020 FY Actual | 2,010,339.11 |
| NH DMS | 2020 FY Budget | 2,999,837.14 |
| NH DMS | 2021 FY Actual | 2,479,915.71 |
| NH DMS | 2021 FY Budget | 4,499,999.74 |
| NH DMS | 2022 FY Actual | 2,616,614.53 |
| NH DMS | 2022 FY Budget | 2,920,674.37 |
| GARVINS SS OCB REPLACEMENT | 2022 FY Actual | 742,001.50 |
| GARVINS SS OCB REPLACEMENT | 2022 FY Budget | 2,505,049.89 |
| 316 LINE DAVIT ARM & STRUCTURE REPL | 2021 FY Actual | 1,528,153.78 |
| 316 LINE DAVIT ARM & STRUCTURE REPL | 2022 FY Actual | 685,314.42 |
| RYE AREA 4KV STUDY | 2019 FY Actual | 2,874,158.60 |
| RYE AREA 4KV STUDY | 2019 FY Budget | 800,000.21 |
| RYE AREA 4KV STUDY | 2020 FY Actual | 883,570.89 |
| RYE AREA 4KV STUDY | 2021 FY Actual | (1,984.20) |
| RYE AREA 4KV STUDY | 2022 FY Actual | (26,944.74) |
| ROCHESTER 4KV CONVERSION | 2019 FY Actual | 1,039,220.42 |
| ROCHESTER 4KV CONVERSION | 2019 FY Budget | 793,000.28 |
| ROCHESTER 4KV CONVERSION | 2020 FY Actual | 1,580,541.79 |
| ROCHESTER 4KV CONVERSION | 2020 FY Budget | 1,812,025.32 |
| ROCHESTER 4KV CONVERSION | 2021 FY Actual | 2,929,630.40 |
| ROCHESTER 4KV CONVERSION | 2021 FY Budget | 1,813,932.95 |
| ROCHESTER 4KV CONVERSION | 2022 FY Actual | (119,048.12) |
| ROCHESTER 4KV CONVERSION | 2022 FY Budget | 292,734.17 |
| ROCHESTER 4KV CONVERSION | 2023 FY Actual | (64,339.75) |
| Ham St Conversion, Dover | 2020 FY Actual | 778,338.78 |
| Ham St Conversion, Dover | 2020 FY Budget | 349,999.74 |

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| Ham St Conversion, Dover | 2021 FY Actual | 28,276.62 |
| GOFFSTOWN SS CONVERSION | 2021 FY Actual | 1,865,905.55 |
| GOFFSTOWN SS CONVERSION | 2021 FY Budget | 999,999.93 |
| GOFFSTOWN SS CONVERSION | 2022 FY Actual | 31,031.02 |
| GOFFSTOWN SS CONVERSION | 2022 FY Budget | 532,706.57 |
| GOFFSTOWN SS ELIM PHASE 2 27W2 CONV | 2022 FY Actual | 382,543.44 |
| GOFFSTOWN SS ELIM PHASE 2 27W2 CONV | 2022 FY Budget | 1,020,000.00 |
| 36W1 CONVERSION/VEC TIE STRATFORD | 2022 FY Budget | 502,000.00 |
| CENTRAL REGION 2015 DA | 2019 FY Actual | 74,888.21 |
| CENTRAL REGION 2015 DA | 2020 FY Actual | (70,002.28) |
| CENTRAL REGION 2015 DA | 2021 FY Actual | 3,125.42 |
| EASTERN REGION 2015 DA | 2019 FY Actual | 770,235.05 |
| EASTERN REGION 2015 DA | 2020 FY Actual | (257,288.59) |
| EASTERN REGION 2015 DA | 2022 FY Actual | (1,623.19) |
| EASTERN REGION 2015 DA | 2023 FY Actual | 4,664.05 |
| NORTHERN REGION 2015 DA | 2019 FY Actual | 17,498.07 |
| NORTHERN REGION 2015 DA | 2020 FY Actual | (675.99) |
| NORTHERN REGION 2015 DA | 2022 FY Actual | (64.29) |
| SOUTHERN REGION 2015 DA | 2019 FY Actual | 10,926.80 |
| SOUTHERN REGION 2015 DA | 2020 FY Actual | (34,777.49) |
| SOUTHERN REGION 2015 DA | 2021 FY Actual | 51,571.56 |
| SOUTHERN REGION 2015 DA | 2022 FY Actual | (4,734.89) |
| TELECOM BUILDOUT AUTOMATION 2015 | 2019 FY Actual | (201,081.45) |
| G&W Viper Warranty Replacment | 2019 FY Actual | 87,566.40 |
| G&W Viper Warranty Replacment | 2020 FY Actual | (25,565.88) |
| DISTRIBUTION AUTOMATION - POLE TOP | 2019 FY Actual | 7,629,452.98 |
| DISTRIBUTION AUTOMATION - POLE TOP | 2020 FY Actual | 214,658.68 |
| DISTRIBUTION AUTOMATION - POLE TOP | 2021 FY Actual | 52,791.55 |
| DISTRIBUTION AUTOMATION - POLE TOP | 2022 FY Actual | (9,714.50) |
| Viper Replacement Project-Bettermnt | 2019 FY Actual | (43,009.27) |
| Viper Replacement Project-Bettermnt | 2020 FY Actual | (163,858.75) |
| DISTRIBUTION AUTOMATION - POLE TOP | 2019 FY Actual | 14,396,023.98 |
| DISTRIBUTION AUTOMATION - POLE TOP | 2019 FY Budget | 16,743,056.52 |
| DISTRIBUTION AUTOMATION - POLE TOP | 2020 FY Actual | 3,339,965.33 |
| DISTRIBUTION AUTOMATION - POLE TOP | 2021 FY Actual | (16,990.73) |
| DISTRIBUTION AUTOMATION - POLE TOP | 2022 FY Actual | (42,900.36) |
| Distribution Automation - Line Sens | 2019 FY Actual | 100,591.81 |
| Distribution Automation - Line Sens | 2019 FY Budget | 179,979.42 |
| Distribution Automation - Line Sens | 2020 FY Actual | 27,685.01 |
| Distribution Automation - Line Sens | 2021 FY Actual | 64.96 |
| Distribution Automation - Telecom | 2019 FY Budget | 100,784.96 |
| Distribution Automation - Substatio | 2019 FY Budget | 999,926.90 |
| Distribution Automation - Substatio | 2020 FY Budget | 48,240.00 |
| DISTRIBUTION AUTOMATION POLE TOP | 2020 FY Actual | 10,345,558.87 |
| DISTRIBUTION AUTOMATION POLE TOP | 2020 FY Budget | 12,000,001.61 |
| DISTRIBUTION AUTOMATION POLE TOP | 2021 FY Actual | 1,987,437.87 |
| DISTRIBUTION AUTOMATION POLE TOP | 2022 FY Actual | (59,508.92) |

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| DISTRIBUTION AUTOMATION POLE TOP | 2023 FY Actual | (17,695.50) |
| DISTRIBUTION AUTOMATION LINE SENSOR | 2020 FY Actual | 185,203.35 |
| DISTRIBUTION AUTOMATION LINE SENSOR | 2020 FY Budget | 179,999.80 |
| DISTRIBUTION AUTOMATION LINE SENSOR | 2021 FY Actual | 34,466.59 |
| DISTRIBUTION AUTOMATION TELECOM | 2020 FY Budget | 99,999.93 |
| DISTRIBUTION AUTOMATION SUBSTATION | 2020 FY Budget | 999,999.76 |
| DISTRIBUTION AUTOMATION POLE TOP | 2021 FY Actual | 5,168,016.13 |
| DISTRIBUTION AUTOMATION POLE TOP | 2021 FY Budget | 6,000,000.35 |
| DISTRIBUTION AUTOMATION POLE TOP | 2022 FY Actual | 1,242,338.68 |
| DISTRIBUTION AUTOMATION POLE TOP | 2023 FY Actual | 53,078.47 |
| DISTRIBUTION AUTOMATION LINE SENSOR | 2021 FY Actual | 372,904.39 |
| DISTRIBUTION AUTOMATION LINE SENSOR | 2021 FY Budget | 179,999.96 |
| DISTRIBUTION AUTOMATION LINE SENSOR | 2022 FY Actual | 54,403.39 |
| DISTRIBUTION AUTOMATION LINE SENSOR | 2023 FY Actual | 260.29 |
| DISTRIBUTION AUTOMATION TELECOM | 2021 FY Budget | 99,999.73 |
| DISTRIBUTION AUTOMATION SUBSTATION | 2021 FY Budget | 999,999.53 |
| 2022 Distr Automation - Line Sensor | 2022 FY Actual | 477,643.72 |
| 2022 Distr Automation - Line Sensor | 2022 FY Budget | 126,000.00 |
| 2022 Distr Automation - Line Sensor | 2023 FY Actual | 9,170.94 |
| DISTRIBUTION AUTOMATION TELECOM | 2022 FY Budget | 93,000.00 |
| DISTRIBUTION AUTOMATION SUBSTATION | 2022 FY Budget | 528,000.00 |
| 2023 Distr Automation - Pole Top | 2023 FY Actual | 6,394,322.02 |
| 2023 Distr Automation - Pole Top | 2023 FY Budget | 6,500,000.00 |
| 2023 Distr Automation - Line Sensor | 2023 FY Actual | 288,636.23 |
| 2023 Distr Automation - Line Sensor | 2023 FY Budget | 180,000.00 |
| SCADA Reclosers at DG Sites | 2023 FY Budget | 500,000.00 |
| 2023 Distribution Automation - SS | 2023 FY Budget | 500,000.00 |
| 2014 DA DEPLOYMENT | 2019 FY Actual | (928.31) |
| REJECT POLE REPLACEMENT | 2019 FY Actual | 3,019,469.03 |
| REJECT POLE REPLACEMENT | 2019 FY Budget | 2,494,741.97 |
| REJECT POLE REPLACEMENT | 2020 FY Actual | 1,602,220.37 |
| REJECT POLE REPLACEMENT | 2020 FY Budget | 2,491,848.59 |
| REJECT POLE REPLACEMENT | 2021 FY Actual | 1,511,565.77 |
| REJECT POLE REPLACEMENT | 2022 FY Actual | (4,756.30) |
| REJECT POLE REPLACEMENT | 2023 FY Actual | 268,324.31 |
| REPLACE STEEL TOWERS | 2019 FY Actual | (39,521.19) |
| REPLACE STEEL TOWERS | 2020 FY Actual | (6,561.82) |
| REPLACE STEEL TOWERS | 2021 FY Actual | 5,225.22 |
| REPLACE STEEL TOWERS | 2022 FY Actual | 131.67 |
| REPL LACONIA UNDRGRD SWITCHGEAR 70W | 2020 FY Actual | (4,760.52) |
| Northern COOS Reliability Loop | 2019 FY Actual | (50,650.20) |
| 3818 NEW 34.5KV LINE 1.6 MI ON RTE | 2022 FY Actual | 908.67 |
| 12H4 West Side Conversion | 2019 FY Actual | (21,129.99) |
| 324 LINE, REBUILD AT INDUSTRIAL AVE | 2020 FY Actual | (3,085.82) |
| 324 LINE, REBUILD AT INDUSTRIAL AVE | 2022 FY Actual | (5,659.59) |
| 11W1 - Replace Submarine Cable | 2019 FY Actual | 805,631.49 |
| 11W1 - Replace Submarine Cable | 2020 FY Actual | 945,696.27 |

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| 11W1 - Replace Submarine Cable | 2021 FY Actual | (163,342.59) |
| 11W1 - Replace Submarine Cable | 2022 FY Actual | (10,627.66) |
| Circuit Tie 3271x2/311x1 | 2019 FY Actual | 7,106.67 |
| CAIDI IMPROVEMENT | 2019 FY Actual | 24,963.69 |
| CAIDI IMPROVEMENT | 2020 FY Actual | 4,472.43 |
| CAIDI IMPROVEMENT | 2021 FY Actual | (10,032.90) |
| CAIDI IMPROVEMENT | 2022 FY Actual | (13,198.23) |
| BROOK ST REPLACE G&W SWITCHGEAR | 2020 FY Actual | 2,738.64 |
| BROOK ST REPLACE G&W SWITCHGEAR | 2021 FY Actual | 20,066.43 |
| BROOK ST REPLACE G&W SWITCHGEAR | 2022 FY Actual | 3,470.26 |
| BROOK ST REPLACE G&W SWITCHGEAR | 2023 FY Actual | (46,057.63) |
| 3.74 PRI VOLT CONV NAVIGATOR RD | 2019 FY Actual | 219.23 |
| 3.74 PRI VOLT CONV NAVIGATOR RD | 2020 FY Actual | 228.54 |
| BLAINE ST SUBSTATION LINE WORK | 2019 FY Actual | (3,338.53) |
| BLAINE ST SUBSTATION LINE WORK | 2020 FY Actual | (6,921.14) |
| CIRCUIT TIE 3115X12 TO 3615X1 | 2019 FY Actual | 9,591.28 |
| CIRCUIT TIE 3115X12 TO 3615X1 | 2020 FY Actual | (19,513.10) |
| CIRCUIT TIE 3115X12 TO 3615X1 | 2021 FY Actual | (15,130.27) |
| 328 LINE RECONDUCTOR | 2019 FY Actual | 3,899,826.37 |
| 328 LINE RECONDUCTOR | 2019 FY Budget | 3,622,942.86 |
| 328 LINE RECONDUCTOR | 2020 FY Actual | 265,228.50 |
| 328 LINE RECONDUCTOR | 2021 FY Actual | 6,174.29 |
| 328 LINE RECONDUCTOR | 2022 FY Actual | (921.28) |
| 380 LINE BETTERMENT | 2019 FY Budget | 140,000.00 |
| ROW Hardening/Reconductoring | 2019 FY Budget | 1,509,999.80 |
| ROW Hardening/Reconductoring | 2020 FY Budget | 1.00 |
| CAIDI IMPROVEMENTS | 2019 FY Actual | 20,869.66 |
| Reconductor copper St Anselm Drive | 2019 FY Actual | 241,202.88 |
| Reconductor copper St Anselm Drive | 2019 FY Budget | 209,280.59 |
| Reconductor copper St Anselm Drive | 2020 FY Actual | (1,912.20) |
| Downtown Portsmouth UG System Impro | 2019 FY Budget | 99,960.93 |
| Downtown Portsmouth UG System Impro | 2020 FY Actual | 120,383.41 |
| Downtown Portsmouth UG System Impro | 2020 FY Budget | 78,135.55 |
| Downtown Portsmouth UG System Impro | 2021 FY Actual | 135,047.75 |
| Downtown Portsmouth UG System Impro | 2021 FY Budget | 99,999.71 |
| Downtown Portsmouth UG System Impro | 2022 FY Actual | 14,798.33 |
| Downtown Portsmouth UG System Impro | 2022 FY Budget | 187,659.09 |
| Downtown Portsmouth UG System Impro | 2023 FY Actual | 41,176.94 |
| Downtown Portsmouth UG System Impro | 2023 FY Budget | 100,000.00 |
| Circuit Ties-Wakefield 362 to 3157 | 2019 FY Actual | 2,289,179.05 |
| Circuit Ties-Wakefield 362 to 3157 | 2019 FY Budget | 2,699,956.03 |
| Circuit Ties-Wakefield 362 to 3157 | 2020 FY Actual | 594,195.94 |
| Circuit Ties-Wakefield 362 to 3157 | 2020 FY Budget | 38,750.00 |
| Circuit Ties-Wakefield 362 to 3157 | 2021 FY Actual | (29,350.10) |
| Circuit Ties-Wakefield 362 to 3157 | 2022 FY Actual | 14.18 |
| DOVER UNDERGROUND BACKFEED RELOCATI | 2019 FY Actual | 220,364.76 |
| DOVER UNDERGROUND BACKFEED RELOCATI | 2020 FY Actual | 572,566.47 |

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| DOVER UNDERGROUND BACKFEED RELOCATI | 2021 FY Actual | 15,857.55 |
| DOVER UNDERGROUND BACKFEED RELOCATI | 2022 FY Actual | (4,999.85) |
| Relocate 1W1 Main Line onto Route 3 | 2019 FY Actual | 291,698.50 |
| Relocate 1W1 Main Line onto Route 3 | 2019 FY Budget | 259,952.45 |
| Relocate 1W1 Main Line onto Route 3 | 2020 FY Actual | (1,059.78) |
| Relocate 1W1 Main Line onto Route 3 | 2022 FY Actual | (6,129.24) |
| Circuit Ties - Laconia 310 to 345 | 2019 FY Actual | 1,341,169.63 |
| Circuit Ties - Laconia 310 to 345 | 2019 FY Budget | 4,100,098.37 |
| Circuit Ties - Laconia 310 to 345 | 2020 FY Actual | 1,381,957.13 |
| Circuit Ties - Laconia 310 to 345 | 2021 FY Actual | 2,685.39 |
| Circuit Ties - Laconia 310 to 345 | 2022 FY Actual | (9,723.74) |
| 346X1 DEFECTIVE SPCA REPLACEMENT | 2019 FY Actual | 188,699.27 |
| 346X1 DEFECTIVE SPCA REPLACEMENT | 2020 FY Actual | (9,589.66) |
| Reconductor #6 Copper @ Fordway Ext | 2019 FY Budget | 350,028.36 |
| Replace Conductor Route 13 Amherst | 2019 FY Actual | 1,083,967.76 |
| Replace Conductor Route 13 Amherst | 2019 FY Budget | 892,980.47 |
| Replace Conductor Route 13 Amherst | 2020 FY Actual | 790,437.76 |
| Replace Conductor Route 13 Amherst | 2020 FY Budget | 500,480.23 |
| Replace Conductor Route 13 Amherst | 2021 FY Actual | 2,717.90 |
| Replace Conductor Route 13 Amherst | 2022 FY Actual | 1,350.20 |
| Relocate 3168X Bridge St S/S | 2019 FY Actual | 777,401.34 |
| Relocate 3168X Bridge St S/S | 2019 FY Budget | 516,969.58 |
| Relocate 3168X Bridge St S/S | 2020 FY Actual | (69,102.18) |
| Relocate 314 Line around Heron Pond | 2019 FY Actual | 927,819.11 |
| Relocate 314 Line around Heron Pond | 2019 FY Budget | 599,992.36 |
| Relocate 314 Line around Heron Pond | 2020 FY Actual | (1,818.60) |
| Repl open wire w/ Spacer cble Rt 63 | 2019 FY Actual | 1,555,675.14 |
| Repl open wire w/ Spacer cble Rt 63 | 2019 FY Budget | 999,983.21 |
| Repl open wire w/ Spacer cble Rt 63 | 2020 FY Actual | 104,424.20 |
| Repl open wire w/ Spacer cble Rt 63 | 2021 FY Actual | 223.50 |
| Repl open wire w/ Spacer cble Rt 63 | 2022 FY Actual | (87,066.41) |
| Relocate feed to Hinsdale Wastewat | 2019 FY Actual | 325,619.06 |
| Relocate feed to Hinsdale Wastewat | 2019 FY Budget | 250,032.55 |
| Relocate feed to Hinsdale Wastewat | 2020 FY Actual | 2,780.26 |
| Relocate feed to Hinsdale Wastewat | 2021 FY Actual | 260.36 |
| Relocate feed to Hinsdale Wastewat | 2022 FY Actual | 31.80 |
| DIST LINE WORK FOR MONADNOCK SS REB | 2020 FY Budget | 600,036.37 |
| DIST LINE WORK FOR MONADNOCK SS REB | 2021 FY Actual | 180.84 |
| DIST LINE WORK FOR MONADNOCK SS REB | 2021 FY Budget | 600,000.13 |
| DIST LINE WORK FOR MONADNOCK SS REB | 2022 FY Actual | 11,365.28 |
| DIST LINE WORK FOR MONADNOCK SS REB | 2022 FY Budget | (82.57) |
| DIST LINE WORK FOR MONADNOCK SS REB | 2023 FY Actual | 348.58 |
| DIST LINE WORK FOR MONADNOCK SS REB | 2023 FY Budget | 446,857.64 |
| 317 Line Reconstruction | 2019 FY Actual | 1,385,749.81 |
| 317 Line Reconstruction | 2020 FY Actual | 20,264.65 |
| Replace Lattice Steel Towers | 2019 FY Actual | 298,545.57 |
| Replace Lattice Steel Towers | 2019 FY Budget | 250,000.22 |

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| Replace Lattice Steel Towers | 2020 FY Budget | 300,105.79 |
| Replace Lattice Steel Towers | 2021 FY Actual | 183.04 |
| Replace Lattice Steel Towers | 2021 FY Budget | 299,999.93 |
| Replace Lattice Steel Towers | 2023 FY Actual | (920.00) |
| Replace Lattice Steel Towers | 2019 FY Actual | 996,801.17 |
| Replace Lattice Steel Towers | 2020 FY Actual | 2,556,538.61 |
| 317 Line ROW section rebuild | 2020 FY Actual | 719,872.47 |
| 317 Line ROW section rebuild | 2021 FY Actual | 759,599.97 |
| 317 Line ROW section rebuild | 2022 FY Actual | 412.60 |
| 317 Line ROW Section Rebuild | 2023 FY Actual | 136.59 |
| Reconductor Strafford St in Lacona | 2020 FY Budget | 130,000.57 |
| Relo 3200' main li fr ROW to roadsi | 2020 FY Budget | 180,000.54 |
| Voltage Conversion Lost Nation Rd a | 2020 FY Budget | 169,999.66 |
| 43W1 (13W1) Construct Circuit Tie | 2020 FY Actual | 2,014,908.12 |
| 43W1 (13W1) Construct Circuit Tie | 2020 FY Budget | 1,649,999.91 |
| 43W1 (13W1) Construct Circuit Tie | 2021 FY Actual | (58,725.66) |
| 43W1 (13W1) Construct Circuit Tie | 2022 FY Actual | 817.87 |
| Millyard SS Distribution Line Work | 2020 FY Budget | 2,938,539.06 |
| Millyard SS Distribution Line Work | 2021 FY Actual | 176,983.21 |
| Millyard SS Distribution Line Work | 2021 FY Budget | 2,900,000.18 |
| Millyard SS Distribution Line Work | 2022 FY Actual | 3,728,199.37 |
| Millyard SS Distribution Line Work | 2022 FY Budget | 2,983,824.47 |
| Millyard SS Distribution Line Work | 2023 FY Actual | 326,343.51 |
| Millyard SS Distribution Line Work | 2023 FY Budget | 510,545.00 |
| 3159X Extend 3 Phase Boston Post Rd | 2020 FY Actual | 334,047.88 |
| 3159X Extend 3 Phase Boston Post Rd | 2020 FY Budget | 255,323.89 |
| 3159X Extend 3 Phase Boston Post Rd | 2021 FY Actual | (51,655.21) |
| Replace 3891X cable along raiload t | 2020 FY Budget | 789,172.76 |
| Replace 3891X cable along raiload t | 2021 FY Actual | 754,159.09 |
| Replace 3891X cable along raiload t | 2021 FY Budget | 850,000.00 |
| Replace 3891X cable along raiload t | 2022 FY Actual | (122,022.57) |
| Replace 3891X cable along raiload t | 2022 FY Budget | 750,000.00 |
| Replace 3891X cable along raiload t | 2023 FY Actual | 2,991.42 |
| Mason Rd Relo 1500' main li to road | 2020 FY Actual | 336,074.00 |
| Mason Rd Relo 1500' main li to road | 2020 FY Budget | 200,029.47 |
| Mason Rd Relo 1500' main li to road | 2021 FY Actual | 5,801.63 |
| Mason Rd Relo 1500' main li to road | 2022 FY Actual | (10,790.12) |
| 3155X6 feed from the 3155X9 | 2020 FY Actual | 603,794.12 |
| 3155X6 feed from the 3155X9 | 2020 FY Budget | 200,195.77 |
| 3155X6 feed from the 3155X9 | 2021 FY Actual | (3,383.70) |
| 3155X6 feed from the 3155X9 | 2022 FY Actual | (23,746.01) |
| Rte 9 Relo 2800' main li to roadsid | 2020 FY Actual | 656,508.74 |
| Rte 9 Relo 2800' main li to roadsid | 2020 FY Budget | 299,934.61 |
| Rte 9 Relo 2800' main li to roadsid | 2021 FY Actual | 5,719.02 |
| Rte 9 Relo 2800' main li to roadsid | 2022 FY Actual | (11,723.85) |
| 3410 and 315 Circuit Tie | 2020 FY Actual | 1,409,279.98 |
| 3410 and 315 Circuit Tie | 2020 FY Budget | 1,349,923.33 |

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|---|---|---|
| 3410 and 315 Circuit Tie | 2021 FY Actual | 658.28 |
| 3410 and 315 Circuit Tie | 2022 FY Actual | 1,401.64 |
| 24X1 and 313X1 Circuit Tie | 2020 FY Actual | 2,185,969.59 |
| 24X1 and 313X1 Circuit Tie | 2020 FY Budget | 2,799,859.18 |
| 24X1 and 313X1 Circuit Tie | 2021 FY Actual | 27,953.20 |
| 24X1 and 313X1 Circuit Tie | 2022 FY Actual | (66,609.52) |
| 317/3410 RECON BRADFORD TO WARNER | 2021 FY Actual | 1,038,924.42 |
| 317/3410 RECON BRADFORD TO WARNER | 2021 FY Budget | 3,000,000.00 |
| 317/3410 RECON BRADFORD TO WARNER | 2022 FY Actual | 266,765.99 |
| 317/3410 RECON BRADFORD TO WARNER | 2023 FY Actual | 7,289.00 |
| 2020 CIRCUIT PATROL REPAIRS | 2020 FY Actual | 1,025,818.09 |
| 2020 CIRCUIT PATROL REPAIRS | 2021 FY Actual | 1,633,475.50 |
| 2020 CIRCUIT PATROL REPAIRS | 2022 FY Actual | (38,168.73) |
| 2020 CIRCUIT PATROL REPAIRS | 2023 FY Actual | (31,806.69) |
| RECONDUCTOR ACADEMY RD PEMBROKE SPA | 2021 FY Budget | 725,651.55 |
| MALVERN VALLEY HANOVER CIRCUIT TIE | 2021 FY Actual | 304,525.87 |
| MALVERN VALLEY HANOVER CIRCUIT TIE | 2021 FY Budget | 583,984.25 |
| MALVERN VALLEY HANOVER CIRCUIT TIE | 2022 FY Actual | 137,908.13 |
| CIRCUIT TIE 14X188 TO 3248 | 2021 FY Actual | 351,631.40 |
| CIRCUIT TIE 14X188 TO 3248 | 2021 FY Budget | 637,380.91 |
| CIRCUIT TIE 14X188 TO 3248 | 2022 FY Actual | (12,017.89) |
| LINE M164 LAMINATED WOOD SYS STR REPL | 2021 FY Actual | 551,856.63 |
| LINE M164 LAMINATED WOOD SYS STR REPL | 2022 FY Actual | (5,979.72) |
| 393 LINE ROW SECTION REBUILD | 2021 FY Actual | 463,288.43 |
| 393 LINE ROW SECTION REBUILD | 2022 FY Actual | 4,677,512.50 |
| 393 LINE ROW SECTION REBUILD | 2022 FY Budget | 3,042,769.44 |
| 393 LINE ROW SECTION REBUILD | 2023 FY Actual | 890.10 |
| CIRCUIT TIE 3191X1B TO 377X2 | 2021 FY Actual | 534,223.56 |
| CIRCUIT TIE 3191X1B TO 377X2 | 2021 FY Budget | 174,999.94 |
| CIRCUIT TIE 3191X1B TO 377X2 | 2022 FY Actual | 158,369.01 |
| CIRCUIT TIE 3191X1B TO 377X2 | 2023 FY Actual | (40,848.64) |
| CIRCUIT TIE 3191X3 TO 3191X | 2021 FY Actual | 853,143.50 |
| CIRCUIT TIE 3191X3 TO 3191X | 2021 FY Budget | 264,999.99 |
| CIRCUIT TIE 3191X3 TO 3191X | 2022 FY Actual | (113,132.50) |
| CIRCUIT TIE 3191X3 TO 3191X | 2023 FY Actual | (40,117.59) |
| 3174X4 ROUTE 11 OFF ROAD SHUNT | 2022 FY Actual | 1,599.62 |
| 3174X4 ROUTE 11 OFF ROAD SHUNT | 2023 FY Actual | 47,424.02 |
| ROADSIDE REJECT POLE REPLACEMENT | 2021 FY Actual | 522,522.70 |
| ROADSIDE REJECT POLE REPLACEMENT | 2021 FY Budget | 2,500,000.02 |
| ROADSIDE REJECT POLE REPLACEMENT | 2022 FY Actual | (38,593.97) |
| ROADSIDE REJECT POLE REPLACEMENT | 2023 FY Actual | 12,890.44 |
| CONSTRUCT NEW FEED FOR RTE 122 | 2021 FY Actual | 308,417.11 |
| CONSTRUCT NEW FEED FOR RTE 122 | 2021 FY Budget | 250,000.21 |
| CONSTRUCT NEW FEED FOR RTE 122 | 2022 FY Actual | (39,560.72) |
| CONSTRUCT NEW FEED FOR RTE 122 | 2023 FY Actual | (19,039.31) |
| 2021 WOOD POLE TREATMENT | 2021 FY Actual | 411,820.31 |
| 2021 WOOD POLE TREATMENT | 2022 FY Actual | (99,346.97) |

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| 2021 WOOD POLE TREATMENT | 2023 FY Actual | (11,151.89) |
| 2021 CIRCUIT PATROL REPAIRS PHASE 2 | 2021 FY Actual | 1,117,560.50 |
| 2021 CIRCUIT PATROL REPAIRS PHASE 2 | 2022 FY Actual | 105,236.76 |
| 2021 CIRCUIT PATROL REPAIRS PHASE 2 | 2023 FY Actual | (9,276.11) |
| Mobile Utility & Mobile Pole Assemb | 2021 FY Actual | 70,477.80 |
| Mobile Utility & Mobile Pole Assemb | 2022 FY Actual | 330,642.50 |
| GOFFSTOWN SS ELIM PHASE 2 27W2 CONV | 2023 FY Actual | 1,368,685.64 |
| GOFFSTOWN SS ELIM PHASE 2 27W2 CONV | 2023 FY Budget | 1,691,629.24 |
| 2022 POLE TOP DISTRIBUTION AUTOMATN | 2023 FY Actual | 613,261.75 |
| NORTH DOVER AUTOMATED SWITCHES | 2022 FY Budget | 439,988.87 |
| 15W4 RUSSELL ST SWITCHGEAR PORTSMTH | 2022 FY Budget | 220,000.00 |
| 386 Line Distribution Underbuild (Y170) | 2022 FY Actual | 5,118.69 |
| 3148X3 REMOVAL - NORTH DOVER | 2022 FY Actual | 1,052,102.56 |
| 32 Line Pole Replacement | 2023 FY Actual | 2,939,356.19 |
| 32 Line Pole Replacement | 2023 FY Budget | 2,754,000.00 |
| 371 Line Pole Replacements | 2023 FY Actual | 3,339,687.88 |
| 371 Line Pole Replacements | 2023 FY Budget | 3,137,000.00 |
| 355 Line Emergent Str Replacement | 2022 FY Actual | 567,733.18 |
| 355 Line Pole Replacement | 2022 FY Actual | 188,365.75 |
| 355 Line Pole Replacement | 2023 FY Actual | 660,476.95 |
| 355 Line Pole Replacement | 2023 FY Budget | 111,000.00 |
| 2022 Roadside Reject Pole Repl | 2022 FY Actual | 1,384,693.41 |
| 2022 Roadside Reject Pole Repl | 2022 FY Budget | 2,250,000.00 |
| 2022 Roadside Reject Pole Repl | 2023 FY Actual | 486,327.59 |
| 3154X2 - 377X1 CIRCUIT TIE | 2022 FY Actual | 28,892.38 |
| 3154X2 - 377X1 CIRCUIT TIE | 2022 FY Budget | 601,000.00 |
| 3154X2 - 377X1 CIRCUIT TIE | 2023 FY Actual | 1,287,738.71 |
| 3217X ROCKY POND RD BACKFEED | 2022 FY Actual | 275,808.67 |
| 3217X ROCKY POND RD BACKFEED | 2022 FY Budget | 128,000.00 |
| 3217X ROCKY POND RD BACKFEED | 2023 FY Actual | (174,039.02) |
| GRIFFIN ROAD CONVERSION LONDONDERRY | 2022 FY Actual | 213,573.75 |
| GRIFFIN ROAD CONVERSION LONDONDERRY | 2023 FY Actual | 490.34 |
| 389X8 Line Relocation | 2022 FY Actual | 55,806.62 |
| 389X8 Line Relocation | 2023 FY Actual | 355,454.80 |
| 3120X2 RT 119 CONVERSION | 2022 FY Actual | 350,261.74 |
| 3120X2 RT 119 CONVERSION | 2022 FY Budget | 421,307.20 |
| 3120X2 RT 119 CONVERSION | 2023 FY Actual | 181,596.72 |
| 3120X2 RT 119 CONVERSION | 2023 FY Budget | 100,000.00 |
| 3140X2 WASHINGTON RD SPACER CABLE | 2022 FY Actual | 67,334.38 |
| 3140X2 WASHINGTON RD SPACER CABLE | 2022 FY Budget | 149,800.00 |
| 3140X2 WASHINGTON RD SPACER CABLE | 2023 FY Actual | 12,642.37 |
| 3140X2 WASHINGTON RD SPACER CABLE | 2023 FY Budget | 50,000.00 |
| 3139X SPOFFORD RD RECONDUCTOR | 2022 FY Actual | 212,604.21 |
| 3139X SPOFFORD RD RECONDUCTOR | 2022 FY Budget | 252,000.00 |
| 3139X SPOFFORD RD RECONDUCTOR | 2023 FY Actual | 420.64 |
| 317/3410 reconstr Roby Rd to Warner | 2022 FY Actual | 2,039,404.99 |
| 317/3410 reconstr Roby Rd to Warner | 2022 FY Budget | 5,707,099.62 |

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| 317/3410 reconstr Roby Rd to Warner | 2023 FY Actual | 2,150,629.06 |
| 317/3410 reconstr Roby Rd to Warner | 2023 FY Budget | 2,155,406.00 |
| 313X1 Riverview UG Replacement | 2022 FY Actual | 374,361.66 |
| 313X1 Riverview UG Replacement | 2023 FY Actual | 11,812.33 |
| 3140X Stoddard Rebuild | 2022 FY Actual | 226,775.65 |
| 3140X Stoddard Rebuild | 2023 FY Actual | 10,760.68 |
| 2022 WOOD POLE TREATMENT | 2022 FY Actual | 232,116.49 |
| 2022 WOOD POLE TREATMENT | 2022 FY Budget | 349,990.94 |
| 2022 WOOD POLE TREATMENT | 2023 FY Actual | 5,783.39 |
| Hampshire Plaza UG Reconfiguration | 2023 FY Budget | 20,000.00 |
| CCI Reject Pole Replacement | 2023 FY Actual | 2,887,469.28 |
| 399X15 Mcintosh Commons | 2023 FY Actual | 38,133.83 |
| 399X15 Mcintosh Commons | 2023 FY Budget | 876,000.00 |
| 392X1-392X2 Circuit Tie | 2023 FY Actual | 81,028.39 |
| 392X1-392X2 Circuit Tie | 2023 FY Budget | 1,738,000.00 |
| 3112X1 Reconductor | 2023 FY Actual | 1,342,943.35 |
| 3112X1 Reconductor | 2023 FY Budget | 1,760,000.00 |
| 3137X1-377X3 Circuit Tie | 2023 FY Actual | 758.90 |
| 3137X1-377X3 Circuit Tie | 2023 FY Budget | 3,133,500.00 |
| North Dover 4kV Conversion | 2023 FY Actual | 427,551.79 |
| North Dover 4kV Conversion | 2023 FY Budget | 2,400,000.00 |
| 355X10 Line Extension | 2023 FY Budget | 1,247,130.00 |
| 338 Line Reconstruction | 2023 FY Budget | 1,500,000.00 |
| 355 Line Reconstruction | 2023 FY Budget | 4,000,000.17 |
| 31W2 Transformer Repl | 2023 FY Budget | 1,000,000.00 |
| 3025 Line Structure Replacement | 2023 FY Actual | 1,287,167.59 |
| 319 Line Structure Repl Bear Hill | 2023 FY Actual | 1,488,975.30 |
| 2023 Roadside Reject Pole Repl | 2023 FY Actual | 2,194,677.96 |
| 2023 Roadside Reject Pole Repl | 2023 FY Budget | 2,000,000.00 |
| 3891 UG Cable Replacement | 2023 FY Budget | 865,000.00 |
| 3155X Install Padmounted Step Xfmr | 2022 FY Actual | 3,149.48 |
| 42X3-316X1 Circuit Tie Ph 1 | 2023 FY Actual | 2,499,141.60 |
| 42X3-316X1 Circuit Tie Ph 1 | 2023 FY Budget | 1,100,000.45 |
| 317 Roadway Rebuild | 2023 FY Actual | 1,034.56 |
| 317 Roadway Rebuild | 2023 FY Budget | 3,140,000.00 |
| 317 / 3410 Removal | 2023 FY Budget | 2,200,000.00 |
| 313 Line Lattice Tower Repl | 2023 FY Budget | 120,000.00 |
| 3178 Line - Lattice Tower Repl | 2023 FY Budget | 500,000.00 |
| 3139X-3178 Circuit Tie | 2023 FY Actual | 9,661.08 |
| Replace Degraded Manholes | 2023 FY Budget | 300,000.00 |
| 2023 Wood Pole Treatment | 2023 FY Actual | 296,166.21 |
| 2023 Wood Pole Treatment | 2023 FY Budget | 420,000.00 |
| 2023 Semi-annual Circuit Patrol | 2023 FY Actual | 1,290,133.96 |
| 322 Line Pole Replacement | 2023 FY Actual | 2,868.74 |
| 3151 Line Pole Replacement | 2023 FY Actual | 3,129.84 |
| DIST LINE ROW PROGRAM | 2019 FY Actual | 4,491,035.87 |
| DIST LINE ROW PROGRAM | 2019 FY Budget | 4,993,797.19 |

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| DIST LINE ROW PROGRAM | 2020 FY Actual | 3,298,539.90 |
| DIST LINE ROW PROGRAM | 2020 FY Budget | 5,040,716.19 |
| DIST LINE ROW PROGRAM | 2021 FY Actual | 6,213,643.02 |
| DIST LINE ROW PROGRAM | 2021 FY Budget | 5,099,999.52 |
| DIST LINE ROW PROGRAM | 2022 FY Actual | 4,474,347.11 |
| DIST LINE ROW PROGRAM | 2022 FY Budget | 4,829,480.85 |
| DIST LINE ROW PROGRAM | 2023 FY Actual | 4,688,750.71 |
| DIST LINE ROW PROGRAM | 2023 FY Budget | 5,000,000.00 |
| RELIABILITY IMPROVEMENTS - LANCASTE | 2019 FY Actual | 331,543 |
| RELIABILITY IMPROVEMENTS - LANCASTE | 2020 FY Actual | 114,891 |
| RELIABILITY IMPROVEMENTS - LANCASTE | 2021 FY Actual | 404,990.91 |
| RELIABILITY IMPROVEMENTS - LANCASTE | 2022 FY Actual | 443,456.97 |
| RELIABILITY IMPROVEMENTS - LANCASTE | 2023 FY Actual | 1,114,318.92 |
| RELIABILITY IMPROVEMENTS - BERLIN | 2019 FY Actual | 75,686 |
| RELIABILITY IMPROVEMENTS - BERLIN | 2020 FY Actual | 7,911 |
| RELIABILITY IMPROVEMENTS - BERLIN | 2021 FY Actual | 43,900 |
| RELIABILITY IMPROVEMENTS - BERLIN | 2022 FY Actual | 22,138 |
| RELIABILITY IMPROVEMENTS - BERLIN | 2023 FY Actual | 159,608 |
| RELIABILITY IMPROVEMENTS - CHOCORUA | 2019 FY Actual | 190,991 |
| RELIABILITY IMPROVEMENTS - CHOCORUA | 2020 FY Actual | 66,591 |
| RELIABILITY IMPROVEMENTS - CHOCORUA | 2021 FY Actual | 76,787 |
| RELIABILITY IMPROVEMENTS - CHOCORUA | 2022 FY Actual | 22,827 |
| RELIABILITY IMPROVEMENTS - CHOCORUA | 2023 FY Actual | 466,041 |
| RELIABILITY IMPROVEMENTS - DERRY | 2019 FY Actual | 173,075 |
| RELIABILITY IMPROVEMENTS - DERRY | 2020 FY Actual | 76,929 |
| RELIABILITY IMPROVEMENTS - DERRY | 2021 FY Actual | 353,346 |
| RELIABILITY IMPROVEMENTS - DERRY | 2022 FY Actual | 292,109 |
| RELIABILITY IMPROVEMENTS - DERRY | 2023 FY Actual | 88,661 |
| RELIABILITY IMPROVEMENTS - EPPING | 2019 FY Actual | 242,051 |
| RELIABILITY IMPROVEMENTS - EPPING | 2020 FY Actual | 177,125 |
| RELIABILITY IMPROVEMENTS - EPPING | 2021 FY Actual | 818,173 |
| RELIABILITY IMPROVEMENTS - EPPING | 2022 FY Actual | 169,021 |
| RELIABILITY IMPROVEMENTS - EPPING | 2023 FY Actual | 164,141 |
| RELIABILITY IMPROVEMENTS - KEENE | 2019 FY Actual | 496,112 |
| RELIABILITY IMPROVEMENTS - KEENE | 2020 FY Actual | 263,710 |
| RELIABILITY IMPROVEMENTS - KEENE | 2021 FY Actual | 540,350 |
| RELIABILITY IMPROVEMENTS - KEENE | 2022 FY Actual | 391,094 |
| RELIABILITY IMPROVEMENTS - KEENE | 2023 FY Actual | 443,468 |
| RELIABILITY IMPROVEMENTS - LACONIA | 2019 FY Actual | 483,126 |
| RELIABILITY IMPROVEMENTS - LACONIA | 2020 FY Actual | 146,761 |
| RELIABILITY IMPROVEMENTS - LACONIA | 2021 FY Actual | 311,583 |
| RELIABILITY IMPROVEMENTS - LACONIA | 2022 FY Actual | 666,368 |
| RELIABILITY IMPROVEMENTS - LACONIA | 2023 FY Actual | 1,205,645 |
| RELIABILITY IMPROVEMENTS - NASHUA | 2019 FY Actual | 692,487 |
| RELIABILITY IMPROVEMENTS - NASHUA | 2020 FY Actual | 1,093,043 |
| RELIABILITY IMPROVEMENTS - NASHUA | 2021 FY Actual | 326,244 |
| RELIABILITY IMPROVEMENTS - NASHUA | 2022 FY Actual | 1,233,963 |

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| RELIABILITY IMPROVEMENTS - NASHUA | 2023 FY Actual | 72,027 |
| RELIABILITY IMPROVEMENTS - PORTSMOU | 2019 FY Actual | 269,204 |
| RELIABILITY IMPROVEMENTS - PORTSMOU | 2020 FY Actual | (49,408) |
| RELIABILITY IMPROVEMENTS - PORTSMOU | 2021 FY Actual | 892,303 |
| RELIABILITY IMPROVEMENTS - PORTSMOU | 2022 FY Actual | 112,570 |
| RELIABILITY IMPROVEMENTS - PORTSMOU | 2023 FY Actual | 221,713 |
| RELIABILITY IMPROVEMENTS | 2019 FY Actual | (12,610) |
| RELIABILITY IMPROVEMENTS | 2019 FY Budget | 2,000,011 |
| RELIABILITY IMPROVEMENTS | 2020 FY Actual | (750) |
| RELIABILITY IMPROVEMENTS | 2020 FY Budget | 2,000,000 |
| RELIABILITY IMPROVEMENTS | 2021 FY Actual | 770 |
| RELIABILITY IMPROVEMENTS | 2021 FY Budget | 2,000,000 |
| RELIABILITY IMPROVEMENTS | 2022 FY Actual | (769) |
| RELIABILITY IMPROVEMENTS | 2022 FY Budget | 2,342,895 |
| RELIABILITY IMPROVEMENTS | 2023 FY Budget | 5,000,000 |
| RELIABILITY IMPROVEMENTS - ROCHESTE | 2019 FY Actual | 204,918 |
| RELIABILITY IMPROVEMENTS - ROCHESTE | 2020 FY Actual | 498,822 |
| RELIABILITY IMPROVEMENTS - ROCHESTE | 2021 FY Actual | 685,891 |
| RELIABILITY IMPROVEMENTS - ROCHESTE | 2022 FY Actual | 213,791 |
| RELIABILITY IMPROVEMENTS - ROCHESTE | 2023 FY Actual | 940,634 |
| RELIABILITY IMPROVEMENTS - NEWPORT | 2019 FY Actual | 166,604 |
| RELIABILITY IMPROVEMENTS - NEWPORT | 2020 FY Actual | 164,804 |
| RELIABILITY IMPROVEMENTS - NEWPORT | 2021 FY Actual | 409,105 |
| RELIABILITY IMPROVEMENTS - NEWPORT | 2022 FY Actual | 363,170 |
| RELIABILITY IMPROVEMENTS - NEWPORT | 2023 FY Actual | 224,458 |
| RELIABILITY IMPROVEMENTS - HOOKSETT | 2019 FY Actual | 68,888 |
| RELIABILITY IMPROVEMENTS - HOOKSETT | 2020 FY Actual | 313,654 |
| RELIABILITY IMPROVEMENTS - HOOKSETT | 2021 FY Actual | 376,276 |
| RELIABILITY IMPROVEMENTS - HOOKSETT | 2022 FY Actual | 92,018 |
| RELIABILITY IMPROVEMENTS - HOOKSETT | 2023 FY Actual | 330,028 |
| RELIABILITY IMPROVEMENTS - BEDFORD | 2019 FY Actual | 171,825 |
| RELIABILITY IMPROVEMENTS - BEDFORD | 2020 FY Actual | 69,425 |
| RELIABILITY IMPROVEMENTS - BEDFORD | 2021 FY Actual | 165,533 |
| RELIABILITY IMPROVEMENTS - BEDFORD | 2022 FY Actual | 210,320 |
| RELIABILITY IMPROVEMENTS - BEDFORD | 2023 FY Actual | 96,704 |
| CONSTRUCT NEW CIRCUIT-BRISTOL S/S | 2022 FY Actual | (15,164.73) |
| Porcelain Change-out | 2019 FY Actual | -9884.81 |
| Porcelain Change-out | 2020 FY Actual | -1893.74 |
| Porcelain Change-out | 2021 FY Actual | 2 |
| Porcelain Change-out | 2022 FY Actual | 718.91 |
| REPLACE VAULT TOPS | 2023 FY Actual | 23,822.56 |
| KEENE DOWNTOWN UG REPLACEMENT PROJ | 2019 FY Actual | 1,003,841.83 |
| KEENE DOWNTOWN UG REPLACEMENT PROJ | 2019 FY Budget | 794,111.25 |
| KEENE DOWNTOWN UG REPLACEMENT PROJ | 2020 FY Actual | 149,990.58 |
| KEENE DOWNTOWN UG REPLACEMENT PROJ | 2021 FY Actual | (296,426.93) |
| KEENE DOWNTOWN UG REPLACEMENT PROJ | 2022 FY Actual | 103,560.75 |
| DIRECT BURIED CABLE REPLACEMENT | 2019 FY Actual | 571,932.98 |

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|---|---|---|
| DIRECT BURIED CABLE REPLACEMENT | 2019 FY Budget | 699,999.63 |
| DIRECT BURIED CABLE REPLACEMENT | 2022 FY Actual | (4,504.81) |
| Replace Degraded Manholes | 2019 FY Budget | 200,053.35 |
| Replace Degraded Manholes | 2020 FY Actual | 42,162.71 |
| Replace Degraded Manholes | 2020 FY Budget | 128,380.47 |
| MANCHESTER NETWORK CABLE REPLACEMEN | 2020 FY Actual | 79,404.73 |
| MANCHESTER NETWORK CABLE REPLACEMEN | 2021 FY Actual | 1,968,368.00 |
| MANCHESTER NETWORK CABLE REPLACEMEN | 2021 FY Budget | 2,064,752.41 |
| MANCHESTER NETWORK CABLE REPLACEMEN | 2022 FY Actual | (105,008.22) |
| MANCHESTER NETWORK CABLE REPLACEMEN | 2022 FY Budget | 91,758.24 |
| CODFISH CORNER ROAD LOOP | 2020 FY Actual | 72,775.81 |
| CODFISH CORNER ROAD LOOP | 2021 FY Actual | 427,042.63 |
| CODFISH CORNER ROAD LOOP | 2021 FY Budget | 454,154.58 |
| Rebuild Berlin UG system | 2020 FY Actual | 322,238.42 |
| Rebuild Berlin UG system | 2020 FY Budget | 649,999.51 |
| Rebuild Berlin UG system | 2021 FY Actual | 103,154.82 |
| Rebuild Berlin UG system | 2022 FY Actual | (17,712.77) |
| TIDEWATER FARM URD LOOP | 2021 FY Actual | 115.51 |
| TIDEWATER FARM URD LOOP | 2022 FY Actual | 173,151.73 |
| Monadnock Trailer Park Underground | 2021 FY Actual | 275,588.41 |
| Monadnock Trailer Park Underground | 2022 FY Actual | (18,618.48) |
| N KEENE S/S NEW DIST CIRC | 2020 FY Actual | 3,653.72 |
| RECON LINES 3110, 353, 3445X | 2020 FY Actual | (15,997.57) |
| PACK MONADNOCK SUMMIT SOLUTION | 2020 FY Actual | 2,623.31 |
| PACK MONADNOCK SUMMIT SOLUTION | 2021 FY Actual | 291,407.48 |
| PACK MONADNOCK SUMMIT SOLUTION | 2021 FY Budget | 400,000.00 |
| REPLACE DEGRADED MANHOLE ROOFS | 2021 FY Actual | 112,212.05 |
| REPLACE DEGRADED MANHOLE ROOFS | 2021 FY Budget | 94,000.48 |
| 49W1 TIMCO ROW TAP REMOVAL | 2021 FY Actual | 116,960.62 |
| 49W1 TIMCO ROW TAP REMOVAL | 2022 FY Actual | (1,253.47) |
| SOMERSWORTH 34.5 KV OCB REPLACEMENT | 2019 FY Actual | 107.46 |
| JACKMAN - REPLACE OBSOLETE EQUIPMEN | 2019 FY Actual | 18,998.76 |
| JACKMAN - REPLACE OBSOLETE EQUIPMEN | 2019 FY Budget | 23,132.70 |
| JACKMAN - REPLACE OBSOLETE EQUIPMEN | 2020 FY Actual | (2,352.29) |
| JACKMAN - REPLACE OBSOLETE EQUIPMEN | 2021 FY Actual | 90.79 |
| JACKMAN - REPLACE OBSOLETE EQUIPMEN | 2022 FY Actual | 126.68 |
| LACONIA SS EQUIPMENT REPLACEMENT | 2019 FY Actual | 1,471,385.08 |
| LACONIA SS EQUIPMENT REPLACEMENT | 2019 FY Budget | 1,530,995.69 |
| LACONIA SS EQUIPMENT REPLACEMENT | 2020 FY Actual | 2,741,783.20 |
| LACONIA SS EQUIPMENT REPLACEMENT | 2020 FY Budget | 1,800,762.49 |
| LACONIA SS EQUIPMENT REPLACEMENT | 2021 FY Actual | (4,469.62) |
| LACONIA SS 24 VDC CNTRL SYS & RELAY | 2019 FY Actual | (6,420.87) |
| AMHERST S/S - PLC AUTOMATION REPLAC | 2023 FY Actual | 142,063.45 |
| AMHERST S/S - PLC AUTOMATION REPLAC | 2023 FY Budget | 23,379.84 |
| SS LTC CONTROL REPLACEMENT | 2020 FY Actual | 406,677.68 |
| SS LTC CONTROL REPLACEMENT | 2020 FY Budget | 343,107.82 |
| SS LTC CONTROL REPLACEMENT | 2021 FY Actual | 6,170.87 |

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| CAPACITOR SWITCH REPLACEMENTS | 2023 FY Budget | 800,000.00 |
| LONG HILL SS 34.5kV CAP BANK SWITCH | 2019 FY Actual | 15,232.90 |
| LONG HILL SS 34.5kV CAP BANK SWITCH | 2020 FY Actual | 834,413.24 |
| LONG HILL SS 34.5kV CAP BANK SWITCH | 2020 FY Budget | 749,999.81 |
| LONG HILL SS 34.5kV CAP BANK SWITCH | 2021 FY Actual | 10,264.96 |
| RIVER ROAD SS UPGRADES | 2023 FY Actual | 1,767,950.93 |
| RIVER ROAD SS UPGRADES | 2023 FY Budget | 1,450,501.64 |
| GARVINS S/S OCB REPLACEMENT | 2022 FY Budget | 2,700,000.00 |
| GARVINS SS OCB REPLACEMENT | 2023 FY Actual | 4,101,320.52 |
| GARVINS SS OCB REPLACEMENT | 2023 FY Budget | 3,630,881.70 |
| DUNBARTON RD SS EQUIP REPLACMNT | 2021 FY Actual | 6,185.27 |
| DUNBARTON RD SS EQUIP REPLACMNT | 2022 FY Actual | 42,174.55 |
| DUNBARTON RD SS EQUIP REPLACMNT | 2023 FY Actual | 44,213.23 |
| REPLACE ROCHESTER SS BUS TIE AUTOCL | 2021 FY Actual | 28,668.41 |
| REPLACE ROCHESTER SS BUS TIE AUTOCL | 2021 FY Budget | 299,999.71 |
| REPLACE ROCHESTER SS BUS TIE AUTOCL | 2022 FY Actual | 442,534.90 |
| REPLACE ROCHESTER SS BUS TIE AUTOCL | 2022 FY Budget | 350,384.54 |
| REPLACE ROCHESTER SS BUS TIE AUTOCL | 2023 FY Actual | 41,167.63 |
| ASHLAND S/S-PLC REPLCMNT& P&C UPGRD | 2023 FY Actual | 1,263,025.12 |
| ASHLAND S/S-PLC REPLCMNT& P&C UPGRD | 2023 FY Budget | 2,086,590.27 |
| SACO VALLEY 34.5kV OCB REPLACE | 2023 FY Budget | 449,612.89 |
| BEEBE RIVER SS TB70 REMOVAL | 2022 FY Actual | 503,964.38 |
| BEEBE RIVER SS TB70 REMOVAL | 2023 FY Actual | 11,119.71 |
| 34.5kV CAP BANK SWTCH REP BROAD ST | 2023 FY Actual | 821,461.24 |
| 34.5kV CAP BANK SWTCH REP BROAD ST | 2023 FY Budget | 604,289.65 |
| REPLACE 5 ABB TPU-2000R RELAYS | 2021 FY Budget | 1,800,000.41 |
| REPLACE 5 ABB TPU-2000R RELAYS | 2022 FY Actual | 5,711.02 |
| REPLACE 5 ABB TPU-2000R RELAYS | 2022 FY Budget | 908,096.38 |
| REPLACE 5 ABB TPU-2000R RELAYS | 2023 FY Actual | 63,940.21 |
| REPLACE 5 ABB TPU-2000R RELAYS | 2023 FY Budget | 799,305.07 |
| Contoocook SS Oil Recloser Replacement | 2023 FY Actual | 12,367.84 |
| Mammoth Rd SS TPU Relay Repl | 2022 FY Actual | 253,832.76 |
| Mammoth Rd SS TPU Relay Repl | 2023 FY Actual | (63,398.85) |
| RESISTANCE SS RETIREMENT | 2022 FY Actual | 181,332.94 |
| RESISTANCE SS RETIREMENT | 2023 FY Actual | 1,690,898.38 |
| RESISTANCE SS RETIREMENT | 2023 FY Budget | 734,520.81 |
| Tasker Farm SS TPU Relay Replacement | 2022 FY Actual | 83,600.54 |
| Tasker Farm SS TPU Relay Replacement | 2023 FY Actual | 19,792.97 |
| Tasker Farm SS TPU Relay Replacement | 2023 FY Budget | 225,332.59 |
| Colebrook SS Oil Recloser Replacement | 2023 FY Actual | 23,143.02 |
| SS OIL RECLOSER REPL PROGRAM | 2022 FY Actual | 18,773.58 |
| SS OIL RECLOSER REPL PROGRAM | 2023 FY Actual | 67,819.55 |
| Great Bay PLC Automation Scheme | 2023 FY Budget | 250,000.00 |
| RE-FEED 20H1 & RETIRE LISBON S/S | 2022 FY Actual | 5,341.03 |
| Pack Monadnock Rbld Single-Phase Li | 2019 FY Actual | 145,625.53 |
| Pack Monadnock Rbld Single-Phase Li | 2020 FY Actual | 659,370.43 |
| Pack Monadnock Rbld Single-Phase Li | 2020 FY Budget | 1,798,668.40 |

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| Pack Monadnock Rbld Single-Phase Li | 2021 FY Actual | 1,273,079.24 |
| Pack Monadnock Rbld Single-Phase Li | 2021 FY Budget | 3,099,999.51 |
| PACK MONADNOCK RBLD SINGLE-PHASE LI | 2022 FY Actual | (140.42) |
| CIRCUIT TIES 3172X1 - 3112X3 | 2019 FY Actual | 468,235.64 |
| CIRCUIT TIES 3172X1 - 3112X3 | 2020 FY Actual | (4,376.52) |
| CIRCUIT TIES 3172X1 - 3112X3 | 2022 FY Actual | (7,897.03) |
| 55H1 PETERBOROUGH URD | 2019 FY Actual | (53,093.70) |
| 316X1 CIRCUIT TIE EASTMAN DEVELOPME | 2019 FY Actual | (20,476.27) |
| 316X1 CIRCUIT TIE EASTMAN DEVELOPME | 2020 FY Actual | 458,396.43 |
| 316X1 CIRCUIT TIE EASTMAN DEVELOPME | 2021 FY Actual | (446,399.72) |
| EMERALD ST LINE WORK | 2019 FY Actual | 112,038.14 |
| EMERALD ST LINE WORK | 2019 FY Budget | 500,000.22 |
| EMERALD ST LINE WORK | 2020 FY Actual | 201,213.80 |
| EMERALD ST LINE WORK | 2021 FY Actual | (74,904.85) |
| 44 & 60 WEST PENN TELECOM | 2019 FY Actual | 303,672.27 |
| 44 & 60 WEST PENN TELECOM | 2020 FY Actual | 152,541.51 |
| 44 & 60 WEST PENN TELECOM | 2020 FY Budget | 95,826.00 |
| Distribution Automation - Substatio | 2019 FY Actual | 8,809.30 |
| Distribution Automation - Substatio | 2022 FY Actual | 37.25 |
| Pettingill Switchgear Reconfigurati | 2019 FY Actual | 131,267.73 |
| Pettingill Switchgear Reconfigurati | 2020 FY Actual | 197,125.70 |
| Advanced Load Flow Software | 2019 FY Budget | 500,000.00 |
| NH DMS Pilot Phase 2 | 2019 FY Budget | 500,034.30 |
| NH LATERAL INITIATIVE | 2019 FY Actual | 5,658,935.57 |
| NH LATERAL INITIATIVE | 2020 FY Actual | 46,473.95 |
| NH LATERAL INITIATIVE | 2021 FY Actual | 1,177.42 |
| 34.5kV CAP BANK SWTCH REP BROAD ST | 2021 FY Actual | 186,591.66 |
| 34.5kV CAP BANK SWTCH REP BROAD ST | 2022 FY Actual | 310,957.99 |
| 34.5kV CAP BANK SWTCH REP BROAD ST | 2022 FY Budget | 1,218,721.24 |
| REMOVE LATTICE STEEL TOWERS W15 | 2021 FY Actual | 252,109.92 |
| 2021 CIRCUIT PATROL REPAIRS | 2021 FY Actual | 1,053,961.61 |
| 2021 CIRCUIT PATROL REPAIRS | 2022 FY Actual | 49,719.66 |
| 2021 CIRCUIT PATROL REPAIRS | 2023 FY Actual | 70,620.93 |
| 323 Line Underbuild Re-attachment | 2022 FY Actual | 544,789.76 |
| 317 Line ROW section rebuild | 2022 FY Actual | 514,895.70 |
| 317 Line ROW Section Rebuild | 2023 FY Actual | 37,026.90 |
| 32 Line Pole Replacement | 2022 FY Actual | 3,207,332.36 |
| 371 Line Pole Replacements | 2022 FY Actual | 3,464,163.83 |
| Remove Lattice Steel Towers – W15 | 2022 FY Actual | 207,286.09 |
| 2022 CIRCUIT PATROL REPAIRS | 2022 FY Actual | 988,878.87 |
| 2022 CIRCUIT PATROL REPAIRS | 2023 FY Actual | (29.15) |
| NH Cutout Installation 2022 | 2022 FY Actual | 3,169,580.40 |
| NH Cutout Installation 2022 | 2023 FY Actual | 46,183.21 |
| 2022 TripSaver Initiative | 2022 FY Actual | 915,232.88 |
| 2022 TripSaver Initiative | 2023 FY Actual | 199,230.91 |
| SMART Inspect Reliability Upgrades Central Region | 2023 FY Actual | 247,560.55 |
| SMART Inspect Reliability Northern | 2023 FY Actual | 341,825.84 |

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| SMART Inspect Reliability Western | 2023 FY Actual | 7,534,498.75 |
| 2023 DB Fault Indicator Repl | 2023 FY Actual | 255,960.19 |
| 2023 DB Fault Indicator Repl | 2023 FY Budget | 285,000.00 |
| 2023 TripSaver Program Phase 1 | 2023 FY Actual | 2,308,460.54 |
| TripSaver Program 2023 Phase 2 | 2023 FY Actual | 7,370,755.27 |
| 2024 NH URD Inspections | 2023 FY Actual | 92,631.03 |
| Distribution Design P134 Line | 2019 FY Actual | (274.87) |
| Distribution Design P134 Line | 2020 FY Actual | 3,112.96 |
| Distribution Design Y138 Line | 2019 FY Actual | 23.01 |
| Distribution Design Y138 Line | 2020 FY Actual | 44.08 |
| UCONN Damage Prediction Model Expan | 2019 FY Actual | (40,898.43) |
| 34.5KV BREAKER REPL PROGRAM | 2019 FY Budget | 1,000,000.00 |
| Portsmouth S/S - add transformer | 2019 FY Actual | 2,403,956.67 |
| Portsmouth S/S - add transformer | 2019 FY Budget | 4,689,270.61 |
| Portsmouth S/S - add transformer | 2020 FY Actual | 2,539,491.97 |
| Portsmouth S/S - add transformer | 2020 FY Budget | 4,434,935.69 |
| Portsmouth S/S - add transformer | 2021 FY Actual | 1,036,082.15 |
| Portsmouth S/S - add transformer | 2021 FY Budget | 1,291,847.33 |
| Portsmouth S/S - add transformer | 2022 FY Actual | 135.42 |
| SUBSTATION BATTERY REPLACEMENT | 2019 FY Actual | (969.24) |
| Substation Battery Replacement | 2023 FY Actual | 28,349.44 |
| SUBSTATION GROUND GRID UPGRADES | 2019 FY Actual | 33,414.56 |
| SUBSTATION GROUND GRID UPGRADES | 2020 FY Actual | 1,889.68 |
| SUBSTATION GROUND GRID UPGRADES | 2021 FY Actual | (2,267.60) |
| GORHAM SS-GENERATION DIVESTITURE | 2019 FY Actual | 9,628.07 |
| GORHAM SS-GENERATION DIVESTITURE | 2019 FY Budget | 20,814.51 |
| GORHAM SS-GENERATION DIVESTITURE | 2020 FY Actual | 3,239.06 |
| GORHAM SS-GENERATION DIVESTITURE | 2021 FY Actual | 165,079.73 |
| GORHAM SS-GENERATION DIVESTITURE | 2022 FY Actual | 11,141.98 |
| GORHAM SS-GENERATION DIVESTITURE | 2023 FY Actual | 46,885.95 |
| GARVINS SUBSTATION REBUILD | 2019 FY Actual | 45,845.47 |
| GARVINS SUBSTATION REBUILD | 2023 FY Actual | 1,555.44 |
| EMERALD STREET SUBSTATION | 2019 FY Actual | 7,174,682.15 |
| EMERALD STREET SUBSTATION | 2019 FY Budget | 8,220,724.52 |
| EMERALD STREET SUBSTATION | 2020 FY Actual | 5,326,424.58 |
| EMERALD STREET SUBSTATION | 2020 FY Budget | 5,078,491.31 |
| EMERALD STREET SUBSTATION | 2021 FY Actual | 2,871,262.20 |
| EMERALD STREET SUBSTATION | 2021 FY Budget | 2,011,398.85 |
| EMERALD STREET SUBSTATION | 2022 FY Actual | (24,207.66) |
| DANIEL SS (WEBSTER)-34.5KV SS UPGRD | 2019 FY Actual | 319,703.12 |
| DANIEL SS (WEBSTER)-34.5KV SS UPGRD | 2020 FY Actual | 133,654.14 |
| DANIEL SS (WEBSTER)-34.5KV SS UPGRD | 2021 FY Actual | 204.86 |
| Brook St S/S - 13TR1 Replacement | 2019 FY Actual | 30,098.23 |
| Brook St S/S - 13TR1 Replacement | 2019 FY Budget | 200,000.21 |
| Brook St S/S - 13TR1 Replacement | 2020 FY Actual | 55,148.59 |
| Brook St S/S - 13TR1 Replacement | 2020 FY Budget | 2,537,698.26 |
| Brook St S/S - 13TR1 Replacement | 2021 FY Actual | 164,204.83 |

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| Brook St S/S - 13TR1 Replacement | 2021 FY Budget | 2,499,606.03 |
| Brook St S/S - 13TR1 Replacement | 2022 FY Actual | 621,483.02 |
| Brook St S/S - 13TR1 Replacement | 2022 FY Budget | 4,614,729.95 |
| Brook St S/S - 13TR1 Replacement | 2023 FY Actual | (874,346.65) |
| Brook St S/S - 13TR1 Replacement | 2023 FY Budget | 6,493,879.00 |
| Blaine St SS add 34.5-12kV 10MVA tr | 2019 FY Actual | 41,501.28 |
| Blaine St SS add 34.5-12kV 10MVA tr | 2020 FY Actual | (1,134.42) |
| West Rye S/S Re-build | 2019 FY Actual | 492,346.91 |
| West Rye S/S Re-build | 2022 FY Actual | (406.92) |
| Second transformer at Lost Nation S | 2019 FY Actual | 1,552,773.65 |
| Second transformer at Lost Nation S | 2019 FY Budget | 1,326,551.64 |
| Second transformer at Lost Nation S | 2020 FY Actual | 45,774.92 |
| Second transformer at Lost Nation S | 2021 FY Actual | (52,795.60) |
| Second transformer at Lost Nation S | 2023 FY Actual | (28,349.44) |
| PLC AUTOMATION SCHEME REPLACEMENT | 2019 FY Budget | 198,756.96 |
| PLC AUTOMATION SCHEME REPLACEMENT | 2020 FY Actual | 603.46 |
| PLC AUTOMATION SCHEME REPLACEMENT | 2021 FY Actual | (603.46) |
| PLC AUTOMATION SCHEME REPLACEMENT | 2021 FY Budget | 450,040.85 |
| PLC AUTOMATION SCHEME REPLACEMENT | 2022 FY Budget | 179,319.39 |
| CLAREMONT AREA SUBSTATION UPGRADES | 2019 FY Actual | 20,348.44 |
| CLAREMONT AREA SUBSTATION UPGRADES | 2019 FY Budget | 100,000.21 |
| CLAREMONT AREA SUBSTATION UPGRADES | 2020 FY Actual | (91,629.55) |
| CLAREMONT AREA SUBSTATION UPGRADES | 2020 FY Budget | 498,594.73 |
| CLAREMONT AREA SUBSTATION UPGRADES | 2021 FY Actual | (175,329.78) |
| CLAREMONT AREA SUBSTATION UPGRADES | 2021 FY Budget | 500,757.18 |
| CLAREMONT AREA SUBSTATION UPGRADES | 2022 FY Actual | (335,578.93) |
| CLAREMONT AREA SUBSTATION UPGRADES | 2022 FY Budget | (284,100.00) |
| GREGGS SS Removal | 2019 FY Actual | 292,863.57 |
| GREGGS SS Removal | 2019 FY Budget | 999,999.76 |
| GREGGS SS Removal | 2020 FY Actual | 323,202.15 |
| GREGGS SS Removal | 2020 FY Budget | 418.65 |
| PINE HILL SS PLC AUTO SCH REPLACE | 2019 FY Actual | 823,845.98 |
| PINE HILL SS PLC AUTO SCH REPLACE | 2019 FY Budget | 764,503.15 |
| PINE HILL SS PLC AUTO SCH REPLACE | 2020 FY Actual | 176.96 |
| TWOMBLEY SS REBUILD | 2019 FY Actual | 836,554.58 |
| TWOMBLEY SS REBUILD | 2019 FY Budget | 1,499,999.55 |
| TWOMBLEY SS REBUILD | 2020 FY Actual | 5,012,077.71 |
| TWOMBLEY SS REBUILD | 2020 FY Budget | 4,436,790.71 |
| TWOMBLEY SS REBUILD | 2021 FY Actual | 11,149.88 |
| TWOMBLEY SS REBUILD | 2022 FY Actual | (6,586.87) |
| OCEAN RD SS 34.5KV OCB REPLACE | 2019 FY Actual | 1,175,585.39 |
| OCEAN RD SS 34.5KV OCB REPLACE | 2019 FY Budget | 901,358.66 |
| OCEAN RD SS 34.5KV OCB REPLACE | 2020 FY Actual | 9,780.46 |
| MESSER ST - REPLACE TB70 | 2019 FY Actual | 3,172,292.65 |
| MESSER ST - REPLACE TB70 | 2019 FY Budget | 2,652,734.58 |
| MESSER ST - REPLACE TB70 | 2020 FY Actual | 13,635.54 |
| Beebe River SS Cap Switcher Replace | 2019 FY Actual | 692,033.99 |

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| Beebe River SS Cap Switcher Replace | 2019 FY Budget | 660,999.74 |
| Beebe River SS Cap Switcher Replace | 2020 FY Actual | 61,956.39 |
| Beebe River SS Cap Switcher Replace | 2021 FY Actual | 208.83 |
| MILLYARD SS REPLACEMENT | 2019 FY Actual | 367,298.38 |
| MILLYARD SS REPLACEMENT | 2019 FY Budget | 1,335,556.48 |
| MILLYARD SS REPLACEMENT | 2020 FY Actual | 1,062,518.89 |
| MILLYARD SS REPLACEMENT | 2020 FY Budget | 3,000,257.74 |
| MILLYARD SS REPLACEMENT | 2021 FY Actual | 3,573,558.13 |
| MILLYARD SS REPLACEMENT | 2021 FY Budget | 3,733,446.73 |
| MILLYARD SS REPLACEMENT | 2022 FY Actual | 6,884,269.85 |
| MILLYARD SS REPLACEMENT | 2022 FY Budget | 6,261,808.25 |
| MILLYARD SS REPLACEMENT | 2023 FY Actual | 1,212,416.92 |
| MILLYARD SS REPLACEMENT | 2023 FY Budget | 973,761.30 |
| NORTH RD SS EQUIPMENT REPLACEMENT | 2019 FY Actual | 1,747,594.51 |
| NORTH RD SS EQUIPMENT REPLACEMENT | 2019 FY Budget | 383,706.73 |
| NORTH RD SS EQUIPMENT REPLACEMENT | 2020 FY Actual | 124,975.83 |
| Monadnock SS Cap Switcher Replaceme | 2019 FY Actual | 183,022.52 |
| Monadnock SS Cap Switcher Replaceme | 2020 FY Actual | 1,089.41 |
| MOBILE 115-34.5KV SUBSTATION | 2019 FY Actual | 486,945.07 |
| BEDFORD SS PLC AUTOMATION SCHEME | 2019 FY Actual | 497,539.65 |
| BEDFORD SS PLC AUTOMATION SCHEME | 2019 FY Budget | 989,248.54 |
| BEDFORD SS PLC AUTOMATION SCHEME | 2020 FY Actual | 2,579,862.11 |
| BEDFORD SS PLC AUTOMATION SCHEME | 2020 FY Budget | 2,391,974.73 |
| BEDFORD SS PLC AUTOMATION SCHEME | 2021 FY Actual | 7,880.50 |
| EDDY SS CONTROL HOUSE | 2019 FY Actual | 556,089.13 |
| EDDY SS CONTROL HOUSE | 2019 FY Budget | 523,325.03 |
| EDDY SS CONTROL HOUSE | 2020 FY Actual | 2,411,374.09 |
| EDDY SS CONTROL HOUSE | 2020 FY Budget | 5,909,690.22 |
| EDDY SS CONTROL HOUSE | 2021 FY Actual | 6,180,483.20 |
| EDDY SS CONTROL HOUSE | 2021 FY Budget | 3,702,132.17 |
| EDDY SS CONTROL HOUSE | 2022 FY Actual | 2,474,126.24 |
| EDDY SS CONTROL HOUSE | 2022 FY Budget | 1,931,282.07 |
| EDDY SS CONTROL HOUSE | 2023 FY Actual | 5,394.84 |
| DOVER SUBSTATION REBUILD | 2019 FY Budget | 1,862,999.67 |
| DOVER SUBSTATION REBUILD | 2020 FY Budget | 500,092.83 |
| DOVER SUBSTATION REBUILD | 2021 FY Actual | 60,591.05 |
| DOVER SUBSTATION REBUILD | 2021 FY Budget | 2,000,000.37 |
| DOVER SUBSTATION REBUILD | 2022 FY Actual | 64,239.55 |
| DOVER SUBSTATION REBUILD | 2022 FY Budget | 1,224,528.21 |
| DOVER SUBSTATION REBUILD | 2023 FY Actual | 52,061.08 |
| DOVER SUBSTATION REBUILD | 2023 FY Budget | 1,731,763.43 |
| WHITE LAKE SS REBUILD | 2020 FY Actual | 19,833.40 |
| WHITE LAKE SS REBUILD | 2020 FY Budget | 500,049.02 |
| WHITE LAKE SS REBUILD | 2021 FY Actual | 149,245.92 |
| WHITE LAKE SS REBUILD | 2021 FY Budget | 1,999,718.27 |
| WHITE LAKE SS REBUILD | 2022 FY Actual | 157,341.42 |
| WHITE LAKE SS REBUILD | 2022 FY Budget | 2,313,418.80 |

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| WHITE LAKE SS REBUILD | 2023 FY Actual | 404,326.97 |
| WHITE LAKE SS REBUILD | 2023 FY Budget | 5,808,816.88 |
| Laconia SS Replace LTC Controls | 2019 FY Actual | 84,548.56 |
| Laconia SS Replace LTC Controls | 2020 FY Budget | 82,931.78 |
| MONADNOCK SS REPLACE TRANSFRMR TB40 | 2019 FY Actual | 58,002.62 |
| MONADNOCK SS REPLACE TRANSFRMR TB40 | 2019 FY Budget | 3,500,394.88 |
| MONADNOCK SS REPLACE TRANSFRMR TB40 | 2020 FY Actual | 114,873.09 |
| MONADNOCK SS REPLACE TRANSFRMR TB40 | 2020 FY Budget | 3,024,765.93 |
| MONADNOCK SS REPLACE TRANSFRMR TB40 | 2021 FY Actual | 62,002.62 |
| MONADNOCK SS REPLACE TRANSFRMR TB40 | 2021 FY Budget | 3,500,120.53 |
| MONADNOCK SS REPLACE TRANSFRMR TB40 | 2022 FY Actual | 297,343.80 |
| MONADNOCK SS REPLACE TRANSFRMR TB40 | 2022 FY Budget | 6,518,322.75 |
| MONADNOCK SS REPLACE TRANSFRMR TB40 | 2023 FY Actual | 860,320.57 |
| MONADNOCK SS REPLACE TRANSFRMR TB40 | 2023 FY Budget | 11,660,700.88 |
| S Milford Relay Replacement | 2019 FY Actual | 358,947.84 |
| S Milford Relay Replacement | 2019 FY Budget | 999,999.68 |
| S Milford Relay Replacement | 2020 FY Actual | 13,753.10 |
| Mobile Substatn 46x34.5kV-12.47/7.2 | 2019 FY Actual | 54,890.27 |
| Mobile Substatn 46x34.5kV-12.47/7.2 | 2019 FY Budget | 1,500,000.42 |
| Mobile Substatn 46x34.5kV-12.47/7.2 | 2020 FY Actual | 485,531.72 |
| Mobile Substatn 46x34.5kV-12.47/7.2 | 2020 FY Budget | 1,000,055.84 |
| Mobile Substatn 46x34.5kV-12.47/7.2 | 2021 FY Actual | 54,075.76 |
| Mobile Substatn 46x34.5kV-12.47/7.2 | 2021 FY Budget | 1,999,999.71 |
| Mobile Substatn 46x34.5kV-12.47/7.2 | 2022 FY Actual | 24,784.51 |
| Mobile Substatn 46x34.5kV-12.47/7.2 | 2022 FY Budget | 1,689,356.30 |
| Mobile Substatn 46x34.5kV-12.47/7.2 | 2023 FY Actual | 66,120.26 |
| Mobile Substatn 46x34.5kV-12.47/7.2 | 2023 FY Budget | 2,000,000.00 |
| Animal Protection at Rimmon SS | 2019 FY Actual | 49,628.04 |
| Animal Protection at Rimmon SS | 2020 FY Actual | 47,276.86 |
| Animal Protection at Rimmon SS | 2020 FY Budget | 77,367.09 |
| Animal Protection at Rimmon SS | 2021 FY Actual | 29,622.61 |
| Animal Protection at Rimmon SS | 2022 FY Actual | 555,482.43 |
| Animal Protection at Rimmon SS | 2022 FY Budget | 199,453.00 |
| Animal Protection at Rimmon SS | 2023 FY Actual | 5,217.36 |
| Retire Foyes Corner S/S 4kV | 2019 FY Budget | 99,999.76 |
| REPLACE LTC CONTROLS AT MADBURY SS | 2019 FY Actual | 162,416.22 |
| REPLACE LTC CONTROLS AT MADBURY SS | 2020 FY Actual | 330,095.38 |
| REPLACE LTC CONTROLS AT MADBURY SS | 2020 FY Budget | 194,074.64 |
| REPLACE LTC CONTROLS AT MADBURY SS | 2021 FY Actual | 742.09 |
| AMHERST S/S - PLC AUTOMATION REPLAC | 2019 FY Actual | 68,063.83 |
| AMHERST S/S - PLC AUTOMATION REPLAC | 2020 FY Actual | 985,752.65 |
| AMHERST S/S - PLC AUTOMATION REPLAC | 2020 FY Budget | 1,120,881.72 |
| AMHERST S/S - PLC AUTOMATION REPLAC | 2021 FY Actual | 1,498,489.31 |
| AMHERST S/S - PLC AUTOMATION REPLAC | 2021 FY Budget | 6,703,019.24 |
| AMHERST S/S - PLC AUTOMATION REPLAC | 2022 FY Actual | 2,219,445.79 |
| AMHERST S/S - PLC AUTOMATION REPLAC | 2022 FY Budget | 2,489,541.41 |
| Install animal protection | 2019 FY Budget | 500,002.22 |

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| Install animal protection | 2020 FY Budget | 249,629.43 |
| Install animal protection | 2021 FY Budget | 600,000.38 |
| Install animal protection | 2022 FY Budget | 496,893.59 |
| Animal Protection at Tasker Farm SS | 2019 FY Actual | 50,060.21 |
| Animal Protection at Tasker Farm SS | 2020 FY Actual | 457.24 |
| Animal Protection at Tasker Farm SS | 2021 FY Actual | 24,430.55 |
| Animal Protection at Tasker Farm SS | 2022 FY Actual | 145.55 |
| Animal Protection at Thornton SS | 2019 FY Actual | 56,463.25 |
| ANIMAL PROTECTION AT AMHERST SS | 2019 FY Actual | 81,057.60 |
| ANIMAL PROTECTION AT AMHERST SS | 2020 FY Actual | 16,022.05 |
| ANIMAL PROTECTION AT VALLEY ST SS | 2019 FY Actual | 6,374.72 |
| ANIMAL PROTECTION AT VALLEY ST SS | 2020 FY Actual | 45,789.05 |
| ANIMAL PROTECTION AT VALLEY ST SS | 2021 FY Actual | 2,457.70 |
| 2023 SS Animal Protection Program | 2023 FY Budget | 500,000.00 |
| 34.5kV OCB BREAKER AND ANCILLARY EQ | 2021 FY Actual | 444,238.88 |
| 34.5kV OCB BREAKER AND ANCILLARY EQ | 2022 FY Actual | (289,250.63) |
| 34.5kV OCB BREAKER AND ANCILLARY EQ | 2023 FY Actual | 67,262.30 |
| REEDS FERRY SS OCB REPLACEMENT | 2019 FY Actual | 323,696.98 |
| REEDS FERRY SS OCB REPLACEMENT | 2020 FY Actual | 2,281,831.01 |
| REEDS FERRY SS OCB REPLACEMENT | 2020 FY Budget | 1,886,204.02 |
| REEDS FERRY SS OCB REPLACEMENT | 2021 FY Actual | 60,089.09 |
| REEDS FERRY SS OCB REPLACEMENT | 2022 FY Actual | (4,732.28) |
| HIGH IMPEDANCE GND FLT DETECT NH | 2020 FY Actual | 2,021.52 |
| HIGH IMPEDANCE GND FLT DETECT NH | 2021 FY Actual | 341,002.21 |
| HIGH IMPEDANCE GND FLT DETECT NH | 2021 FY Budget | (10.53) |
| HIGH IMPEDANCE GND FLT DETECT NH | 2022 FY Actual | (8,633.48) |
| East Northwood SS Regulator Replace | 2020 FY Actual | 181,256.34 |
| East Northwood SS Regulator Replace | 2021 FY Actual | 7,248.24 |
| East Northwood SS Regulator Replace | 2022 FY Actual | 291.44 |
| REPLACE CT TRNSF BERLIN ES SS | 2020 FY Actual | 2,622.97 |
| REPLACE CT TRNSF BERLIN ES SS | 2021 FY Actual | 388,656.52 |
| BYRD AVE SS UPGRADES | 2020 FY Actual | 517,027.34 |
| BYRD AVE SS UPGRADES | 2021 FY Actual | 221,882.91 |
| SPRING STREET SS UPGRADES | 2020 FY Actual | 1,292,012.72 |
| SPRING STREET SS UPGRADES | 2021 FY Actual | 23,066.72 |
| SPRING STREET SS UPGRADES | 2022 FY Actual | 5,521.87 |
| SUGAR RIVER SS UPGRADES | 2021 FY Actual | 1,332,322.33 |
| SUGAR RIVER SS UPGRADES | 2021 FY Budget | 0.49 |
| SUGAR RIVER SS UPGRADES | 2022 FY Actual | (321.95) |
| RIVER ROAD SS UPGRADES | 2022 FY Actual | 543,106.69 |
| RIVER ROAD SS UPGRADES | 2022 FY Budget | 411,939.60 |
| NEWPORT SS RECLOSER PROJECT | 2021 FY Actual | 1,023,070.05 |
| NEWPORT SS RECLOSER PROJECT | 2022 FY Actual | 8,245.72 |
| NEWPORT SS RECLOSER PROJECT | 2023 FY Actual | 71,166.74 |
| ANIMAL PROTECTION AT BEDFORD SS | 2020 FY Actual | 50,679.23 |
| ANIMAL PROTECTION AT BEDFORD SS | 2021 FY Actual | 26,726.66 |
| ANIMAL PROTECTION AT BEDFORD SS | 2022 FY Actual | 3,101.96 |

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| ANIMAL PROTECTION AT MAMMOTH SS | 2020 FY Actual | 43,642.53 |
| ANIMAL PROTECTION AT MAMMOTH SS | 2021 FY Actual | 13,971.34 |
| ANIMAL PROTECTION AT WEARE SS | 2020 FY Actual | 29,171.60 |
| ANIMAL PROTECTION AT WEARE SS | 2022 FY Actual | 4,220.38 |
| ANIMAL PROTECTION TIMBER SWAMP SS | 2020 FY Actual | 62,956.13 |
| ANIMAL PROTECTION TIMBER SWAMP SS | 2021 FY Actual | 34,865.48 |
| ANIMAL PROTECTION TIMBER SWAMP SS | 2022 FY Actual | 189.97 |
| Spare 345-34.5kV Transformer | 2020 FY Actual | 26,411.82 |
| SPARE 345-34.5kV TRANSFORMER | 2021 FY Actual | 645,006.36 |
| SPARE 345-34.5kV TRANSFORMER | 2021 FY Budget | 3,000,000.17 |
| SPARE 345-34.5kV TRANSFORMER | 2022 FY Actual | 723,107.19 |
| SPARE 345-34.5kV TRANSFORMER | 2022 FY Budget | 4,645,902.01 |
| SPARE 345-34.5kV TRANSFORMER | 2023 FY Actual | 3,578,219.59 |
| SPARE 345-34.5kV TRANSFORMER | 2023 FY Budget | 522,852.67 |
| BROAD ST CAP SWITHHER REPL | 2021 FY Budget | 1,000,000.35 |
| GARVINS S/S OCB REPLACEMENT | 2021 FY Budget | 2,299,999.57 |
| NH T&D IEC 61850 SIMULATOR | 2020 FY Actual | 965,782.33 |
| NH T&D IEC 61850 SIMULATOR | 2021 FY Actual | 171,663.77 |
| NH T&D IEC 61850 SIMULATOR | 2021 FY Budget | 599,999.58 |
| NH T&D IEC 61850 SIMULATOR | 2022 FY Actual | (278.61) |
| GE L90 RELAYS MOD 14 REPLACE NH D | 2020 FY Actual | 3,063.47 |
| GE L90 RELAYS MOD 14 REPLACE NH D | 2021 FY Actual | 3,125.67 |
| GE L90 RELAYS MOD 14 REPLACE NH D | 2021 FY Budget | 200.11 |
| GOFFSTOWN SS CONVERSION | 2023 FY Actual | 119,987.80 |
| GOFFSTOWN SS CONVERSION | 2023 FY Budget | 98,588.00 |
| GARVINS RELIABILITY PROJECT | 2022 FY Budget | 100,000.00 |
| Animal Protection Madbury SS | 2023 FY Actual | 112,769.57 |
| MADBURY RELIABILITY PROJECT | 2022 FY Budget | 100,000.00 |
| PORTSMOUTH 12KV RELIABILITY (CUTT S | 2022 FY Actual | 5,943.54 |
| PORTSMOUTH 12KV RELIABILITY (CUTT S | 2022 FY Budget | 100,000.00 |
| PORTSMOUTH 12KV RELIABILITY (CUTT S | 2023 FY Actual | 38,322.54 |
| PORTSMOUTH 12KV RELIABILITY (CUTT S | 2023 FY Budget | 68,000.00 |
| Portsmouth 12kV Capacity (D Line) | 2022 FY Actual | 10,288.16 |
| Portsmouth 12kV Capacity (D Line) | 2023 FY Actual | 63,693.28 |
| Portsmouth 12kV Capacity (D Line) | 2023 FY Budget | 19,000.00 |
| WEIRS SUBSTATION REBUILD | 2021 FY Actual | 60,046.02 |
| WEIRS SUBSTATION REBUILD | 2021 FY Budget | 200,030.36 |
| WEIRS SUBSTATION REBUILD | 2022 FY Actual | 22,720.27 |
| WEIRS SUBSTATION REBUILD | 2022 FY Budget | 524,281.86 |
| ASHLAND S/S-PLC REPLCMNT& P&C UPGRD | 2021 FY Actual | 149,004.38 |
| ASHLAND S/S-PLC REPLCMNT& P&C UPGRD | 2022 FY Actual | 424,046.53 |
| ASHLAND S/S-PLC REPLCMNT& P&C UPGRD | 2022 FY Budget | 330,217.14 |
| ASHLAND RELIABILITY SS WORK | 2022 FY Actual | 52,531.11 |
| ASHLAND RELIABILITY SS WORK | 2023 FY Actual | 21,095.29 |
| ASHLAND RELIABILITY SS WORK | 2023 FY Budget | 1,519.06 |
| LACONIA SS RELIABILITY PROJECT | 2022 FY Actual | 104,557.76 |
| LACONIA SS RELIABILITY PROJECT | 2023 FY Actual | 45,465.60 |

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|---|---|---|
| SACO VALLEY 34.5kV OCB REPLACE | 2022 FY Budget | 100,046.67 |
| Ashland SS Rel Proj - Line Work | 2022 FY Actual | 41,022.26 |
| Ashland SS Rel Proj - Line Work | 2023 FY Actual | 74,579.97 |
| Ashland SS Rel Proj - Line Work | 2023 FY Budget | 1,240.06 |
| ANIMAL PROTECTION AT CHESTER SS | 2021 FY Actual | 28,301.01 |
| ANIMAL PROTECTION AT CHESTER SS | 2022 FY Actual | 55,317.99 |
| ANIMAL PROTECTION AT CHESTER SS | 2023 FY Actual | 4,862.16 |
| DERRY RELIABILITY PROJECT | 2022 FY Budget | 100,000.00 |
| DERRY RELIABILITY PROJECT | 2023 FY Budget | 750,000.00 |
| LAWRENCE RD TRANSFORMER BREAKER | 2022 FY Budget | 100,000.00 |
| LAWRENCE RD TRANSFORMER BREAKER | 2023 FY Budget | 100,000.00 |
| SWANZEY SS CIRCUIT SWITCHER | 2021 FY Actual | 24,266.31 |
| SWANZEY SS CIRCUIT SWITCHER | 2022 FY Actual | (24,266.31) |
| SWANZEY SS CIRCUIT SWITCHER | 2022 FY Budget | 554,799.17 |
| North Road SS Reliability | 2022 FY Actual | 13,904.76 |
| North Road SS Reliability | 2023 FY Actual | 23,514.67 |
| North Road SS Reliability | 2023 FY Budget | 96,000.00 |
| N KEENE SS HIGH IMP GRND FAULT DET | 2021 FY Actual | 181,566.32 |
| N KEENE SS HIGH IMP GRND FAULT DET | 2022 FY Actual | 42,759.29 |
| N KEENE SS HIGH IMP GRND FAULT DET | 2023 FY Actual | 439.90 |
| SUGAR RIVER SS GMP TRANSFER TRIP | 2021 FY Actual | 80,571.26 |
| SUGAR RIVER SS GMP TRANSFER TRIP | 2022 FY Actual | 510,243.12 |
| SUGAR RIVER SS GMP TRANSFER TRIP | 2022 FY Budget | 331,352.33 |
| SUGAR RIVER SS GMP TRANSFER TRIP | 2023 FY Actual | 351,974.84 |
| SUGAR RIVER SS GMP TRANSFER TRIP | 2023 FY Budget | 179,098.35 |
| Gas Monitor Replacement Program | 2022 FY Actual | 43.82 |
| Gas Monitor Replacement Program | 2023 FY Actual | 228.90 |
| SUBSTATION RTU UPGRADE/REPLACE PROG | 2023 FY Budget | 201,491.81 |
| Animal Protection Brentwood SS | 2023 FY Actual | 50,291.22 |
| ANIMAL PROTECTION OAK HILL SS | 2023 FY Actual | 91,454.29 |
| Animal Protection Hudson SS | 2023 FY Actual | 79,971.17 |
| Animal Protection Reeds Ferry SS | 2023 FY Actual | 68,786.72 |
| Swanzey TB8S Xfmr SCADA Upgrade | 2023 FY Actual | 40,922.41 |
| BATTERY REPLACEMENT PROGRAM | 2022 FY Actual | 12,777.27 |
| BATTERY REPLACEMENT PROGRAM | 2023 FY Actual | 63,228.16 |
| BATTERY REPLACEMENT PROGRAM | 2023 FY Budget | 40,870.14 |
| SS Station Service Transformer Repl Program | 2023 FY Actual | 7,596.27 |
| Jackman Transformer TB61 Replacement | 2023 FY Actual | 32,447.23 |
| Brook Street Switchgear & Transformer Replacement | 2023 FY Actual | 3,279,056.30 |
| WEBSTR SS EXPN/CAP BNK SHRD ASTS-CE | 2019 FY Actual | (18,738.78) |
| Distribution Design for F107 Projec | 2019 FY Actual | (41,457.27) |
| Distribution Design for F107 Projec | 2019 FY Budget | (169,456.60) |
| Distribution Design for F107 Projec | 2020 FY Actual | (183,444.03) |
| Distribution Design for F107 Projec | 2020 FY Budget | (161,264.20) |
| Distribution Design for F107 Projec | 2021 FY Actual | 58,876.87 |
| Distribution Design for F107 Projec | 2022 FY Actual | 2,931.56 |
| DISTRIBUTION DESIGN L176 LINE REPLA | 2019 FY Actual | (3,279.42) |

| | | |
|---|---|---|
| DISTRIBUTION DESIGN L176 LINE REPLA | 2023 FY Actual | (0.00) |
| DIST. S/S ANNUAL - DM | 2019 FY Actual | 837,202 |
| DIST. S/S ANNUAL - DM | 2019 FY Budget | 749,948 |
| DIST. S/S ANNUAL - DM | 2020 FY Actual | 971,716 |
| DIST. S/S ANNUAL - DM | 2020 FY Budget | 745,594 |
| DIST. S/S ANNUAL - DM | 2021 FY Actual | 172,834 |
| DIST. S/S ANNUAL - DM | 2021 FY Budget | (0) |
| DIST. S/S ANNUAL - DM | 2022 FY Actual | 333,928 |
| DIST. S/S ANNUAL - DM | 2023 FY Actual | 12,544 |
| DIST. S/S ANNUAL - DM | 2021 FY Actual | 266,093 |
| DIST. S/S ANNUAL - DM | 2021 FY Budget | 765,000 |
| DIST. S/S ANNUAL - DM | 2022 FY Actual | 222,756 |
| DIST. S/S ANNUAL - DM | 2023 FY Actual | 6,585 |
| DIST S/S ANNUAL - P&C | 2019 FY Actual | 2,427 |
| DIST S/S ANNUAL - P&C | 2022 FY Actual | 7 |
| SUBSTATION ANNUAL-SUBSTATION | 2019 FY Actual | 933,860.68 |
| SUBSTATION ANNUAL-SUBSTATION | 2019 FY Budget | 1,000,015 |
| SUBSTATION ANNUAL-SUBSTATION | 2020 FY Actual | 351,916.38 |
| SUBSTATION ANNUAL-SUBSTATION | 2020 FY Budget | 699,026.33 |
| SUBSTATION ANNUAL-SUBSTATION | 2021 FY Actual | 103,766.99 |
| SUBSTATION ANNUAL-SUBSTATION | 2021 FY Budget | (0.26) |
| SUBSTATION ANNUAL-SUBSTATION | 2022 FY Actual | (69,831.07) |
| SUBSTATION ANNUAL-SUBSTATION | 2023 FY Actual | 74,762.05 |
| SUBSTATION ANNUAL-SUBSTATION | 2021 FY Actual | 11,616.42 |
| SUBSTATION ANNUAL-SUBSTATION | 2021 FY Budget | 999,999.85 |
| SUBSTATION ANNUAL-SUBSTATION | 2022 FY Actual | 17,050.96 |
| SUBSTATION ANNUAL-SUBSTATION | 2023 FY Actual | (34.06) |
| 2022 NH D SS Planned Annual (Eng.) | 2022 FY Actual | 130,321.77 |
| 2022 NH D SS Planned Annual (Eng.) | 2022 FY Budget | 695,000.00 |
| 2022 NH D SS Planned Annual (Eng.) | 2023 FY Actual | 277,657.53 |
| 2023 NH D SS Planned Annual (Eng) | 2023 FY Actual | 287,595.96 |
| 2023 NH D SS Planned Annual (Eng) | 2023 FY Budget | 500,000.00 |
| 2022 NH D SS Planned Annual (Ops) | 2022 FY Actual | 433,354.74 |
| 2022 NH D SS Planned Annual (Ops) | 2022 FY Budget | 200,000.00 |
| 2022 NH D SS Planned Annual (Ops) | 2023 FY Actual | 134,925.09 |
| 2023 NH D SS Planned Annual (Ops) | 2023 FY Actual | 105,809.12 |
| 2023 NH D SS Planned Annual (Ops) | 2023 FY Budget | 255,000.00 |
| Electromechanical Relay Replacement | 2023 FY Budget | 1,400,000.00 |
| BES BATTERY MONITOR INSTALL PROGRAM | 2022 FY Actual | 68,664.23 |
| BES BATTERY MONITOR INSTALL PROGRAM | 2022 FY Budget | 38,162.80 |
| BES BATTERY MONITOR INSTALL PROGRAM | 2023 FY Actual | 69,559.94 |
| BES Battery Monitoring Madbury SS | 2022 FY Actual | 78,609.65 |
| BES Battery Monitoring Madbury SS | 2023 FY Actual | 6,126.90 |
| BES Battery Monitor Ocean Rd SS | 2022 FY Actual | 910.67 |
| BES Battery Monitor Ocean Rd SS | 2023 FY Actual | 85,118.76 |
| BES Battery Monitor Huse Road SS | 2022 FY Actual | 118,219.34 |
| BES Battery Monitor Huse Road SS | 2023 FY Actual | 5,058.35 |

| | | |
|---|---|---|
| BES Battery Monitor Lawrence Rd SS | 2022 FY Actual | 113,908.41 |
| BES Battery Monitor Lawrence Rd SS | 2023 FY Actual | 8,506.12 |
| BES Battery Monitor Oak Hill SS | 2023 FY Actual | 85,331.18 |
| CAPSWITCHER REPLACEMENT | 2019 FY Budget | 800,080.06 |
| NH DMS | 2023 FY Actual | 582,943.44 |
| NH DMS | 2023 FY Budget | 1,000,000.00 |
| 316 LINE DAVIT ARM & STRUCTURE REPL | 2023 FY Actual | 623.43 |
| DIRECT BURIED CABLE REPLACEMENT | 2019 FY Actual | (40,023.62) |
| DIRECT BURIED CABLE REPLACEMENT | 2020 FY Actual | (1,838.87) |
| DIRECT BURIED CABLE REPLACEMENT | 2021 FY Actual | 33,211.28 |
| DIRECT BURIED CABLE REPLACEMENT | 2022 FY Actual | 43,945.15 |
| REPLACED FAILED CABLE - POST TESTED | 2019 FY Actual | 199,201.51 |
| REPLACED FAILED CABLE - POST TESTED | 2020 FY Actual | 114,288.50 |
| REPLACED FAILED CABLE - POST TESTED | 2022 FY Actual | (4,804.99) |
| DIRECT BURIED CABLE INJECTION | 2019 FY Actual | (1,819.71) |
| DIRECT BURIED CABLE INJECTION | 2020 FY Actual | (1,177.09) |
| DIRECT BURIED CABLE INJECTION | 2021 FY Actual | 41.52 |
| BOUCHARD ST RPL CBL & SWTCHGR | 2020 FY Actual | 426,854.14 |
| BOUCHARD ST RPL CBL & SWTCHGR | 2020 FY Budget | 450,300.89 |
| BOUCHARD ST RPL CBL & SWTCHGR | 2021 FY Actual | 75,326.49 |
| BOUCHARD ST RPL CBL & SWTCHGR | 2022 FY Actual | (10,090.71) |
| MANCHESTER NETWORK CABLE REPLACEMEN | 2023 FY Actual | 7,641.93 |
| FOUNDRY PLACE SWITCHGEAR | 2020 FY Actual | 310,998.96 |
| FOUNDRY PLACE SWITCHGEAR | 2021 FY Actual | 62,248.12 |
| FOUNDRY PLACE SWITCHGEAR | 2022 FY Actual | (19,675.66) |
| DB CBLE REPLACE MAPLE HILL ACREA | 2020 FY Actual | 1,066,613.67 |
| DB CBLE REPLACE MAPLE HILL ACREA | 2020 FY Budget | 1,300,106.92 |
| DB CBLE REPLACE MAPLE HILL ACREA | 2021 FY Actual | (714.00) |
| DB CBLE REPLACE MAPLE HILL ACREA | 2022 FY Actual | (4,355.38) |
| CIRCUIT 3138 RIVERWAY PL CABLE REPL | 2021 FY Actual | 367,594.95 |
| CIRCUIT 3138 RIVERWAY PL CABLE REPL | 2022 FY Actual | 9,441.07 |
| 1275 MAPLEWOOD AVE DB CABLE REPL | 2021 FY Actual | 153,700.58 |
| 1275 MAPLEWOOD AVE DB CABLE REPL | 2022 FY Actual | 9,326.94 |
| REBUILD APPLE TREE CINEMA URD | 2021 FY Actual | 347,684.85 |
| REBUILD APPLE TREE CINEMA URD | 2021 FY Budget | 399,999.54 |
| REBUILD APPLE TREE CINEMA URD | 2022 FY Actual | 99,894.63 |
| REPLACE PINE ISLE DRIVE URD | 2021 FY Actual | 536,205.09 |
| REPLACE PINE ISLE DRIVE URD | 2021 FY Budget | 350,000.27 |
| REPLACE PINE ISLE DRIVE URD | 2022 FY Actual | 68,609.56 |
| REPLACE PINE ISLE DRIVE URD | 2023 FY Actual | 248.38 |
| Manchester NetworK Cable Repl Ph 2 | 2022 FY Actual | 1,617,922.30 |
| Manchester NetworK Cable Repl Ph 2 | 2022 FY Budget | 2,535,889.85 |
| Manchester NetworK Cable Repl Ph 2 | 2023 FY Actual | 168,211.71 |
| Manchester NetworK Cable Repl Ph 2 | 2023 FY Budget | 35,562.10 |
| Manchester Network Cable Repl Ph 3 | 2023 FY Actual | 1,260,089.69 |
| Submarine Cable Repair | 2023 FY Budget | 50,000.00 |
| Manchester Network Cable Ph 4 | 2023 FY Actual | 21,912.15 |

| Charge Cost Center | D01:NH Operations |
|---|---|

| Sum of Amount | | | |
|---|---|---|---|
| Parent 1 | Parent 2 | Parent Project | Parent Project Description |
| Basic Business-ED | Emergent Equipment Failures - Substation | A12N01A | BERLIN 4KV SYSTEM RECONFIGURATION |
| Basic Business-ED | Emergent Equipment Failures - Substation | A14N21 | BERLIN EASTSIDE 34.5KV LINE BREAKER |
| Basic Business-ED | Emergent Equipment Failures - Substation | A21C43 | REPLACE LTC CONTROLS EDDY SS |
| Basic Business-ED | Emergent Equipment Failures - Substation | A21N78 | BERLIN EAST SIDE SS REPLACE TRANSFO |
| Basic Business-ED | Emergent Equipment Failures - Substation | DS9RD2 | 2022 NH D SS Emergent Annual |
| Basic Business-ED | Emergent Equipment Failures - Substation | DS9RD3 | 2023 NH D SS Emergent Annual |
| Basic Business-ED | Basic Business - Other | A16X01 | ESCC control of Generation |
| Basic Business-ED | Basic Business - Other | A16X05 | NH Energy Park: audio visual equip |
| Basic Business-ED | Basic Business - Other | A16X06 | NH SOC/ESCC Backup |
| Basic Business-ED | Basic Business - Other | A16X08 | 1250 Hooksett Rd - AV Project |
| Basic Business-ED | Basic Business - Other | A18W22 | Peterborough Roadway and Bridge Pro |
| Basic Business-ED | Basic Business - Other | A21C38 | ANIMAL PROTECTION AT BROOK ST SS |
| Basic Business-ED | Basic Business - Other | A21C40 | ANIMAL PROTECTION AT EDDY SS |
| Basic Business-ED | Basic Business - Other | A21E41 | Animal Protection Madbury SS |
| Basic Business-ED | Basic Business - Other | A22C54 | 3271X Sound Barrier Pad-Mount Step |
| Basic Business-ED | Basic Business - Other | A22E79 | Animal Protection Brentwood SS |
| Basic Business-ED | Basic Business - Other | A22N80 | ANIMAL PROTECTION OAK HILL SS |
| Basic Business-ED | Basic Business - Other | A22S81 | Animal Protection Hudson SS |
| Basic Business-ED | Basic Business - Other | A22S82 | Animal Protection Reeds Ferry SS |
| Basic Business-ED | Basic Business - Other | A23E44 | 15W4 Commercial Alley |
| Basic Business-ED | Basic Business - Other | A23W27 | W15 Lattice Tower Removal |
| Basic Business-ED | Basic Business - Other | A23X47 | NH Rubber Goods Lab Rebuild |
| Basic Business-ED | Basic Business - Other | DTC9R | 2022 Elec Sys Ops Equip Annual |
| Basic Business-ED | Basic Business - Other | GF9R | Misc office equipment |
| Basic Business-ED | Basic Business - Other | PT9R | Temporary Work Annual |
| Basic Business-ED | Basic Business - Other | PT9R | Temporary Work Annual |
| Basic Business-ED | Basic Business - Other | PT9R | Temporary Work Annual |
| Basic Business-ED | Basic Business - Other | PT9R | Temporary Work Annual |
| Basic Business-ED | Basic Business - Other | PT9R | Temporary Work Annual |
| Basic Business-ED | Basic Business - Other | PT9R | Temporary Work Annual |
| Basic Business-ED | Basic Business - Other | PT9R | Temporary Work Annual |
| Basic Business-ED | Basic Business - Other | PT9R | Temporary Work Annual |
| Basic Business-ED | Basic Business - Other | PT9R | Temporary Work Annual |
| Basic Business-ED | Basic Business - Other | PT9R | Temporary Work Annual |
| Basic Business-ED | Basic Business - Other | PT9R | Temporary Work Annual |
| Basic Business-ED | Basic Business - Other | PT9R | Temporary Work Annual |
| Basic Business-ED | Basic Business - Other | PT9R | Temporary Work Annual |
| Basic Business-ED | Basic Business - Other | PT9R | Temporary Work Annual |
| Basic Business-ED | Basic Business - Other | PT9R | Temporary Work Annual |
| Basic Business-ED | Basic Business - Other | PW9R | Private Work Annual |
| Basic Business-ED | Basic Business - Other | PW9R | Private Work Annual |
| Basic Business-ED | Basic Business - Other | PW9R | Private Work Annual |
| Basic Business-ED | Basic Business - Other | PW9R | Private Work Annual |
| Basic Business-ED | Basic Business - Other | PW9R | Private Work Annual |
| Basic Business-ED | Basic Business - Other | PW9R | Private Work Annual |
| Basic Business-ED | Basic Business - Other | PW9R | Private Work Annual |
| Basic Business-ED | Basic Business - Other | PW9R | Private Work Annual |
| Basic Business-ED | Basic Business - Other | PW9R | Private Work Annual |
| Basic Business-ED | Basic Business - Other | PW9R | Private Work Annual |
| Basic Business-ED | Basic Business - Other | PW9R | Private Work Annual |
| Basic Business-ED | Basic Business - Other | PW9R | Private Work Annual |
| Basic Business-ED | Basic Business - Other | PW9R | Private Work Annual |
| Basic Business-ED | Basic Business - Other | PW9R | Private Work Annual |
| Basic Business-ED | Line Relocations/Act of Public Authority | 9N031138P | LINE RELOCATE EAST HOLLIS ST NASHUA |
| Basic Business-ED | Line Relocations/Act of Public Authority | A18C21 | MANCHESTER AIRPORT DUCT RELOCATION |
| Basic Business-ED | Line Relocations/Act of Public Authority | A18E23 | Rochester Comcast Make Ready |
| Basic Business-ED | Line Relocations/Act of Public Authority | A18W13 | Route 9 Roxbury-Sullivan 10439 |
| Basic Business-ED | Line Relocations/Act of Public Authority | A20N29 | LACONIA COMCAST NON-BILLABLE 2020 |
| Basic Business-ED | Line Relocations/Act of Public Authority | A20N30 | LACONIA COMCAST BILLABLE 2020 |
| Basic Business-ED | Line Relocations/Act of Public Authority | A20N31 | GILFORD COMCAST NON-BILLABLE 2020 |
| Basic Business-ED | Line Relocations/Act of Public Authority | A20N32 | GILFORD COMCAST BILLABLE 2020 |
| Basic Business-ED | Line Relocations/Act of Public Authority | A20N50 | NHDOT LINE RELOC RTE 106 LOUDON |

# PROGRAM SUMMARY
# PSNH ELECTRIC OPERATIONS

| | | 2019 | 2020 | 2021 | 2022 | 2023 | 5-Year Total |
|---|---|---|---|---|---|---|---|
| **DISTRIBUTION** | | | | | | | |
| | | | | | | | |
| NEW CUSTOMER | BUDGET | 11,250.4 | 11,508.3 | 14,738.0 | 11,269.9 | 14,981.6 | 63,748.3 |
| | ACTUAL | 13,661.2 | 13,942.9 | 29,614.0 | 24,025.7 | 29,356.2 | 110,600.0 |
| | VARIANCE | 2,410.8 | 2,434.6 | 14,876.0 | 12,755.8 | 14,374.5 | 46,851.8 |
| BASIC BUSINESS | BUDGET | 29,589.3 | 28,751.2 | 31,006.0 | 33,222.3 | 43,052.5 | 165,621.4 |
| | ACTUAL | 33,857.6 | 34,416.8 | 44,018.3 | 48,502.2 | 65,469.8 | 226,264.6 |
| | VARIANCE | 4,268.3 | 5,665.6 | 13,012.3 | 15,279.8 | 22,417.2 | 60,643.2 |
| RELIABILITY | BUDGET | 87,667.3 | 83,028.7 | 78,901.2 | 71,521.3 | 102,883.6 | 424,002.1 |
| | ACTUAL | 90,352.9 | 77,708.7 | 63,756.3 | 60,102.2 | 86,298.8 | 378,218.9 |
| | VARIANCE | 2,685.5 | -5,320.0 | -15,144.8 | -11,419.1 | -16,584.9 | -45,783.3 |
| REGULATORY COMMITMENTS | BUDGET | 1,259.3 | 3,098.7 | 4,600.0 | 11,403.4 | 0.0 | 20,361.4 |
| | ACTUAL | 390.4 | 2,501.2 | 3,896.7 | 10,707.3 | 48.6 | 17,544.2 |
| | VARIANCE | -869.0 | -597.5 | -703.3 | -696.1 | 48.6 | -2,817.2 |
| PEAK LOAD / CAPACITY | BUDGET | 6,930.6 | 5,892.1 | 5,096.4 | 6,509.4 | 22,278.5 | 46,707.1 |
| | ACTUAL | 3,133.9 | 7,351.5 | 7,502.7 | 7,287.3 | 7,807.5 | 33,082.9 |
| | VARIANCE | -3,796.8 | 1,459.4 | 2,406.3 | 777.8 | -14,471.1 | -13,624.3 |
| | | | | | | | |
| **NH OPERATIONS DISTRIBUTION** | **BUDGET** | **136,697.1** | **132,279.0** | **134,341.6** | **133,926.4** | **183,196.4** | **720,440.4** |
| | **ACTUAL** | **141,395.9** | **135,921.2** | **148,788.1** | **150,624.6** | **188,980.8** | **765,710.6** |
| | **VARIANCE** | **4,698.8** | **3,642.2** | **14,446.4** | **16,698.2** | **5,784.5** | **45,270.2** |
| | | | | | | | |

# BUDGET PROGRAM SUMMARY
## As of YTD December 2019

| | | 2019 BUDGET | JAN 2019 | FEB 2019 | MAR 2019 | APR 2019 | MAY 2019 | JUN 2019 | JUL 2019 | AUG 2019 | SEP 2019 | OCT 2019 | NOV 2019 | DEC 2019 | YTD 2019 | YEP |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **DISTRIBUTION** | | | | | | | | | | | | | | | | |
| | BUDGET | 11,250.4 | 915.2 | 911.0 | 908.5 | 910.3 | 912.2 | 1,045.2 | 916.1 | 917.9 | 919.8 | 921.6 | 1,054.6 | 917.9 | 11,250.4 | |
| | PROJECTION | 13,661.2 | 809.8 | 1,547.5 | 1,054.7 | 69.7 | 678.0 | 1,511.9 | 537.6 | 1,466.6 | 1,294.2 | 783.7 | 1,768.6 | 2,138.7 | | |
| NEW CUSTOMER | ACTUAL | | 809.8 | 1,547.5 | 1,054.7 | 69.7 | 678.0 | 1,511.9 | 537.6 | 1,466.6 | 1,294.2 | 783.7 | 1,768.6 | 2,138.7 | 13,661.2 | 13,661.2 |
| | VARIANCE | | -105.4 | 636.5 | 146.2 | -840.6 | -234.2 | 466.7 | -378.6 | 548.7 | 374.4 | -137.9 | 714.0 | 1,220.8 | 2,410.8 | 2,410.8 |
| | BUDGET | 29,589.3 | 3,351.5 | 2,531.5 | 2,143.7 | 1,764.7 | 2,471.0 | 3,190.2 | 2,291.7 | 2,523.1 | 2,604.8 | 2,254.2 | 2,264.5 | 2,198.4 | 29,589.3 | |
| | PROJECTION | 33,857.6 | 2,959.6 | 1,799.2 | 2,599.9 | 3,782.0 | 1,980.8 | 2,875.7 | 2,877.9 | 2,850.3 | 2,553.1 | 2,735.2 | 3,695.4 | 3,148.4 | | |
| BASIC BUSINESS | ACTUAL | | 2,959.6 | 1,799.2 | 2,599.9 | 3,782.0 | 1,980.8 | 2,875.7 | 2,877.9 | 2,850.3 | 2,553.1 | 2,735.2 | 3,695.4 | 3,148.4 | 33,857.6 | 33,857.6 |
| | VARIANCE | | -391.9 | -732.2 | 456.2 | 2,017.4 | -490.2 | -314.5 | 586.2 | 327.2 | -51.7 | 481.0 | 1,430.9 | 950.0 | 4,268.3 | 4,268.3 |
| | BUDGET | 87,667.3 | 6,858.8 | 5,665.1 | 9,361.0 | 7,433.3 | 7,639.2 | 11,018.6 | 8,680.7 | 7,868.6 | 4,810.5 | 7,190.6 | 6,733.3 | 4,407.8 | 87,667.3 | |
| | PROJECTION | 90,352.9 | 6,348.5 | 8,870.3 | 10,055.7 | 11,233.3 | 7,425.9 | 8,487.7 | 6,889.3 | 7,445.6 | 7,688.3 | 4,272.9 | 5,601.5 | 6,046.5 | | |
| RELIABILITY | ACTUAL | | 6,348.5 | 8,865.5 | 10,055.2 | 11,230.0 | 7,425.9 | 8,493.0 | 6,889.2 | 7,445.0 | 7,688.3 | 4,272.9 | 5,592.9 | 6,046.5 | 90,352.9 | 90,352.9 |
| | VARIANCE | | -510.3 | 3,200.5 | 694.2 | 3,796.7 | -213.3 | -2,525.6 | -1,791.5 | -423.6 | 2,877.8 | -2,917.7 | -1,140.4 | 1,638.7 | 2,685.5 | 2,685.5 |
| | BUDGET | 1,259.3 | 104.2 | 0.5 | 0.5 | 206.6 | 214.3 | 270.0 | 209.0 | 193.4 | 4.3 | 4.3 | 48.0 | 4.4 | 1,259.3 | |
| | PROJECTION | 390.4 | 744.6 | -223.0 | -351.0 | -251.6 | 393.8 | -38.4 | -1.1 | 5.6 | -24.9 | 127.9 | -12.5 | 21.1 | | |
| REGULATORY COMMITMENTS | ACTUAL | | 744.6 | -223.0 | -351.0 | -251.6 | 393.8 | -38.4 | -1.1 | 5.6 | -24.9 | 127.9 | -12.5 | 21.1 | 390.4 | 390.4 |
| | VARIANCE | | 640.4 | -223.5 | -351.4 | -458.2 | 179.6 | -308.5 | -210.1 | -187.9 | -29.2 | 123.6 | -60.5 | 16.7 | -869.0 | -869.0 |
| | BUDGET | 6,930.6 | 285.5 | 261.1 | 187.9 | 817.6 | 170.2 | 313.2 | 603.5 | 922.0 | 820.7 | 698.7 | 526.3 | 1,324.0 | 6,930.6 | |
| | PROJECTION | 3,133.9 | 171.6 | 130.9 | 127.8 | 200.1 | 392.6 | 428.9 | 441.9 | 202.0 | 74.5 | 425.5 | 202.8 | 335.3 | | |
| PEAK LOAD / CAPACITY | ACTUAL | | 171.6 | 130.9 | 127.8 | 200.1 | 392.6 | 428.9 | 441.9 | 202.0 | 74.5 | 425.5 | 202.8 | 335.3 | 3,133.9 | 3,133.9 |
| | VARIANCE | | -113.8 | -130.2 | -60.1 | -617.6 | 222.4 | 115.7 | -161.6 | -719.9 | -746.2 | -273.2 | -323.6 | -988.7 | -3,796.8 | -3,796.8 |
| | **BUDGET** | **136,697.1** | **11,515.2** | **9,369.1** | **12,601.5** | **11,132.5** | **11,406.8** | **15,837.3** | **12,701.0** | **12,425.0** | **9,159.9** | **11,069.4** | **10,626.8** | **8,852.5** | **136,697.1** | |
| | **PROJECTION** | **141,395.9** | **11,034.1** | **12,125.0** | **13,487.1** | **15,033.5** | **10,871.1** | **13,265.9** | **10,745.6** | **11,970.1** | **11,585.1** | **8,345.2** | **11,255.8** | **11,690.0** | | |
| **NH OPERATIONS DISTRIBUTION (D01)** | **ACTUAL** | | **11,034.1** | **12,120.2** | **13,486.6** | **15,030.2** | **10,871.1** | **13,271.1** | **10,745.5** | **11,969.5** | **11,585.1** | **8,345.2** | **11,247.2** | **11,690.0** | **141,395.9** | **141,395.9** |
| | **VARIANCE** | | **-481.1** | **2,751.0** | **885.1** | **3,897.6** | **-535.7** | **-2,566.1** | **-1,955.5** | **-455.5** | **2,425.2** | **-2,724.2** | **620.4** | **2,837.6** | **4,698.8** | **4,698.8** |

# BUDGET PROGRAM SUMMARY
## As of YTD December 2020

| | | 2020 BUDGET | JAN 2020 | FEB 2020 | MAR 2020 | APR 2020 | MAY 2020 | JUN 2020 | JUL 2020 | AUG 2020 | SEP 2020 | OCT 2020 | NOV 2020 | DEC 2020 | YTD 2020 | YEP |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **DISTRIBUTION** | | | | | | | | | | | | | | | | |
| | BUDGET | 11,508.3 | 1,113.0 | 1,113.6 | 1,114.1 | 1,114.2 | 1,114.4 | 1,190.7 | 1,190.9 | 1,191.4 | 1,192.0 | 1,007.6 | 1,116.0 | -949.6 | 11,508.3 | |
| | PROJECTION | 13,942.9 | 787.4 | 871.2 | 307.3 | 378.8 | 1,146.7 | 1,235.2 | 1,911.3 | 845.0 | 1,276.7 | 1,378.4 | 569.2 | 3,235.9 | | |
| NEW CUSTOMER | ACTUAL | | 787.4 | 871.2 | 307.3 | 378.8 | 1,146.7 | 1,235.2 | 1,911.3 | 845.0 | 1,276.7 | 1,378.4 | 569.2 | 3,235.9 | 13,942.9 | 13,942.9 |
| | VARIANCE | | -325.6 | -242.5 | -806.8 | -735.5 | 32.3 | 44.5 | 720.4 | -346.4 | 84.7 | 370.8 | -546.7 | 4,185.4 | 2,434.6 | 2,434.6 |
| | BUDGET | 28,751.2 | 2,758.2 | 2,450.6 | 2,605.6 | 2,883.9 | 2,871.5 | 3,221.0 | 2,836.5 | 2,882.0 | 2,786.3 | 2,603.2 | 2,459.0 | -1,606.5 | 28,751.2 | |
| | PROJECTION | 34,416.8 | 1,537.8 | 2,267.7 | 4,450.7 | 2,980.9 | 2,240.9 | 4,128.5 | 3,238.3 | 2,567.0 | 3,342.0 | 2,403.3 | 2,309.0 | 3,178.8 | | |
| BASIC BUSINESS | ACTUAL | | 1,537.8 | 2,267.7 | 4,450.7 | 2,980.9 | 2,240.9 | 4,128.5 | 3,238.3 | 2,567.0 | 3,342.0 | 2,403.3 | 2,395.1 | 2,864.7 | 34,416.8 | 34,416.8 |
| | VARIANCE | | -1,220.4 | -182.9 | 1,845.2 | 97.0 | -630.6 | 907.5 | 401.8 | -315.0 | 555.8 | -200.0 | -63.9 | 4,471.3 | 5,665.6 | 5,665.6 |
| | BUDGET | 83,028.7 | 8,769.2 | 6,655.4 | 8,867.1 | 10,134.8 | 9,848.8 | 8,697.3 | 5,608.0 | 5,738.1 | 5,285.4 | 5,010.6 | 5,404.5 | 3,009.6 | 83,028.7 | |
| | PROJECTION | 77,708.7 | 8,208.5 | 9,403.4 | 4,560.3 | 11,616.5 | 5,518.9 | 5,280.7 | 4,444.9 | 4,372.6 | 4,483.9 | 7,113.8 | 6,444.6 | 8,651.2 | | |
| RELIABILITY | ACTUAL | | 8,208.5 | 9,403.4 | 4,562.0 | 11,622.4 | 5,518.7 | 5,280.7 | 4,444.3 | 4,372.6 | 4,483.9 | 7,113.8 | 6,150.4 | 6,548.0 | 77,708.7 | 77,708.7 |
| | VARIANCE | | -560.7 | 2,748.0 | -4,305.1 | 1,487.6 | -4,330.1 | -3,416.6 | -1,163.7 | -1,365.5 | -801.6 | 2,103.2 | 745.9 | 3,538.4 | -5,320.0 | -5,320.0 |
| | BUDGET | 3,098.7 | 0.0 | 0.0 | 11.6 | 11.6 | 11.6 | 11.6 | 458.3 | 548.2 | 549.0 | 549.8 | 502.4 | 444.5 | 3,098.7 | |
| | PROJECTION | 2,501.2 | 52.6 | 24.4 | 292.0 | 85.4 | 3.0 | 6.0 | 3.2 | 2.8 | 373.2 | 206.7 | 110.7 | 1,341.3 | | |
| REGULATORY COMMITMENTS | ACTUAL | | 52.6 | 24.4 | 292.0 | 85.4 | 3.0 | 6.0 | 3.2 | 2.8 | 373.2 | 206.7 | 110.7 | 1,341.3 | 2,501.2 | 2,501.2 |
| | VARIANCE | | 52.6 | 24.4 | 280.4 | 73.8 | -8.6 | -5.6 | -455.0 | -545.4 | -175.8 | -343.2 | -391.7 | 896.8 | -597.5 | -597.5 |
| | BUDGET | 5,892.1 | 519.8 | 366.7 | 964.7 | 708.9 | 869.2 | 476.7 | 476.6 | 523.3 | 414.3 | 362.3 | 203.6 | 6.1 | 5,892.1 | |
| | PROJECTION | 7,351.5 | 493.5 | 203.9 | 394.7 | 871.1 | 660.6 | 746.2 | 935.8 | 634.8 | 880.2 | 654.3 | 648.3 | 228.0 | | |
| PEAK LOAD / CAPACITY | ACTUAL | | 493.5 | 203.9 | 394.7 | 871.1 | 660.6 | 746.2 | 935.8 | 634.8 | 880.2 | 654.3 | 648.3 | 228.0 | 7,351.5 | 7,351.5 |
| | VARIANCE | | -26.3 | -162.8 | -570.0 | 162.2 | -208.6 | 269.6 | 459.2 | 111.5 | 465.9 | 292.0 | 444.7 | 221.9 | 1,459.4 | 1,459.4 |
| | **BUDGET** | **135,217.5** | **13,160.1** | **10,586.3** | **13,563.0** | **14,853.5** | **14,715.4** | **13,597.3** | **10,570.2** | **10,883.0** | **10,227.0** | **9,533.7** | 10,175.2 | **904.0** | **132,279.0** | |
| | **PROJECTION** | **135,921.2** | **11,079.8** | **12,770.5** | **10,004.9** | **15,932.6** | **9,570.1** | **11,396.6** | **10,533.5** | **8,422.3** | **10,356.0** | **11,756.5** | **9,873.8** | **16,635.1** | | |
| **NH OPERATIONS DISTRIBUTION (D01)** | **ACTUAL** | | **11,079.8** | **12,770.5** | **10,006.6** | **15,938.5** | **9,569.9** | **11,396.6** | **10,532.9** | **8,422.3** | **10,356.0** | **11,756.5** | **9,873.8** | **14,217.9** | **135,921.2** | **135,921.2** |
| | **VARIANCE** | | **-2,080.4** | **2,184.2** | **-3,556.4** | **1,085.0** | **-5,145.6** | **-2,200.7** | **-37.4** | **-2,460.7** | **129.0** | **2,222.9** | **301.4** | **13,313.8** | **3,642.2** | -101.2 |

# BUDGET PROGRAM SUMMARY
## As of YTD Dec 2021

| | | 2021 BUDGET | JAN 2021 | FEB 2021 | MAR 2021 | APR 2021 | MAY 2021 | JUN 2021 | JUL 2021 | AUG 2021 | SEP 2021 | OCT 2021 | NOV 2021 | DEC 2021 | YTD 2021 | YEP |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **DISTRIBUTION** | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | |
| | BUDGET | 14,738.0 | 1,316.0 | 1,316.0 | 1,326.0 | 1,326.0 | 1,619.2 | 1,326.0 | 1,326.0 | 1,619.2 | 1,619.2 | 1,326.0 | 1,619.2 | -1,000.6 | 14,738.0 | |
| | PROJECTION | 29,614.0 | 2,593.9 | 1,994.6 | 1,703.5 | 225.0 | 2,164.7 | 2,704.7 | 1,350.2 | 2,315.0 | 3,186.8 | 2,716.9 | 1,612.2 | 7,046.4 | | |
| NEW CUSTOMER | ACTUAL | | 2,593.9 | 1,994.6 | 1,703.5 | 225.0 | 2,164.7 | 2,704.7 | 1,350.2 | 2,315.0 | 3,186.8 | 2,716.9 | 1,612.2 | 7,046.4 | 29,614.0 | 29,614.0 |
| | VARIANCE | | 1,277.9 | 678.6 | 377.5 | -1,101.0 | 545.5 | 1,378.7 | 24.2 | 695.9 | 1,567.7 | 1,390.9 | -7.0 | 8,047.0 | 14,876.0 | 14,876.0 |
| | BUDGET | 31,006.0 | 2,890.9 | 2,506.3 | 3,149.4 | 3,399.8 | 2,581.5 | 2,953.4 | 3,338.3 | 3,211.8 | 2,771.3 | 2,746.5 | 2,558.8 | -1,102.1 | 31,006.0 | |
| | PROJECTION | 44,018.3 | 2,531.0 | 4,981.5 | 3,469.2 | 2,827.0 | 3,610.3 | 4,662.6 | 3,172.9 | 3,196.5 | 3,204.9 | 4,078.7 | 3,130.9 | 5,152.8 | | |
| BASIC BUSINESS | ACTUAL | | 2,531.0 | 4,981.5 | 3,469.2 | 2,827.0 | 3,610.3 | 4,662.6 | 3,172.9 | 3,196.5 | 3,204.9 | 4,078.7 | 3,130.9 | 5,152.8 | 44,018.3 | 44,018.3 |
| | VARIANCE | | -359.9 | 2,475.2 | 319.8 | -572.8 | 1,028.8 | 1,709.2 | -165.4 | -15.3 | 433.6 | 1,332.2 | 572.1 | 6,254.9 | 13,012.3 | 13,012.3 |
| | BUDGET | 78,901.2 | 3,560.8 | 4,706.8 | 6,536.8 | 6,356.2 | 7,372.0 | 5,506.8 | 6,437.3 | 7,686.7 | 7,220.6 | 6,499.0 | 10,582.5 | 6,435.6 | 78,901.2 | |
| | PROJECTION | 63,756.3 | 6,252.4 | 7,176.5 | 6,440.8 | 4,454.4 | 4,885.9 | 3,355.1 | 2,758.8 | 2,043.7 | 4,440.0 | 6,047.8 | 7,537.0 | 8,364.0 | | |
| RELIABILITY | ACTUAL | | 6,252.6 | 7,176.5 | 6,440.8 | 4,454.4 | 4,885.9 | 3,355.1 | 2,758.8 | 2,043.7 | 4,440.0 | 6,047.8 | 7,537.0 | 8,364.0 | 63,756.3 | 63,756.3 |
| | VARIANCE | | 2,691.8 | 2,469.6 | -96.0 | -1,901.9 | -2,486.2 | -2,151.7 | -3,678.5 | -5,643.0 | -2,780.6 | -451.2 | -3,045.5 | 1,928.4 | -15,144.8 | -15,144.8 |
| | BUDGET | 4,600.0 | 428.1 | 428.1 | 1,083.8 | 418.3 | 418.3 | 418.3 | 948.4 | 1,125.1 | 418.3 | 418.3 | 369.2 | -1,874.5 | 4,600.0 | |
| | PROJECTION | 3,896.7 | -413.7 | -88.4 | 139.7 | 158.6 | 362.3 | 427.1 | 915.1 | 418.3 | 604.9 | 310.2 | 132.8 | 929.9 | | |
| REGULATORY COMMITMENTS | ACTUAL | | -413.7 | -88.4 | 139.7 | 158.6 | 362.3 | 427.1 | 915.1 | 418.3 | 604.9 | 310.2 | 132.8 | 929.9 | 3,896.7 | 3,896.7 |
| | VARIANCE | | -841.8 | -516.6 | -944.1 | -259.8 | -56.1 | 8.8 | -33.4 | -706.9 | 186.6 | -108.1 | -236.4 | 2,804.4 | -703.3 | -703.3 |
| | BUDGET | 5,096.4 | 244.5 | 101.2 | 183.0 | 1,857.2 | 1,978.9 | 733.3 | 199.5 | 174.5 | 570.4 | 535.5 | 185.2 | -1,666.7 | 5,096.4 | |
| | PROJECTION | 7,502.7 | 765.3 | 343.0 | 330.8 | 292.1 | 682.6 | 1,026.6 | 472.1 | 566.1 | 826.2 | 959.0 | -432.0 | 1,671.0 | | |
| PEAK LOAD / CAPACITY | ACTUAL | | 765.3 | 343.0 | 330.8 | 292.1 | 682.6 | 1,026.6 | 472.1 | 566.1 | 826.2 | 959.0 | -432.0 | 1,671.0 | 7,502.7 | 7,502.7 |
| | VARIANCE | | 520.8 | 241.8 | 147.8 | -1,565.1 | -1,296.3 | 293.3 | 272.6 | 391.6 | 255.9 | 423.5 | -617.2 | 3,337.6 | 2,406.3 | 2,406.3 |
| | | | | | | | | | | | | | | | | |
| | **BUDGET** | **134,341.6** | **8,440.3** | **9,058.5** | **12,279.0** | **13,357.5** | **13,970.0** | **10,937.8** | **12,249.5** | **13,817.3** | **12,599.8** | **11,525.3** | **15,314.8** | **791.8** | **134,341.6** | |
| | **PROJECTION** | **148,788.1** | **11,728.9** | **14,407.2** | **12,084.0** | **7,957.0** | **11,705.8** | **12,176.1** | **8,669.1** | **8,539.6** | **12,262.9** | **14,112.5** | **11,980.8** | **23,164.1** | | |
| **NH OPERATIONS DISTRIBUTION (D01)** | **ACTUAL** | | **11,729.0** | **14,407.2** | **12,084.0** | **7,957.0** | **11,705.8** | **12,176.1** | **8,669.1** | **8,539.6** | **12,262.9** | **14,112.5** | **11,980.8** | **23,164.1** | **148,788.1** | **148,788.1** |
| | **VARIANCE** | | **3,288.7** | **5,348.7** | **-195.1** | **-5,400.5** | **-2,264.2** | **1,238.3** | **-3,580.5** | **-5,277.8** | **-336.9** | **2,587.2** | **-3,334.0** | **22,372.3** | **14,446.4** | **14,446.4** |

# BUDGET PROGRAM SUMMARY
## As of YTD December 2022

| | | 2022 BUDGET | JAN 2022 | FEB 2022 | MAR 2022 | APR 2022 | MAY 2022 | JUN 2022 | JUL 2022 | AUG 2022 | SEP 2022 | OCT 2022 | NOV 2022 | DEC 2022 | YTD 2022 | YEP |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **DISTRIBUTION** | | | | | | | | | | | | | | | | |
| | BUDGET | 11,269.9 | 929.0 | 929.0 | 939.0 | 939.0 | 939.0 | 939.0 | 939.0 | 939.0 | 939.0 | 939.0 | 939.0 | 961.5 | 11,269.9 | |
| | PROJECTION | 24,025.7 | 592.8 | 1,522.5 | 1,468.2 | 1,442.9 | 1,449.5 | 1,670.9 | 2,123.4 | 2,169.7 | 1,765.7 | 2,679.9 | 2,269.1 | 4,871.2 | | |
| NEW CUSTOMER | ACTUAL | | 592.8 | 1,522.5 | 1,468.2 | 1,442.9 | 1,449.5 | 1,670.9 | 2,123.4 | 2,169.7 | 1,765.7 | 2,679.9 | 2,269.1 | 4,871.2 | 24,025.7 | 24,025.7 |
| | VARIANCE | | -336.2 | 593.5 | 529.3 | 503.9 | 510.6 | 732.0 | 1,184.5 | 1,230.7 | 826.7 | 1,740.9 | 1,330.1 | 3,909.8 | 12,755.8 | 12,755.8 |
| | BUDGET | 33,222.3 | 3,448.6 | 2,458.9 | 3,557.8 | 2,372.6 | 2,316.0 | 2,770.1 | 3,148.8 | 3,432.0 | 2,746.2 | 2,365.3 | 2,296.2 | 2,309.8 | 33,222.3 | |
| | PROJECTION | 48,502.2 | 2,551.6 | 3,727.1 | 5,645.1 | 4,585.3 | 4,447.5 | 4,506.1 | 2,344.2 | 2,532.0 | 2,941.1 | 5,188.9 | 5,353.2 | 4,680.1 | | |
| BASIC BUSINESS | ACTUAL | | 2,551.6 | 3,727.1 | 5,645.1 | 4,585.3 | 4,447.5 | 4,506.1 | 2,344.2 | 2,532.0 | 2,941.1 | 5,188.9 | 5,353.2 | 4,680.1 | 48,502.2 | 48,502.2 |
| | VARIANCE | | -897.0 | 1,268.2 | 2,087.3 | 2,212.6 | 2,131.5 | 1,736.0 | -804.6 | -900.1 | 194.9 | 2,823.6 | 3,057.1 | 2,370.4 | 15,279.8 | 15,279.8 |
| | BUDGET | 71,521.3 | 4,586.6 | 4,556.9 | 9,524.3 | 5,815.1 | 5,262.0 | 5,611.7 | 7,599.1 | 5,319.1 | 6,141.6 | 6,615.9 | 5,031.7 | 5,457.2 | 71,521.3 | |
| | PROJECTION | 60,102.2 | 2,459.6 | 2,752.5 | 3,328.1 | 5,391.1 | 7,692.6 | 4,041.1 | 5,347.7 | 2,686.3 | 4,413.8 | 5,280.7 | 5,811.9 | 10,896.9 | | |
| RELIABILITY | ACTUAL | | 2,459.6 | 2,752.5 | 3,328.1 | 5,391.1 | 7,692.6 | 4,041.1 | 5,347.7 | 2,686.3 | 4,413.8 | 5,280.7 | 5,811.9 | 10,896.9 | 60,102.2 | 60,102.2 |
| | VARIANCE | | -2,127.0 | -1,804.4 | -6,196.3 | -424.0 | 2,430.6 | -1,570.6 | -2,251.5 | -2,632.7 | -1,727.8 | -1,335.2 | 780.2 | 5,439.6 | -11,419.1 | -11,419.1 |
| | BUDGET | 11,403.4 | 1,322.3 | 1,723.9 | 2,315.2 | 2,043.7 | 2,274.6 | 104.3 | 282.7 | 130.2 | 98.4 | 453.5 | 341.1 | 313.6 | 11,403.4 | |
| | PROJECTION | 10,707.3 | 1,304.0 | 1,097.4 | 1,432.5 | 1,850.5 | 992.7 | 740.1 | 344.9 | 733.3 | 244.7 | 337.5 | 500.2 | 1,129.5 | | |
| REGULATORY COMMITMENTS | ACTUAL | | 1,304.0 | 1,097.4 | 1,432.5 | 1,850.5 | 992.7 | 740.1 | 344.9 | 733.3 | 244.7 | 337.5 | 500.2 | 1,129.5 | 10,707.3 | 10,707.3 |
| | VARIANCE | | -18.3 | -626.4 | -882.7 | -193.3 | -1,281.9 | 635.8 | 62.3 | 603.2 | 146.3 | -116.0 | 159.1 | 815.9 | -696.1 | -696.1 |
| | BUDGET | 6,509.4 | 136.6 | 136.6 | 652.3 | 839.3 | 1,043.6 | 941.6 | 455.6 | 566.4 | 560.4 | 648.4 | 432.1 | 96.6 | 6,509.4 | |
| | PROJECTION | 7,287.3 | 776.4 | 523.7 | 311.6 | -151.4 | 340.9 | 1,035.0 | 889.9 | 1,656.3 | 1,237.1 | -518.3 | 728.0 | 458.2 | | |
| PEAK LOAD / CAPACITY | ACTUAL | | 776.4 | 523.7 | 311.6 | -151.4 | 340.9 | 1,035.0 | 889.9 | 1,656.3 | 1,237.1 | -518.3 | 728.0 | 458.2 | 7,287.3 | 7,287.3 |
| | VARIANCE | | 639.8 | 387.2 | -340.7 | -990.7 | -702.8 | 93.4 | 434.2 | 1,089.9 | 676.7 | -1,166.7 | 295.9 | 361.6 | 777.8 | 777.8 |
| | **BUDGET** | **133,926.4** | **10,423.1** | **9,805.1** | **16,988.6** | **12,009.7** | **11,835.2** | **10,366.7** | **12,425.2** | **10,386.6** | **10,485.5** | **11,022.1** | **9,039.9** | **9,138.6** | **133,926.4** | |
| | **PROJECTION** | **150,624.6** | **7,684.4** | **9,623.2** | **12,185.4** | **13,118.2** | **14,923.2** | **11,993.3** | **11,050.1** | **9,777.6** | **10,602.4** | **12,968.7** | **14,662.3** | **22,035.9** | | |
| **NH OPERATIONS DISTRIBUTION (D01)** | **ACTUAL** | | **7,684.4** | **9,623.2** | **12,185.4** | **13,118.2** | **14,923.2** | **11,993.3** | **11,050.1** | **9,777.6** | **10,602.4** | **12,968.7** | **14,662.3** | **22,035.9** | **150,624.6** | **150,624.6** |
| | **VARIANCE** | | **-2,738.8** | **-182.0** | **-4,803.2** | **1,108.6** | **3,088.0** | **1,626.6** | **-1,375.2** | **-609.0** | **116.8** | **1,946.6** | **5,622.4** | **12,897.2** | **16,698.2** | **16,698.2** |

# BUDGET PROGRAM SUMMARY
## As of YTD December 2023

| | | 2023 BUDGET | JAN 2023 | FEB 2023 | MAR 2023 | APR 2023 | MAY 2023 | JUN 2023 | JUL 2023 | AUG 2023 | SEP 2023 | OCT 2023 | NOV 2023 | DEC 2023 | YTD 2023 | YEP |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **DISTRIBUTION** | | | | | | | | | | | | | | | | |
| | BUDGET | 14,981.6 | 1,287.4 | 1,311.4 | 1,311.4 | 1,333.4 | 1,311.4 | 996.4 | 1,238.4 | 1,238.4 | 1,238.5 | 1,238.5 | 1,238.5 | 1,238.5 | 14,981.6 | |
| | PROJECTION | 29,356.2 | -543.7 | 1,753.0 | 1,383.1 | 3,095.8 | 1,436.1 | 2,486.2 | 2,338.6 | 1,929.0 | 4,029.8 | 1,940.4 | 3,378.2 | 6,129.7 | | |
| NEW CUSTOMER | ACTUAL | | -543.7 | 1,753.0 | 1,383.1 | 3,095.8 | 1,436.1 | 2,486.2 | 2,338.6 | 1,929.0 | 4,029.8 | 1,940.4 | 3,378.2 | 6,129.7 | 29,356.2 | 29,356.2 |
| | VARIANCE | | -1,831.0 | 441.6 | 71.7 | 1,762.4 | 124.8 | 1,489.9 | 1,100.2 | 690.6 | 2,791.3 | 701.9 | 2,139.8 | 4,891.2 | 14,374.5 | 14,374.5 |
| | BUDGET | 43,052.5 | 3,748.9 | 3,613.3 | 3,658.4 | 3,436.8 | 3,645.2 | 3,593.2 | 3,568.0 | 3,593.0 | 3,592.6 | 3,517.6 | 3,517.6 | 3,567.6 | 43,052.5 | |
| | PROJECTION | 65,469.8 | 1,509.2 | 5,233.2 | 3,574.5 | 4,713.0 | 4,760.0 | 8,154.4 | 5,709.6 | 5,239.8 | 4,358.4 | 8,400.6 | 8,459.1 | 5,357.9 | | |
| BASIC BUSINESS | ACTUAL | | 1,509.2 | 5,233.2 | 3,574.5 | 4,713.0 | 4,760.0 | 8,154.4 | 5,709.6 | 5,239.8 | 4,358.4 | 8,400.6 | 8,459.1 | 5,357.9 | 65,469.8 | 65,469.8 |
| | VARIANCE | | -2,239.7 | 1,619.8 | -83.8 | 1,276.2 | 1,114.8 | 4,561.2 | 2,141.6 | 1,646.7 | 765.8 | 4,882.9 | 4,941.4 | 1,790.3 | 22,417.2 | 22,417.2 |
| | BUDGET | 102,883.6 | 7,324.4 | 7,236.4 | 7,916.1 | 9,103.1 | 7,344.4 | 6,928.2 | 5,976.5 | 8,210.7 | 13,215.4 | 9,818.4 | 9,572.5 | 10,237.5 | 102,883.6 | |
| | PROJECTION | 86,298.8 | 5,301.4 | 5,422.2 | 6,064.4 | 8,362.8 | 3,868.3 | 11,404.7 | 6,937.3 | 11,137.7 | 13,893.3 | 6,135.1 | 5,574.6 | 2,197.0 | | |
| RELIABILITY | ACTUAL | | 5,301.4 | 5,422.2 | 6,064.4 | 8,362.8 | 3,868.3 | 11,404.7 | 6,937.3 | 11,137.7 | 13,893.3 | 6,135.1 | 5,574.6 | 2,197.0 | 86,298.8 | 86,298.8 |
| | VARIANCE | | -2,023.0 | -1,814.2 | -1,812.8 | -719.3 | -3,493.8 | 4,458.9 | 915.2 | 2,749.4 | 500.4 | -3,860.9 | -4,175.4 | -8,218.0 | -16,584.9 | -16,584.9 |
| | BUDGET | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| | PROJECTION | 48.6 | 0.5 | 1.7 | 0.1 | 1.2 | 32.4 | 1.5 | 3.3 | 4.3 | 0.2 | 1.5 | 1.4 | 0.4 | | |
| REGULATORY COMMITMENTS | ACTUAL | | 0.5 | 1.7 | 0.1 | 1.2 | 32.4 | 1.5 | 3.3 | 4.3 | 0.2 | 1.5 | 1.4 | 0.4 | 48.6 | 48.6 |
| | VARIANCE | | 0.5 | 1.7 | 0.1 | 1.2 | 32.4 | 1.5 | 3.3 | 4.3 | 0.2 | 1.5 | 1.4 | 0.4 | 48.6 | 48.6 |
| | BUDGET | 22,278.5 | 827.7 | 696.3 | 652.0 | 831.3 | 836.3 | 918.8 | 724.9 | 2,652.5 | 3,244.0 | 3,910.6 | 3,650.8 | 3,333.5 | 22,278.5 | |
| | PROJECTION | 7,807.5 | 330.6 | -73.4 | 271.4 | 553.6 | 317.0 | 807.8 | 838.8 | 928.1 | 1,049.2 | 299.4 | 1,736.6 | 748.4 | | |
| PEAK LOAD / CAPACITY | ACTUAL | | 330.6 | -73.4 | 271.4 | 553.6 | 317.0 | 807.8 | 838.8 | 928.1 | 1,049.2 | 299.4 | 1,736.6 | 748.4 | 7,807.5 | 7,807.5 |
| | VARIANCE | | -497.1 | -769.7 | -380.6 | -277.7 | -519.3 | -111.0 | 113.9 | -1,724.4 | -2,194.8 | -3,611.2 | -1,914.1 | -2,585.0 | -14,471.1 | -14,471.1 |
| | **BUDGET** | **183,196.4** | **13,188.4** | **12,857.4** | **13,537.8** | **14,704.5** | **13,137.4** | **12,436.6** | **11,507.8** | **15,694.6** | **21,290.5** | **18,485.1** | **17,979.3** | **18,377.0** | **183,196.4** | |
| | **PROJECTION** | **188,980.8** | **6,598.1** | **12,336.7** | **11,293.5** | **16,726.3** | **10,413.9** | **22,854.7** | **15,827.6** | **19,238.8** | **23,330.8** | **16,776.9** | **19,150.0** | **14,433.5** | | |
| **NH OPERATIONS DISTRIBUTION (D01)** | **ACTUAL** | | **6,598.1** | **12,336.7** | **11,293.5** | **16,726.3** | **10,413.9** | **22,854.7** | **15,827.6** | **19,238.8** | **23,330.8** | **16,776.9** | **19,150.0** | **14,433.5** | **188,980.8** | **188,980.8** |
| | **VARIANCE** | | **-6,590.3** | **-520.7** | **-2,205.3** | **2,042.8** | **-2,741.2** | **10,400.5** | **4,274.2** | **3,366.7** | **1,862.8** | **-1,885.7** | **993.1** | **-4,121.0** | **5,784.5** | **5,784.5** |

| |
|---|
| **Basic Business-ED** |
| Third Party/Joint Owner Work |
| Basic Business - Other |
| Insurance Claim/Keep Cost |
| Line Relocations/Act of Public Authority |
| Pre-Cap Line Transformers |
| Lighting |
| Emergent Equipment Failures - Line |
| Emergent Equipment Failures - Substation |
| Environmental |
| Capital Tool Purchases |
| |
| **New Customer-ED** |
| Distributed Generation |
| Customer Driven |
| |
| **Peak Load / Capacity** |
| Distribution Line Capacity |
| Substation Capacity |
| **Regulatory Commitments** |
| Regulatory Commitments-Other |
| |
| **Reliability** |
| Distribution Automation |
| Distribution Line Reliability |
| Distribution ROW Line Reliability |
| Substation Reliability |
| CCI Reject Pole Replacement |
| **Total Distribution** |

| Budget Category | Budget Sub-Category | Project # | Project Title | 2025 ($1,000) | 2026 ($1,000) | 2027 ($1,000) | 2028 ($1,000) | 2029 ($1,000) | Description |
|---|---|---|---|---|---|---|---|---|---|
| New Customer | Customer Driven | DN9R | DN9R - NEW/EXISTING CUSTOMERS - PSNH | 25,209 | 25,966 | 26,744 | 27,547 | 28,373 | |
| New Customer | Customer Driven | DV9R | SERVICES - PSNH | 4,141 | 4,265 | 4,393 | 4,525 | 4,660 | |
| | | | **Totals ==>** | **29,350** | **30,230** | **31,137** | **32,071** | **33,034** | |

| Budget Category | Budget Sub-Category | Project # | Project Title | 2025 ($1,000) | 2026 ($1,000) | 2027 ($1,000) | 2028 ($1,000) | 2029 ($1,000) | Description |
|---|---|---|---|---|---|---|---|---|---|
| Basic Business | 3rd Party/Joint Owner Work | C03CTV | CABLE TV PROJECTS ANNUAL | 5,150 | 5,305 | 5,464 | 5,628 | 5,796 | |
| Basic Business | 3rd Party/Joint Owner Work | C03TEL | TELEPHONE PROJECTS ANNUAL | 52 | 53 | 55 | 56 | 58 | |
| Basic Business | 3rd Party/Joint Owner Work | C01SPA01 | Joint Pole | 52 | 53 | 55 | 56 | 58 | |
| Basic Business | Line Relocations/Act of Public Authority | C03DOT | NHDOT PROJECT ANNUAL | 1,576 | 1,623 | 1,672 | 1,672 | 1,774 | |
| Basic Business | Line Relocations/Act of Public Authority | | NHDOT Route 106 | | 2,000 | | | | |
| Basic Business | Line Relocations/Act of Public Authority | DH9R | LINE RELOCATIONS | 2,126 | 2,190 | 2,255 | 2,255 | 2,393 | |
| Basic Business | Environmental | CO1PCB | PCB Transformer Replacements | 412 | 424 | 437 | 450 | 464 | |
| Basic Business | Lighting | DA9R | NON-ROADWAY LIGHTING | 1,257 | 1,294 | 1,000 | 1,350 | 1,414 | |
| Basic Business | Lighting | HPS9R | HPS ADDS/CHNGS | 278 | 286 | 295 | 304 | 313 | |
| Basic Business | Basic Business - Other | GF9R | GEN OFF FURN/EQUIP - ED | 105 | 108 | 111 | 115 | 118 | |
| Basic Business | Basic Business - Other | PT9R | Temporary Work | 341 | 351 | 362 | 373 | 384 | |
| Basic Business | Basic Business - Other | PW9R | Private Work | 119 | 123 | 127 | 131 | 134 | |
| Basic Business | Capital Tool Purchases | GM9R23 | Tools and Equipment- 1250 | 420 | 433 | 446 | 459 | 473 | |
| Basic Business | Capital Tool Purchases | GT9R | Tools and Equipment- Troubleshooters | 525 | 541 | 557 | 574 | 591 | |
| Basic Business | Capital Tool Purchases | GX9R | TOOLS/EQUIPMENT CONSTRUCTION - E | 1,051 | 1,082 | 1,115 | 1,148 | 1,182 | |

| Budget Category | Budget Sub-Category | Project # | Project Title | 2025 ($1,000) | 2026 ($1,000) | 2027 ($1,000) | 2028 ($1,000) | 2029 ($1,000) | Description |
|---|---|---|---|---|---|---|---|---|---|
| Basic Business | Insurance Claim/Keep Cost | INSOH9R | Claims OH, UG, DB | 1,442 | 1,485 | 1,530 | 1,576 | 1,623 | |
| Basic Business | Emergent Equipment Failures - Line | DQ9R | DQ (Double Poles) | 1,751 | 1,804 | 1,858 | 1,913 | 1,971 | |
| Basic Business | Emergent Equipment Failures - Line | DQ9R | DQ (Split By Region for 2024) | 23,820 | 24,534 | 25,270 | 26,029 | 26,809 | |
| Basic Business | Emergent Equipment Failures - Line | DS9RE | ROW DQ | 1,313 | 1,353 | 1,393 | 1,435 | 1,478 | |
| Basic Business | Emergent Equipment Failures - Line | MINOR9R | MINOR STORM WORK - VARIOUS AWC'S | 1,576 | 1,623 | 1,672 | 1,722 | 1,774 | |
| Basic Business | Emergent Equipment Failures - Line | STORMCAP | STORM CAPITALIZATION | 2,943 | 3,031 | 3,122 | 3,216 | 3,312 | |
| Basic Business | Pre-Cap Line Transformers | DT7P | Transformer and Regulators Annual | 23,195 | 23,890 | 24,607 | 25,345 | 26,106 | |
| Basic Business | Capital Tool Purchases | GE9R | Tools and Equipment | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | Engineering tool budget |
| Basic Business | Emergent Equipment Failure - Substation | | Power Transformer Failure | 2,850 | 2,850 | 2,850 | 2,850 | 2,850 | |
| | | | **Totals ==>** | **73,374** | **77,459** | **77,273** | **79,677** | **82,097** | |

| Budget Category | Budget Sub-Category | Project Title | 2025 ($1,000) | 2026 ($1,000) | 2027 ($1,000) | 2028 ($1,000) | 2029 ($1,000) | FERC Account | Company Accouting Account # | Financing Expectations | Depreciable Life of the assets | Depreciation Method |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Reliability | Distribution Line Reliability | Reject Pole Replacement | 3,296 | 3,395 | 3,497 | 3,602 | 3,710 | | | | | |
| Reliability | Distribution Line Reliability | Wood Pole Treatment | 420 | 420 | 420 | 420 | 420 | | | | | |
| Reliability | Distribution ROW Line Reliability | Pembroke Pines - ROW Rebuild ## Structures | 1,900 | | | | | | | | | |
| Reliability | Distribution ROW Line Reliability | ROW Rebuild Section of Line, Swamp Section Rundlett Hill | 2,200 | | | | | | | | | |
| Reliability | Distribution ROW Line Reliability | HWY Crossing Holderness - 12 Structures w/ HWY crossing | 1,600 | | | | | | | | | |
| Reliability | Distribution ROW Line Reliability | W15 Lattice Tower Removal | | | $ 6,000 | | | | | | | |
| Reliability | Distribution ROW Line Reliability | ROW Rebuild - Replace 2 miles, 55 poles and reconductor | | 150 | $ 5,350 | | | | | | | |
| Reliability | Distribution ROW Line Reliability | Durham, 32 section line upgrade from 336 to 795 | | 100 | $ 2,260 | | | | | | | |
| Reliability | Distribution ROW Line Reliability | ROW Rebuild - (Straits Rd to NHEC Meredith) Multi-year | 200 | $ 1,300 | | | | | | | | |
| Reliability | Distribution ROW Line Reliability | ROW Swamp Crossing - Replace poles in swamp and update guying | 100 | $ 1,553 | | | | | | | | |
| Reliability | Distribution ROW Line Reliability | ROW Dbl Circuit - 19 structures | 100 | $ 5,000 | | | | | | | | |
| Reliability | Distribution ROW Line Reliability | Lattic Tower Replacement 18 Tower replacement | | $ 110 | $ 500 | | | | | | | |
| Reliability | Distribution ROW Line Reliability | Lattice Tower Replacement - 54 Towers Envior/Permitting | | $ 110 | $ 500 | | | | | | | |
| Reliability | Distribution ROW Line Reliability | Replacement - 18 Structures - ROW btw Laconia to Gilford | | | | $ 100 | $ 550 | | | | | |
| Reliability | Distribution ROW Line Reliability | ROW River Crossing - Six ROW structures replacement | | $ 500 | | | | | | | | |
| Reliability | Distribution ROW Line Reliability | Resistance Retirement related Line Work | 15,247 | 11,645 | | | | | | | | |
| Reliability | Distribution Automation | Distribution Automation - Pole Top | 7,000 | 7,000 | 3,500 | 3,500 | 3,500 | | | | | |
| Reliability | Distribution Automation | Distribution Automation - Capacitor Banks & Regulators | 1,500 | 1,500 | 1,500 | 1,500 | 1,500 | | | | | |
| Reliability | Distribution Automation | Add SCADA Reclosers to DG Sites | 500 | 500 | | | | | | | | |
| Reliability | Distribution Automation | Distribution Automation - Line Sensors | 200 | 200 | 200 | 200 | 200 | | | | | |
| Reliability | Distribution Line Reliability | Reliability Improvements Annual / TripSavers | 7,500 | 5,000 | 5,000 | 5,000 | 5,000 | | | | | |
| Reliability | Distribution Line Reliability | Gratham, 316X1 & 42X3 Circuit Tie - Phase 2 | 5,000 | | | | | | | | | |
| Reliability | Distribution Line Reliability | Hooksett, Route 3 Circuit Tie | 1,187 | | | | | | | | | |
| Reliability | Distribution Line Reliability | 3137X1 / 377X3 Ckt Tie | 3,781 | | | | | | | | | |
| Reliability | Distribution Line Reliability | 41H2 Conversion - Dover | 1,800 | | | | | | | | | |
| Reliability | Distribution Line Reliability | 347X3 Jack Frost Ln URD | 410 | | | | | | | | | |
| Reliability | Distribution Line Reliability | 3159X Dahl Rd URD replacement | 520 | | | | | | | | | |
| Reliability | Distribution Line Reliability | 320 Cable Replacement IFR | 870 | | | | | | | | | |
| Reliability | Distribution Line Reliability | 14W7 Auburn - Spruce rd URD Rebuild - Reliability | 1,340 | | | | | | | | | |
| Reliability | Distribution Line Reliability | 24X1/23X6 Francestown/Mount Vernon - Circuit Tie - Reliability | 4,400 | 4,000 | | | | | | | | |
| Reliability | Distribution Line Reliability | 371X1 Rochester - Old Dover Rd relocate offroad section - Reliability | 393 | | | | | | | | | |
| Reliability | Distribution Line Reliability | Weare, Rt. 114 Circuit tie and conversion | 3,200 | | | | | | | | | |
| Reliability | Distribution Line Reliability | New Ispswich, 4.16 to 34.5 Conversion and change N.O. Point to remove feed from Temple rd to Highbridge/turnpike rd | | 3,750 | | | | | | | | |
| Reliability | Distribution Line Reliability | Campton, 12.47 to 34.5kV converstionto create a loop | 633 | | | | | | | | | |
| Reliability | Distribution Line Reliability | Laconia, Outerbridge Rd, MOST switch Replacement | | 808 | | | | | | | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Reliability | Distribution Line Reliability | Franklin, Double Circuit to feed and change NO point for 34.5kV system | | 1,943 | | | | | | | | |
| Reliability | Distribution Line Reliability | Nashua, Harris Rd, convert 1PH to 3PH and create a circuit tie | 1,014 | | | | | | | | | |
| Reliability | Distribution Line Reliability | Tilton, Remove 34.5kV out of Swamp that feeds 3M | | | $ 240 | | | | | | | |
| Reliability | Distribution Line Reliability | Milan, 1PH to 3Ph conversion, improve reliablity, by segmentation | | | | $ 2,705 | | | | | | |
| Reliability | Distribution Line Reliability | Franklin, 4.16 to 34.5 Converstion for Fault Current improvement | | | | $ 1,461 | | | | | | |
| Reliability | Distribution Line Reliability | Campton, Loop feed Pond Rd | | | | $ 2,134 | | | | | | |
| Reliability | Distribution Line Reliability | Rochester, Loop feed to the 340X5, Large load area | | | | $ 1,000 | | | | | | |
| Reliability | Distribution Line Reliability | Portsmouth, Convert 4.16kV to 34.5 and create loop | | | | $ 715 | | | | | | |
| Reliability | Substation Reliability | Eddy Transformer TB81 & TB26 Replacement | 5,000 | 6,750 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | Brook St S/S - Switchgear and Transformer Replacement | 7,500 | 0 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | Distribution Automation - Substation | 4,000 | 4,000 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | DA - Capacitor Banks & Regulators | 4,000 | 4,000 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | Hudson SS OCB Replacement | | | 3,500 | 250 | | | | | | |
| Reliability | Substation Reliability | RTU Replacement Program (NH - D) | 3,000 | 3,000 | 3,250 | 3,250 | | | | | | |
| Reliability | Substation Reliability | Ashland Reliability Project | | 250 | 2,975 | 1,000 | | | | | | |
| Reliability | Substation Reliability | Merrimack Distribution Oil Recloser Replacement | 2,520 | 2,450 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | Loudon 31W1 & 31W2 Recloser replacements | 2,520 | 0 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | DA- Distribution Feeder Relay Replacement Program | 2,500 | 2,500 | 2,500 | 2,500 | 2,500 | | | | | |
| Reliability | Substation Reliability | SACO VALLEY 34.5kV OCB REPLACEMENT | 2,300 | 3,000 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | East Northwood SS Oil Recloser Replacement | 1,295 | 0 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | Byrd Ave 61W2 Recloser Replacement | 1,285 | 0 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | Northwood Narrows Oil Recloser Repl. | 1,195 | 0 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | Tate Rd 42H1 Recloser Replacement | 1,185 | 0 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | Replacement Battery Program (NH - D) | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | | | | | |
| Reliability | Substation Reliability | Chester SS Station Service Voltage Transformer Repl. | 850 | 0 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | Capacitor Bank Switch Replacements | 800 | 800 | 800 | 800 | 800 | | | | | |
| Reliability | Substation Reliability | Station Service Transformer Replacement Program (NH-D) | 1,000 | 750 | 3,000 | 1,000 | 2,000 | | | | | |
| Reliability | Substation Reliability | Long Hill Station Service Voltage Xfmr Repl | 700 | 200 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | Mammoth Rd. Station Service Voltage Xfmr Repl | 700 | 200 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | Dover S/S Rebuild (cocheco) | 600 | 1,000 | 9,000 | 22,000 | | | | | | |
| Reliability | Substation Reliability | Huse Rd New Gas Monitor Install | 600 | 0 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | Gas Monitor & Health Monitor Installation Program - (NH - D) | 520 | 520 | 520 | 520 | | | | | | |
| Reliability | Substation Reliability | SS Oil Recloser Replacement Program (NH) | 500 | 1,500 | 3,500 | 3,500 | | | | | | |
| Reliability | Substation Reliability | SS ANIMAL PROTECTION PROGRAM | 500 | 500 | 500 | 500 | | | | | | |
| Reliability | Substation Reliability | Swanzey TB8S Transformer SCADA | 500 | 0 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | NH Unit SS Replacement Program | 500 | 1,000 | 1,000 | 2,000 | | | | | | |
| Reliability | Substation Reliability | Brentwood - RTU Replacement Project (D) | 331 | 376 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | Oak Hill SS OCB Replacement | 250 | 750 | 250 | 0 | | | | | | |
| Reliability | Substation Reliability | Rochester SS OCB Replacements | 250 | 750 | 250 | 0 | | | | | | |
| Reliability | Substation Reliability | Warner Transformer 33H1 Phase 3 Replacement | 250 | 3,750 | 8,000 | 0 | | | | | | |
| Reliability | Substation Reliability | Center Ossipee Transformer 19W1 Replacement | 250 | 1,000 | 3,750 | 0 | | | | | | |
| Reliability | Substation Reliability | Chestnut Hill TB98 Transformer Replacement | 250 | | | 2,000 | 3,750 | | | | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Reliability | Substation Reliability | 34.5kV OCB Breaker and Ancillary Equipment Replacement Program | 250 | 2,750 | 2,500 | 3,750 | 4,250 | | | | | |
| Reliability | Substation Reliability | North Road Substation Reliability Project | 200 | 0 | 1,000 | 2,000 | | | | | | |
| Reliability | Substation Reliability | BES Battery Monitor Installation Program – Rimmon Substation Release | 100 | 0 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | BES Battery Monitor Installation Program – Weare Substation | 100 | 0 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | BES BMIP North Road Release | 0 | 100 | | | | | | | | |
| Reliability | Substation Reliability | Chester SS Replacement Battery Prg Release IFR | 0 | 100 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | BES BMIP Chestnut Hill Release | 75 | | | | | | | | | |
| Reliability | Substation Reliability | BES Battery Monitor Installation Program – Bedford Substation Release | 50 | 0 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | Replacement Battery Prgm – Great Bay | 50 | 0 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | BES BMIP Garvins Release | 50 | 50 | 0 | | | | | | | |
| Reliability | Substation Reliability | Foyes Corner 3202 Recloser Replacement | 35 | 1,185 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | Lancaster Oil Recloser Replacement | 30 | 1,285 | 0 | 0 | | | | | | |
| Reliability | Substation Reliability | Long Hill Transformer TR40 Replacement | 250 | 1,000 | 1,750 | | | | | | | |
| Reliability | Substation Reliability | Great Falls Upper Transformer TR122PH1 Replacement | 250 | 3,750 | 8,000 | | | | | | | |
| Reliability | Substation Reliability | Pittsfield 90H Replacement | 0 | 250 | 1,000 | 3,750 | | | | | | |
| Reliability | Substation Reliability | Opechee Transformer TB9 Replacement | 0 | 250 | 1,000 | 3,750 | | | | | | |
| Reliability | Substation Reliability | Tate Rd Transformer 42H1 Replacement | 0 | 0 | | 250 | 3,750 | | | | | |
| Reliability | Substation Reliability | Edgeville Transformer TR16 Replacement | 0 | 0 | | 250 | 1,000 | | | | | |
| Reliability | Substation Reliability | New Market TR13 Transformer Replacement | 0 | 0 | | 250 | 1,000 | | | | | |
| Reliability | Substation Reliability | BES Battery Monitor Installation Program - (NH - D) | 0 | 0 | 0 | 200 | | | | | | |
| Reliability | Substation Reliability | Garvins Reliability Project | 0 | 700 | 1,300 | 0 | | | | | | |
| Reliability | Substation Reliability | Forecast Proj for SS Switchgear | 0 | 1,000 | 6,000 | 3,000 | 3,000 | | | | | |
| Reliability | Substation Reliability | Substation Security | 0 | 500 | 1,000 | 1,000 | 1,000 | | | | | |
| Reliability | Distribution Line Reliability | Scope To be Determined after updates Annual Worst Performing circuits list (done annually) | | | | 9,400 | 18,400 | | | | | |
| Reliability | Distribution ROW Line Reliability | Scope To be Determined at later date | | | | 15,000 | 23,000 | | | | | |
| Reliability | Substation Reliability | Scope To be Determined at later date | | | 1,000 | | 23,000 | | | | | |
| | | **Totals** | **116,402** | **101,950** | **97,312** | **105,257** | **103,330** | | | | | |

| Budget Category | Budget Sub-Category | Project Title | 2025 ($1,000) | 2026 ($1,000) | 2027 ($1,000) | 2028 ($1,000) | 2029 ($1,000) | FERC Account | Company Accouting Account # | Financing Expectations |
|---|---|---|---|---|---|---|---|---|---|---|
| Peak Load | Distribution Line Capacity | Deerfield, Conversion 4.8kV to 34.5kV | 2,030 | | | | | | | |
| Peak Load | Distribution Line Capacity | Dover, Conversion of Long Hill Rd from 12.47kV to 34.5kV | 471 | | | | | | | |
| Peak Load | Distribution Line Capacity | 3548X2 Liberty Ave Conversion | 1,340 | | | | | | | |
| Peak Load | Distribution Line Capacity | 347 Route 16 Conversion | 634 | | | | | | | |
| Peak Load | Distribution Line Capacity | Derry, High range Road additional Phase | 1,288 | | | | | | | |
| Peak Load | Distribution Line Capacity | 28W1 Jaffery - Offload to 3120 - Load | 227 | | | | | | | |
| Peak Load | Distribution Line Capacity | 348X7 Bethlem - Rt 302 area conversion - Load | 1,099 | | | | | | | |
| Peak Load | Distribution Line Capacity | 3140X2 Washington - S. Main St area conversion - Load | 900 | | | | | | | |
| Peak Load | Distribution Line Capacity | 40W1 Nashua - Marmon Dr. area conversion - Load | 680 | | | | | | | |
| Peak Load | Distribution Line Capacity | 334X18 Pembroke - Relocate & Reconductor to Whittemore Rd - Load/Resiliency | 433 | | | | | | | |
| Peak Load | Distribution Line Capacity | 347X3 - Chocorua, Eaton Rd, Convert 7.2 to 19.9 to offload 500 KW steps | | 2,400 | | | | | | |
| Peak Load | Distribution Line Capacity | 362X1 - Convert to Offload Overloaded Step | | 1,300 | | | | | | |
| Peak Load | Distribution Line Capacity | 319X1 - Tilton, Brindle Pond Rd, 12.47 to 34.5kV conversion for overloaded steps | | 2,028 | | | | | | |
| Peak Load | Distribution Line Capacity | 3133X_23 - Windham, 12.47 to 34.5kV along Lowell Road south of Range Rd to the state Line, off load overloaded steps | | 875 | | | | | | |
| Peak Load | Distribution Line Capacity | 398X2 - Laconia, 12.47 to 34.5kV along Province Rd | | 5,040 | | | | | | |
| Peak Load | Distribution Line Capacity | 21W1/334X2 - Manchester, Dunbarton Rd Substation Replacement | | | 1,970 | | | | | |
| Peak Load | Distribution Line Capacity | 3615X1 - Candia, Main st 8.32 to 34.5kV | | | 551 | | | | | |
| Peak Load | Distribution Line Capacity | 3103X1/377X7 - Fremont, 8.32kV to 34.5kV along Middle rd, east of Route 125 | | | 4,625 | | | | | |
| Peak Load | Distribution Line Capacity | 392X7 - New Barrington, Hold after completion of area study | | | 5,000 | | | | | |
| Peak Load | Distribution Line Capacity | 3115X7 - Raymond, 8.32 to 34.5 along Old Manchester Rd | | | 1,280 | | | | | |
| Peak Load | Distribution Line Capacity | Load Projects (Scope to be determined at later planning cycle) | | | | | | | | |
| Peak Load | Distribution Line Capacity | Scope to be determined later | | 7,000 | 5,500 | 12,000 | 14,000 | | | |
| Peak Load | Substation Capacity | Monadnock SS - Replace Transformer TB40 | 17,000 | 0 | 0 | 0 | | | | |
| Peak Load | Substation Capacity | White Lake SS Rebuild | 8,582 | 11,324 | 3,320 | 0 | | | | |
| Peak Load | Substation Capacity | Portsmouth 12kV Capacity Project | | 3,500 | 2,500 | 0 | | | | |
| Peak Load | Substation Capacity | Jackman Station TB61 Transformer Replacement | | 2,000 | 2,500 | 500 | | | | |
| Peak Load | Substation Capacity | Eddy Transformer TB81 & TB26 Replacement | | 2,000 | 7,750 | 2,000 | | | | |
| Peak Load | Substation Capacity | Lochmere Transformer 2W2 Replace | | 1,000 | 3,750 | 0 | | | | |
| Peak Load | Substation Capacity | Ronald Street Transformer TR15 Replacement | | 250 | 1,000 | 3,750 | | | | |
| Peak Load | Substation Capacity | Tilton Transformer TB37 Replacement | | 250 | 1,000 | 3,750 | | | | |
| Peak Load | Substation Capacity | Madbury Reliability & Capacity Project | | 250 | 1,000 | 3,000 | | | | |
| Peak Load | Substation Capacity | Loudon Transformer 31W2 Replacement | 0 | 0 | 250 | 1,000 | | | | |
| Peak Load | Substation Capacity | Whitefield TB89 Transformer Replacement | 0 | 0 | 250 | 2,000 | | | | |
| Peak Load | Substation Capacity | Scope to be determined later | | 8,000 | 3,000 | 8,000 | 24,000 | | | |

| Budget Category | Budget Sub-Category | Project Title | 2025 ($1,000) | 2026 ($1,000) | 2027 ($1,000) | 2028 ($1,000) | 2029 ($1,000) | FERC Account | Company Accouting Account # | Financing Expectations |
|---|---|---|---|---|---|---|---|---|---|---|
| | | **Totals ==>** | **34,684** | **47,217** | **45,246** | **36,000** | **38,000** | | | |

***Public Service of NH***
***Grid Mod Costs 2021-2023***

| **Field Work** | **Project #** | **Description** | **2023** | **2022** | **2021** |
|---|---|---|---|---|---|
| Distribution Automation Projects | A23DA/A22DA/A21DA | 2023 Pole top DA | 5,630,151 | | |
| Distribution Automation Projects | A22DA/A21DA/A20DA/A18DA | 2022 Pole top DA | | 7,994,241 | |
| Distribution Automation Projects | A21DA/A20DA/A19DA/A18DA | 2021 Pole top DA | | | 6,413,424 |
| | | SubTotal Field | $ 5,630,151 | $ 7,994,241 | $ 6,413,424 |
| **IT Projects** | | | | | |
| Distribution Management System | A20X21 | DMS | | 7,106,869 | |
| Aclara | A21LS/A22LS/A23LS | Aclara | 152,502 | 597,732 | 283,543 |
| Outage Management System | KMOP61C1/DOPP61C1/DOUT61C1/NMSP61C2/OUAP61C2/DOAC61C2 | OMS | 5,520,757 | 12,960,042 | 936,319 |
| Synergi | IT20455 | Synergi | | 873,996 | |
| Power Clerk | IT22447 | Power Clerk | 3,343,362 | | |
| | | SubTotal IT | $ 9,016,621 | $ 21,538,639 | $ 1,219,862 |
| | | Grand Total | $ 14,646,772 | $ 29,532,880 | $ 7,633,286 |
| | | Total Capital Additions | $ 196,732,930 | $ 168,147,249 | $ 148,185,878 |
| | | Grid Mod Percent | 7% | 18% | 5% |

***Public Service of NH***
***Grid Mod Costs 2021-2023***

| **Field Work** | **Project #** | **Description** | **2023** | **2022** | **2021** |
|---|---|---|---|---|---|
| Distribution Automation Projects | A23DA/A22DA/A21DA | 2023 Pole top DA | 5,630,151 | | |
| Distribution Automation Projects | A22DA/A21DA/A20DA/A18DA | 2022 Pole top DA | | 7,994,241 | |
| Distribution Automation Projects | A21DA/A20DA/A19DA/A18DA | 2021 Pole top DA | | | 6,413,424 |
| | | SubTotal Field | $ 5,630,151 | $ 7,994,241 | $ 6,413,424 |
| | | | | | |
| **IT Projects** | | | | | |
| Distribution Management System | A20X21 | DMS | | 7,106,869 | |
| Aclara | A21LS/A22LS/A23LS | Aclara | 152,502 | 597,732 | 283,543 |
| Outage Management System | KMOP61C1/DOPP61C1/DOUT61C1/NMSP61C2/OUAP61C2/DOAC61C2 | OMS | 5,520,757 | 12,960,042 | 936,319 |
| Synergi | IT20455 | Synergi | | 873,996 | |
| Power Clerk | IT22447 | Power Clerk | 3,343,362 | | |
| | | SubTotal IT | $ 9,016,621 | $ 21,538,639 | $ 1,219,862 |
| | | Grand Total | $ 14,646,772 | $ 29,532,880 | $ 7,633,286 |
| | | Total Capital Additions | $ 196,732,930 | $ 168,147,249 | $ 148,185,878 |
| | | Grid Mod Percent | 7% | 18% | 5% |

**PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE**

**K-BAR ELIGIBLE CAPITAL**
**Attachment ES-DPH-2 including Grid Enhancement Programs**

**('000s)**

| Line | | Forecast | | | Total | |
|---|---|---|---|---|---|---|
| 10 | DISTRIBUTION CAPITAL EXPENDITURES | Year 2025 | Year 2026 | Year 2027 | 2025-2027 | Reference |
| 12 | Operations Distribution | | | | | |
| 13 | Peak Load Growth and New Business | $ 64,163 | $ 77,347 | $ 76,399 | $ 217,909 | |
| 14 | Basic Business Requirements | 73,358 | 77,441 | 77,587 | 228,386 | |
| 15 | Aging Infrastructure | 122,222 | 104,511 | 96,667 | 323,400 | |
| 17 | Total Operations - Distribution | $ 259,743 | $ 259,299 | $ 250,653 | $ 769,695 | Sum of Lines 13 through 15 |
| 19 | Other Distribution | | | | | |
| 20 | Operation Services | $ 15,133 | $ 15,429 | $ 15,291 | $ 45,853 | |
| 21 | Engineering | 6,518 | 6,920 | 14,620 | 28,058 | |
| 22 | Facilities | 14,500 | 21,000 | 7,800 | 43,300 | |
| 23 | Information Technology | 7,411 | 1,800 | 3,248 | 12,459 | |
| 24 | Customer and All Other Shared Services | 7,677 | 6,462 | 6,734 | 20,872 | |
| 26 | Total Other Distribution | $ 51,239 | $ 51,611 | $ 47,692 | $ 150,542 | Sum of Lines 21 through 25 |
| 28 | **TOTAL CORE DISTRIBUTION CAPITAL EXPENDITURES** | **$ 310,982** | **$ 310,910** | **$ 298,345** | **$ 920,237** | Line 17 + Line 26 |
| 30 | INCREMENTAL PROGRAMS - GRID ENHANCEMENTS | | | | | |
| 31 | Grid Modernization/VVO | $ 5,000 | $ 6,000 | $ 5,000 | $ 16,000 | |
| 32 | Resiliency | 10,000 | 15,000 | 15,000 | 40,000 | |
| 34 | **TOTAL INCREMENTAL PROGRAMS** | **$ 15,000** | **$ 21,000** | **$ 20,000** | **$ 56,000** | Line 31 + Line 32 |
| 36 | **TOTAL K-BAR ELIGIBLE CAPITAL** | **325,982** | **331,910** | **318,345** | **976,237** | Line 28 + Line 34 |
| 38 | **K-BAR ELIGIBLE CAPITAL CALCULATION:** | | | | | |
| 40 | Total K-Bar Eligible Distribution Capital Expenditures | $ 325,982 | $ 331,910 | $ 318,345 | $ 976,237 | Line 36 |
| 42 | Cumulative K-Bar Eligible Distibution Capital Expenditures | 325,982 | 657,893 | 976,237 | 976,237 | Sum of 2025 thru Current CY Line 40 |
| 44 | 10% Capital Constraint | 32,598 | 65,789 | 97,624 | 97,624 | Line 42 * 10% |
| 46 | Total Capital Allowed for K-Bar Adjustment | $ 358,581 | $ 723,682 | $ 1,073,861 | $ 1,073,861 | Line 42 + Line 44 |
| 48 | Actual K-Bar Capital Investment In-Service (incl. COR) | $ 284,952 | $ 310,184 | $ 317,000 | $ 912,136 | Exh. ES-DPH-1 at 4 and 5, Column (A) Lines 10-12; CY Additions + CY COR |
| 50 | Cumulative K-Bar Capital Investment (incl. COR) | $ 284,952 | $ 595,136 | $ 912,136 | $ 912,136 | Sum of 2025 thru CY Line 48 |
| 52 | Actuals Higher Than Spending Constraint | NO | NO | NO | NO | YES if Line 50 > Line 46 |
| 54 | Investment Above Cap | $ - | $ - | $ - | $ - | Line 48 - Line 46 if cap is reached |
| 56 | **TOTAL ALLOWABLE K-BAR CAPITAL (CAPPED)** | **$ 284,952** | **$ 310,184** | **$ 317,000** | **$ 912,136** | **Line 48 - Line 54** |
| 60 | NOTE: For Informational Purposes Only | | | | | |
| 61 | Total Actual K-Bar Eligible Distribution Capital Expenditures | $ - | $ - | $ - | $ - | To be updated in Annual PBRA Filings |
| 62 | Total Forecast K-Bar Eligible Distribution Capital Expenditures | $ 325,982 | $ 331,910 | $ 318,345 | $ 976,237 | Line 40 |
| 63 | Difference | $ (325,982) | $ (331,910) | $ (318,345) | $ (976,237) | Line 56 - Line 57 |

70 NOTE: Numbers may not add due to rounding.

**Comparative Analysis of PSNH's Proposal with PBR Plans in Massachusetts[1]**

| Company/Element | I Factor | X Factor | Consumer Dividend | Exogenous Z Factor | K Factor | ESM | Term/Stay Out |
|---|---|---|---|---|---|---|---|
| PSNH Proposed | GDP-PI | Zero | 0.15 % when inflation exceeds 2 % | Includes but not limited to positive or negative cost changes from (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. Threshold = $1.5M | K-Bar with rolling three year average base K-Bar amount adjusted to current dollars and capped at 10% above the company's capital forecast for that year. Major co-optimization projects recoverable when they exceed the 10% K-Factor cap | Asymmetrical ESM with 25 BP deadband above authorized ROE. Gains shared 75 % ratepayers / 25 % company. with no sharing of loses | 5 year stay out and 4 year PBR term with an option for an additional 5 year stay out |
| NSTAR PBR1[2] | GDP-PI | -1.56 % | 0.25 % when inflation exceeds 2 % | Includes but not limited to positive or negative cost changes from (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the | No K-Factor but mandated grid modernization program (GMP) investments recoverable outside the price cap. | Asymmetrical ESM with 200 BP deadband above authorized ROE. Gains shared 75 % ratepayers / 25 % company and no sharing of losse | 5 years |

[1] All of the sample PBR Plans set going in rates based on historical test years adjusted for known and measurable changes. None of the plans include a growth factor, a Y factor, or a re-opener provision.
[2] D.P.U. 17-05

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. Threshold = 0.001253 times total operating revenues = $5M adjusted by GDP-PI annually | | | |
| NSTAR GAS PBR1[3] | GDP-PI | -1.18 % | 0.15 % | Positive or negative cost changes from (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry.[4] Threshold = 0.001253 times total operating revenues = | No K Factor | Asymmetric deadband of 100 BP above & 150 BP below authorized ROE. Gains shared 75 % ratepayers / 25 % company. Losses up to 200 BP shared 50/50 Losses over 200 BP shared 75 % ratepayers / 25 % company. | 10 years |

[3] D.P.U. 19-120
[4] The Department accepted an additional exogenous event due to certain pipeline safety requirements

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | $700,000 adjusted by GDP-PI annually | | | |
| NSTAR PBR2[5] | GDP-PI | Zero | 0.25 % when inflation exceeds 2 % | Includes but not limited to positive or negative cost changes from (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. Threshold = 0.001253 times total operating revenues = $5M adjusted by GDP-PI annually | K-Bar with rolling five year average base K-Bar amount adjusted to current dollars and capped at 10% above the company's capital forecast for that year. | Asymmetrical ESM with 200 BP deadband above authorized ROE. Gains shared 75 % ratepayers / 25 % company and no sharing of losses | 5 years with an option for an additional 5 years |
| Unitil Electric PBR1[6] | GDP-PI | Zero | 0.25 % when inflation exceeds 2 % | Includes but not limited to positive or negative cost changes from (1) changes in tax laws that uniquely affect the relevant | K-Bar with rolling five year average base K-Bar amount adjusted to current dollars and capped at 10% above the | Asymmetrical ESM with 100 BP deadband above authorized ROE. Gains shared 75 % ratepayers / 25 % company and | 5 years |

[5] D.P.U. 22-22
[6] D.P.U. 23-80

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. Threshold = 0.001253 times total operating revenues = $110,000 adjusted by GDP-PI annually | company's capital forecast for that year. | no sharing of losses | |

# Eversource New Hampshire Distribution System Assessment

5/28/2021

**Prepared For:**

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**Prepared By:**

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# 1. Executive Summary

Over the last eight years, The Public Service Company of New Hampshire d/b/a Eversource Energy ("Eversource" or the "Company") has updated planning processes, enhanced standards, and increased investments aimed at improving system reliability for customers and hardening its distribution system for greater resiliency in light of increasingly recurring major weather events observed since at least 2008. These activities were highlighted in the Company's 2019 Request for Permanent Rates, through which parties requested that Eversource better justify increased expenditures associated with these system resiliency investments.

TRC has conducted this distribution system assessment to satisfy the requirements of Section 11 of the Settlement Agreement filed between Eversource and parties in that rate filing, Docket DE 19-057. As part of this assessment, TRC has reviewed the use of the following materials and activities for reliability and resiliency improvements:

- Use of distribution-class steel poles as a standard in off-road right-of-way
- Use of Class 2 wood poles as a standard in road-side primary distribution lines
- Use of spacer cable as a standard for overhead conductor
- Use of fiberglass crossarms
- Planning methods for line relocation and reconductoring activities
- Vegetation management activities, including Enhanced Tree Trimming, Enhanced Tree Removal, and Right-Of-Way Clearing, in addition to Scheduled Maintenance Trimming
- Substation transformer and circuit breaker replacement processes

To assess these standards and practices, TRC reviewed Eversource's current practices for each of the above topic areas and identified typical usage and installation procedures for equipment and materials. TRC surveyed industry research to identify common practices across peer utilities and develop a business case of the benefits for each engineering decision or activity. Finally, TRC conducted a cost analysis, where applicable, to identify lifecycle costs of proposed or alternative equipment or materials, factoring in upfront costs and ongoing maintenance and replacement costs, in addition to escalation over assets' expected life. Based on these research activities, TRC proposed recommendations for future standards or activities within each topic area.

Additionally, TRC reviewed more broadly the current state of utility planning for resiliency and grid hardening measures around the country to identify trends or best practices for how peer utilities approach resiliency investments. This industry research, which included a literature review and expert interviews, found that utilities and regulators across multiple regions of the U.S. are renewing their interest and planning processes for resiliency both in reaction to recent severe weather events that cause widespread outages and in recognition of future risks anticipated due to climate change. Utilities in New York and Florida provide two templates for how to plan for and prioritize enhanced distribution system resiliency. In both cases, utilities have identified and prioritized the risks inherent to their distribution system architecture, developed tailored solutions to address those risks, estimated the costs, and implemented resiliency measures to address those risks. Despite the increased planning and investment across the country, research and experts point to a lack of any accepted approach for determining cost effectiveness of resiliency investments. The severe events that grid hardening aims to guard against, low-frequency yet high-impact, make it difficult to measure how hardening mitigations may or may not perform.

TRC's findings and recommendations relevant to each of the study topic areas are listed below:

*Figure ES-1-1. Summary of Key Findings and Recommendations by Study Topic Area*

| Topic Area | Key Findings | Recommendations |
|---|---|---|
| **System Condition** | • The distribution system has many components that are beyond their expected life and require replacement to maintain system reliability and resiliency.<br>• Substantial numbers of wood poles, circuits of primary conductor, substation breakers and substation transformers are at the end of life.<br>• Wood poles are structurally overloaded due to their age and number of attachments.<br>• Many circuit lines in the ROW are inaccessible due to location and difficult to maintain.<br>• Trees and canopy are in close proximity to distribution system making the lines vulnerable to outages. | • Accelerate replacement of aged equipment (poles, conductor, substation breakers & transformers), with a systematic plan (defined in sections 3 & 4) for each equipment type, based on system criticality and age.<br>• Replace wood poles that are structurally overloaded 90% or more, with the properly sized poles in the next 10 years.<br>• Identify candidate lines for relocation to roadside and develop 5-year plan to rebuild.<br>• Increase vegetation management and spacer cable installation for vulnerable lines.<br>• Consolidate current resiliency/hardening efforts into an overarching program following the decision framework outlined by the Department of Energy. |
| **Steel Poles** | • Benefits of steel poles include improved strength, reduced likelihood of catastrophic failure, and lower maintenance costs.<br>• Steel poles have twice the expected useful life of an equivalent wood pole. | • Given lower lifecycle costs and difficulty in patrolling and replacing remote right-of-way assets in the event of a failure, continue to use steel poles as the standard in these environments. |

| Topic Area | Key Findings | Recommendations |
|---|---|---|
| | • While upfront costs are higher, the improved longevity of steel yields a lower total lifecycle cost compared to wood poles. | • Establish a proactive program to identify and replace five circuit miles/year of wood poles in the ROW with steel, in areas susceptible to damage or failure. |
| **Class 2 Wood Poles** | • Class 2 wood poles can withstand 60% greater force than smaller-diameter class 4 poles, improving outcomes during tree strikes or high winds.<br>• Class 2 wood poles have marginally (2-4%) higher costs than equivalent Class 3 poles.<br>• At current failure rates, if 8-9 poles (~5%) did not fail due to use of stronger Class 2 poles, incremental costs would be negated. | • Continue use of Class 2 wood poles due to low additional costs and strength improvements in severe weather scenarios. |
| **Spacer Cable** | • Spacer cable is the Eversource standard for new and rebuilt three phase distribution lines.<br>• Spacer cable is designed to reduce faults from tree and animal contacts and can survive larger tree strikes, compared to open-wire designs.<br>• Spacer cable is more compact, requiring less ROW clearance.<br>• Spacer cable is approximately double the cost of open wire. | • Follow the Eversource 2016 Resiliency Guidelines for spacer cable.<br>• Develop 5-year plan to replace open-wire circuits with spacer cable in vulnerable areas. Work in conjunction with the inaccessible line relocations to the roadside and steel pole installation projects. |
| **Fiberglass Crossarms** | • Fiberglass crossarms are the Eversource standard for new and replacement crossarm construction.<br>• Fiberglass crossarms yield improved longevity, strength, material predictability, and installation compared to wood.<br>• Fiberglass crossarms pass the heaviest ice loading, heavy-tree contact, and high-wind simulations where wood crossarms failed. | • Continue to use fiberglass crossarms as specified. Lower lifecycle costs and improved strength in severe weather are main advantages. |

TRC

| Topic Area | Key Findings | Recommendations |
|---|---|---|
| | • Fiberglass crossarms pair well with steel poles due to the extended lifecycle of both.<br>• Total lifecycle costs of fiberglass crossarms are 38-44% of the total for wood crossarms. | |
| **Vegetation Management** | • A portfolio approach to vegetation management (SMT, ETT, ETR, and ROW clearing) has led to reductions in tree related SAIFI and SAIDI scores, improving customer reliability.<br>• Inside-zone tree reliability metrics have improved dramatically over the last decade, while outside-zone metrics show a slight downward trend.<br>• Deferring scheduled maintenance cycles or reducing annual investments in vegetation management can lead to disproportionately negative impacts, as additional vegetation growth during those periods increases per-mile costs for management in the future and reduces the Company's ability to maintain regular cycles. | • For SMT, address an average 2,440 miles annually to follow the 60-month clearing cycle.<br>• Accelerate ETT to 80 miles per year to address the remaining 500 miles of the backbone circuits within the next seven years.<br>• Continue ROW clearing at the current pace to allow for the restoration of the full original easement where vegetation has encroached.<br>• For ETR, target approximately 19,000 hazard tree removals annually following the current identification and prioritization practice. |
| **Substation Transformers** | • Standardizing substation transformer sizes can provide benefits for streamlining inventory and reducing event response time. | • Standardize substation transformer sizes wherever possible based on voltage class to allow for greater efficiency in maintaining stock of fewer transformer sizes and flexibility in responding to contingency events and coordination with neighboring state service areas.<br>• Continue to assess to determine when circuit breakers should be used in place of circuit switchers for operational and reliability benefits. |

| Topic Area | Key Findings | Recommendations |
|---|---|---|
| **Distribution Planning** | • Eversource conducts distribution planning to maintain system operations within established operating criteria.<br>• Engineers develop solutions to address capacity, power quality, and reliability concerns based on historical performance data and forward-looking forecasts.<br>• Line relocation and reconductoring are two options to address reliability issues. | • Establish a tracking program to compare historical outage data for line segments for 3-5 years (as data is available) and then report annually on that segment post-improvement. Such a system will document the improved reliability and resiliency delivered by relocation and reconductoring projects.<br>• Reduce the number of feeders without tie capability to allow for circuit reconfiguration and load pickup throughout the system.<br>• Maintain awareness for distribution project cost increases that may arise as projects are delayed. |

## 2. Introduction

This section provides a summary of the project's background and TRC's methodology for undertaking the study and associated engineering analysis.

### 2.1 Project Background

TRC conducted this distribution infrastructure condition assessment study to satisfy the requirements of Section 11 of the Settlement Agreement filed between Eversource and parties in Docket DE 19-057. Below is a summary of the regulatory history preceding the settlement agreement.

In Eversource's 2019 Request for Permanent Rates,[1] the Company identified a set of initiatives intended to improve the performance and resiliency of the distribution system. Like many electric utilities around the country[2], Eversource is increasing its capital spending for distribution system investments to add automation and replace aging or "substandard" equipment to maintain and improve reliability and to develop better system resiliency. At the time of the rate filing, most of Eversource's capital budget was directed toward investments in reliability improvements – nearly two-thirds of the $137 million planned for 2019. As part of this capital plan, Eversource intended to address relocations of lines in rights-of-way, line reconstruction and equipment replacement, and asset condition replacements. The Company uses these replacement opportunities to increase the strength, intelligence, and resiliency capabilities of plant and assets, where an incremental benefit may be gained for the benefit of the system and does not simply replacing assets "like for like."

Although the Company has recorded improvements in the duration and number of customers experiencing outages as a result of its increased investments, Eversource has also experienced an increase in the number of outages at the same time. This trend is driven by both improved granularity of data, and an increase in significant weather events that cause widespread outages. Over the past 12 years, the Company has experienced five storm events with an impact to more than 40% of customers, including the 2008 ice storm, or an extreme event nearly every two years, on average. The recurrence of these weather events has prompted Eversource to revisit the materials composition, size, construction, and accessibility of overhead distribution poles, crossarms, circuits, and substation equipment. These strategies include:

- Use of Class 2 wooden poles in place of 40-foot class 4 poles for standard construction
- Use of light-duty steel poles in off-road rights-of-way

[1] Public Service Company of New Hampshire (Eversource), Testimony of Joseph A. Purington and Lee G. Lajoie - Docket No. DE 19-057, May 2019. https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-057/INITIAL%20FILING%20-%20PETITION/19-057_2019-05-28_EVERSOURCE_DTESTIMONY_PURINGTON_LAJOIE.PDF

[2] See Chapter 3 of this report for a detailed look at industry trends relating to distribution system planning and investments for reliability and resiliency.

- Use of fiberglass cross-arms
- Reconstruction or relocation of older, 34.5-kV distribution lines in off-road rights-of-way
- Upgrades of undersized wire in off-road rights-of-way and use of covered conductor or spacer cable for off-road lines
- Upgrades of roadside three-phase lines by reconductoring, including use of spacer cable, stronger poles, and shorter spans
- Use of vacuum circuit breakers in place of oil circuit breakers in substations

Additionally, outside of the Company's capital distribution planning, Eversource conducts a range of vegetation management activities to maintain reliability of its system. Tree-related incidents are by far the leading cause of outages, 3 to 4 times greater than the next closest categories, as shown in Figure 5-22. These vegetation management activities include Scheduled Maintenance Trimming, Enhanced Tree Trimming, Full-width Right-of-Way Clearing, and Enhanced Hazard Tree Removal.

On top of these base activities, Eversource sought to obtain authorization for investments in resiliency and projects needed to prepare the grid for integration of future advanced energy solutions. Eversource referred to this incremental investment plan as the "Grid Transformation and Enablement Program" (GTEP), which was designed to enable accelerated asset replacements above the pace of the traditional, base capital plans described above. Following discussion with parties throughout the proceeding, Eversource withdrew the GTEP proposal for resubmission in a separate docket, outside of DE 19-057.

In response to Eversource's proposal, Commission staff raised concerns with several of the asset replacement and upgrade activities described in the base capital plan. Specifically, Staff indicated that Eversource had not properly demonstrated the need for these higher standards of investments or replacements of infrastructure.[3]

For both the pole and crossarm standards and right-of-way/reconductoring initiatives, Staff's view was that there was insufficient analysis or understanding of the value provided to customers through the proposed investments. To support the additional cost, a "cost-benefit analysis" or business case would be needed to quantify the benefits of such investments. For the substation oil circuit breaker replacement initiative, Staff's view was that the existing breakers have not reached the end of expected useful life or caused issues related to outages, environmental damage, or maintenance costs.

Staff also viewed metrics in relation to current and proposed vegetation management practices. Eversource requested $15M for base O&M vegetation management activities in 2019, with annual escalation of 2-3% through 2023. Eversource also requested $5M for Enhanced Tree

[3] For example, Staff Testimony stated that the "Company has the burden of justifying the increased expenditure that provides little to no measurable benefits, even if the Company cites a standardization requirement." See Direct Testimony of Kurt Demmer, Docket DE 19-057, December 20, 2019. https://www.puc.nh.gov/regulatory/Docketbk/2019/19-057/TESTIMONY/19-057_2019-12-23_STAFF_TESTIMONY_DEMMER.PDF

Trimming (ETT), $10M for Enhanced Hazard Tree Removal (ETR), and $2M for Right-of-Way (ROW) clearing. Staff concluded there was "little to no evidence of overall SAIFI or SAIDI performance as the ETT activity progressed," noting high costs of ETT compared to scheduled maintenance trimming. Staff recommended no funding for ETT, limited ($2.5M) funding for ETR, and the full $2M for ROW clearing.

As part of the settlement of the proceeding, Eversource agreed to engage an expert distribution engineering firm to conduct an assessment of Eversource distribution system infrastructure "to provide recommendations related to the Company's short and long-term system needs consistent with the requirements of least-cost integrated resource planning." The assessment was stipulated to include a review of the cost effectiveness of using or conducting:

- Steel poles in right-of-way
- Class 2 poles as a standard pole
- Fiberglass cross arms
- Relocated ROW facilities
- Spacer cable and tree wire
- Reconductoring of under-sized wire
- Enhanced Tree Trimming and Hazard Tree Removal activities

Eversource engaged TRC to conduct the distribution system assessment and related scope as outlined in Section 2.1 herein.

### *2.1.1 Prior Reliability-Focused Investments and Historical Performance*

Eversource established a Reliability Enhancement Plan (REP) in in its 2006 rate case, funding capital and O&M spending to improve system reliability. The plan has been extended numerous times since its launch in 2007, including a bridge to the most recent rate case described in the above section, DE 19-057.[4] In its latest Report to the New Hampshire Public Utilities Commission on the REP program, the Company noted that:

*"Since the REP was implemented, the trend from 2006 onward has been improved reliability on a weather normalized basis. Eversource's customers continue to see benefits from the REP activities. REP programs are preventing problems from occurring (improving SAIFI) and reducing outage times (improving SAIDI) and reducing the number of customers impacted by outages which do occur. The REP activities have proven to be a critical component to improving reliability and have been important in concert with Eversource's continued efforts to maintain and improve the system in the normal course of business."*

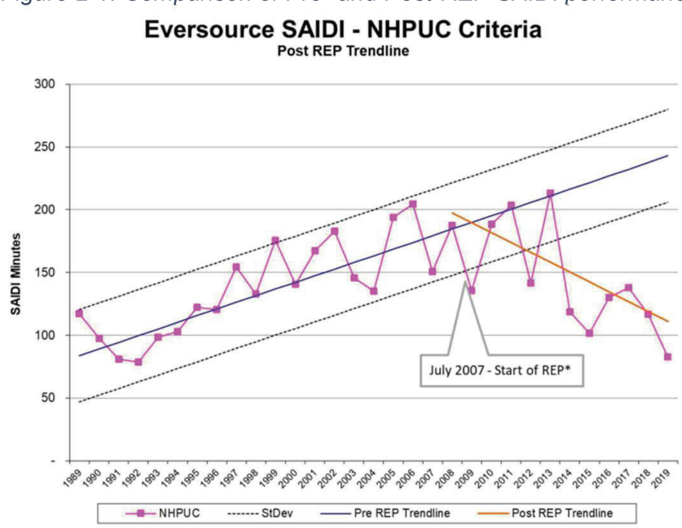
[4] Eversource, Proposal to Extend Reliability Enhancement Program, De 17-196, November 2018. https://www.puc.nh.gov/Regulatory/Docketbk/2018/18-177/INITIAL%20FILING%20-%20PETITION/18-177_2018-11-16_EVERSOURCE_PETITION_CONTINUATION_REP.PDF

For 2018, the REP program expenditures totaled $10.4M for O&M activities and $5.2M for capital expenditures.[5] In 2019, O&M increased to $25.3M, and capital expenditures decreased to $3.5M,[6] and included the following activities:

- Reject pole replacement
- Direct buried cable replacement
- Regular and enhanced vegetation management
- National Electrical Safety Code inspections
- Switch and recloser maintenance
- Partial funding of the troubleshooter organization.

As of the 2019 REP report, Eversource reported a decrease in SAIDI – the number of average minutes customers were without power – due to the investments made through the REP program. Over the period of 1989 to 2005, annual SAIDI exhibited a consistent increase in SAIDI minutes, or reduced reliability. Since REP began in 2007, Eversource's SAIDI performance shows a multi-year trend of improved reliability performance or declining SAIDI minutes.

*Figure 2-1. Comparison of Pre- and Post-REP SAIDI performance*



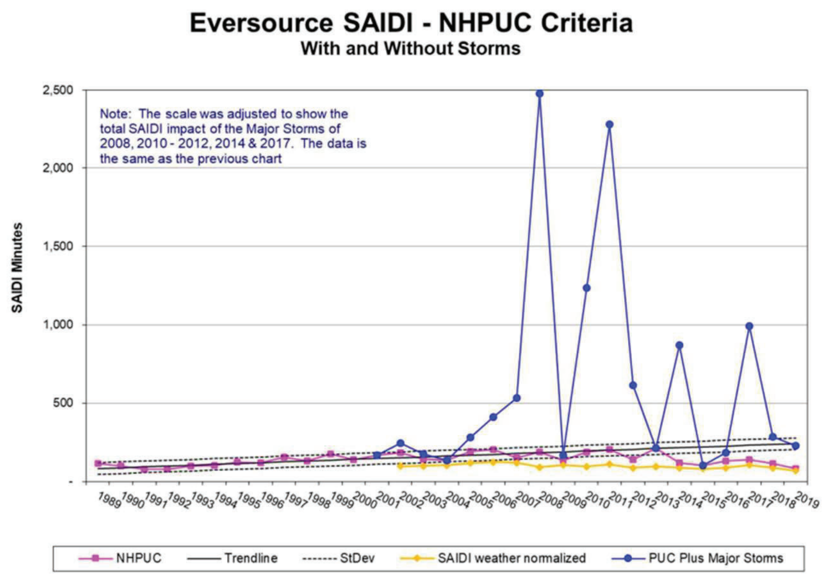

*Source: Eversource Reliability Enhancement Program 2019 Report to the NHPUC*

[5] Eversource. Reliability Enhancement Program 2018 Report to the New Hampshire Public Utilities Commission. April 2019. https://www.puc.nh.gov/Regulatory/Docketbk/2018/18-177/LETTERS-MEMOS-TARIFFS/18-177_2019-05-28_EVERSOURCE_REV_2018_REP_RPT.PDF

[6] Eversource. Reliability Enhancement Program 2019 Report to the New Hampshire Public Utilities Commission. May 2020. https://www.puc.nh.gov/Regulatory/Docketbk/2018/18-177/LETTERS-MEMOS-TARIFFS/18-177_2020-05-01_EVERSOURCE_2019_REP_RPT.PDF

Notably, Eversource also tracks SAIDI performance including Major Storms,[7] which are removed from the weather-normalized NHPUC Criteria SAIDI results. The comparison of performance with and without Major Storms reveals the impact of these storms since data began in 2000. While some years had few or no Major Storm-related increases in SAIDI minutes, Major Storms in 2008, 2010, 2011, 2012, 2014, and 2017 significantly impacted customer outage durations.

*Figure 2-2. Eversource SAIDI Performance Including Major Storms*




*Source: Eversource Reliability Enhancement Program 2019 Report to the NHPUC*

The REP focused on asset replacement and vegetation management to improve reliability (i.e., SAIDI, SAIFI metrics). By comparison, the GTEP investments were targeted to refurbish infrastructure to create a more durable and resilient distribution system for major weather events[8]. As shown in *Figure 2-2*, the major weather events have contributed to several spikes in customer outage duration in numerous years since 2000. Five significant weather events since 2008 caused outages impacting over 200,000 customers, or more than 40 percent of the customer base.

The analysis in TRC's System Assessment accordingly encompasses material, equipment and activities that were included within the REP and (proposed) GTEP programs.

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[7] A Major Storm is defined as an event that results in either: a) 10% or more of Eversource's retail customers being without power in conjunction with more than 200 reported troubles; or b) more than 300 reported troubles during the event

[8] Public Service Company of New Hampshire, Direct Testimony of Joseph A. Purington and Lee G. Lajoie - Grid Transformation and Enablement Program: Acceleration of Targeted Infrastructure Upgrades, Docket DE 19-057, 5/28/2019. https://www.puc.nh.gov/regulatory/Docketbk/2019/19-057/INITIAL%20FILING%20-%20PETITION/19-057_2019-05-28_EVERSOURCE_DTESTIMONY_PURINGTON_LAJOIE.PDF

## 2.2 Objectives of the Distribution System Assessment

TRC's scope of work for this assessment of the Eversource distribution system and plans included the following requirements:

1) Assess and evaluate the performance of the existing system at the five and ten-year planning levels, including assessment of the electric system's ability to serve projected load requirements.
2) Review industry best practices and challenges experience by peer utilities and stakeholders in developing and evaluating distribution system investment plans for reliability and resiliency.
3) Recommend improvements to focus on a broad view of the distribution system to achieve the objective of reliable, resilient, and cost-effective electric service over the ten-year planning horizon, and beyond, with a focus on:
   a) Asset age and health
   b) Reliability and resiliency
   c) Ability to meet future load growth needs through the use of non-wires alternatives, including targeted energy efficiency, electric vehicles, etc.
4) Perform a cost-effectiveness analysis of the Company's use of certain materials for distribution line construction, substation, and vegetation management activities, including:
   a) The use of steel poles for construction in distribution rights-of-way
   b) The use of Class 2 poles as a standard pole
   c) The use of fiberglass cross arms
   d) The potential relocation right-of-way facilities to roadside
   e) The use of spacer cable versus open wire
   f) The proactive reconductoring of under-sized
   g) Enhanced Tree Trimming and Hazard Tree Removal activities.
   h) Substation transformers and breakers

## 2.3 System Assessment Methodology

This section details the methodology TRC employed for the Distribution System Assessment.

**Introduction**

TRC conducted its assessment of Eversource's distribution system in accordance with the Settlement Agreement filed in DE 19-057, dated October 9, 2020. This study provides a condition assessment of the Company's distribution infrastructure, including substations and overhead infrastructure, along with recommendations related to Eversource 's short and long-term system needs consistent with the requirements of least-cost integrated resource planning. As part of the condition assessment, TRC reviewed the cost-effectiveness and benefits of utilizing the materials listed below for construction and specific vegetation management activities:

- The use of steel poles for construction in off-road distribution rights-of-way
- The use of Class 2 poles as a standard pole for roadside construction
- The use of fiberglass cross arms
- Distribution planning and potential relocation right-of-way facilities to roadside
- The use of spacer cable versus open wire
- The proactive reconductoring of under-sized wire
- Enhanced Tree Trimming and Hazard Tree Removal activities.

**Planning System Assessment**

TRC assessed and evaluated the performance of the existing system at the five and ten-year planning levels. The existing system analysis included an assessment of the electric system's ability to serve projected load requirements. Assessing system capacity was area based and looked at the system needs for impacted substations at a time where there is a projected capacity concern. TRC reviewed individual capital projects to evaluate their effectiveness in providing for future growth and making the system more resilient based on cost effectiveness and good engineering practices. In addition, TRC focused on a broad view of the distribution system to achieve the objective of more reliable, resilient, and cost-effective electric service over the ten-year planning horizon, and beyond. This included the following:

- Asset age, health, and condition
- Ability to meet future load growth needs using traditional wires and non-wires alternatives, including targeted energy efficiency
- Reliability and resiliency
- Overall capability of distribution circuits for carrying the load, physical integrity, and ability to recover from outages to minimize the impact on service reliability

**Eversource Current Practices**

TRC performed a preliminary review of the data and guidelines set forth by Eversource as described in the Direct Testimony of Joseph A. Purington and Lee G Lajoie on May 28, 2019 (current/proposed maintenance programs), and discussions held with subject matter experts to gather contextual information regarding current engineering practices. These discussions included:

- Specific operating problem areas
- Engineering and operating challenges and/or concerns
- Capital project execution including planned or ongoing construction
- Areas of focus for the field assessments per interviews with Eversource's staff

**Physical/Visual Inspection of Assets**

TRC performed visual inspection of representative portions of the Company's distribution system, both roadside and Right of Way (ROW). Representative portions were determined from the review of circuit performance data, mapping information, and local utility knowledge. ROW inspections were conducted by helicopter patrol and roadside inspections by motor vehicle to document data and incorporate the results into a formal report.

- **Vegetation:** TRC created a map that shows all line and pole data with aerial imagery superimposed. TRC flagged areas that are suspect to trees that are approximately 13ft from center of the pole.
- **Roadside:** TRC selected and visually inspected several worst performing feeders to view vegetation and condition of the lines. This was done via vehicle and walking in select areas.
- **ROW:** TRC selected and visually inspected a sampling of circuits to see vegetation around the lines, condition, and access issues.
- **Substation:** TRC selected and visually inspected several recently completed improvement projects and planned projects for substation improvement.

**Review of Industry and Other Utility Practices**

TRC researched regarding best practices and the challenges utilities face evaluating distribution system investments for reliability, resiliency, and hardening. The research assessed varying perspectives, including other utilities, regulators, and industry experts. The data collection activities included:

- Literature review of industry documentation and research regarding best practices for resiliency and system hardening.
- In-depth interviews with three experts from industry organizations and peer utilities, conducted via virtual meetings.

The literature review and interviews collected around several key themes:

- Planning strategies around equipment standards and practices identified
- Utilities demonstration of capital expenditures for distribution system investments
    - Use of benefit-cost analysis and calculation methods
- Future issues impacting distribution system investments: resilience, electrification, and smart distribution systems
    - Concerns around overbuilding systems
    - Deferral and non-wires alternatives
- Regulatory processes and stakeholder views
    - Venues under which utilities propose resiliency investments
    - Coordination with broader distribution system planning activities

TRC analyzed findings from these data collection activities and summarized trends and findings.

**Cost-Effectiveness Analysis**

TRC performed an analysis relating to the cost-effective use of materials for distribution line construction, substation, and vegetation management. These analyses include:

- Total lifecycle costs of the current or proposed standards or practices compared to an alternative or previous practice.
- Present worth analysis of the practices, where applicable.
- Avoided cost savings by using the new materials.

Methods applied are dependent on the applicability for each new standard or practice. The total lifecycle analysis compared the current or proposed standards or practices total ownership cost, to an alternative or previous practice for the anticipated in-service life for each of the components or practices. Equipment in-service useful life was acquired from industry data or Eversource historical information. Built into the lifecycle cost model were the following assumptions:

- Labor, material, and overhead costs to install the equipment
- Escalation rates of labor and materials provided by Eversource
- Maintenance costs (escalated) over the life of the equipment. Specific rates are included in each cost analysis assumptions.
- Other assumptions applicable to the equipment or practice.

The present worth analysis includes the assumptions listed above for the lifecycle analyses with carrying charge and discount rate provided by the Company. Present worth analysis is not applicable to all scenarios.

Avoided cost analysis calculates the incremental cost not incurred by using a current or proposed standard. This method is used in the larger class wood poles scenario.

## 2.4 Organization of the Distribution System Assessment

The remaining sections detail the results of TRC's research and analysis. They are organized as follows:

- Chapter 3 reviews the industry findings from the literature review and expert interviews.
- Chapter 4 provides an assessment of the age and condition of various distribution system elements, with focus on the impact of each equipment type and work practice used to support the system. Also included is an overall assessment of the system, to provide a broader picture of areas where additional investment may be needed.
- Chapter 4.0 details the assessment results for distribution line, substation, and vegetation management materials and practices. In each section TRC reviews current practices, typical usage and installation parameters, industry findings, details of the business case and cost analysis, and recommendations.
- Chapter 6 provides a summary of findings and recommendations.

# 3. Review of Industry Practices for Reliability and Resiliency Investment Planning

Utility activities for resiliency planning and investment have accelerated across the country over the last two decades, spurred by several factors, including 1) increases in extreme weather events, 2) customer desire for shorter and less frequent power interruptions, and 3) new or improved technologies. Responding to these factors, utilities are upgrading and updating their systems to enable harder, smarter grids that can better withstand, react to, and recover from outages.

While many resiliency investments are similar or even identical to distribution system and reliability-related investments utilities have made for decades, they are designed to prevent a different category of risk than historical distribution system investments. As a result, utility and regulatory methods for valuing and evaluating these types of investments are less well developed than those made for traditional reliability outcomes.

This chapter reviews practices among utilities and regulators around the country to plan for and assess investments to improve resiliency through system hardening efforts. As part of this research, TRC conducted a literature review of published studies and utility documentation related to resiliency planning and interviewed experts on current trends and best practices. The sections below detail findings related to:

- Growing interest and activity around resiliency and grid hardening
- Frameworks for utility resiliency planning
- Evaluating cost-effectiveness for resiliency and hardening investments
- Regulatory and stakeholder input
- Implications for Eversource

Key findings from the literature review and expert interviews include:

1) Increased resiliency and hardening investment and planning activity across the majority of states is driven by an increase in severe weather events that can significantly impact outage durations.
2) Resiliency planning frameworks stress assessment of local climate risks to identify tailored solutions for each utility.
3) Evaluating cost-effectiveness of resiliency investments remains a critical challenge for utilities and regulators, as the benefits are difficult to monetize.
4) Shifts in the traditional utility business model are impacting investment decisions. The move away from a cost-plus ratemaking approach and moving to a performance-based structure (e.g., New York and Massachusetts) has allowed regulators to incorporate metrics around grid hardening and provides greater flexibility to utilities in their system investment.

5) Cost recovery remains central to the ongoing industry debate. This research identifies various approaches currently being advanced, presented later in this chapter. These approaches demonstrate the range in considerations and fragmented nature of the responses across the country.

## 3.1 Resiliency, Grid Hardening, and State interest in Integrated Distribution and Resilience Planning Initiatives

Over the last two decades, investor-owned utility spending on distribution system investments has grown over 2.5 times, from $14 billion in 1999 to nearly $40 billion in 2019. An estimated two-thirds of that capital spend in 2019 is driven by emergency repairs, aging infrastructure replacement, reliability improvements, or resiliency. The 2019 spend on aging infrastructure replacement, reliability and resiliency alone is greater than the total distribution system investment from the 20 years prior. As the scale of these investments has grown, states are increasingly looking to integrated planning initiatives for distribution and resiliency. The Department of Energy counted 29 states and territories where regulatory commissions have begun such an effort as of 2019.[9]

Resiliency includes the ability to harden the power system against, and quickly recover from, high-impact, low-frequency events.[10] Such events can threaten lives, disable communities, and devastate generation, transmission, and distribution systems. Included are severe weather or natural events such as:

- Hurricanes and consequent flooding,
- Severe wind events
- Earthquakes and consequent tsunamis
- Wildfires
- Ice storms

Reliability is the adequacy of the system to provide customers a continuous supply of electricity at the proper voltage and frequency, virtually all of the time. The system needs to withstand sudden, unexpected disturbances such as short circuits and unexpected loss of system elements due to natural or man-made causes. There are three commonly used standard industry performance measures for reliability:

- System Average Interruption Frequency Index (SAIFI)
- Customer Average Interruption Duration Index (CAIDI)
- System Average Interruption Duration Index (SAIDI)

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[9] U.S. Department of Energy, Resiliency Decision Framework – Presentation to NARUC 2019 Annual Meeting, November 20, 2019. https://pubs.naruc.org/pub/6A146D0E-B6A2-89F8-1469-484C2B6E8FFE
[10] ELECTRIC POWER SYSTEM RESILIENCY: CHALLENGES AND OPPORTUNITIES, February 2016

Both resiliency and reliability are affected by various factors such as the age and condition of assets, vegetation, and severe events.

In many cases it is difficult to delineate investments for reliability, aging infrastructure replacement, emergency repairs, and resiliency. However, the literature makes clear that, unlike general reliability, resiliency is specifically targeted at major events, typically those causing outages of 24 hours or longer. These events are unexpected, infrequent, and their impacts are widespread.[11] Typical measures of reliability—system average interruption frequency and duration indexes (SAIFI and SAIDI)—are designed to factor out these major events given their unpredictability. As shown in Figure 3-1 below, when major events are included, the frequency index only increases by 17%, but the duration index with major events factored in is 74% longer than without major events.

*Figure 3-1. EIA-reported SAIDI and SAIFI performance for 137 Investor-Owned Utilities in 2015*

| IEEES Standard 1366 | Investor-Owned Utility 2015 Reliability Reporting | % Difference with Major Events |
|---|---|---|
| **SAIFI** without major events | 1.2 | |
| **SAIFI** with major events | 1.4 | +17% |
| **SAIDI** without major events | 136 | |
| **SAIDI** with major events | 237 | +74% |

SOURCE: LAWRENCE BERKELEY NATIONAL LABORATORY

Discussions with industry experts suggest that the increased interest in resiliency in many states is most often prompted after a widespread or extended outage, such as a major weather event. However, after such an external event, "there's a lot of activity, a lot of grandstanding," but only in some cases, do states and energy providers follow through with investments in system hardening. An expert noted that Texas faced a significant winter storm in 2011 that pointed to the need to winterize assets, but a similar significant winter storm in 2021 revealed little had been done to address system deficiencies that were identified 10 years earlier.

Florida and New York, by contrast, made significant investments in hardening their systems after weather events caused major interruptions. Following hurricanes in 2004-2005, Florida regulators in 2006 instituted requirements for storm-hardening plans on a three-year cycle, along with a set of 10 initiatives for inspection, hardening and local collaboration to reduce impacts of future storms. Similarly, following the 2012 impacts of Superstorm Sandy in New York, regulators created a resiliency collaborative, and Con Edison developed a resilience enhancement plan with estimated incremental costs. Once approved, this began a multi-year system-hardening initiative that included asset relocation, strengthening, and improved flexibility

[11] Lawrence Berkeley National Laboratory, Reliability Metrics and Reliability Value-Based Planning, March 2019. https://eta-publications.lbl.gov/sites/default/files/6._eto_-_reliability_metrics_and_rvbp.pdf

using advanced controls to reduce the impacts of potential flooding or high winds.[12] While the outcomes are similar, some states, such as Florida, have not specifically described these investments under a "resiliency" frame, while other states are more explicit about outlining planning and investments as "resiliency."

The Electric Power Research Institute (EPRI) characterizes resiliency within three categories:[13]

- **Damage Prevention**: the application of engineering designs and advanced technologies that harden the power system to limit damage.
- **System Recovery**: the use of tools and techniques to restore service as soon as practicable.
- **Survivability**: the use of innovative technologies to aid consumers, communities, and institutions in continuing some level of normal function without complete access to their normal power sources.

Damage prevention, often referred to as hardening, helps reduce the frequency of these events; system recovery aims to address the duration; survivability acknowledges that, as one expert interview noted, there is no perfect level of system reliability in practice. Given the focus of this assessment, this chapter primarily focuses on findings related to distribution grid hardening activities. These types of activities include vegetation management and enhancing or reinforcing the physical strength and security of distribution facilities against storms or attacks. Though not a focus of this assessment, one area of significant recent research, due to increasing severity of storms and wildfires, is the undergrounding of distribution and transmission circuits.[14]

## 3.2 Resiliency and Hardening Planning Frameworks

The Department of Energy notes that, despite the increased interest across much of the country, resiliency "planning methods and tools are largely immature or non-existent" today.[15] Several of the studies reviewed pointed to the significant uncertainty of climate and resiliency needs leading to difficulty determining the appropriate timing and level of investment. Lawrence Berkeley National Lab (LBNL) points out there is "no actuarial basis to establish a likelihood of occurrence" of significant weather or outage events.[16] A white paper from consultancy ICF, which works with utilities on integrated grid planning and climate analysis, notes that "lack of insight into the degree of infrastructure exposure" and "the complexity around how to measure

[12] Lawrence Berkeley National Lab, Case Studies of the Economic Impacts of Power Interruptions and Damage to Electricity System Infrastructure from Extreme Events, November 2020. https://eta-publications.lbl.gov/sites/default/files/impacts_case_studies_final_30nov2020.pdf
[13] EPRI, Electric Power System Resiliency: Challenges and Opportunities, February 2016. https://www.epri.com/research/products/000000003002007376
[14] Larsen, Severe Weather, Power Outages, and A Decision to Improve Electric Utility Reliability, March 2016. http://purl.stanford.edu/sc466vy9575
[15] U.S. Department of Energy.
[16] LBNL (Reliability Metrics and Reliability Value-Based Planning)

vulnerabilities, hazards, and stressors" make planning for resiliency investments challenging.[17] This uncertainty also makes it difficult to value those investments' costs and benefits. This topic is further addressed in Section 3.4.

Industry experts noted utilities' current reliance on the Interruption Cost Estimate (ICE) Calculator developed by LBNL and Nexant.[18] Funded by the Department of Energy, this tool can be used to help estimate direct societal costs of power interruptions to assess investments in reliability by understanding the avoided costs for customers from outages. However, the tool's accuracy and usefulness degrade for outage events longer than 24 hours, as the inputs used for modeling were not designed around these types of major events. For example, the costs of a shorter, typical outage are generally contained within a utilities' service area. But a longer, multi-day outage has the potential to have national impacts as supply chains and other interstate systems are halted until power is restored. Because the costs of long-duration outages are less well understood at present, they are often not factored into utility planning decisions as completely as short-duration outages.[19]

Nonetheless, several utilities have taken more structured approaches to resiliency planning. Examples from Con Edison and Florida Power and Light are detailed below. In many cases these planning exercises are compelled by state regulators or legislatures, prompted by one or multiple significant outage events. The Department of Energy proposes that utilities need to begin transitioning from reactive resiliency investments to those that are proactive, anticipating future impacts as new hazards emerge.[20]

**Industry Example: Con Edison**

Con Edison recently published a Climate Change Vulnerability Study[21] that addresses resiliency planning through better understanding of the risks to operations and assets from climate change. First, the utility characterizes each of the major threats to the utility's energy system, including heat and temperature, precipitation, flooding and sea-level rise, and extreme and multi-hazard events. Next, based on a better understanding of climate science and projections for extreme weather, Con Edison can assess and prioritize the risks these threats pose to operations, planning and assets, evaluate costs and benefits of mitigations, and then prioritize paths to improve resiliency. Stemming from the Vulnerability Study, Con Edison will complete a

[17] ICF, Resilient Power: How Utilities Can Identify and Effectively Prepare for Increasing Climate Risks, March 2021. https://www.icf.com/insights/energy/resilient-power-utilities-prepare-climate-risks#

[18] See: https://www.icecalculator.com/home

[19] Lawrence Berkeley National Laboratory, A Hybrid Approach to Estimating the Economic Value of Enhanced Power Resilience, February 2021. https://eta-publications.lbl.gov/sites/default/files/hybrid_paper_final_22feb2021.pdf

[20] U.S. Department of Energy – Office of Electricity, North American Energy Resilience Model, July 2019. https://www.energy.gov/sites/default/files/2019/07/f65/NAERM_Report_public_version_072219_508.pdf

[21] ConEdison, Climate Change Vulnerability Study, December 2019. https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/climate-change-resiliency-plan/climate-change-vulnerability-study.pdf?la=en

Climate Change Implementation Plan with a timeline for risk mitigation measures, scope, and costs for 5-, 10-, and 20-year plans.

Regarding proactivity, Con Edison notes that, “the key to designing resilient infrastructure is to update design standards, specifications, and ratings to account for likely changes in climate over the life cycle of the infrastructure.” Standards should not be based solely on historical impacts, but on expected needs over the asset’s expected useful life. In other words, while historical asset performance may be one indicator of investment needs, it should not be the only factor considered. Con Edison also highlights the need to remain flexible as future conditions change. In a review of studies on grid hardening, the Edison Electric Institute further noted that while storm response creates a natural opportunity for replacing assets with harder equipment, hardening activities or replacements should also be included with regular maintenance.[22]

**Industry Example: Florida Power and Light**

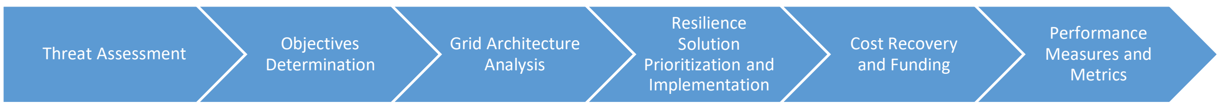
Florida Power and Light (FPL) has 15 years of planning for storm hardening, a requirement that began in 2006 following significant hurricanes in previous years. The state legislature in 2019 extended requirements for utilities to file Storm Protection Plans every three years, with a 10-year planning horizon. The 2020-2029 plan[23] includes elements divided among distribution, transmission, and substation, with a focus on pole/structure inspection, circuit hardening and undergrounding, and vegetation management.

For the distribution feeder hardening initiative, FPL upgrades existing feeders and certain critical distribution poles—and designs new lines—to meet “extreme wind loading” criteria established by the National Electric Safety Code. The utility is targeting this hardening or undergrounding of all distribution feeders by 2024. FPL conducted forensic analyses of prior storm events to find that wind was the primary cause of pole breakage, and that performance of assets built to the extreme wind loading standard was sufficient. Before conducting work on a specific circuit, FPL conducts a field survey of the facilities in place to determine what is needed to meet the required wind ratings for that region. The utility also relies on a toolkit of designs to harden circuits, including storm guying, equipment relocation, adding intermediate poles, upgrading pole classes, and undergrounding facilities. FPL also prioritizes these activities based on spreading projects throughout the service territory, historical performance, areas with restoration difficulties, and coordination with ongoing or municipal projects. While FPL estimates the cost of the program (roughly $500-650 million/year between 2017 and 2025), its estimation of benefits is mostly qualitative, primarily citing the improved reliability of feeders that have been hardened to meet new standards (benefits to customers), in comparison to feeders that have not yet been hardened. FPL also notes the reduction in additional restoration costs. FPL conducted analyses to estimate these restoration cost savings based on the magnitude of damage from previous observed hurricanes.

[22] Edison Electric Institute, Before and After the Storm, March 2014. https://www.energy.gov/sites/prod/files/2015/03/f20/Edison%20Electric%20Institue%20Comments%20and%20Resources-%20QER%20-%20Enhancing%20Infrastructure%20Resiliency%20FINAL.pdf
[23] Florida Power and Light’s 2020-2029 Storm Protection Plan, Exhibit MJ-1.

The above examples demonstrate an important point from the literature: utilities must develop and tailor plans that are specific to the unique risks to their region and the sensitivities of their own assets.[24] Mitigation strategies designed for areas prone to wildfires in the West may not be appropriate to address hurricanes in the Southeast, ice storms in the Northeast, or wind in the Midwest. The utilities above also generally follow the Resilience Decision Framework proposed by the Department of Energy, which is shown Figure 3-2 below.

*Figure 3-2. Resilience Decision Framework Development Process*




*Source: U.S. Department of Energy, Office of Electricity*

One expert noted in an interview that ideally, hardening initiatives are not just planned around climatic threats, but future distribution system planning as well. For example, severe weather risk may point to a potential need for stronger distribution poles in the near term. But stronger poles may be needed in the medium-to-long term due to expected load growth necessitating reconductoring, or anticipated increases in attachments to the pole as more smart equipment is added. The Department of Energy's Decision Framework also advocates for this "whole grid view"[25] to enable greater understanding of implications and coordination. This more holistic view can also help improve analysis of cost-benefit, as resiliency measures are aligned with greater overall system needs and future trends for beneficial electrification and growth in electric vehicles.

## 3.3 Estimating Cost Effectiveness of Resilience

Perhaps the greatest barrier to making needed improvements for resiliency is the difficulty in valuing the benefits of these plans and investments. Without accurate ways to account for these benefits, utilities, regulators, and their stakeholders have difficulty determining which activities to pursue, how much of a given activity is the right amount, or how resilient a new asset should be. These types of investments are not able to be valued as easily as reliability improvements that lead to reductions in SAIFI and SAIDI—or demand response, energy efficiency, or generation investments. While the industry does not have a standard protocol for valuing the benefits and costs of resiliency investment, research is ongoing in this area with a recognition that there is a risk to simply wait until there is a proven process before making investment decisions.

Expert interviews indicate there are three primary ways utilities have described the value proposition of investments in resiliency, each problematic in its own way: First, some utilities simply state that they can't quantify dollar values and point to qualitative benefits instead. Second, utilities may use the ICE calculator (described above) and extrapolate values out

[24] ICF.
[25] U.S. Department of Energy.

beyond 24 hours, though the tool is not designed for this use. Third, utilities may attempt to quantify cost-benefit, instead of cost-effectiveness, leaving the monetary value of those benefits undetermined.

Further complicating the cost-effectiveness picture is the infrequent but extreme nature of resiliency events that make their impacts highly uncertain. In turn, it is difficult to accurately assign costs to these low-probability, variable events.[26] Despite these challenges, regulators still want to know "what works best and how to direct ratepayer money to the most effective solutions."[27]

From the examples in Florida and New York noted above, FPL has been able to justify its investments and quantify avoided costs due to years of similar storms and over a decade pursuing resiliency investments and activities.[28]

## 3.4 Regulatory Review of Hardening Initiatives

Increased spending on distribution system investments for asset replacement, hardening, and resiliency has prompted increased interest and review by regulators and stakeholders working to ensure utility investments are made in customers' best interests. Whether reacting to previous extreme events or reviewing proactive proposals, regulators face competing priorities in evaluating such investments. Discussions with experts (including former state regulators) point to the need to balance affordable rates for customers while also ensuring high levels of reliability amidst increasingly severe weather events.

Further confounding regulatory processes is the challenge of understanding the cost-effectiveness of resiliency investments. This makes it difficult for utilities to prove their proposals are prudent, despite a perceived need prompted by increasing large-scale outage events. LBNL found in interviews with regulatory staff that generally there was little distinction between reliability and resilience among economic regulators in how they evaluate proposed investments. However, as noted in the previous sections, while related, these two concepts have differences in the types of events they seek to address, and the metrics to measure their performance are increasingly different (in fact, research into determining appropriate resiliency metrics is still ongoing).[29]

Research indicates that hardening activities are often proposed and considered within general rate cases, as these types of investments align with the proceedings where "classic asset

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[26] EPRI.

[27] National Association of Regulatory Utility Commissioners, State Commission Staff "Surge" call: Evaluating Reliability Investments. https://www.naruc.org/default/assets/File/Surge%20grid%20hardening%20summary%20051418-final.pdf

[28] ICF.

[29] Lawrence Berkeley National Laboratory, Evaluating Proposed Investments in Power System Reliability and Resilience: Preliminary Results from Interviews with Public Utility Commission Staff, January 2017. https://eta-publications.lbl.gov/sites/default/files/lbnl-_1006971.pdf

management" activities are typically reviewed. A 2018 discussion among state regulatory staff pointed out that including these investments in general rate cases can make it difficult for staff to separate those investments and weigh them against the benefits of reduced interruptions.[30] Increasingly, resiliency activities are proposed and coordinated in separate proceedings, where they can be reviewed in conjunction with other grid modernization activities and long-term planning.

Utilities and regulators are also beginning to look toward new methods for cost-recovery of resiliency and hardening investments. The Edison Electric Institute points to examples in eight states and territories[31], including:

- Financial penalties in Connecticut, Massachusetts, and Illinois for non-compliance with increased performance standards and metrics from grid modernization plans, tree trimming and hardening measures.
- Financing via public bonds to support undergrounding in Washington, D.C.
- Performance-based formula rates for investments in transmission and distribution systems in Illinois.
- Performance and outcome-based incentives in New York to achieve objectives of reliability and resiliency.
- New rate adjustment mechanisms in Indiana, Pennsylvania, and Texas to allow for cost-recovery of distribution investments between rate cases.

The example of undergrounding funded via public-private partnership in Washington, D.C., highlights another issue raised by experts. As previously noted, resiliency investments provide benefits that may be regional or national, as long-duration outage events can indirectly impact customers outside of a given utility's service area. As a result, non-utility funding, either from local, state, or federal sources, can be appropriate, given the wider scope of these indirect impacts and benefits.

Finally, research indicates that equity can be an increasing issue of importance in planning and review of resiliency investments. This can come into consideration for prioritization of projects, where utilities may overlay historical outage performance with areas of disadvantaged or low-income communities to identify if that performance disproportionately impacted "socially vulnerable" customers. The utility can then prioritize projects in those areas to ensure benefits of resiliency and hardening accrue to those most impacted. Existing tools for estimating outage impacts and costs (i.e., the ICE calculator) may not sufficiently factor these equity-focused issues into their inputs and analyses.

[30] NARUC.
[31] Edison Electric Institute.

## 3.5 Implications for Eversource Hardening Activities

The Company's practices and plans to increase standards and activities for system hardening align with trends observed in utilities across the country responding to increases in severe weather and long-duration outage events, improvements in technologies, and higher customer reliability standards. Typically, these changes are prompted by one or repeated widespread, long-duration outage events, and often utility and regulatory activity is spurred by legislative action after these events.

The Company is taking a more proactive, rather than reactive, approach updating standards and practices for distribution system resiliency without significant prompting. TRC recommends that the utility consolidate its current resiliency/hardening efforts into an overarching program following the decision framework outlined by the Department of Energy in Figure 3-2 in assessing threats posed by climate or other external factors, identifying resiliency objectives, and then tailoring and prioritizing solutions based on the data and goals defined. Con Edison's Climate Change Vulnerability Study provides a template for this future-looking threat assessment. Florida Power and Light's Storm Protection Plan also exemplifies targeted solutions tailored to individual project conditions but built to meet a specific and defined standard against wind hazards.

As detailed in Section 3.3, identifying the values of avoided costs resulting from resiliency investments is particularly difficult given the rare nature of severe events, and indirect, widespread impacts that these events have. As a result, traditional measures of cost-effectiveness are likely insufficient at truly capturing the value of the increased standards or enhanced hardening practices that Eversource has proposed. To the extent the Company can quantify or qualify the benefits from increased hardening activities and investments, it may provide regulators and stakeholders more context around these investments, in lieu of difficulties calculating traditional cost-effectiveness.

Further, identifying areas of crossover or co-benefits between distribution hardening activities and other grid modernization initiatives and investments may help ensure that choices being made today for reliability or resiliency also support future plans or customer needs. For example, decisions to strengthen pole standards today for storm hardening may also align with anticipated growth in needs to support additional utility or non-utility attachments over the life of that pole. Updates to substations might consider if significant new or critical loads may be expected to be served by that asset, and the implications of its failure with more customers served in the future.

Finally, it is standard practice to consider the grid hardening investments evaluated within this assessment as part of a general rate case. Eversource should continue to track the performance of these assets and circuits in comparison to those that have not been hardened so that the utility, regulators, and stakeholders can understand the reliability and resiliency benefits that these activities support.

# 4. Distribution System Age and Condition Assessment

This section provides an assessment of the age and condition of various distribution system elements, with focus on the impact of each equipment type and work practice used to support the system. Also included is an overall assessment of the system, to provide a broader picture of areas where additional investment may be needed.

The Company's electric distribution system in New Hampshire consists of approximately 12,200 miles of overhead distribution circuits, including approximately 3,000 miles of roadside, three-phase distribution circuits and 600 miles of distribution lines within off-road rights-of-way. Approximately 17% of the distribution system is considered backbone and the remaining 83% consists of overhead laterals stemming off backbone circuits.

The distribution system is dynamic and constantly changing with upgrades, new line extensions, relocations, removals, and maintenance activities. The distribution facilities reviewed ranged in age from equipment that was installed in the early 1900's to equipment that will be installed in 2021. Information pertaining to the age, condition and in-service dates are not always available to assess the remaining servicing capabilities and make specific recommendations for each individual piece of equipment. However, the data available shows that there are significant numbers of distribution equipment still in service, that are beyond their expected life expectancy.

The equipment attributes evaluated were provided from the Company's GIS and other data sources to the extent possible. The in-service records for distribution poles and substation transformers were readily available and the data is analyzed in this report to draw conclusions and provide recommendations as to the funding levels, maintenance intervals and equipment replacement strategy to build and maintain a resilient distribution system. Other equipment, such as primary conductors, do not have specific aging information and are generally addressed as part of the overall Distribution Poles and Equipment Assessment. TRC's experience has been the primary conductor typically stays with the original pole line installation and is replaced when the line is reconductored and the older facilities retired. There is still a strong possibility that older primary conductor remains in service when poles are replaced due to damage or failing the pole inspection program and these older primary lines are to be considered for reconductoring as part of the aged facility assessment.

Transformers, reclosers and other distribution equipment attached to the poles are independent of the pole installation and their in-service dates vary greatly depending on the customer requirements and operational needs. The impact of this equipment age and condition on the overall system should be addressed separately to assess the service capabilities. The exception is the third-party attachments as they affect the pole structural load carrying ability that cause premature pole failure due to overloading. The impact of the third-party attachments is addressed in the Pole Loading Assessment of Existing Eversource Poles.

New Hampshire is ranked second in the United States for forest cover, with an estimated 84% covered in timberland.[32] Most of the overhead distribution lines are in forested areas and subject to vegetation management. Tree canopy has matured over the years and in many cases, towers over the existing distribution system. Mature trees, commonly reaching 100 ft. in height, are outside of the rights of way, making power lines vulnerable to trees well outside of the maintained rights of way. Information on the Vegetation Management program is also readily available and a detailed evaluation, impact of changing the existing practices and recommendations, are provided and present a clear direction to the program. The data and evaluations tools available for this specific program offer a defined link between the expenditures and impact to the customers and reliability of the system.

The substation transformer and breaker assessment focus on those specific pieces of equipment. The remainder of the substation equipment (buss work, structures, and protective equipment) are not part of the evaluation. These elements should be evaluated separately as their serving capabilities are independent of the substation transformers and breakers.

The Company develops a 5-year plan for capital expenditures to provide adequate capacity for serving customer load and providing reliable service. Similar to other utilities that TRC has worked with, aging assets, higher customer expectations and resilience of the system have become emerging considerations.  The capital budget plan addresses these issues in a timely manner, incorporating financial prudence and sound engineering judgement. There are multiple factors considered by distribution planners that affect different stakeholders, each with varying priorities. These include:

- Public and employee safety
- Circuit reliability data
- Age of assets
- Operations experience
- System hardening needs
- Capital funding availability
- System planning criteria and capacity requirements
- Customer impact
- Regulatory requirements

Selecting the projects for the budget plans takes into account many of these factors in conjunction with discussions between the various disciplines within the Company leadership. Capital plans contain line items for individual projects and programs for annual funding to address ongoing work related to maintenance, replacement of assets and reliability

[32] USDA - Forest Inventory and Analysis Fiscal Year 2016 Business Report. Page 71-72. Table B-11. Land and forest area and FIA annualized implementation status by State and region, FY 2016. (Percentages for states derived by dividing third column by second column.) Data for territories: Page 70: Table B-10. Status of FIA special project areas excluded from annualized inventory. Retrieved January 8, 2019

improvements. Examples include pole inspection and replacements, reliability projects under $100,000 and distribution automation. These programs address both known and emerging issues that engineering, operations, and other stake holders identify.

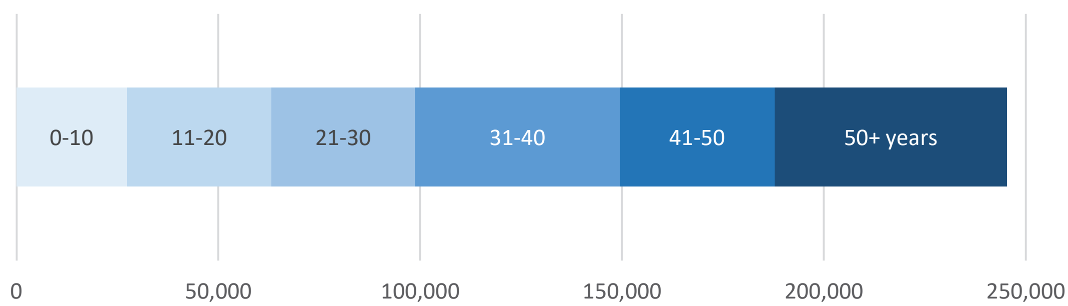
**Distribution Poles and Equipment Assessment**

The Company has maintenance responsibility for 276,000 distribution poles and has distribution facilities attached to approximately 455,000 poles that are either jointly or solely owned by the Company.[33] Upon reviewing the pole data provided from the GIS database, two concerns are emergent: the age of the poles and the structural load placed on the poles with attached equipment.

## 4.1 Pole and Equipment Age Analysis

The overhead distribution system is currently comprised of a large proportion of older, outmoded utility poles originally built to serve smaller electrical loads. Currently, 39% of the distribution poles owned and maintained by PSNH are over 40 years old, with more than 57,500, or nearly one-quarter of poles, exceeding 50 years. This is beyond the estimated useful life of 45 years for a wood distribution pole. Figure 4-1, below, shows the age groupings of the Company's distribution pole inventory taken from the GIS data.

*Figure 4-1. Age of Distribution Poles by Year Grouping*




*Source: Eversource GIS, 2019*

Wood poles can remain in service for longer than 50 years when regularly inspected and treated as necessary. However, as wood poles age beyond their expected useful life, they experience a loss of strength from the natural degradation of the wood due to structural wear and decay from fungus, insects, and animals. One analysis of wood pole decay rates indicates strong evidence that the probability of pole degradation accelerates rapidly in poles over 50 years old.[34] Typically, the Eversource equipment (framing, conductors, down guys, etc.) attached to the older poles are of the same vintage as the poles and will also need to be replaced along with the pole. In TRC's experience, it is a common and good utility practice, to inspect/maintain poles, and replace them prior to failure. The Company conducts a wood pole inspection

[33] Eversource system data

[34] Timing of Wood Pole Replacement Based on Lifetime Estimation, Steiner Refsnaes, Lars Rollfseng, Eivind Solvang and Jorn Heggset, July 2006

program to identify and replace failing wood poles, but the pace of replacement of the older poles is not adequate to address all aged wood poles in a timely manner.

Aging poles may also be structurally overloaded and not be able to carry the load of conductors, transformers, reclosers, third-party attachments, etc. in an NESC Heavy Loading Zone. The NESC initially added wind and ice loading criteria in 1940, and the most recent specifications were published in 2017. An analysis of the structural strength of the poles, compared to existing poles that have been analyzed is addressed in the Pole Loading Assessment below. Pole aging and the loss of pole strength are closely linked and need to be addressed together when pole assessments are performed.

### *4.1.1 Pole Loading Assessment of Existing Poles*

TRC conducted an analysis on the ability of the existing poles to withstand the structural wind and ice loads that are experienced in the New Hampshire NESC Heavy Loading Zone[35]. Specifically, the 2017 NESC requires that all distribution facilities be designed to withstand a 40 MPH wind with ½" of ice on the line at 15º F. Requirements are also in place for the facilities to withstand a 95 MPH wind at 60º F. This analysis focuses on the first design criteria of the Heavy Loading wind and ice requirement.

TRC did not have individual pole loading information for the Company's NH service territory; instead, this analysis relied on a proxy dataset of loading for 41,000 poles from a representative utility that uses similar construction. TRC then applied the results of that analysis to the Company's pole population as an aggregated group, to identify the average pole loading and number of poles that may be overloaded.

The analysis of the representative utility data calculated the strength of poles installed in the field and in the same NESC Heavy Loading Zone. Actual pole loading data was not extensively available for the Company's poles. Poles were analyzed by pole class, with all primary conductor types and a varied number of third-party attachments. TRC used the SPIDAcalc analysis tool to determine the average pole loading and the percentage of poles that are structurally overloaded. The assumptions for the representative utility pole calculations are listed below. Poles in this data set are in the field with known class, attachments, and span lengths.

- Pole loading is the average of all poles with those attributes (primary conductors and third-party attachments).
- % Overload is the percentage of locations where the poles are overloaded.
- Only situations with 6 primary wires (each primary line on a tangent pole is modeled as two wires for calculation purposes) or three phase lines.
- Includes all primary conductor sizes.

[35] 2017 National Electric Safety Code

- Heavy–Grade B Loading
- All representative utility field data was collected with a Hastings Hotstick and TruPulse laser.
- Structural analysis was performed using SPIDA Software's SPIDAcalc application.
- The data used for this analysis spans from 2009 to 2021 and includes a total of 41,314 locations.

For purposes of this report, the poles analyzed were the most common three phase poles in service today utilized by Eversource. These are the 40 and 45-foot poles in classes 1, 2, 3, 4 and 5. The data are presented below in Figure 4-2 as the Percentage of Poles Overloaded by Class and Attachments of the representative utility.

*Figure 4-2. Percentage of 40 and 45-foot Poles Overloaded by Class and Attachments (Representative Utility Data)*

| | **Number of attachments** | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Pole Size (ft) & Class** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** |
| **40-1** | 0.00% | 12.00% | 0.00% | 60.00% | | | | |
| **40-2** | 3.13% | 7.57% | 11.76% | 26.67% | 25.32% | 26.09% | | |
| **40-3** | 7.14% | 8.79% | 19.40% | 32.14% | 12.50% | 100.00% | | |
| **40-4** | 14.45% | 25.55% | 30.96% | 37.56% | 46.15% | 66.67% | 75.00% | |
| **40-5** | 33.33% | 45.77% | 48.15% | 40.00% | 80.00% | 50.00% | 100.00% | |
| **45-1** | 0.00% | 7.02% | 7.50% | 25.00% | 17.86% | 16.00% | | |
| **45-2** | 5.34% | 8.59% | 15.59% | 20.87% | 18.85% | 29.12% | 28.89% | 25.00% |
| **45-3** | 13.33% | 25.23% | 22.61% | 35.38% | 52.17% | 37.50% | 100.00% | |
| **45-4** | 21.10% | 27.25% | 38.62% | 37.50% | 48.42% | 33.33% | 66.67% | 60.00% |
| **45-5** | 40.00% | 56.41% | 58.33% | 0.00% | | | | |

*Source: TRC analysis of Representative Utility data*

Pole data provided from Eversource are shown in Figure 4-3 below. There are 148,988 40-foot and 30,500 45-foot poles which were recorded in the GIS system without the class designation. Based on TRC's discussions with Eversource SME's, these are likely older poles that were installed and not recorded with the same attributes as the GIS captures today. Eversource indicated that prior to the 1980's, Class 4 was the standard for 40 and 45 ft. poles. It is likely the majority of the 40 and 45 ft poles are Class 4. For analysis purposes, TRC conservatively assumed that these unclassified poles are Class 3. As of 2016, Class 2 poles are the standard and are shown in the chart below. It is noted that the pole data includes all poles that Eversource has facilities attached, not just the poles the Company owns and maintains. The 40-foot and 45-foot poles were chosen because they will typically be used for construction of the three phase facilities.

*Figure 4-3. Eversource 40 and 45-foot Poles by Length and Class*

| Pole Length | Pole Class | # Poles |
|---|---|---|
| **40 Foot** | Unknown | 148,988 |
| | 1 | 113 |
| | 2 | 19,847 |
| | 3 | 20,545 |
| | 4 | 459 |
| **45 Foot** | Unknown | 30,533 |
| | 1 | 647 |
| | 2 | 15,317 |
| | 3 | 3,137 |
| | 4 | 9 |

Source: Eversource GIS

The Company's SMEs estimated that there is an average of two attachments by third- party companies on each pole with many poles having more. Looking at the number of 45-foot Class 3 poles, as an example, and using the 23% of poles overloaded from the Representative Utility data analysis in Figure 4-2, we can conclude that there are potentially 7,700 (15% of 45-foot poles) overloaded and could fail during a heavy loading event. The number of poles subject to failure is shown in Figure 4-4, below. Availability of specific pole size, class, conductor, and third-party attachments data would be needed to provide information to assess each individual pole.

*Figure 4-4. Estimated Percent of Eversource Poles Overloaded by Class*

| Pole Length and Class | # Poles | Avg Pole Loading w/2 Attachments | # Poles Overloaded |
|---|---|---|---|
| **40 (Assume Class 3)** | 148,988 | 19% | 28,904 |
| **40, 1** | 113 | 0% | 0 |
| **40, 2** | 19,847 | 12% | 2,332 |
| **40, 3** | 20,545 | 19% | 3,986 |
| **40, 4** | 459 | 31% | 142 |
| **45 (Assume Class 3)** | 30,533 | 23% | 7,023 |
| **45, 1** | 647 | 8% | 52 |
| **45, 2** | 15,317 | 16% | 2,388 |
| **45, 3** | 3,137 | 23% | 709 |
| **45, 4** | 9 | 39% | 3 |

The data shows that there are over 45,000 40-foot and 45-foot wood poles in the distribution system that are potentially structurally overloaded due to the pole attachments. The pole failures will be more common with the older poles in the system.

Figure 4-5 is a 40-foot, Class 4 pole set in 1979. Based on the pole size and number of attachments, TRC believes this pole is structurally overloaded and should be replaced with a standard wood pole.

*Figure 4-5. Structurally Overloaded Eversource Class 4 Wood Distribution Pole*

*Source: Eversource*

Figure 4-6 is a 30-foot pole set in 1938. The pole brand could not be found, so the class is unknown and likely to be Class 4 or smaller. Based on pole age and number of attachments, TRC believes this pole is structurally overloaded and should be replaced with a standard wood pole.

*Figure 4-6. Structurally Overloaded 80+ year-old Eversource Wood Distribution Pole*

*Source: Eversource*

### *4.1.2 Pole Maintenance and Capital Programs*

The Eversource Maintenance Program – 5.61 Wood Poles, provides the procedure for the inspection, treatment (further explained in the Section 5.1.2), restoration and replacement of wood distribution poles that are owned and maintained by Eversource. It defines the schedule, inspection method, and reporting requirements for these poles. All Eversource NH poles are to be inspected at least every 10 years while they are in service. The procedure uses a pole type and age method to determine the inspection type performed, as shown in Figure 4-7 below.

*Figure 4-7. Eversource Wood Distribution Pole Inspection Types*

| 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 |

*Source: Eversource Maintenance Program*

Results of the distribution pole inspection program over the last 11 years are shown below in Figure 4-8 and indicate that the reject rate averages 2% per year. Reject poles are placed in either a normal or priority reject designation based on the criteria in the Eversource Maintenance Program –6.61 Wood Pole Inspection document. Priority reject poles are to be made safe within 10 days. The rate is in line with industry averages, but it includes all poles in the fleet that are at least 15 years old; the poles that are younger are less prone to inspection failure since they have not been in service as long. Data on the reject rate by age of pole is not available.

*Figure 4-8. Eversource Wood Distribution Pole Inspection Results*

| Year | Poles Inspected | Reject Count | Reject Rate |
|---|---|---|---|
| 2011 | 24,209 | 203 | 0.80% |
| 2012 | 24,008 | 247 | 1.00% |
| 2013 | 27,145 | 570 | 2.10% |
| 2014 | 25,666 | 440 | 1.70% |
| 2015 | 15,681 | 327 | 2.10% |
| 2016 | 51,758 | 1,487 | 2.90% |
| 2017 | 32,916 | 549 | 1.70% |
| 2018 | 21,964 | 558 | 2.50% |
| 2019 | 16,857 | 403 | 2.40% |
| 2020 | 16,668 | 380 | 2.30% |
| **Totals** | **256,872** | **5,164** | **2.01%** |

*Source: Eversource*

Based on the United States Department of Agriculture Rural Utility Services (RUS) Bulletin 1730B-121, Wood Pole Inspection and Maintenance[36] and other common utility practices in the same decay zone, the inspection interval should be between 10-12 years for each pole for Decay Zone 2. Figure 4-9 below shows the recommended intervals by the RUS bulletin and although Eversource meets the industry accepted wood inspection cycle, the Company does not address the issue of the aging poles.

[36] United States Department of Agriculture Rural Utility Services, RUS Bulletin 1730B-121, Wood Pole Inspection and Maintenance, 2013

*Figure 4-9. RUS Wood Pole Inspection Program*

| Decay Zone | Initial Inspection | Subsequent Re-Inspection | Percent of Total Poles Inspected Each Year |
|---|---|---|---|
| **1** | 12-15 Years | 12 Years | 8.3 |
| **2 and 3** | 10-12 Years | 10 Years | 10 |
| **4 and 5** | 8-10 Years | 8 Years | 12.5 |

*Source: U.S. Department of Agriculture.*

With over one-third of Eversource's poles aged at 40 years, the inspection program should focus on older poles and include a more aggressive sound and bore or groundline excavation inspection cycle for those poles.

### *4.1.3 Pole Assessment Summary and Recommendations*

The data above indicates two related issues regarding their wood pole plant and the equipment attached to the poles. Many of the poles (over one-third) are reaching the end of expected useful life or already beyond it and there is a greater potential for pole failure as they continue to age. While the company has experienced roughly 200 pole failures per year in recent years, this number could accelerate as the wood pole population continues to age without replacement at the same rate. While the Company has experienced roughly 200 pole failures per year in recent years, this number could accelerate as the wood pole population continues to age without replacement at the same rate. Compounding the older poles and equipment, many poles are likely structurally overloaded based on the NESC Heavy Loading Criteria and susceptible to failure during ½" ice with 40 MPH winds and other extreme weather events. This played out during Hurricane Isaias in August 2020 when Eversource lost more than 2,000 poles.

To minimize the impact of these events on system reliability, TRC recommends the following.

1) Establish a systematic asset replacement program to replace wood poles on an age basis, that support three phase lines, over the next 5 years. Beginning with poles 70 years and older poles, with priority on the smaller class 4, 5 and below, then address the 60- and 50-year-old poles using the same class criteria. There are about 42,000 wood poles aged 50 years and older that will need to be identified and prioritized for replacement. It is estimated that 20% (8,400) of those poles support three phase lines, requiring approximately 1,700 poles/year of the poles in this age group be replaced in conjunction with the other pole replacement efforts.

2) TRC recommends poles that are identified as structurally loaded at 90% or greater, be replaced with the correct sized poles to carry the mechanical load under the mandated NESC design conditions. To accomplish this, TRC also recommends that 10% (approx. 4,500) of the overloaded poles, be replaced on an annual basis. Priority should be given to the poles that are overloaded by the greatest amount and/or most critical to the system. It is also essential that all new poles that are installed have pole loading analysis completed to ensure the design criteria is met. Individual pole loading analysis will need

to be performed on all angle, tap and dead-end poles. Typical tangent pole analysis can be modeled to promote efficient design.

3) Continue the practice to use a minimum of Class 2 wood poles for all applications and ensure that NESC pole loading requirements are met for both the heavy loading and extreme wind scenarios. Based on analysis of the representative data, Class 2 wood poles are half as likely to be overloaded with attachments compared to Class 3 poles.

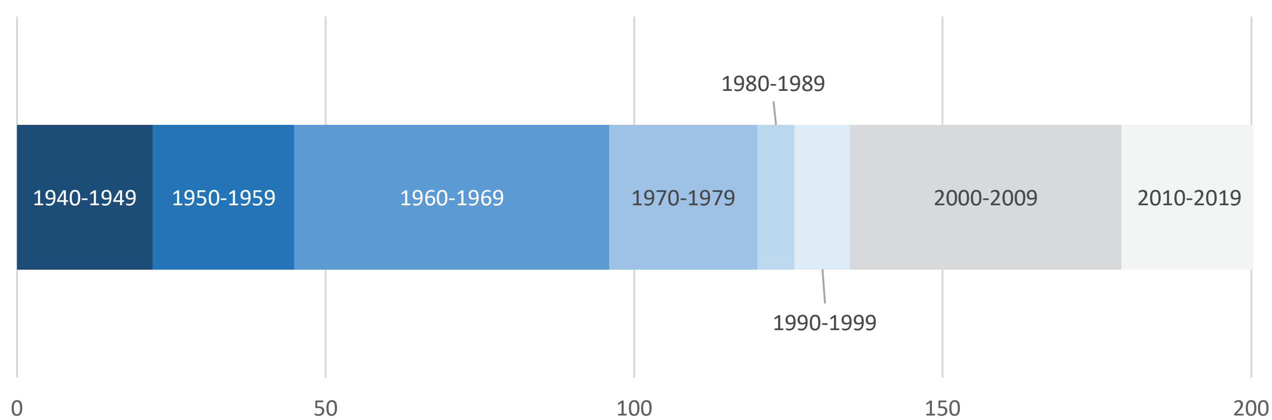
## 4.2 Substation Transformers & Breakers

Eversource operates 124 distribution substations across its New Hampshire service territory, serving a total of approximately 528,000 customers. Each substation typically contains 1-2 transformers, with 207 distribution power transformers across the system in total. Their system across New Hampshire also contains 523 distribution circuit breakers.

### Substation Transformer Assessment

These substations represent another critical portion of system infrastructure with a growing number of aging assets. Figure 3-8 below shows the distribution of substation transformers within the distribution system based on the decade manufactured. The system currently includes 45 transformers (22%) that are over 60 years old, and 51 transformers (25%) between 50 and 60 years in age. Transformer loading is typically the primary driver for station transformer replacement, although transformer age and condition should be considered too, as shown in Figure 5-43 and discussed further in Section 5.3.

*Figure 4-10. Eversource Substation Transformers by Decade Manufactured*




*Source: Eversource New Hampshire Substation Transformer Database*

Aging transformers can pose a risk to reliability if they are not properly maintained and have been overloaded over the years. Transformers have a typical design life of 25-40 years.[37] There

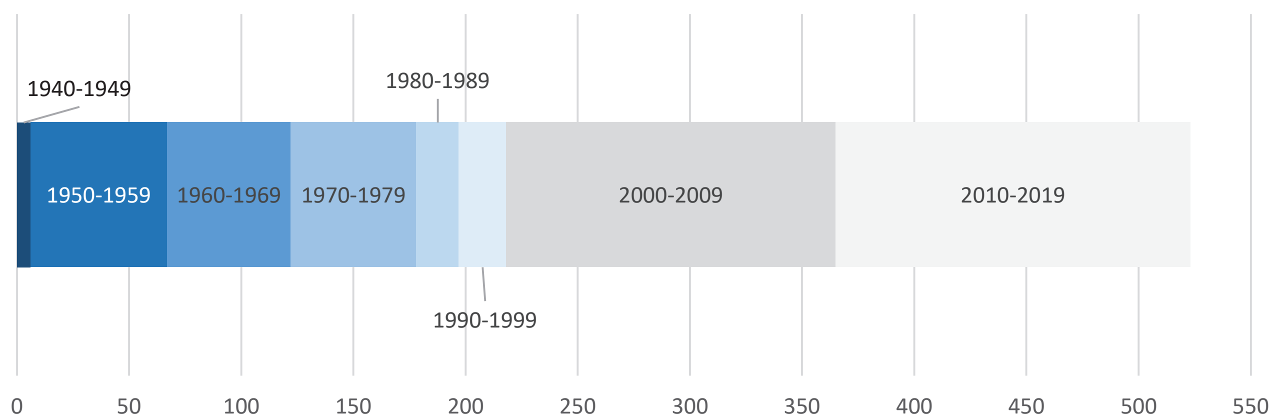
[37] IEEE, Standard for General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers (C57).

are 120 transformers within the system that are exceeding the maximum typical design life of 40 years. Though some transformers operate effectively without any significant signs of a replacement being needed beyond the design life, it is necessary to maintain them properly. There are also 45 transformers over the age of 60 years and another 55 transformers that will be reaching that age in the next 10 years. TEPCO has established a life expectancy of 65 years for extra-high voltage/HV transformers and 75 years for distribution transformers, as these are the time periods when winding clamping force begins to decrease, causing a marked influence on mechanical performance. However, as the life expectancy of a transformer subject to rapidly decreasing degree of polymerization because of high-water content in the paper insulation or where the risk of failure has been established, premature replacement of the transformer is necessary.[38]

### Substation Breaker Assessment

Substation breakers are generally newer than transformers, with almost 60% manufactured since 2000 breaker assets across the distribution system. Only 13%, or 67 substation breakers date prior to 1960. Figure 4-11 below provides additional detail regarding the manufacture date of substation breakers.

*Figure 4-11. Eversource Substation Breakers by Decade Manufactured*




*Source: Eversource New Hampshire Substation Breaker and Recloser Database*

Eversource's substations use four different types of breakers. Approximately 50% of the 523 breakers in the system use current standard vacuum (VCB) technology. The remainder of the breakers are comprised of primarily oil (OCBs) and air circuit breakers (ACBs). Figure 4-12 below represents the number of breakers within the system by equipment type:

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[38] Shimomugi, Kojiro, et al. "How Transformers Age." *T&DWorld*, 21 Feb. 2019, www.tdworld.com/substations/article/20972255/how-transformers-age.

*Figure 4-12. Eversource Substation Breakers by Type*

| Vacuum | SF6 | Oil | Air |
|---|---|---|---|
| **244** | 67 | 90 | 88 |

*Source: Eversource New Hampshire Substation Breaker and Recloser Database*

Since 2005, 221 VCB's have been installed across New Hampshire. VCB's have been used to replace aging and obsolete assets such as Oil Circuit Breakers (OCB) and air circuit breakers (ACB). These older oil and air breakers are becoming obsolete due to availability of replacement parts as well as not being able to upgrade to new control systems within some substations. If an aging breaker is experiencing issues with operation or is unable to be maintained properly, it will warrant a replacement. Breakers are mainly replaced in conjunction with other major projects that are going on within a substation.

### Substation Assessment Summary and Recommendations

TRC recommends analyzing aging station transformers and breakers. The Company should follow the transformer system violation ranking as shown in Figure 5-43 but the quantity of aging transformers needs to be taken into consideration. Age should still not be the sole driving factor for a replacement, but any transformer that has seen a larger load and use during its life should be higher on the priority list. A transformer replacement program is recommended that addresses the aging assets in conjunction with future loading projections.

TRC recommends breakers be replaced due to age if they are becoming obsolete or test results are showing excessive internal degradation. Obsolete breakers create issues with maintenance, inventory of spare parts, as well as integration with new controls. Failure of oil circuit breakers will lead to both reliability and environmental issues, so replacing these with the current standard vacuum circuit breakers is recommended. If the breakers are not posing an immediate threat to reliability, it is recommended to address breaker replacements in coordination with other station upgrade projects.

# 5. Eversource Distribution System Assessment Practices, Findings, and Recommendations

This section details the findings of TRC's assessments of distribution engineering materials and equipment, substations, and vegetation management practices. For each area of focus, the section reviews current practices, typical usage and installation, industry research findings, business case and cost analysis, and recommendations.

## 5.1 Distribution Engineering Materials and Equipment

### *5.1.1 Steel Poles*

**Current Practices**

Prior to 2019, Eversource's distribution engineering standards specified the use of wood poles for all distribution line construction and maintenance. In October 2019, the Company reviewed its distribution engineering standards for distribution poles and implemented distribution class weathering steel poles as the new standard for all new and rebuilt distribution line construction in the off-road Right-Of-Way (ROW), from 4kV up to 34.5kV.

The Overhead Distribution Standards[39] specify requirements for the design and construction of distribution class steel poles. The poles are to be installed in the off-road ROW when a wood pole for three phase circuits is replaced at end of life or due to failure. Steel poles are not specified for single phase circuits or service poles. The Company has installed 189 steel poles for new or rebuilt distribution lines since 2018. It should be noted that steel distribution structures have been used in the ROW applications as cost beneficial alternatives for over 100 years.

During interviews with TRC, the Company's SMEs indicated the decision to update this standard was driven by a variety of advantages steel poles provide over wood poles alternatives. These advantages include:

- Greater longevity
- Ease of construction due to less weight
- Superior material design characteristic predictability
- Differing failure mode resulting in reduced catastrophic failures
- Improved reliability in severe weather events
- Lower maintenance cost

This change to the pole standard was also precipitated by an increase in severe weather events since 2008. Severe weather events have led to a sustained level of pole failures due to

[39] Eversource, Overhead Distribution Standards Section 10, DTRs 10.620-642.

vegetation falling into the lines, the physical overloading of poles brought on by ice loading, and windstorms resulting in 689 pole failures since 2018.[40] Given the incidence of replacements required by these failures and the difficulties of replacing these poles in remote off-road ROW settings, the standards were updated to reduce the number of pole replacements due to failure. To date, no known failures of the distribution steel poles have occurred on the Company's distribution system.

### Typical Usage and Installation Practices

Distribution class steel poles are available in Class 1, H1, H9[41] and used for three phase circuits. Steel poles are drilled and prepared in the field to accommodate framing, equipment, and guying holes per the design standard. Poles are accessed from bucket trucks, if that option is available, but they do accommodate removable climbing steps to be used as needed. The standards allow for reclosers, risers and other devices to be installed on the steel poles. The pole lines in the ROW can be in rough terrain that is inaccessible by vehicle and pose unique construction and maintenance design and access issues. Outages on these lines can be longer because of these access and construction challenges. Benefits and disadvantages will be addressed in the Industry and Other Utility Findings section below.

*Figure 5-1. Eversource Structure Replacement, Circuit 3614*

*Source: Eversource*

[40] Eversource NH Storm Data
[41] Sabre Industries Wood Pole Equivalents

### Industry Findings

Wood poles have been the standard distribution system support structure for over 100 years. They provide a readily available resource to build, maintain and operate the system. Over the past 25 years, new innovations in distribution pole types have led to an increase in standards specifying steel (and fiberglass) poles instead of wood poles. While steel poles have a higher initial cost, they provide greater durability, strength, predictability, and require less ongoing maintenance[42]. In addition, from an installation perspective, steel poles are lighter and easier to construct than wood poles.

Light duty distribution class steel poles have been the most prevalent standard distribution pole in the West and Southwestern regions of the USA over the last 20 years. These poles are specified to provide line hardening capabilities to combat high winds, wildfires and extreme ice loading conditions that have increased in frequency. Light duty steel poles are the standard distribution pole for utilities such as APS, Dominion Virginia Power, TEP, San Diego Gas and Electric, Austin Energy, and several Cooperatives throughout the USA. These utilities have experienced improvements in their construction and maintenance costs and system resiliency[43] as outlined in the business case below.

There have also been reports, including one from prepared by the President's Council of Economic Advisors and the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability, advocating for upgraded poles and structures with stronger materials as a primary strategy. This study specifically states[44]:

*"For distribution systems, this usually involves upgrading wooden poles to concrete, steel or a composite material and installing support wires and other structural supports."*

Steel poles are recognized by the industry as a key component to building a robust and resilient distribution system.

### Business Case

Considerations for the standard use of steel poles compared to wood poles is outlined below:

- **Longevity**: Steel poles are proven to have a longer life than wood poles due to the inherent nature of the materials. Wood poles degrade and lose strength at a much higher due to the susceptibility to failure from decay, insects, and animals. Based on industry information, the projected life of a wood pole is 30 to 45 years or more depending on the installation environment. Steel poles have a projected life of 90 years

[42] Michigan Technological University, Age-Dependent Fragility and Life-Cycle Cost Analysis of Timber and Steel Distribution Poles Subjected to Hurricanes, Salman 2014. https://digitalcommons.mtu.edu/cgi/viewcontent.cgi?article=1779&context=etds
[43] Steel Utility Pole Coalition, Case Studies. https://steelpowerpoles.com/library/case-studies/

[44] Economic Benefits of Increasing Electric Grid Resiliency to Weather Outages -Executive Office of the President, August 2013 Page 13
https://www.energy.gov/sites/prod/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf

and likewise remain in service longer depending on the installation environment. Steel poles are also susceptible to degradation due to corrosion and galvanic losses. This degradation occurs at a slower rate can be mitigated by pole coatings.[45]

- **Constructability**: Steel poles are lighter in weight, easier to handle and can cost less to install. Steel poles are 50 to 70% lighter[46] than equivalent class wood poles allowing for lighter duty equipment to perform handling and construction activities. It is a common practice for manufacturers to pre-drill holes for typical framing, equipment, and down guy configurations, thereby eliminating the time required to drill holes in the field, if that option is chosen. In Eversource's off-road installation environment, the installation of the steel and wood poles is the same. In remote areas that have limited or no vehicle access, helicopter pole sets are required. The weight advantage of steel poles includes the flexibility to utilize lighter duty helicopters to perform the pole sets that are less costly and increase the speed of the pole set.
- **Material Characteristic Predictability**: Steel, as a material, has more predictable design parameters than wood. For design purposes, the National Electric Safety Code (NESC)[47] accounts for the greater variability of wood pole composition by using higher design safety factors than are used for steel poles. Wood pole strength safety factors are 0.65 (Grade B) and 0.85 (Grade C) as compared to 1.0 (Grade B &C) for steel. Because wood strength declines significantly over time, this degradation has to be accounted for when performing pole loading analysis for future attachments and modifications.
- **Failure Mode**: In TRC's experience, steel poles do not typically fail catastrophically. They maintain form and lean over based on the causal factor. If a tree falls onto a steel pole line, the poles typically kink and/or bend and can remain in service, unless other components (crossarms, conductor, insulator, etc.) fail as well.[48] The same holds true with steel poles that fail due to excessive wind or ice load, where the poles typically lean but do not go to ground. Wood poles can, and often do fail catastrophically. Wood poles typically break at the point of pressure or the pole's weak point, and if the damage is severe enough, go completely to the ground with all attachments, causing service interruption and potentially endangering persons and property in the area due to downed lines. The Company's steel poles standards in the ROW reduces both the chance of catastrophic failure and related safety concerns.

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[45] Salam, Age-Dependent Fragility and Life-Cycle Cost Analysis of Timber and Steel Distribution Poles Subjected to Hurricanes
[46] Eversource Wood and Steel Pole Standards
[47] 2017 National Electric Safety Code Section 250, General Loading Requirements and Maps
[48] UC Synergetic, Structural Analysis of Distribution Designs Northeast Utilities – Final Report. December 30, 2013

*Figure 5-2. Illustrative example of wood pole failure due to ice loading*

*Source: Courtesy of Intelli-pole.com*

- **Reliability**: Distribution lines are designed to meet the regional requirements dictated by the NESC for poles, attachments, wind, ice, equipment, clearances, etc. Designs for steel distribution lines in New Hampshire also must take into consideration forested areas and the potential for trees to fall onto energized lines. These events can cause long outages due to limited or difficult access to the outage event. One study conducted by UC Synergetic found that often the pole failure is the weak link causing extended outage durations. This study found that specifying Class 1 poles would reduce these events.[49] Furthermore, steel poles would reduce the risk of catastrophic failure as described in the Failure Mode bullet above. The standardized implementation of steel poles has been in place for over two years and limits the ability to measure any impacts to distribution system performance.

The primary drawback of steel poles is their higher initial cost compared to an equivalent wood pole. Individual steel pole generally cost 2.5 to 4 times the cost of wood poles. However, the total installed cost for construction of lines with steel poles tends to be less than similar construction using wood poles due to the weight difference between the poles. These costs and savings will be further detailed in the Cost Analysis section below.

## Cost Analysis

The cost analysis is based on life cycle costs. This method accounts for the initial cost to build the poles and any cost to maintain and replace them based on the equipment's useful life. The following parameters are built into the cost analysis model for the steel pole evaluation:

[49] UC Synergetic, Structural Analysis of Distribution Designs Northeast Utilities – Final

- 45’- Class 2 Wood pole life 45 years (2 wood poles will be modeled)
- 45’- Class 1 Weathering Steel pole life 90 years[50]
- Wood Pole Visual, Sound and Bore or Partial Excavation Maintenance at 10-year intervals @$13.29/test
- Steel Pole Visual inspection at 10-year intervals @ $5.36/inspection
- Escalation costs 3% labor and materials annually
- Escalate 4% annually for wood products based on lumber index over last 40 years
- Installation in off-road ROW location

Eversource follows a 10-year visual, sound and bore, or partial excavation wood pole inspection program for all poles including the poles in the off-road ROW. Inspections are visual only up to 9 years and require a sound and bore test or partial excavation at year 10 and every 10-year interval thereafter. Steel poles do not have an equivalent intrusive inspection and only require a visual inspection as part of the line patrol. The escalated cost to maintain the 10-year maintenance cycle for both the steel and wood poles is included in the model.

*Figure 5-3. Total lifecycle cost Analysis of 45-foot steel and wood poles*

| Project | Initial Cost | Year 10 | Year 20 | Year 30 | Year 40 | Wood Pole Replacement (45 years) | Year 50 | Year 60 | Year 70 | Year 80 | Lifecycle Total | Present Worth |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 45-1 Steel Pole Hendrix | $ 6,924.36 | $ 7.20 | $ 9.68 | $ 13.01 | $ 17.48 | $ - | $ 23.50 | $ 31.58 | $ 42.44 | $ 57.04 | **$ 7,126.29** | **$ 25,935.62** |
| Labor | $ 2,262.00 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 2,262.00 | |
| Materials | $ 2,401.00 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 2,401.00 | |
| Overhead | $ 2,256.00 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 2,256.00 | |
| Maintenance | $ 5.36 | $ 7.20 | $ 9.68 | $ 13.01 | $ 17.48 | $ - | $ 23.50 | $ 31.58 | $ 42.44 | $ 57.04 | $ 207.29 | |
| 45-2 Wood Pole Hendrix | $ 5,189.94 | $ 42.92 | $ 57.69 | $ 77.53 | $ 104.19 | $ 20,419.49 | $ 140.02 | $ 188.18 | $ 252.90 | $ 339.87 | **$ 26,812.72** | **$ 19,260.36** |
| Labor | $ 2,262.00 | $ - | $ - | $ - | $ - | $ 8,553.97 | $ - | $ - | $ - | $ - | $ 10,815.97 | |
| Materials | $ 934.00 | $ - | $ - | $ - | $ - | $ 4,325.24 | $ - | $ - | $ - | $ - | $ 5,259.24 | |
| Overhead | $ 1,962.00 | $ - | $ - | $ - | $ - | $ 7,419.49 | $ - | $ - | $ - | $ - | $ 9,381.49 | |
| Maintenance | $ 31.94 | $ 42.92 | $ 57.69 | $ 77.53 | $ 104.19 | $ 120.78 | $ 140.02 | $ 188.18 | $ 252.90 | $ 339.87 | $ 1,356.02 | |

Results show the cost of the steel poles are more cost effective than similar wood poles when longevity and maintenance costs are considered in the total lifecycle of the pole. It should be noted that the Net Present Worth Analysis was performed using the same input data and the results showed that the steel pole has a 35% greater present worth than the wood pole over the life of the pole.

## Recommendations

Poles are a major infrastructure investment.  Life cycle cost analysis offers a broader perspective of costs over time. Based on the above analysis, industry and environmental trends, steel distribution poles are an investment that provide a long-term solution for safe, reliable, and cost-effective service to the customer. This investment is one component of improved distribution line resiliency. Steel poles used in off-road right-of-way settings provide additional resiliency benefits to guard against what would be a longer duration outage, given the difficulty in patrolling and replacing these more remote assets in the event of a failure during a severe

[50] Eversource has steel transmission structures that have been in service for over 100 years.

weather event. EPRI notes that this type of selective equipment application is often the most appropriate for grid hardening investments:[51]

*"There is no 'silver bullet' that enables utilities to substantially eliminate interruptions during severe weather events. Utilities need to identify potential resiliency solutions, determine the costs, and added value associated with each solution, and then select a combination of solutions that best serves all stakeholders. Hardening solutions, with the possible exception of vegetation management solutions, are generally not cost effective for universal application throughout a utility's electric system. Hardening options need to be selectively applied based on careful consideration of the costs and benefits expected for each utility system, regional demographics, environmental characteristics, and other factors."*

The combination of steel poles in off-road ROW applications along with larger class standard wood poles, spacer cable and fiberglass crossarms are together distribution equipment hardening solutions that provide greater reliability and resiliency. The current practice installs steel poles in the ROW to replace existing wood poles or obsolete steel lattice towers (such as circuit 3178X3) that are either damaged or at end of life.

TRC recommends adding a proactive program to replace wood poles or obsolete steel lattice towers in the ROW on a planned basis in addition to the current practice. The plan should include a minimum of five circuit miles of off-road ROW, three phase rebuilds, including rebuilds that are part of the inaccessible line relocation projects. Line projects need to be prioritized by reliability performance and susceptibility to damage or failure from trees.

### *5.1.2 Class 2 Wood Poles*

**Current Practices**

Eversource historically stocked and specified Class 3 or 4 wood poles for distribution line construction and maintenance of facilities. In 2016, Eversource changed the pole standard to Class 2 wood poles as the minimum class pole for all primary poles installed. This change was precipitated by a need to provide enhanced storm hardening capabilities[52] and to gain consistency with standards for wood poles.

As with the ROW installed steel poles, spacer cable and fiberglass crossarms, the system hardening needs were driven by an increase in severe weather events since 2008, as shown in the Eversource NH Major Storm Events report. These types of events have led to a sustained level of pole failures (689 pole failures since 2018, roughly 200 per year) due to vegetation falling into the lines and the physical overloading of poles brought on by ice loading and windstorms. Given the persistent pole replacements brought on by these failures, the standards were updated to Class 2 poles to reduce the number of failures causing outages and emergency replacement.

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[51] Electric Power Research Institute, Distribution Grid Resiliency: Prioritization of Options, 2015. https://www.epri.com/research/products/3002006668
[52] UC Synergetic, Structural Analysis of Distribution Designs Northeast Utilities – Final Report

### Typical Usage and Installation Practices

Eversource Overhead Distribution Standards[53] specify standards for the design, construction, and maintenance of distribution poles. The Distribution System Engineering Guide (Eversource Section 02.50 Reliability- Storm Resiliency Guidelines)[54] provides the instructions and guidelines to implement storm hardening practices. There has been a total of 12,941 Class 2 Chromated Copper Arsenate (CCA) treated wood poles installed in the Eversource system since 2018, ranging in length from 35' to 55'. The CCA Class 2 wood poles were installed in roadside applications as new and replacement poles for distribution voltages ranging from 34.5kV three phase to service voltages. A 45' Class 2 pole is the minimum class for three phase circuits and a 40' Class 2 pole is the minimum class for single phase circuits. Additionally, the Storm Resiliency Guidelines specifies that all junction poles are to be a minimum of a Class1 wood pole.

The Class 2 and Class 1 (junction poles) size poles are the minimum classes to be specified in the roadside installations. If the pole application requires a larger class pole, as determined by Pole Loading Analysis (PLA) software, then a pole designed for that installation shall be specified. The PLA tool models two scenarios and uses the worst case as the final design criteria. The criteria are designed as follows:

1) 95 MPH Wind at 60º C with No Ice
2) 40 MPH Wind at 15º C with ¾" Ice

The first design criteria are based on the Extreme Wind Loading criteria as specified by 2017 NESC Rule 250C.[55] Design criteria 2 represents the Extreme Ice with Concurrent Wind Loading as specified by the 2017 NESC Rule 250D[56]. Both scenarios are relevant to the Eversource system as they were experienced with Hurricane Irene and Storm Alfred in 2011.

### Industry Findings

As stated in the Distribution Class Steel Pole section of the report, wood poles have been the standard distribution system support structure for life of the distribution industry. Wood poles are relatively inexpensive compared to other alternatives (steel, concrete, fiberglass) but are prone to unseen imperfections and deterioration due to insects, animals and fungus making the design and longevity less predictable than other alternatives.[57] Eversource has distribution facility attachments to about 455,000 distribution poles with maintenance responsibility for about 276,000 of those poles[58] making up their distribution pole fleet. The wood pole integrity and strength play a pivotal role in reducing the number and duration of outages on the distribution system.

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[53] Eversource, Overhead Distribution Standards, Section L3-OH05, DTRs 101-309.
[54] Eversource, Reliability – Storm Resiliency Guidelines, 2016.
[55] 2017 National Electric Safety Code, Section 250C.
[56] 2017 National Electric Safety Code, Section 250D.
[57] Salam, Age-Dependent Fragility and Life-Cycle Cost Analysis of Timber and Steel Distribution Poles Subjected to Hurricanes
[58] Direct Testimony of Purington and Lajoie)

The increase of significant storm events in the USA and specifically in the Northeast has prompted utilities to look for ways to determine optimal designs for storm resiliency for the distribution system. Two comprehensive studies were conducted in 2013 and 2015 that address recommended practices regarding the larger class wood poles in addition to other system improvements (insulators, crossarms, spacer cable, etc.) that can be implemented to reduce the impact of the storms and improve reliability overall.

The first study conducted in 2015 by the Electric Power Research Institute, titled Distribution Grid Resiliency: Overhead Structures[59], was a three-year, multi-deliverable research project, addressing methods to evaluate hardening solutions to improve distribution grid performance related to major weather events. The study had participation and input from 27 electric utilities throughout the USA and included field testing of actual structures (poles, trees, or other structural load) falling or structurally imposed on distribution pole lines to measure the impact on the withstand capabilities of the poles, conductors, crossarms, down guys and other equipment installed on the distribution poles. The EPRI report provides detailed findings associated with each component scenario tested. A summary of the study results concluded that the pole top circumference was the largest determining factor for the performance of the poles subject to dynamic stresses, such as tree impacts on distribution lines. Performance in terms of energy increases as a function of the top circumference to at least the fourth power. In the case of a 40' Class 4 pole (31.5" circum.) versus a 40' Class 2 (38.5" circum.) pole, the Class 2 pole impact force withstand capability will be approximately 60% greater than the Class 4 pole.

The second study was conducted by UC Synergetic in 2013 and titled Structural Analysis of Distribution Designs – Northeast Utilities.[60] The overview states that the study is to perform structural analysis on a variety of distribution wood pole structure designs so that a quantitative analysis can be developed to optimize designs for storm resiliency. This study also looked at the impact of trees falling on lines and the ability to withstand ice loading. All analysis was based on PLS-CADD™ models for all components of a distribution line including poles, conductor, crossarms, insulators and other structural supports. The analysis modeled simulations of trees falling onto distribution lines for the following scenarios:

- NESC Heavy Loading (1/2" Ice at 40 MPH Wind)
- ½" Ice at 0ºC
- ¾" Ice at 15ºC
- 95 MPH wind at 60ºC

These parameters fit very closely to the Eversource Storm Resiliency Guidelines. Conclusions are as summarized.

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[59] EPRI, Distribution Grid Resiliency: Overhead Structures, December 2015. https://www.epri.com/research/products/000000003002006780

[60] Salam, Age-Dependent Fragility and Life-Cycle Cost Analysis of Timber and Steel Distribution Poles Subjected to Hurricanes

- Class 3 poles failed in all NESC Heavy Loading cases
- Class 2 poles passed the light tree (1,500 lbs.) simulation but failed in the heavy tree (3,840 lbs.) simulation
- Class 2 and 3 poles passed in the light and heavy tree simulations for ½" and ¾" ice
- Class 3 poles failed in 95 MPH simulation

It should be noted that during a storm event (or any outage event on a distribution line), a pole failure is the least desirable outcome, as pole replacements are typically the most difficult and costly to repair compared to replacing conductors or crossarms. Splicing conductors, replacing crossarms or insulators would be preferable to reduce costs and outage durations.

The results of the two studies present both an in-the-field and a calculated example of the benefit of larger class poles to prevent distribution line outages from trees falling on distribution lines and extreme ice and wind loading. The study's findings complemented each and bear out that the decision by Eversource to change to a minimum of Class 2 wood poles will reduce distribution line outages.

**Business Case/Cost Analysis**

The information contained in the two studies constitutes the majority of the business case for the specification of a Class 2 wood pole as the minimum size, with the exception of the financial consideration. The table below shows the installed cost of the typically used pole sizes comparing the Class 3 with the Class 2, provided by Eversource.

*Figure 5-4. Comparison of wood pole installed costs by size and class*

| Pole Size (Southern yellow pine, CCA treated) | Class 3 Installed Cost | Class 2 Installed Cost | Class 2 Cost Differential |
|---|---|---|---|
| **40 ft length** | $1,403 | $1,440 | +2.6% ($37) |
| **45 ft length** | $1,475 | $1,540 | +4.4% ($65) |
| **50 ft length** | $1,554 | $1,586 | +2.1% ($32) |

*Source: Eversource internal data*

The installed cost difference between Class 3 and Class 2 poles is relatively small and the improvement in reliability (SAIFI and SAIDI) realized by using the stronger Class 2 poles coupled with the avoided cost of broken pole replacement, should quickly offset the incremental cost difference. In the case of Eversource, during 2018 storm events, the Company replaced 175 poles. The cost increase for using Class 2, 45-ft poles in these events would be $11,375. If just eight poles, or 5%, had not failed due to use of the stronger Class 2 poles, the cost savings would be justified.

*Figure 5-5. Eversource count of broken poles caused by storms from 2018-2021*

| Storm Year | Replaced Poles |
|---|---|
| **2018** | 175 |
| **2019** | 255 |
| **2020** | 180 |
| **2021-Q1** | 58 |

*Source: Eversource internal data*

From an operational perspective, reducing the number of pole classes needed in inventory by specifying a minimum of Class 2 poles provides the opportunity for better purchase prices, less warehousing costs, and the ability to share pole resources across distribution networks depending on localized needs.

Figure 5-6 below shows an example of a 45' Class 2 wood pole installed in 2018 with a three-phase line and multiple third-party attachments.

*Figure 5-6. Example of Class 2 wood pole with fiberglass crossarm*

*Source: Eversource*

**Recommendations**

The use of higher-class poles (Class 2) has been shown to prevent and reduce the outage impacts brought on by trees falling on distribution lines, heavy ice loading, and extreme wind situations experienced throughout the United States. The Company has seen a regular occurrence of major event outages causing greater chances for prolonged outages since 2008. Using Class 2 wood poles as a minimum size can reduce the number and severity of the outages with a minimal cost difference over Class 3 poles.

Based on the review of Eversource's pole standards, cost analysis and industry information, standardizing road-side distribution construction and emergency replacement utilizing Class 2 poles, within the PSNH service territory, is sound engineering judgement and within good utility practices.

### *5.1.3 Spacer Cable*

**Current Practices**

Eversource has been using spacer cable for several decades and made it the standard overhead conductor in 2015.[61] Since 2015, the Company has installed approximately 386 miles of 35 kV spacer cable. Although there are no formal plans to replace all open wire bare conductor with spacer cable, current design guidelines established in 2016 specify the use of spacer cable for all new three-phase primary distribution lines. Spacer cable continues to be used to replace open-wire bare primary on a case-by-case basis to improve performance and reliability of specific areas. Tree wire is used on a limited basis for single phase laterals and will not be addressed in this report.

The implementation of the Eversource Storm Resiliency Guidelines in 2016 was a strategic response to outages due to an increase in severe weather events that occurred prior to 2016. These events, comprised of wind and ice storms, had led to an increase in widespread tree related outages, and in many cases, severe damage. The guideline recommendations covered the increased use of steel poles, Class 2 wood poles, spacer cable, fiberglass crossarms, and other solutions covered in this report.

Eversource staff indicated the 2016 design guidelines, that expanded the use of spacer cable, were driven by a variety of advantages over the use of open wire bare conductor designs. These advantages include:

- Minimized temporary faults due to tree branches and incidental animal contact
- Ability to survive larger tree and limb falls while remaining in-service
- Less space required on the pole than an open wire design, minimizing ROW requirements
- Smaller tree trimming envelopes

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[61] Interview with Eversource Standards Group, March 18, 2021

- NESC Rule 230D, Covered Conductors[62] compliant

**Typical Usage and Installation Practices**

Eversource has standardized the following spacer cable sizes. Each of these insulated cables are covered in a rugged polymer jacket:[63]

- 795 mcm AAC (all aluminum conductor) 35 kV and 15 kV (Standard)
- 556 AAC 25/30 kV
- 477 mcm AAC 35 kV and 15 kV (Standard)
- 336 mcm AAC 25/30 kV
- 1/0 ACSR/AW (aluminum cable, steel reinforced with an Alumoweld core) 35 kV, 25/30 kV and 15 kV (Standard)

The Company purchased several high-strength messenger wire types, but the 052 AWA is the most used. The 052 AWA is a bare wire, and the description indicates it is a 7-strand wire having 5 strands of Alumoweld wire and 2 strands of aluminum wire. The combined cable is electrically equivalent to 1/0 aluminum. The messenger wire is the system neutral, except in rare situations that may require a separate neutral wire.

The spacers and the anti-sway bracket are made of track resistant UV protected polymer. The spacers have four integral clamps for the cables and messenger wire. The clamps can be opened and closed if needed to temporarily remove a cable from the spacer to allow for repairs or for splicing.

[62] 2017 National Electric Safety Code Section 230D
[63] Eversource Energy Material Standards MAT C-2

*Figure 5-7. 35 kV MGY and Below – Spacer Cable Construction Tangent and Small Corner*

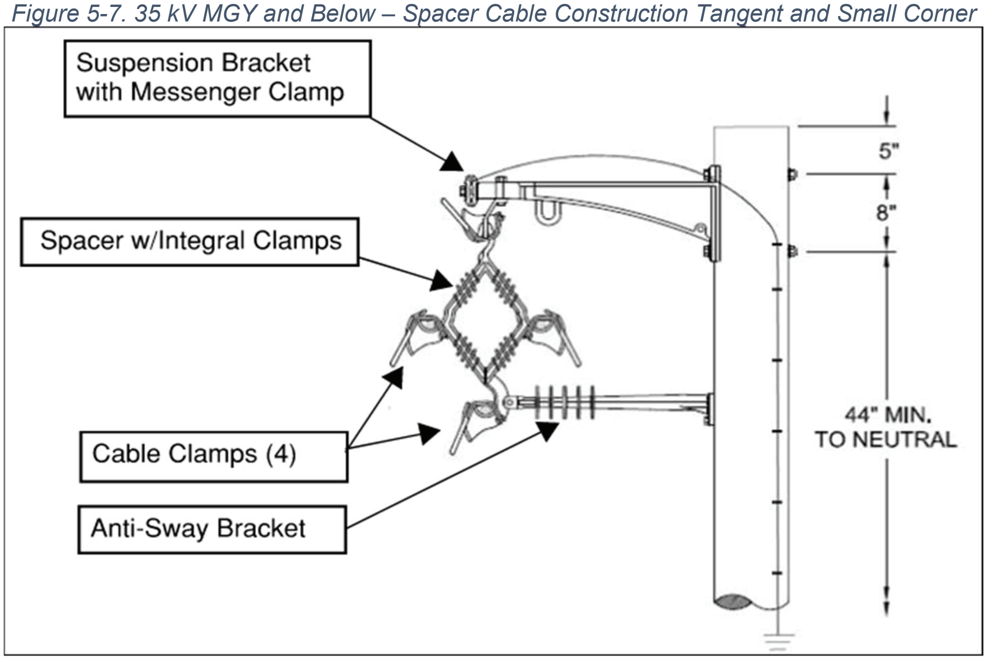


Figure 5-7 above from Standard DTR 10-738 illustrates a 35 kV three phase spacer cable tangent pole and components. The three 35 kV cables are clamped into their positions on the spacer and the spacer is suspended from the messenger wire. The messenger is then installed and secured to the metal suspension bracket. The anti-sway bracket is used to restrict the movement of the spacer cable assembly and is not used on every pole.

### Industry and Utility Findings

Spacer cable was invented in the 1950's and has been in use industry-wide for several decades. It is an established, readily available component used to enhance system resiliency and reliability.[64] According to Hendrix - Kerite Wire and Power Cable, spacer cable is used by over 50 investor-owned utilities, such as National Grid, Avangrid, AEP, Georgia Power, PG&E, Entergy, and over 75 Cooperatives and Municipals throughout the USA and is commonly reflected in their distribution standards. TRC has direct design experience with many of the utilities that specify spacer cable for their distribution system.

Spacer cable installations have been the most prevalent in forested areas throughout the USA. They are specified to enhance the system to combat tree related outages resulting from high winds and ice loading conditions. It is also used in congested alley ways and along busy streets to improve clearances to buildings, signs, and other structures. Spacer cable is not limited to short span situations. River crossings in excess of 1500 feet have used spacer cable to provide clearance over water for sail boats and commercial river traffic.

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[64] EPRI, Distribution Grid Resiliency: Overhead Structures.

### Business Case

As noted above, spacer cable has several important benefits compared to open wire bare conductor designs. The first two directly address tree-related outages, which is the leading cause of outages at Eversource. The Company has seen a decrease in both SAIFI and SAIDI over the ten-year period ending in 2020. It is not possible at this time to determine how much of that decline is attributed specifically to spacer cable, but it is a component of the overall resiliency program along with other equipment addressed in this report.

For additional information on spacer cable and other active resiliency/reliability methods and metrics, refer to the IEEE Report PES TR83 "Resiliency Framework, Methods, and Metrics for the Electricity Sector" published in 2020[65], see especially Section 6.1 on page 22.

Benefits associated with spacer cable are:

- **Spacer cable minimizes temporary faults due to tree and incidental animal contact.** Spacer cable is an insulated cable constructed with a thick UV protected polymer jacket; tree branches, twigs, etc. that fall across phases do not result in recloser operations or sustained outages. The same holds true for branches laying across the messenger and phase. Animal related outages, those due to metalized balloons, vandalism, etc. are also minimized for the same reason. Furthermore, these objects can be removed during normal working hours thus avoiding an overtime callout. In some cases, a bucket truck is not needed, just a line mechanic with hook stick. Figure 5-8 below shows outages with bare wire compared to spacer cable installations for Northeast Utilities over a five-year period. Overall, spacer cable has been attributed to a 75% outage reduction for this study.
- **Spacer cable has a demonstrated ability to survive larger tree and limb falls**[66][67]. Spacer cable does have its limits and there are trees and limbs heavy enough to break the messenger, poles, etc. However, as illustrated in Figure 5-9 and Figure 5-10 below, spacer cable has a higher tolerance for such events. These images show a substantial tree limb has broken away and come to rest on an Eversource spacer cable segment, without resulting in an outage. Details of trees on conductor testing are included in the referenced EPRI report.
- **Spacer cable requires a smaller tree trimming envelope**. Since the cables are insulated and resistant to physical damage from tree branches, etc., tree trimming corridors along the line offer the potential of being reduced in width. Figure 5-11 below shows the Eversource 8 Foot clearance zone spec. Note that with a 10 ft. crossarm, the clearance envelope is 26 ft. If spacer cable is used, the trimming zone is reduced to about 19 ft.
- **Spacer cable can be used to solve encroachment problems by eliminating the overhanging of energized conductors over private property.** Some property owners refuse to have trees trimmed, and spacer cable can be a solution. Figure 5-12 below is

[65] IEEE Report PES TR83 "Resiliency Framework, Methods, and Metrics for the Electricity Sector"
[66] EPRI, Distribution Grid Resiliency: Overhead Structures.
[67] UC Synergetic.

an Eversource photo showing a situation where the customer refused to allow tree trimming. This is a good example of where space cable could be utilized to reduce the risk of an outage event.

- **A spacer cable circuit occupies less space on the pole than an open wire design.** This translates into more efficient use of existing poles. For example, in Figure 5-13 below, an additional circuit was installed adjacent to the existing one using the same bolt-holes, thus avoiding a pole change-out.
- **Spacer cable is NESC Rule 230D[68] compliant.** Rule 230D allows the use of spacer cable and states the clearance between conductors of the same or different circuits, including grounded conductors, may be reduced below the requirements for open conductors when the conductor covering provides sufficient dielectric strength to limit the likelihood of a short circuit in case of momentary contact between conductors or between conductors and the grounded neutral. Intermediate spacers may be used to maintain conductor clearance and support. (See Figure 5-13)

The following photos and graphics illustrate some of the benefits of spacer cable described above:

*Figure 5-8. Outages based on 100 circuit miles/year over Five years*

| Cause of Outage | Bare Wire | | | Spacer Cable | % Reduction |
|---|---|---|---|---|---|
| Tree Related | 17.6 | | | 1.8 | 90 |
| Animals | 12.1 | | | 2.9 | 76 |
| Lightning | 3.4 | | | 1.0 | 71 |
| Unknown | 5.9 | | | 1.0 | 83 |
| All Other | 11.3 | | | 5.9 | 48 |
| **Total** | **50.3** | | | **12.5** | **75** |

Northeast Utilities 5 Year Statistics
Based on 100 circuit miles per year

Hendrix kerite

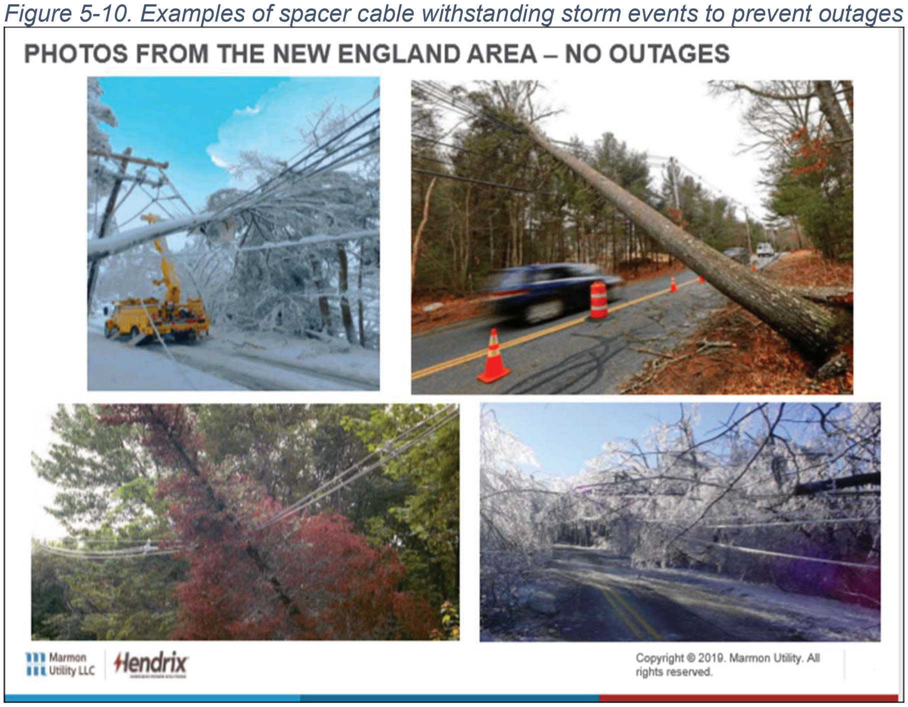
Source: Hendrix Aerial Cable Systems

[68] 2017 National Electric Safety Code Section 230D

*Figure 5-9. Photo of a tree incursion on an Eversource line using spacer cable that remained intact*

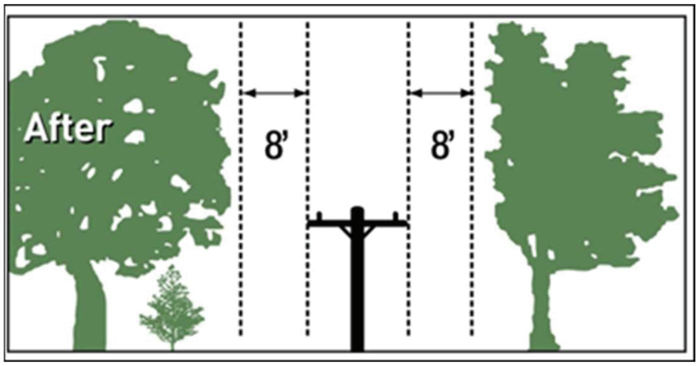
*Source: Eversource*

*Figure 5-10. Examples of spacer cable withstanding storm events to prevent outages*




*Source: Marmon/Hendrix (used with permission)*

*Figure 5-11. Example of enhanced tree trimming clearances needed for a typica mainline circuit; less clearance is needed for spacer cable installations due to lower profile of installations.*

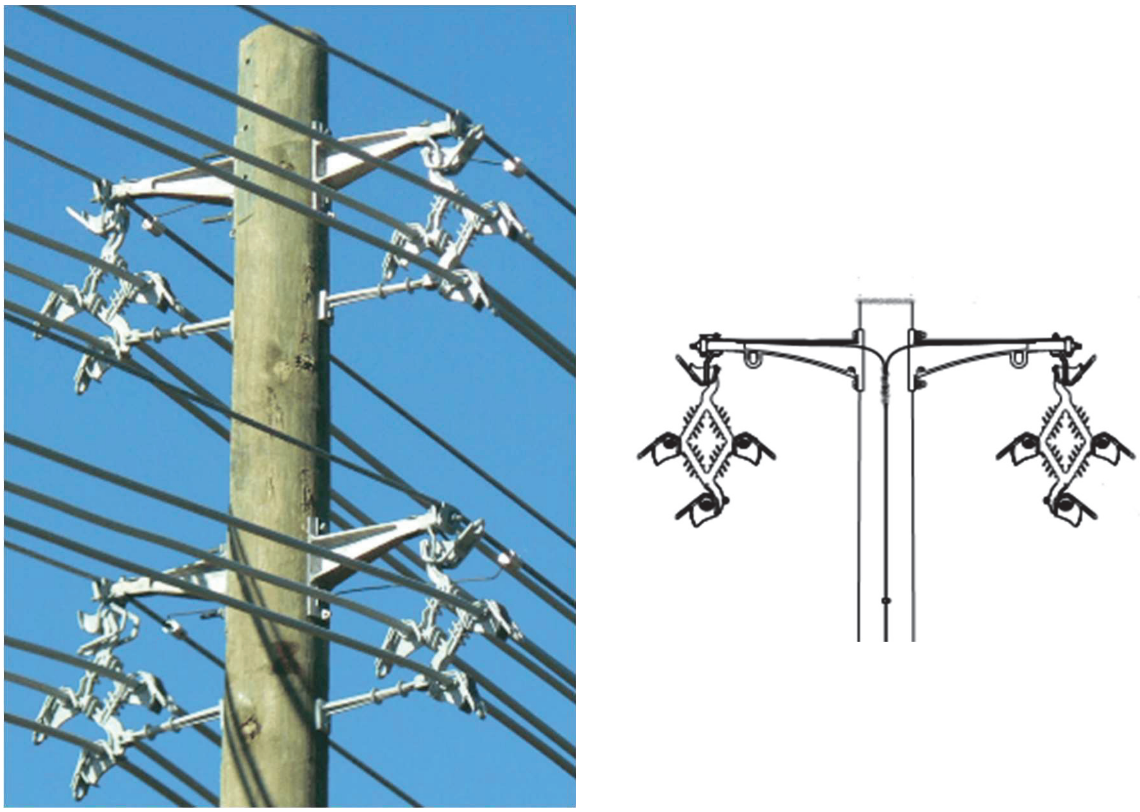



*Source: Eversource ETT Specifications*

*Figure 5-12. Example of an open-wire cable distribution line with vegetation encroachment due to a customer’s refusal to allow tree trimming.*

*Source: TRC Field Inspection*

*Figure 5-13. Image and graphic of spacer cable design showing compact nature of installations*



Source: Marmon/Hendrix and TRC

**Cost Analysis**

Spacer cable construction requires a greater upfront cost than open bare wire conductor. The two scenarios in Figure 5-14 represent the Company's estimated costs to construct a mile of a three-phase open wire bare conductor line and a mile-long spacer cable line. Both scenarios have the same periodic inspection costs for circuits built using wood pole construction. Based on TRC's experience, the total cost difference is generally consistent with vendor information and other utilities.

1) The benefits of using spacer cable can be attributed to directly improving system reliability and resiliency. The cost savings, as described earlier in this report, remains a critical challenge for utilities and regulators, as the benefits are difficult to monetize. Avoided costs include those incurred due to outages and maintenance and construction.

*Figure 5-14. Estimate Cost per Mile of Three-Phase Open Wire Bare Conductor and Spacer Cable*

| | Labor | Materials | Overheads | Total |
|---|---|---|---|---|
| **Open Wire Bare Conductor** | $24,167 | $31,238 | $47,043 | $102,448 |
| **Spacer Cable** | $44,954 | $66,684 | $93,760 | $205,398 |

*Source: Eversource internal data*

**Recommendations**

Spacer cable is an essential component to a comprehensive resiliency and reliability program that will also include expanded use of steel poles, stronger wood poles, fiberglass crossarms, and a robust ROW vegetation clearing program. Tree contacts remain the leading cause of outages. Despite these measures, trees will continue to fall over, and limbs and branches will continue to break, some of which are light enough to be taken by the wind into the wires. Utilities are required to obtain authorization from property owners to trim trees, and some property owners are unwilling to grant the necessary authorization. Spacer cable prevents or minimizes those tree-related outages that occur regardless of a robust ROW clearing program. Spacer cable can reduce or eliminate outages due to animals, vandalism, etc. Overtime callouts to correct these and tree related situations can be reduced.

TRC recommends the following:

- Continue the spacer cable program as outlined in the Eversource's 2016 Resiliency Guidelines.
- As part of the capital planning process, accelerate the rebuilding/reconductoring of the open wire, three phase lines that are the most susceptible to outages in heavily treed and narrow ROW areas over the next 5-years. Work in conjunction with the inaccessible line relocations to the roadside and steel pole installation projects in the steel pole section.

### *5.1.4 Fiberglass Crossarms*

**Current Practices**

Eversource has been using fiberglass crossarms for approximately five years beginning around the third quarter of 2016; fiberglass crossarms were integrated into their standards at the same time.

Although there are no formal plans to replace all existing wood crossarms with fiberglass, current design guidelines in 2016[69] specify their use for all new construction and on an as-needed basis resulting from pole inspections and observations.

[69] Eversource, Reliability – Storm Resiliency Guidelines.

The implementation of the 2016 design guidelines was a comprehensive response to outages due to an increase in severe weather events that occurred prior to 2016. These events, comprised of wind and ice storms, led to an increase in tree related outages, and in many cases, severe damage. Eversource SMEs indicated the decision to update their standards to use fiberglass crossarms was driven by a variety of perceived advantages over wood arms. These advantages include:

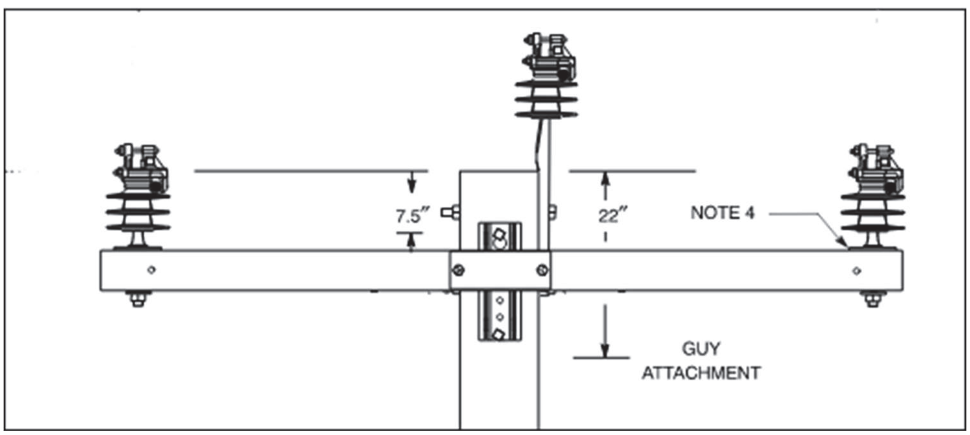
- Improved Longevity
- Ease of Installation
- Greater Material Uniformity and Consistency
- Improved Reliability

**Typical Usage and Installation Practices**

The Company standardized on several fiberglass cross arm sizes. This report will focus on the 10-foot tangent and 10-foot dead-end arm, the most used size.

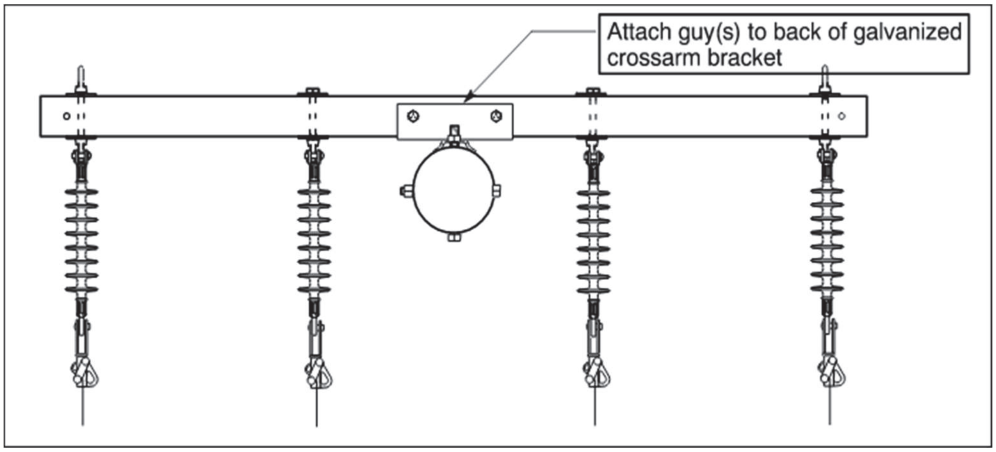
Fiberglass arms do not require braces as wood arms do; they are delivered with 2-hole metal mounting brackets as can be seen in Figure 5-15 and Figure 5-16 below.

*Figure 5-15. 27.6kV Fiberglass Crossarm Construction, Three-Phase Small Angle/Tangent Pole*




*Source: Eversource Energy Construction Standard DTR 11.211*

*Figure 5-16. 27.6 kV Fiberglass Crossarm Construction, Three-Phase Dead-end Pole*




*Source: Eversource Energy Construction Standard DTR 11.219*

### Industry and Utility Findings

The use of fiberglass crossarms began in the early 1990's; fiberglass is not new to the electric energy industry. Because fiberglass is a good electrical insulator, it has been used in products since the late 1950's such as bucket truck booms, and later, in electrical products such as guy insulators. Vendors began shipping crossarms in the early 1990's and two of the larger manufacturers claim to have delivered over 7 million crossarms since then. Many IOUs and others are now using fiberglass arms including National Grid, Avangrid, AEP, Georgia Power, PG&E, Entergy, and many Cooperatives and Municipals throughout the USA. One of the important applications is on distribution steel poles and to support distribution lines on steel transmission structures. The longevity of fiberglass arms is a good match to the longevity of steel poles.

### Business Case

As noted above, fiberglass crossarms have several important benefits when compared to wood. Benefits associated with fiberglass crossarms are:

- **Improved Longevity**: Fiberglass crossarms are not susceptible to decay, insect, or woodpecker damage. Fiberglass crossarms are constructed with integral UV protection, not just in the surface coating, and are considered to have a life expectancy of 60+ years according to manufacturers such as PUPI. Because of this longevity, fiberglass arms are a good match for installation on steel poles.
- **Withstanding splitting and decay:** Wood crossarms are susceptible to longitudinal and end splitting, allowing moisture to collect and remain in the wood, thus promoting decay. Wood arms are often damaged by woodpeckers, insects, and weathering. Figure 5-17 below illustrates the problem, although both insects and decay were probably involved. Note that a visual inspection from the ground most likely would not have caught this.
- **Ease of Installation**: Fiberglass crossarms are lighter and easier to handle, weighing just up to 1/3 the weight of wood arms. They typically do not need braces, which are necessary with comparable wood arms. Fiberglass crossarms, both tangent and dead-end, include an installed two-hole metal mounting bracket, and therefore take less time

to install on poles. The mounting bracket on the dead-end arms also includes guy attachment points, which is an advantage.

- **Greater Material Predictability**: Fiberglass crossarms are an engineered, manufactured product using controlled processes and materials that offer a uniform product with consistency. Conversely, wood is a highly variable material. Even newly processed wood crossarms can have naturally occurring internal voids and defects. This variability is compensated for by applying load factors, as outlined in the NESC 253, when making strength calculations. The amount of wood preservative retained in the wood, typically pentachlorophenol (PCP)[70], lessens with time. As a result, the strength of wood crossarms degrade over time. Figure 5-18 shows the components of a typical fiberglass crossarm.

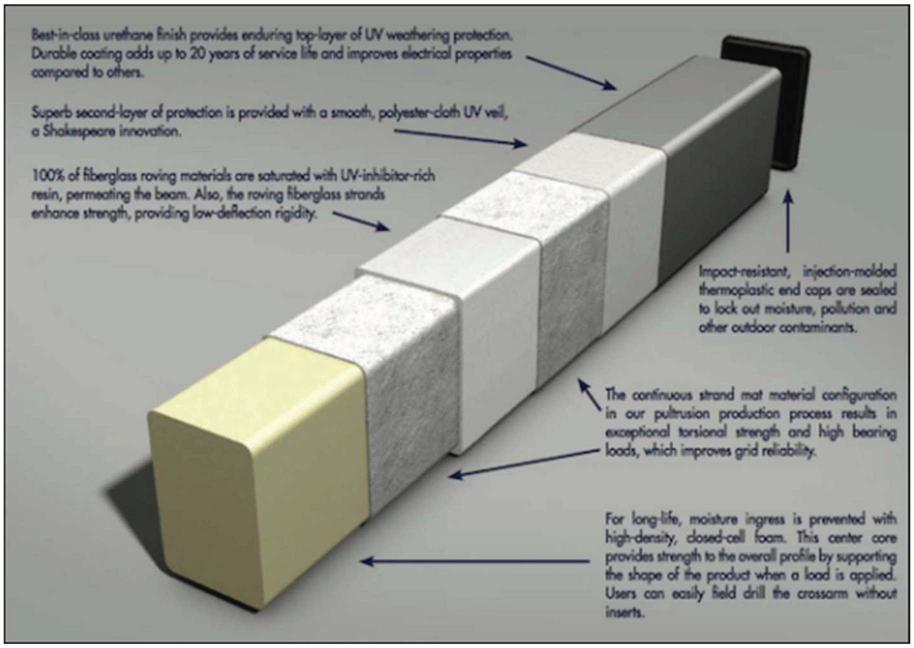
These benefits translate into improved resiliency and reliability of fiberglass cross arms compared to wood.

*Figure 5-17. Insect Damage on an Eversource Wood Crossarm*

*Source: Eversource Photo*

[70] In a March 9, 2021 article in the Chemical & Engineering News (C&EN) a publication of the American Chemical Society "The End of Pentachlorophenol is Near", the Environmental Protection Agency (EPA) is considering banning the use of PCP as a health risk. This comes on the heels of an announcement from the only producer of PCP in North America that it was shutting down its PCP production.

*Figure 5-18. Fiberglass Crossarm Composition Drawing*




*Source: Valmont/Shakespeare*

Longevity and strength are the keys to reliability. As noted earlier, fiberglass crossarms have exceptional longevity, 60+ years. According to a report by Electric Power Research Institute titled Distribution Grid Resiliency: Overhead Structures[71],fiberglass crossarms are approximately 30% stronger than wood and have superior electrical properties. This study notes that their use is now considered a common industry practice.

One study conducted to optimize designs for storm resiliency looked at a variety of distribution wood pole structure designs, as well as the impact of trees falling on lines and the ability of these structures to withstand ice and wind loading.[72] All analysis was based on PLS-CAD™ models for all components of a distribution line, including poles, conductor, crossarms, insulators and other structural supports. The analysis modeled simulations of trees falling onto distribution lines for the following scenarios:

- NESC Heavy Loading (1/2” Ice, wind at 40 MPH)
- ½” Ice at 0ºC and ¾” ice at 15ºC
- 95 MPH wind at 60ºC

The simulations included 8 ft. and 10 ft. fiberglass and wood crossarms and found:

[71] EPRI Distribution Grid Resiliency: Overhead Structures
[72] UC Synergetic, Structural Analysis of Distribution Designs – Northeast Utilities

- For the NESC Heavy Loading case, fiberglass crossarms passed all cases, including the heavy tree simulation (3,840 lbs.). Wood crossarms failed the heavy tree simulation.
- For the ½" and ¾" icing cases, wood and fiberglass arms passed the light tree (1500 lbs.) simulation.
- For the 95 mph. wind test, fiberglass arms passed all cases, while wood arms failed in several.
- The simulations that focused on dead-end structures showed that wood crossarms were utilized to more than 80% of capacity. Fiberglass arms showed a capacity 5 times greater than wood arms.

It should be noted that during storm events, broken poles present the most challenging problems, with crossarms a close second. In some cases, special equipment, such as dozers or cranes, are needed just to deliver the normal equipment and materials to the damage site. However, replacing crossarms, installing conductor splices, pins or insulators can be less dependent on specialized equipment. In some cases, with fewer broken large components, the repair work can be accomplished by line personnel utilizing their climbing skills.

**Cost Analysis**

The cost analysis model below looks at both the lifecycle and present worth costs to install 10 ft. fiberglass and wood tangent arms, as well as dead-end arms, on wood poles. Additional assumptions for this analysis include:

- The life of the wood pole is assumed to be 45 years.
- Wood crossarms are expected to be replaced at 25 to 30 years.
- Fiberglass crossarms do not require replacement for the life of the pole.
- The periodic maintenance cost of $2.14 is for a visual inspection of the installed cross arms (wood and fiberglass), which is assumed to be conducted concurrently with the periodic pole inspection.

The life-cycle cost analysis with a wood crossarm replacement midway through the life of the wood pole shows the fiberglass crossarm is a better investment over the life of the pole.

*Figure 5-19. Wood and Fiberglass Crossarm Lifecycle & Present Worth Costs*

| Project | Initial Cost | Year 10 | Year 20 | Wood Arm Replacement (25-30 years) | Year 30 | Year 40 | Year 50 | Year 60 | Life Cycle Cost | Present Worth Cost |
|---|---|---|---|---|---|---|---|---|---|---|
| **Fiberglass arm, Tangent** | $ 170.23 | $ 2.88 | $ 3.87 | $ - | $ 5.19 | $ 6.98 | $ 9.38 | $ 12.61 | **$ 211.14** | **$ 538.05** |
| Labor | $ 12.15 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 12.15 | |
| Materials | $ 122.00 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 122.00 | |
| Overhead | $ 33.94 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 33.94 | |
| Maintenance | $ 2.14 | $ 2.88 | $ 3.87 | $ - | $ 5.19 | $ 6.98 | $ 9.38 | $ 12.61 | $ 43.05 | |
| **Wood arm, Tangent** | $ 96.83 | $ 2.88 | $ 3.87 | $ 337.70 | $ 5.19 | $ 6.98 | $ 9.38 | $ 12.61 | **$ 475.43** | **$ 318.62** |
| Labor | $ 18.25 | $ - | $ - | $ 38.21 | $ - | $ - | $ - | $ - | $ 56.46 | |
| Materials | $ 51.77 | $ - | $ - | $ 239.74 | $ - | $ - | $ - | $ - | $ 291.51 | |
| Overhead | $ 24.67 | $ - | $ - | $ 51.65 | $ - | $ - | $ - | $ - | $ 76.32 | |
| Maintenance | $ 2.14 | $ 2.88 | $ 3.87 | $ 8.09 | $ 5.19 | $ 6.98 | $ 9.38 | $ 12.61 | $ 51.14 | |
| **Fiberglass arm, Deadend** | $ 335.53 | $ 2.88 | $ 3.87 | $ - | $ 5.19 | $ 6.98 | $ 9.38 | $ 12.61 | **$ 376.44** | **$ 1,049.28** |
| Labor | $ 12.15 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 12.15 | |
| Materials | $ 260.00 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 260.00 | |
| Overhead | $ 61.24 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 61.24 | |
| Maintenance | $ 2.14 | $ 2.88 | $ 3.87 | $ - | $ 5.19 | $ 6.98 | $ 9.38 | $ 12.61 | $ 43.05 | |
| **Wood arm, Deadend Dbl** | $ 223.62 | $ 2.88 | $ 3.87 | $ 734.51 | $ 5.19 | $ 6.98 | $ 9.38 | $ 12.61 | **$ 999.04** | **$ 662.69** |
| Labor | $ 54.71 | $ - | $ - | $ 114.55 | $ - | $ - | $ - | $ - | $ 169.26 | |
| Materials | $ 103.54 | $ - | $ - | $ 479.48 | $ - | $ - | $ - | $ - | $ 583.02 | |
| Overhead | $ 63.23 | $ - | $ - | $ 132.39 | $ - | $ - | $ - | $ - | $ 195.62 | |
| Maintenance | $ 2.14 | $ 2.88 | $ 3.87 | $ 8.09 | $ 5.19 | $ 6.98 | $ 9.38 | $ 12.61 | $ 51.14 | |

## Recommendations

Fiberglass crossarms are an essential component to any system hardening and resiliency program. Benefits include:

- The longevity of fiberglass crossarms, and consistency maintained by the manufacturing process. Fiberglass crossarms are stronger than wood arms of similar dimensions and have superior electrical properties. Their use is now considered a common industry practice.
- Fiberglass arms are stronger and more predictable than their wood counterparts
- Fiberglass arms are easier to install because they are lighter than wood. They are typically delivered with mounting hardware installed and predrilled holes.
- Fiberglass crossarms are cost effective based on the lifecycle cost.

TRC recommends continuing the use of fiberglass crossarms instead of wood crossarms for all new line construction, line rebuild projects and replacement of existing crossarms for maintenance. Crossarm inspection and replacements should also continue to be part of the pole inspection program to identify failing crossarms.

## 5.2 Vegetation Management

### Current Practices

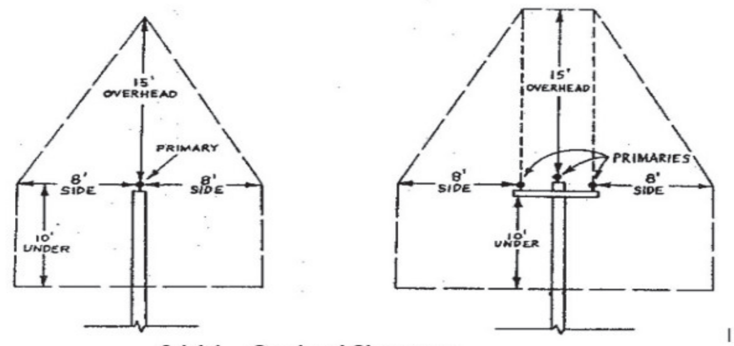
New Hampshire is ranked second in the United States for forest cover, with an estimated 84% timberland, according to the U. S. Department of Agriculture Forest Service.[73] Eversource has approximately 12,200 miles of overhead distribution lines in New Hampshire which are subject to vegetation management. Presently, Eversource implements four vegetation management methods: Scheduled Maintenance Trimming (SMT), Enhanced Tree Trimming (ETT), Full width ROW clearing (ROW), and Enhanced Hazard Tree Removal (ETR), which are detailed below.

**SMT:** Eversource is within the New Hampshire Public Utility Commission's mandate of a 60-month cycle schedule for SMT. Eversource currently follows this trim cycle targeting approximately 2,400 miles per year. Eversource has attempted to reduce the cycle length to 4.5 years by addressing additional mileage when possible. The Eversource Specification for both single phase and three phase construction calls for the following, as shown in Figure 5-20:

- 15 feet of overhead clearance measured vertically from the highest primary conductor.
- 8 feet side clearances measured horizontally outward from the outermost primary conductors.
- 10 feet under clearance measured vertically downward from the lowest primary conductor.
- Selective removal for brush and vine clearance; only the tree brush which is presently at least 16 feet tall within the removal zone should be removed. All vines growing up poles or guy wires should be cut at the ground line and cleared 6 feet up the pole or guy.

[73] USDA, Forest Inventory and Analysis Fiscal Year 2016 Business Report. Page 71-72. Table B-11. Land and forest area and FIA annualized implementation status by State and region, FY 2016. (Percentages for states derived by dividing third column by second column.) Data for territories: Page 70: Table B-10. Status of FIA special project areas excluded from annualized inventory. Retrieved January 8, 2019

*Figure 5-20. Eversource SMT Specifications*




2.1.1.1. **Overhead Clearances**
15 feet overhead clearance shall be measured vertically upward from the highest primary.

2.1.1.2. **Side Clearances**
8 feet (10 feet MA-E) side clearance shall be measured horizontally outward from the outermost primary.

2.1.1.3. **Under Clearances**
10 feet under clearance shall be measured vertically downward from the lowest primary.

2.1.1.4. **Brush and Vine Clearances**
Selectively remove only that tree brush which is presently at least 16 feet tall within the zone or growing into the zone. All vines which are growing up poles or guy wires shall be cut at the ground line and cleared 6 feet up the pole or guy.

**ETT:** For 2021, ETT is scheduled to be performed on approximately 50 miles of backbone or mainline circuits and on some poorer performing circuits selected from Eversource reliability data and other performance factors. In 2020, 49 miles were addressed. The average mileage over between 2014 and 2020 was approximately 80 miles annually. To date, approximately 1,100 miles of the 1,600 miles of backbone mainline have been completed. The ETT specifications call for 8 feet side clearances, measured horizontally outward from the outermost primary conductor to either side of the utility poles and primary conductor from the ground up. This includes removal of:

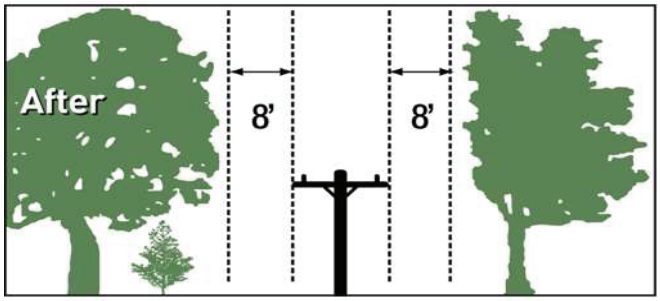
- All overhanging limbs. If overhanging limbs cannot be 100% removed, the tree should be considered for removal. If greater than 1/3 of the tree is to be trimmed to meet the overhang requirement, then the entire tree is to be removed.
- All brush and all trees within the clearance zone.
- All vegetation 10 feet around poles and guying systems.

Additionally, specifications state that:

- Consent forms and details about tree work will be delivered to each property owner in advance of any work performed. Property owner consent is required in writing. Any refusal will be documented and submitted to Eversource weekly.
- Arborist will field verify the completed work.

ETT is only performed on a backbone portion of a circuit one time. Future vegetation management is performed with SMT.

*Figure 5-21. Eversource ETT Specifications*




**Full-Width ROW Clearing:** ROW clearing allows an easement that has been encroached upon with vegetation to be fully cleared and restored to the full easement width from when the line was originally constructed. Once restored, future vegetation management will be performed with SMT.

**ETR:** ETR 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. During the SMT cycle,[74] trees are identified that may fail or are a threat to electrical facilities or public safety. These trees are inspected by arborists in the fall zone (i.e., the area outside of the roadside clearance zone where an uprooted tree could strike the conductor and cause an outage).

Trees identified for removal in the fall zone will be approved by the property owner or their representative prior to removal. If consent is denied, the tree will remain as a hazard.

The following contingencies are considered:

- If greater than 1/3 of the tree is to be trimmed via SMT, ETT, or ROW clearing, the tree should be removed as an in-zone removal.
- If a tree is not a hazard at present, but a customer wants it removed regardless, the tree should be removed after being approved by the Owner's Representative. Tree species and form, future maintenance costs, and aesthetics should be considered.

The Company's SMEs indicated that the majority of their customers live among trees. When SMT is performed, hazard trees are identified on three-phase lines and in heavy customer areas; the entire 3-phase line is looked at during SMT. A list of hazard trees is provided to the arborists, who then evaluate the trees to make the determination of which to remove. Once identified, the hazard trees are generally removed within several weeks.

[74] Since hazard trees are identified during the SMT cycle, Eversource is not likely to revisit a circuit for four to five years.

### Industry and Utility Findings

Vegetation management is performed in accordance with the Vegetation Management Document Number 5.60, Rev 2, which states, “Work is performed in compliance with OSHA 1910.269 and ANSI Z133.1safety standards, ANSI A300 Pruning Standards, International Society of Arboriculture Best Management Practices for Utility Pruning and Eversource’s Specification for Distribution Line Clearance Tree and Brush Work.” The document further states “Property owner consent for tree pruning or removal is required along public roads and on private property.”

Hazard tree removal follows the guide from The International Society of Arboriculture (ISA)’s Handbook of Hazard Tree Evaluation for Utility Arborists. Hazard trees in the fall zone are evaluated based on soil type, depth, drainage and wind susceptibility, tree growth, species, form, insect infestation and tree defects such as: cavities, nesting holes, decay conks, old wounds, 'V' crotches, poor rooting, and poor basal flare.

An article from the Transmission & Distribution World publication in June 2012[75] references the ANSI standard A300 (Part 9) for Tree Risk Assessment. The article states:

> *“Utility vegetation management programs have traditionally focused on preventing tree-line contact by obtaining specified clearances. While such programs certainly reduce tree-line contact and prevent some interruptions, many outages are caused by tree and branch failures that originate from outside the specified [vegetation management] scope of work. To improve system performance, utilities are increasingly focusing resources on hazard tree abatement, or, more accurately, tree risk management. Utilities can increase the value of their vegetation management investment by systematically concentrating on trees that pose the highest level of risk. Completely mitigating the risk posed by trees would require utilities to specify pruning or removing any tree with the potential to strike a utility line. Of course, this would be cost prohibitive and raise customer acceptance concerns. More importantly, it would be quite unnecessary since many trees in close proximity to utility lines pose relatively low risk. The key to improving the effectiveness of vegetation management efforts is for utilities to determine the relative level of risk posed, allocate resources to benefit the greatest number of customers, and establish written specifications that clearly define the scope of work for contracted personnel.”*

[75] Transmission & Distribution World, “ANSI Standard Helps Utilities,” June 2012. https://www.tdworld.com/vegetation-management/article/20963624/ansi-standard-helps-utilities-manage-risk

### Business Case

One study conducted by Eversource in Connecticut, and summarized in the Journal of Environmental Management, evaluated and compared outage rates for tree related causes on backbone and lateral conductors that received ETT and lateral conductors that had not received ETT to evaluate the effectiveness of ETT on reducing tree related power outages during storm events.[76] The study, which covered the Eversource system across the entire state of Connecticut for the period 2005-2007,[77] found ETT-treated conductors had storm outage rates that ranged from 35-180% lower than the service-area's average annual outage rate for untreated conductors. Further, it found a “35-45% reduction in annual storm-related outage rates for backbone lines in storm-damaged areas, when compared to untreated laterals lines: this result is consistent with Eversource's internal performance review which attributed a 35-40% reduction in outage rates to ETT for backbone lines during major storms.”[78] Additionally, the study provided empirical information to support the claim that ETT treatment has an impact on reducing power outage rates during storm conditions and referenced other industry reports that supported this claim.

Lastly, the study referenced a report that found “hazardous tree removal and “storm proof” trimming reduced outage rates by 20–30% for an electric utility in Massachusetts.”[79] The findings of this study and the others referenced clearly support ETT as an effective practice to reduce outages caused by trees, particularly during storm events.

### Reliability

There are two reliability measurements that are most impacted by vegetation management: The System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index (SAIDI).

**SAIFI:** SAIFI is the average number of sustained interruptions per consumer during the year. It is the ratio of the annual number of interruptions to the total number of customers served. Figure 5-22 shows overall SAIFI by various outage cause categories between 2011 and 2020 in Eversource’s New Hampshire territory. It is evident that tree related outages have been the leading cause of outage events during this time.

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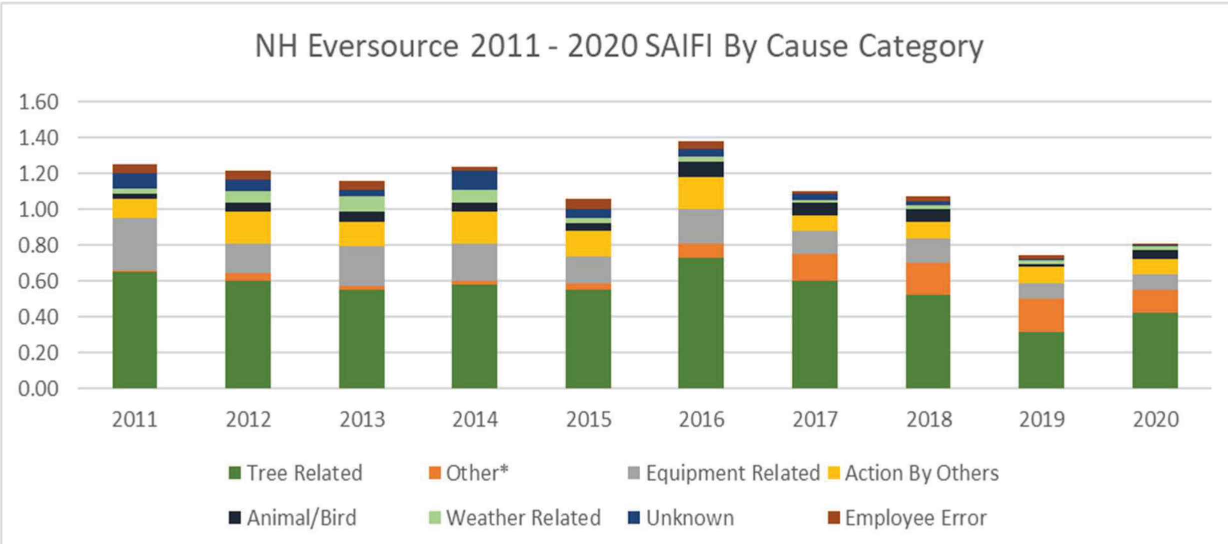
[76] From Journal of Environmental Management 241 (2019) 397–406 Research article “An analysis of enhanced tree trimming effectiveness on reducing power outages”.
Jason R. Parent∗, Thomas H. Meyer, John C. Volin, Robert T. Fahey, Chandi Witharana P398

[77] The variations for weather, tree cover, and wire type were controlled by pairing ETT-treated zones with nearby untreated zones.

[78] Journal of Environmental Management. “An analysis of enhanced tree trimming effectiveness on reducing power outages.”

[79] Journal of Environmental Management. “An analysis of enhanced tree trimming effectiveness on reducing power outages.”

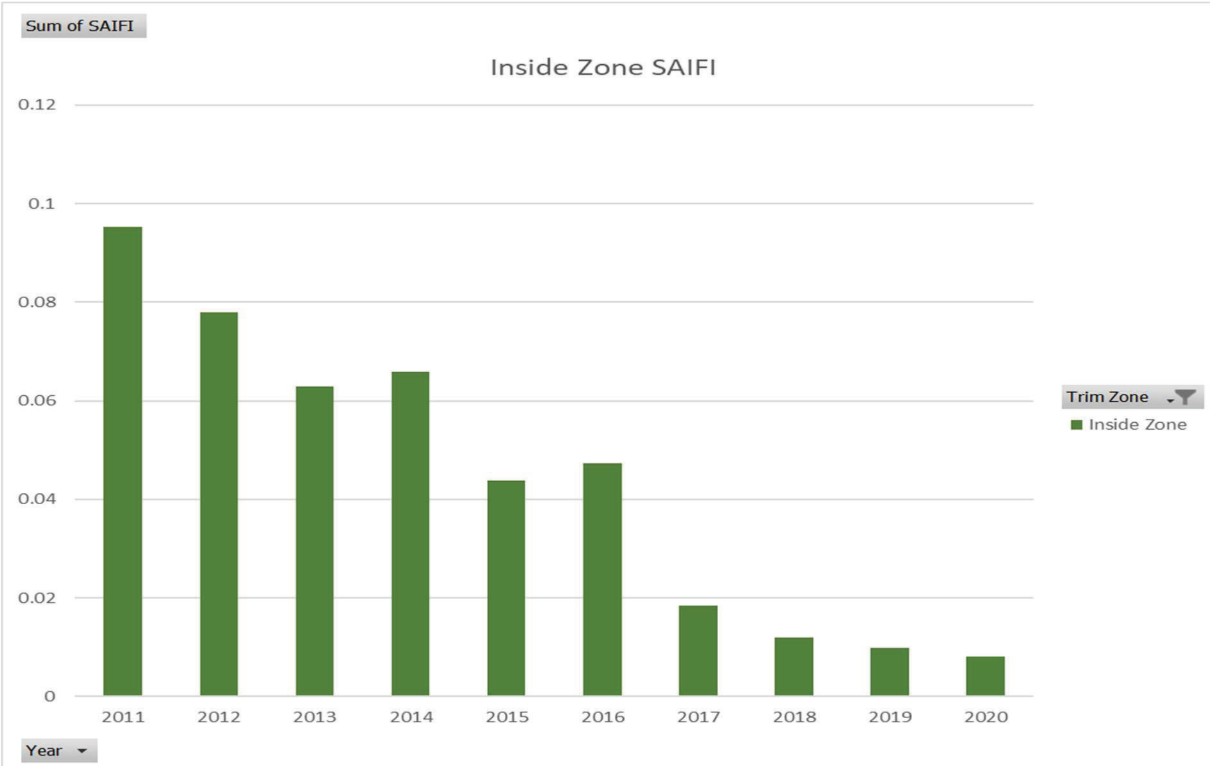
*Figure 5-22. SAIFI By Causal Category*




SAIFI is a common measure for tree related performance since it is impact-based rather than time-based. Reduction in SAIFI better reflects a reduction in the number of outage events.

SMT, ETT, and ROW typically affect Trees Inside Zone events. ETR involves the removal of trees both within and outside standard trimming zones and therefore affects both Trees Inside Zone and Trees Outside Zone caused outage events. Since 2011, there has been a significant reduction in SAIFI related to tree inside zone outages due to SMT, ETT and ROW as seen in Figure 5-23.

*Figure 5-23. SAIFI for Tree Inside Zone Caused Outages*




The eventual leveling off for SAIFI, as shown in the above figure, is expected as the zone around the primary lines are cleared and maintained. Since ETT and ROW are typically applied one time on a given distribution line as described previously, it becomes necessary to continue the current SMT program to maintain that level of SAIFI for tree inside zone caused outages.

Figure 5-24 shows vegetation growth on a single-phase distribution transformer pole that SMT will remove.

*Figure 5-24. Vegetation on Distribution Transformer Pole*

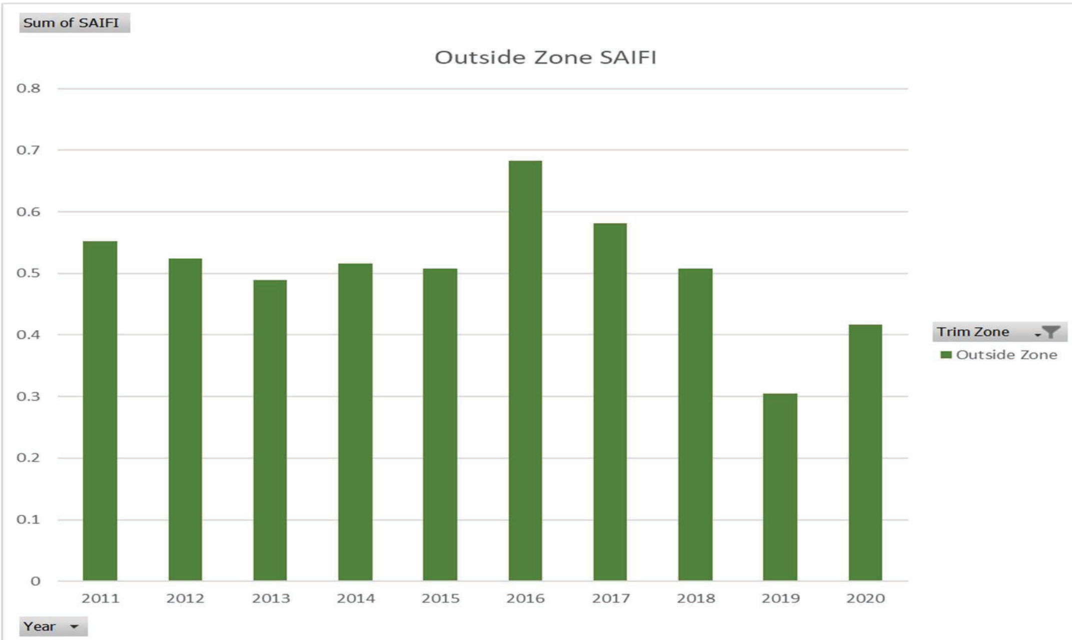
*Source: TRC Field Inspections*

Since 2016, there has been a downward trend in SAIFI related to tree outside zone outages as seen in Figure 5-25. The Company has direct control over the trees inside the zone due to their right to clear vegetation in the easements. For trees outside the zone, two challenges exist:

- It is difficult to identify all the trees which are either a hazard to the line either from branches breaking or trees falling into the line.
- It is not always possible to acquire permission from the property owner, which is required before trees outside the zone can be trimmed or removed.

For these reasons, the SAIFI for trees Outside Zone will not be as low as Inside Zone.

*Figure 5-25. SAIFI for Tree Outside Zone Caused Outages*




Trees identified by Eversource as ones that may fail and fall into a distribution primary line are removed. However, not all trees that are hazards can be identified. During the time between SMT, trees outside the zone can develop into hazards due to insect infestation, decay or other factors and cause outages.

TRC conducted visual site inspections of distribution circuits located both along roadsides and off-road in ROW. In these locations, vegetation management had been completed via SMT or ETT, with ROW clear. However, it was evident in a number of locations that there were a significant number of trees outside the zone that were more than two times the height of the distribution line. An undetected hazard tree that fails and falls toward the line would likely damage the primary and or poles. Due to the sample number of locations observed and the amount of vegetation existing outside the easement, it is unlikely that the amount of Tree Outside Zone caused outages would continue to reduce in the same manner the Trees Inside Zone metric has in recent years.

Figure 5-26 and Figure 5-27 show a portion of circuits that have been cleared with trees outside the zone.

*Figure 5-26. Trees Outside Zone in Right-of-Way*

*Source: TRC Field Inspections*

*Figure 5-27. Trees Outside Zone Along Roadside*

*Source: TRC Field Inspections*

Figure 5-28 and Figure 5-29 show a portion of a circuit before and after ETT and ETR clearing was performed. Trees on the right side are encroaching on the line including several potential hazard trees.

*Figure 5-28. Eversource circuit prior to ETT clearing*

*Source: Eversource*

*Figure 5-29. Eversource circuit after ETT clearing*

*Source: Eversource*

Figure 5-30 and Figure 5-31 show a distribution line before and after ROW clearing was performed.

*Figure 5-30. Eversource circuit prior to ROW clearing*

*Source: Eversource*

*Figure 5-31. Eversource Circuit following ROW clearing*

*Source: Eversource*

Figure 5-32 and Figure 5-33 show a before and after ROW clearing was performed to remove trees and vegetation encroaching on the right-of-way and mitigate the potential for tree contact.

*Figure 5-32. Eversource circuit prior to ROW clearing*

*Source: Eversource*

*Figure 5-33. Eversource circuit after ROW clearing*

*Source: Eversource*

The impacts of the extended times between trim cycles or reducing the annual miles to be trimmed may have a significant negative effect on reliability. One study conducted to evaluate the impact of deferring vegetation clearing on distribution lines found that the cost to clear the line after one year of deferral required a significant increase in labor and cost to bring the line clearance in line with specifications.[80] The study was conducted on three electric utility properties in the U.S. by Environmental Consultants, Inc. Field data was collected and used in a predictive model looking at labor requirements, cost impacts and biomass disposal resulting from deferred maintenance. As shown in Figure 5-34, labor time and cost both increase when SMT is deferred. The study also projected that biomass (chipped debris) could double with one year of trimming deferral which would increase the cost for removal.

[80] The Economic Impacts of Deferring Electric Utility Tree Maintenance, by D. Mark Browning and Harry V. Wiant, from Journal of Arboriculture 23(3): May 1997. pp 106 – 111. https://www.eci-consulting.com/wp-content/uploads/2017/10/Deferring-Electric-Utility-Tree-Maintenance_JOA.pdf

*Figure 5-34. Impact of Deferring SMT*

| Number of Years Trimming is Deferred | Average Labor Time Increase | Average Relative Cost Increase |
|---|---|---|
| **1 Year** | 21% | 20% |
| **2 Years** | 38% | 37% |
| **3 Years** | 52% | 51% |
| **4 Years** | 62% | 60% |

*Source: Journal of Arboriculture*

The study also modeled a 20 percent decrease in annual funding for a cycle-based maintenance program. Although it would seem that a 5-year cycle would increase to 6.25 years with a 20 percent decrease in annual funding, in reality, the cycle is extended much longer – to 9 years, due to the additional years' growth beyond what would have to be managed in a 5-year cycle. This study did not account for the impact on the deferred trimming on reliability or the additional off cycle maintenance costs.

**SAIDI:** SAIDI is the average duration of interruptions per customer during the year, measured in minutes. It is the ratio of the annual duration of sustained interruptions to the total number of customers served.

An NHPUC Utility Analyst notes that while SAIDI is an appropriate second level decision tool for tree-based reliability enhancements, care should be taken to ensure inputs are uniform:[81]

*"…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."*

There has been a significant reduction in SAIDI related to tree inside zone outages since 2011 as seen in Figure 5-35 and a slight downward trend in SAIDI related to tree outside zone outages since 2016 as shown in Figure 5-36.

[81] Direct Testimony Kurt Demmer, Utility Analyst NHPUC, December 20, 2019, page 21.

*Figure 5-35. SAIDI for Tree Inside Zone Caused Outages*

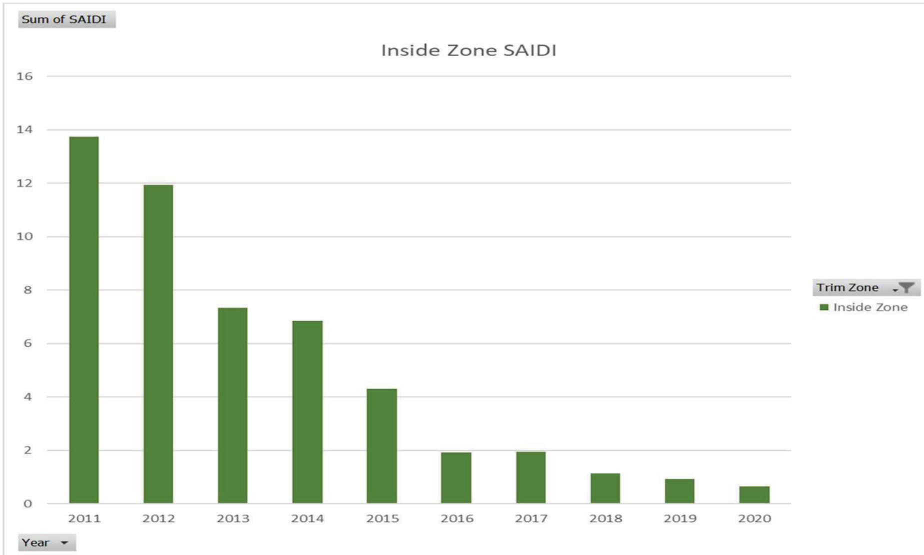
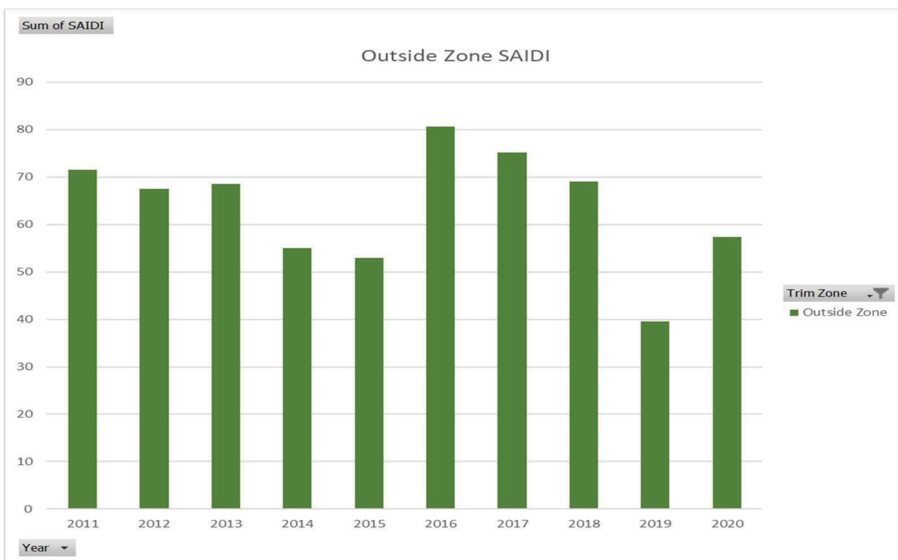



*Figure 5-36. SAIDI for Tree Outside Zone Caused Outages*




The SMT, ETT and ROW programs have addressed Inside Zone trees, resulting in significantly fewer outages. Outages from Outside Zone trees tend to result in more severe damage from trees falling into the line, which can increase in the amount of time spent on service restoration. Although service restoration is not a vegetation management expense, it is an operational expense that can be directly related to vegetation conditions and should therefore be considered.

## Cost Analysis

Eversource has budgeted $27.1M for vegetation management in 2021, more than half of which is designated for SMT.[82] The breakout of activities is shown below in Figure 5-376.

*Figure 5-37. Eversource 2021 Vegetation Management Portfolio Budget*

| Vegetation Management Activity | 2021 Budget ($M) |
|---|---|
| SMT | $14.0 |
| ETT & ETR | $11.6 |
| ROW | $1.5 |

*Source: Eversource Direct Testimony*

As noted in Figure 5-23 and Figure 5-35, both SAIFI and SAIDI for Inside Zone tree-caused outages have shown reductions over the last decade and appear to have leveled off. SMT will now be an ongoing program that will mitigate mostly Tree Inside Zone caused outages. To maintain the current level of reliability with SMT and comply with New Hampshire Public Utility Commission's mandate of a 60-month cycle schedule, the Company would need to maintain an average of 2,440 miles annually, or 20% of the system.

Eversource's current vegetation management contract for SMT covers the 4-year period from January 1, 2021 through December 31, 2024. The estimated cost for SMT in 2021 is approximately $7,000 per mile, which is up from $6,000 per mile in 2020 and from $5,235 per mile between 2016 and 2018.[83] The increase is attributed to market conditions, as contractors have been challenged with the availability of skilled and experienced tree resource labor and an increase in areas expecting more significant traffic control, such as a police detail instead of flaggers. The cost increases will likely continue through the remainder of the current contract due to these prevailing conditions. Based on the current $7,000 per mile, Eversource would require $17.1 million, more than $3 million more than budgeted, to complete SMT for the average 2,440 miles annually. This gap will continue to widen if per mile costs increase over the contract period.

At current per-mile costs and the present funding level of $14.0 million, Eversource would be able to maintain approximately 2,000 miles in 2021, approximately 82% of the amount required under the 60-month schedule. Figure 5-38 illustrates the impact of deferring SMT in additional cost and labor. A one-year deferral in SMT would increase the cost from $7,000 to $8,400 per mile deferred. Sustaining the 2021 budget level of $14 million for SMT would lead to increasing deferrals and escalating average costs per mile. As shown in Figure 5-387, by 2024, almost all of Eversource's SMT activities would be addressing miles that were deferred in the previous year – at a higher cost per mile. By 2025, some miles would begin to be deferred by two years,

[82] Public Service Company of New Hampshire, Direct Testimony of Joseph A. Purington and Lee G. Lajoie - Grid Transformation and Enablement Program: Acceleration of Targeted Infrastructure Upgrades, Docket DE 19-057, 5/28/2019. https://www.puc.nh.gov/regulatory/Docketbk/2019/19-057/INITIAL%20FILING%20-%20PETITION/19-057_2019-05-28_EVERSOURCE_DTESTIMONY_PURINGTON_LAJOIE.PDF
[83] New Hampshire Public Utilities Commission, Direct Testimony of Kurt Demmer, Docket DE 19-057 December 20, 2019

further increasing costs-per-mile (to nearly $9,600), and this spiraling of average costs would continue until investment levels are increased to return to a five-year schedule or market conditions changed to reduce costs for vegetation management resources.

*Figure 5-38. Cost increases resulting from under-investment in vegetation management*

| | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|
| **Budget** | $14,000,000 | $14,000,000 | $14,000,000 | $14,000,000 |
| **Base cost-per-mile** | $7,000 | $7,000 | $7,000 | $7,000 |
| **Deferred cost per mile (1 year)** | | $8,400 | $8,400 | $8,400 |
| **Previous year deferred miles** | | 440 | 968 | 1,602 |
| **Budget used to address deferral** | | $3,696,000 | $8,131,200 | $13,453,440 |
| **Remaining budget for base SMT** | | $10,304,000 | $5,868,800 | $546,560 |
| **Base miles maintained** | 2,000 | 1,472 | 838 | 78 |
| **Average Cost per Mile** | $7,000 | $7,322 | $7,750 | $8,335 |

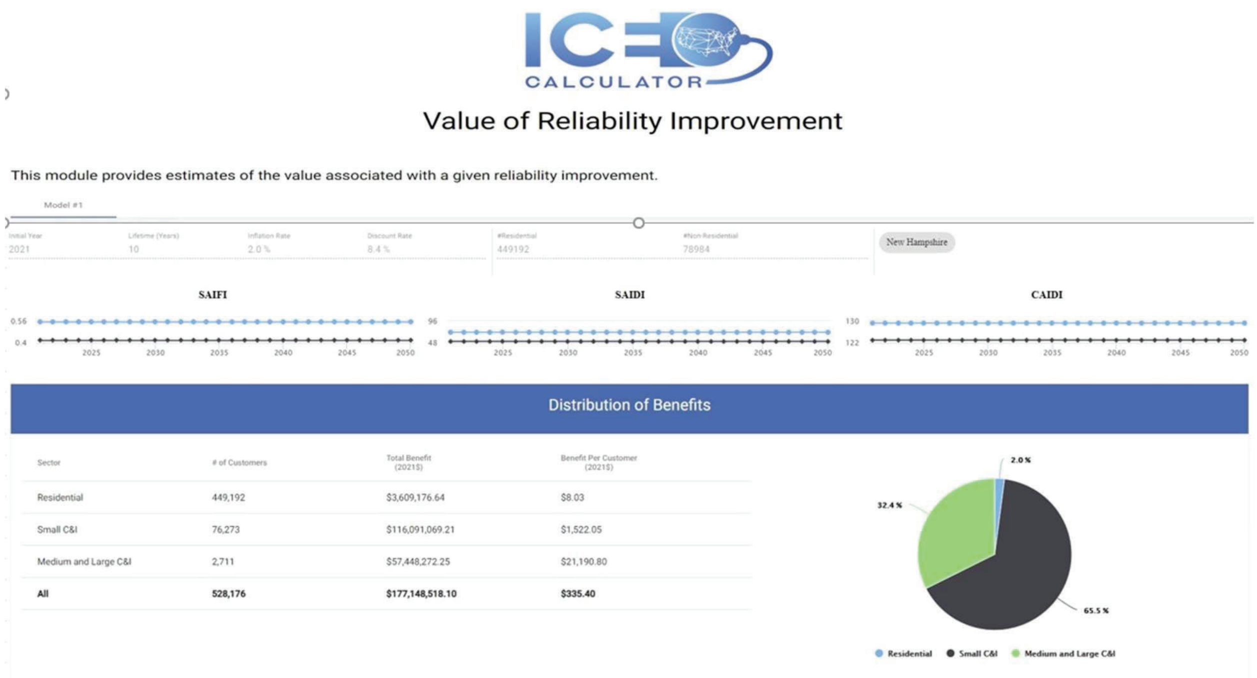
Notably, the modeling above is conservative in that it does not reflect expected cost increases per mile as described above due to market conditions; if these were factored in, the trends would be further exacerbated. The increasing rate of deferred miles modeled above would lead to a regression in the reliability metric improvements noted above. In total, Eversource would see both increasing costs per mile and decreasing reliability benefits at the same time if this underinvestment in SMT persists. As a result, TRC recommends the SMT budget be increased to $17.1 million for 2021 to maintain the 5-year maintenance schedule. Future year budgets should be adjusted as necessary to account for increasing labor resource costs.

Since SMT targets Tree Inside Zone-caused outages, ETT, ETR and ROW will primarily address the Tree Outside Zone caused outages. The 2021 budget for these programs is $13.1 million. During the past 5 years, the average ETT spend was $5.1 million, ETR was $10.2, and combined ETT/ETR spend $15.3 million. If a portion of this budget were repurposed to address the shortfall in SMT described above, TRC expects that the progress in Tree Outside-Zone caused outages would be reversed as fewer resources are available to address these hazards.

TRC analyzed overall vegetation management costs and benefits using the Department of Energy's Interruption Cost Estimate (ICE) Calculator.[84] This tool was designed for electric utility reliability planners, government organizations or other entities to help estimate interruption costs and/or the benefits associated with reliability improvements in the United States. Looking at the SAIFI and SAIDI improvements for Tree-caused outages between 2011 and 2020, the tool shows a reliability benefit per customer of $335 over a ten-year period. See Figure 5-39 below.

[84] U.S. Department of Energy Office of Electricity, Interruption Cost Estimate (ICE) Calculator, accessed 5/3/21. https://www.icecalculator.com/home

*Figure 5-39. ICE Calculator Value of Reliability Improvement for Eversource 2011-2020 Vegetation Management*




*Source: U.S. DOE ICE Calculator*

On an annual basis, this reliability benefit equates to $33.50 per customer. Based on the current level of spend for the non-SMT vegetation management of $13.1 million, the annual average cost per customer is $24.77, which results in a net benefit of nearly $9 per customer. The annual average benefit of $33.50 would support an increased budget of up to approximately $17.7 million annually for the combined ETT, ETR and ROW programs, before costs would outweigh these customer benefits.

ETT has averaged over 80 miles of backbone circuit per year between 2014 and 2020. The target is 50 miles in 2021.

TRC performed a second, more targeted cost effectiveness analysis for ETT using 11 circuits which had most, if not all the backbone trimmed to ETT specifications. In this analysis, TRC compared the circuit reliability for SAIFI and Customer Average Interruption Duration Index (CAIDI) for the years 2011 through the year ETT was completed against the metrics for years after ETT was conducted. There was an observed 58% decrease in SAIFI between the pre- and post-ETT years and a decrease of 5% in CAIDI of 5% for these circuits following the ETT clearing, as seen in Figure 5-40 and Figure 5-41.

*Figure 5-40. Pre- and Post-ETT SAIFI for 11 Analyzed*

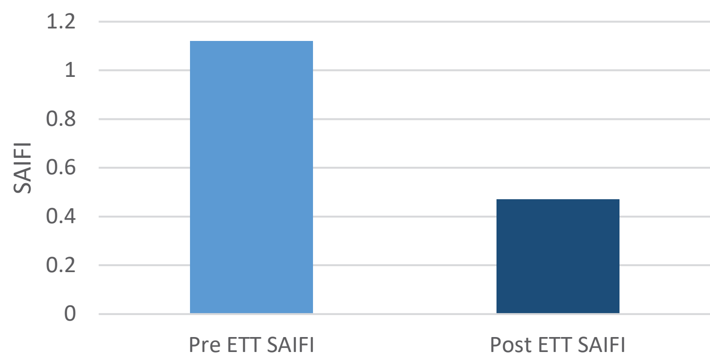
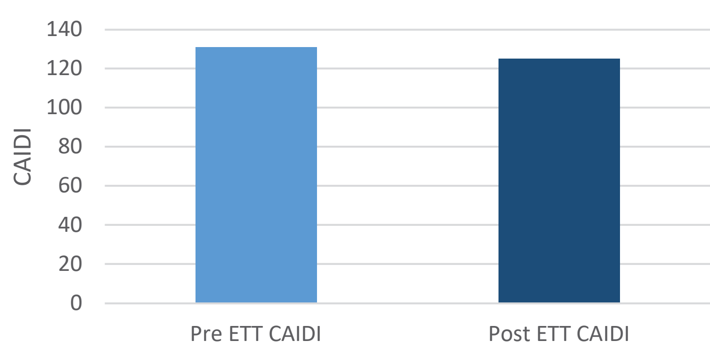



*Figure 5-41. Pre- and Post-ETT CAIDI for 11 Analyzed Circuits*




This group of circuits shows improvement in reliability when comparing reliability before ETT and after ETT was performed. This information was then applied in the Interruption Cost Estimate (ICE) Calculator tool focusing at the SAIFI and CAIDI improvements for Tree caused outages between 2011 and 2019, as shown in Figure 5-42.

*Figure 5-42. ICE Calculator Value of Reliability Improvement for Eversource 2011-2020 Vegetation Management – Pre- and Post-ETT on 11 Circuits*


*Source: U.S. DOE ICE Calculator*

The tool shows a reliability benefit per customer of $1,510 over a ten-year period. This is the benefit gained for these entire circuits where ETT has been performed on the backbone. Using the total mileage of ETT performed on these 11 circuits, average costs per year when they were performed, and number of customers served by each circuit, the average cost per customer for these ETT activities was $371, significantly less than the total reliability benefit per customer of $1,510. Based on these findings, we conclude the ETT activities to be highly cost effective for the value of reliability benefits according to the ICE calculator.

During the past 3 years, ETR has been performed under unit pricing. The cost per removal was based on the negotiated amount by tree diameter size. Between 2018 and 2020, an average of 18,900 trees were removed annually at an average cost of $680 each.

**Recommendations**

Based on the cost-effectiveness findings of the ICE calculator tool, TRC recommends continuing with Scheduled Maintenance Trimming (SMT), Enhanced Tree Trimming (ETT), Full width ROW clearing (ROW), and Enhanced Hazard Tree Removal (ETR), and funding these efforts to avoid incurring escalating costs from deferred maintenance. TRC recommends the following:

- **SMT:** Address an average 2,440 miles annually to follow the 60-month clearing cycle. This will focus on the Inside Zone vegetation and maintain the level of tree caused outages at current levels as indicated by Figure 5-23. Deferral of this work for a year or more will risk erasing the progress on tree-related reliability improvements achieved over the last decade and lead to increasing costs per mile and physical resource needs. This will likely have an impact on the budget. Based on the Company's estimate of $7,000 per mile for 2021, it would cost $17.1 million to complete SMT for this year. Budget adjustments may be necessary in subsequent years to maintain this pace.
- **ETT:** Accelerate ETT to 80 miles per year to address the remaining 500 miles of the backbone circuits within the next seven years. This will likely have an impact on the budget and be subject to availability of physical resources.
- **ROW:** Continue clearing at the current pace to allow for the restoration of the full original easement where vegetation has encroached.
- **ETR:** Target approximately 19,000 hazard tree removals annually following the current identification and prioritization practice. The cost for this will be subject to the size of the trees removed. Evaluate additional strategies to drive improvements in outside-zone tree-related outage performance.

## 5.3 Substation Transformers

### Current Practices

Eversource Distribution System Planning Guide defines the design criteria for the sizing of a distribution power transformer. Any facility that operates at a voltage of 100kV or higher is considered part of the Bulk Electric System (BES).[85] The loading of bulk transformers under normal operation (N-0) system conditions are not to exceed 95% of the normal rating. Any loading beyond this will increase the risk of equipment failure and reduce customer reliability when exposed to a single contingency operation (N-1). The loading of non-bulk transformers varies slightly from that of bulk transformers. Non-bulk transformers planned loading shall not exceed 100% of the normal rating under (N-0) system conditions. Under (N-1) conditions for non-bulk transformers, the loading of the transformer is to be reduced below the long-term emergency (LTE) rating.

The criteria above are set to provide proper pre-loading conditions to allow the transformers to operate effectively below LTE, short-term emergency (STE), and drastic action limit (DAL) ratings. The condition rating percentages do not restrict the actual operation of the transformer. All transmission owners in New England are required to provide their own set ratings and duration times for these categories per ISO-NE PP-7 section 2.3[86]. These include durations for both summer and winter loading. Eversource utilizes the following durations for contingency

[85] NERC. *NERC Review of Bulk Electric System Definition Thresholds*. Mar. 2013, www.nerc.com/pa/Stand/Project%20201017%20Proposed%20Definition%20of%20Bulk%20Electri/bes_phase2_pc_report_final_20130306.pdf.
[86] ISO NEW ENGLAND PLANNING PROCEDURE NO.7. ISO New England, 7 Nov. 2014, www.iso-ne.com/static-assets/documents/rules_proceds/isone_plan/pp07/pp7_final.pdf.

analysis:

- Normal Ratings – Continuous
- Winter LTE (W LTE) – 4 hours
- Summer LTE (S LTE) – 12 hours
- Winter STE (W STE) – 30 minutes
- Summer STE (S STE) – 30 minutes
- Drastic Action Limits (DAL) - Equal to the STE for summer and winter ratings

To maximize the substation output, Eversource bulk distribution stations are designed to consider the loss of the largest distribution element during an (N-1) contingency, in addition to the load that can be transferred out of the station post contingency. Dispatcher initiated load transfers are to be available to keep transformer winding loads below the LTE rating within the set time frame detailed below:

- The initial post-event assessment period for dispatchers to identify/assess the event shall be 10 minutes.
- The time to implement each load transfer is 5 minutes.
- All load transfers are sequential, when more than one is needed:
    - Two transfers take 10 minutes.
    - Three transfers take 15 minutes.
- Where possible, there should be at least one extra load transfer available if one of the primary load transfers cannot be accomplished.

Following the loss of a non-bulk transformer, if distribution switching cannot restore customers within 24 hours, it will be required to position a mobile substation to restore service. For restoration of a bulk transformer, restoration capacity is required within the distribution system to ensure no loss of service. Eversource is required to perform annual tests and regularly schedule maintenance in accordance with Eversource Maintenance plan chapters 5.58 and 6.58 to maintain reliability.

**Typical Usage and Installation Practices**

Eversource is required to make transformer and substation upgrades to mitigate any risks to capacity, power quality, and reliability. Various strategic criteria are assessed when deciding to make substation upgrades. The upgrades to bulk distribution substations are based on the following order when addressing criteria violations:

1) Highest to lowest overloads under normal (N-0) and (N-1) contingency conditions.
2) Load loss under first contingency (N-1) conditions.
3) Highest to lowest number of customers impacted during contingency conditions.
    a) Associated risk evaluation of substation based on individual components (Asset condition). The asset condition criteria do not include equipment with asset

conditions deemed a safety hazard, those should be prioritized and resolved under emergency conditions.

These steps help prioritize reliability driven replacements to provide reduced outage time to those that may be affected by power outages. Individual substations are then assessed by distribution system planning for violations and then ranked based on Figure 5-43 below.

*Figure 5-43. System Violation Ranking*

| Priority Number | Violation Type | Description |
|---|---|---|
| 1. | Capacity | Bulk Distribution Substation Overloads |
| 2. | Capacity | Non-Bulk Distribution Substation Overload |
| 3. | Reliability | Single Contingency (N-1) load loss |
| 4. | Reliability<br>Power Quality | Substations with higher risk of equipment failure, due to asset condition or power quality violations, supplying High Load Density Areas |
| 5. | Reliability<br>Power Quality | Substations with higher risk of equipment failure, due to asset condition or power quality violations, supplying Low Load Density Areas |
| 6. | Power Quality | Power quality Violations such as Harmonics, TOV, ROI |
| 7. | Reliability | Non-Standard Substation Design |

*Source: Section 2.9 of the Eversource Distribution System Planning Guide*

Once a distribution transformer is identified for replacement at a substation, the sizing of that transformer is based on the respective substation voltage class. Figure 5-44 shows Eversource transformer sizes based on recent completed projects and proposed future upgrades.

*Figure 5-44. Eversource Bulk Transformer Sizing*

| Substation Voltage (kV) | Transformer Size (MVA) |
|---|---|
| **34.5** | 62.5 |
| **12.48** | 30 |
| **4.16** | 10 |

*Source: Eversource interviews*

*Figure 5-45. New 62.5 MVA Transformer at Pemigewasset Substation*

*Source: TRC Field Inspections*

Per Eversource interviews, the standard high side point of disconnect for a station power transformer is currently a circuit switcher. The amperage rating of the circuit switcher is based on the size of the transformer. The key driver for the addition of a new circuit switcher would be to increase reliability from stations that rely on disconnect switches as the point of disconnect on the high side of the transformer. A circuit switcher would also need to be replaced to support a transformer addition if the current circuit switcher is not rated properly for the increase in size. If the fault current is too large, the circuit switcher would be unable to trip, leading to reliance on remote breakers and slowing the switching scheme. Eversource typically interrupts faults on the low side of the transformer, which is why circuit switchers are the current installation standard. The addition of a vacuum circuit breaker on the high side of the transformer provides more reliability for transformer differential currents and over-current protection than a circuit switcher.

Feeder breakers within distribution yards are used to provide protection for incoming feeder lines. The typical standard breakers used for new feeder installs are 1200-amp outdoor circuit breakers. A breaker replacement is typically triggered by the age of the breaker; there is no set number of years that will trigger a replacement, but age is the main factor that determines what breakers to replace. Equipment failure can lead to replacements as well. If a certain breaker is experiencing repeated maintenance over time, this could trigger a breaker replacement project.

### Industry and Other Utility Findings

Changes in electricity usage and risks to the electric grid across the country are driving new investments in substations to build a more resilient electric system at these critical nodes. The US Energy Information Administration projects electricity usage will continue to grow at approximately 1% per year through 2050.[87] In addition to severe weather, these risks include cyber threats, physical threats, an increasingly renewable and intermittent generation portfolio, and the growing interdependencies of natural gas and water usage. The insufficient integration of natural gas and water into the electric grid opens the door to threats such as vulnerability to cyber threats and severe weather. Utilities and the U.S. Department of Energy are pushing for transformer upgrades across the grid to increase customer resiliency.[88]

One program designed to address challenges associated with power transformers is the Transformer Resilience and Advanced Components (TRAC) program,[89] which promotes transformer upgrades. This program supports the research and development (R&D) activities to advance technologies and approaches that maximize the value and lifetimes of existing grid components. The goal is to accelerate grid modernization by addressing deficiencies of large power transformers, Solid State Power Substations, and other critical grid hardware components. Also, to increase the resilience of aging assets and identify new requirements for future grid components.[90] The program has increased its scope and funding since 2016 to pinpoint the industry's critical application needs and technology challenges.

Other Utilities within the Northeast are focusing on transformer upgrades to increase resiliency as well. These utilities are focusing on standardizing their transformers to not only provide a more reliable service, but to increase efficiencies and operational consistency. This leads to more spare power transformers across the system, reduces the amount of maintenance required, and provides access to replacement parts.

### Business Case

Eversource's planning criteria calls for restoring service within established criteria, with in-place capacity. To standardize transformer(s) it is important to consider the loss of the largest element during an N-1 contingency condition in addition to the load that can be transferred out of the station post contingency. Firm and Load Carrying Capability (LCC) ratings are used to account for both of these limits. Firm Capacity is defined as the total LTE rating of the remaining transformer(s) after the loss of the largest transformer (refer to Section 6.1 of Guide for full

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[87] U.S. Energy Information Administration, Annual Energy Outlook 2021, February 2021, https://www.eia.gov/outlooks/aeo/electricity/sub-topic-01.php

[88] U.S DOE Office of Electricity, Solid State Power Substation Technology Roadmap, June 2020, www.energy.gov/sites/default/files/2020/07/f76/2020%20Solid%20State%20Power%20Substation%20Technology%20Roadmap.pdf.

[89] U.S DOE Office of Electricity, Transformer Resilience and Advanced Components (TRAC) Program. www.energy.gov/oe/transformer-resilience-and-advanced-components-trac-program.

[90] U.S DOE Office of Electricity, 2019 Transformer Resilience and Advanced Components Program Review. https://www.energy.gov/oe/2019-transformer-resilience-and-advanced-components-program-review

definition). LCC is defined as the Firm Capacity plus Distribution Transfer Switching Capacity. Distribution Transfer Switching Capacity is calculated by assuming successful transfers of load to other stations is completed within 30 minutes.

The 30-minute STE limit used for Distribution Transfer Capacity is driven by constraints under various operational conditions. The Portsmouth Substation – Second Transformer project serves as an example of these constraints. Here, Eversource determined that additional capacity was needed in the area. To meet the planning criteria, the selected plan called for replacing the existing 44 MVA transformer at Portsmouth station with a 62.5 MVA unit and adding a second 62.5 MVA unit, enabling the planning criteria to be met. An alternative, adding a 62.5 MVA transformer along with the existing 44.8 MVA unit, would not provide adequate capacity to meet the planning criteria under the LTE rating. If the 44.8 MVA transformer was the standard, a third 44.8 MVA transformer would need to be installed. This would likely require additional bus work on the 115 kV source side, additional transformer protection and additional work to integrate the distribution bus work. The differential cost between the 62.5 MVA and 44.8 MVA transformers would be far exceeded by the cost of this additional work.[91] The standard size transformer strategy supports timely load carry or transfer for event-based response, resulting in less dependency on mobile substations. A lesser, but notable benefit is a more consistent and streamlined spare parts inventory.

**Cost Analysis**

Per Eversource interviews, power transformers are typically custom made, with lead times of up to a year or more to deliver; parts across size and manufacturer are not readily interchangeable. Per Eversource, Hyosung Corporation states it is difficult to compare historical costs of transformers as they vary greatly based on the markets. Standardizing transformer sizing could reduce costs by having a more consistent replacement parts inventory and increase efficiencies through engineering, procurement, installation, maintenance, and testing.

The 115-34.5 kV power transformer is the most common distribution transformer within Eversource NH. It is beneficial to look at the costs of upgrading these from the typical 44.8MVA transformer to the new 62.5 MVA transformer. Per Eversource interviews, it is typically around an 8-10% increase in price to go from a 44.8 MVA transformer to a 62.5 MVA transformer. This would be about an $85,000-$110,000 increase in cost. The current pricing for a 62.5 MVA transformer is around $1.1 million. Standard size transformers are essential to planning guide compliance. The incremental cost of any of the transformers is a small portion of the typical project cost needed to install them.

The Company has decided to right-size new equipment to comply with the established reliability planning criteria, which is an event-based system reconfiguration required to maintain the level

[91] Dispatcher initiated load transfers (using distribution automation capabilities, manual switching is not used for this purpose) must be available to lower transformer winding loads to below the LTE rating, within the time frame given below. When distribution load transfers are used for reducing transformer winding loads to below the LTE rating, following the time frames as described in section 1 (Eversource Practices).

of reliability specified by the Eversource Distribution System Planning Guide. Continued use of smaller transformers would not support the outlined planning criteria and lead to longer outage times.

When looking into the point of isolation on the high side of the transformer, the 115kV circuit switcher and 115kV circuit breaker are to be compared. Per Eversource interviews, a 115kV circuit breaker cost is around $63,800. The breaker has current transformers which allow for a smaller protection zone, so when attached to the bus it can be wired into different schemes. The cost of a circuit switcher would be around $112,800. The relay and control wiring cost for the breaker is larger than the differential in material cost between the breaker and circuit switcher. The foundation and steel requirements are similar in comparison. Overall, the total install cost for a circuit breaker is around 10% more than that of the circuit switcher.

**Recommendations**

Transformer resiliency is a significant issue today which leads to increased outages, outage duration, and loss of service for customers. The criteria for replacing transformers internally within Eversource sets strict guidelines that capture the need to replace transformers under certain criteria and address specific areas of concern.

Networking feeds will decrease the need for mobile substation readiness and relying solely on mobile substations to pick up load. The install and maintenance of mobile stations is a burden among field personnel and maintenance crews. Per Eversource, since a mobile substation consists of a transformer and supporting device to support simplified installation during an event, the typical maintenance of a mobile substation is three weeks as compared to that of a regular transformer of one week. Eversource needs to ensure that all mobile substations are adequately sized and can restore load due to the increase in standard 115-34.5kV transformer sizes.

TRC recommends following Eversource guidelines of standardizing transformer sizes throughout the system based on voltage class. Standardization will lead to more consistency, efficiency, and potentially reducing spare transformer stock and will benefit as follows:

- Standardized replacement parts would result in a more consistent and streamlined parts inventory. This could help reduce event response time, especially if it reduces the need for a mobile substation.
- This will reduce the cost of engineering across standardized vendor drawings. The internal review process of standardized transformers will be more reliable and efficient, reducing the overall procurement cycle.

Any transformer that is removed from service due to a substation improvement project could be redeployed elsewhere on the system where practical. Strategically retain any reliable non-standard sized transformers that was removed from service under the planning guide for future use as an emergency replacement in kind.

TRC recommends continuation of the standard sized transformer implementation strategy.

## 5.4 Distribution Planning

**Eversource Standard Planning Practices:**
The Eversource Distribution System Planning Guide (Guide) states that

> *Distribution Feeder design is intended to provide safe, reliable service within allowed voltage limits at a reasonable cost. Reliability generally addresses interruptions of service for both the number and length of interruption duration. Eversource uses three reliability measures adopted by the utility industry: System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAFI), and Customer Average Interruption Duration Index (CAIDI), refer to Distribution System Engineering Manual (DSEM), Reliability Section 02.11. There are limits as to what degree of reliability is practical or achievable, depending on the investment cost and rates permitted by regulatory authorities. To evaluate the effectiveness of reliability projects and determine the most cost-effective solution, Eversource follows DSEM 03.30.*[92]

Eversource utilizes the following solutions to maintain approved regulatory reliability indices where reliability improvements are needed:

- Add automatic sectionalizing devices to limit exposure to 500 customers or less per switchable zone. Refer to DSEM 02.30, DSEM 06.51, and DSEM 10.42.
- Eliminate or reconfigure triple circuit pole lines to minimize customer exposure for single emergency events that result in more than 1000 customers out of service
- Reconfigure double circuit pole lines where both the normal and alternate source supply the same group of customers resulting in more than 1000 customers out of service.
- Arranging distribution feeders in order to give the best possible load balance on the system, by identifying feeders where load imbalance exceeds 50 amps between phases and considering improvements to reduce imbalance to less than 50 amps. (Guide page 7)
- Adding automatic sectionalizing devices to limit exposure to 500 customers or less per switchable zone. (Guide page 10)
- Using Age/Asset Health indexes in determining reliability risk for prioritizing upgrades. (Guide page 39)

Options on further improving reliability include:

- Consider options on creating and expanding system redundancy
- Improving on existing system redundancy for resiliency
- Examine and review feeder length

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[92] Eversource, Distribution System Engineering Guide, page 10

- Reduce existing and potential equipment materials vulnerability to nature

Eversource Distribution Planning Engineers follow the Guide for study procedures and project justifications. This document was last updated in 2020. Planning objectives outlined in the Guide include:[93]

- Build sufficient capacity to meet instantaneous demand
- Satisfy power quality/voltage requirements within applicable standards
- Provide adequate availability to meet customer requirements
- Deliver power with required frequency
- Reach all customers wherever they exist

**Planning and Operating Criteria**

Conductor Loading: The Guide provides loading and voltage criteria with respect to applicable seasonal (Summer/Winter) ratings. Loading criteria for conductors are:

- Normal Rating - the maximum loading without incurring loss of life above the design-loading limit, and system changes are developed when limits are expected to exceed 100% during normal operation or 100% of cables during contingent operation (Guide page 6-7).
  - Feeder upgrades are required in the event that feeder ratings are being exceeded (Guide page 13).
- Emergency Rating – the maximum loading of overhead wires during contingent operation.

The Company's service territory comprises a range of both rural and urban areas that vary in electric supply characteristics and requirements. Electric distribution substations are diversified in size and redundancy in matching the difference in ratio between rural and urban areas. To maintain adequate levels of reserve capacity, power quality, and reliability, Bulk Distribution Substations are designed to sustain any Single Contingency (N-1) with no Load Loss. Specific transmission and distribution system considerations include:

- **Transmission System Considerations:** The transmission system supplying distribution bulk substations shall be designed so that the outcome of any single contingency event at the transmission side does not result in a condition greater than a Single Contingency (N-1) at the distribution bulk substation.

- **Distribution System Considerations:** The distribution system shall be designed so that any feeder outage does not result in thermal or voltage violation above design criteria.[94]

[93] Eversource, Distribution System Engineering Manual, p. 4
[94] Eversource, Distribution System Engineering Manual, Sections 2.2 and 2.4., p. 10

Continuous development in reliability can result in system trade-offs. For instance, the overall cost for improvement may take several years to see the return in investment. Upgrading a line voltage could reduce line loss, but at the cost of increasing sensitivity to momentary interruptions and outages due to contact with vegetation.

Reliability Statistics offer methods for self-evaluation. Metrics defined in the IEEE 1366 include measurement for long-term performance of a system. These metrics include SAIFI, SAIDI and CAIDI. Metrics currently used by Eversource include SAIFI, SAIDI, CAIDI, Contribution to System SAIDI, and SAIDI minutes, which are defined below:

- SAIFI is the average number of sustained interruptions (defined by IEEE 1366 as an interruption lasting 5 minutes or more) per consumer during the year. It is the ratio of the annual number of interruptions to the total number of customers served.[95]
- SAIDI indicates the total duration of interruption for the average customer during a predefined period of time (measured either in minutes or hours).[96]
- CAIDI is expressed in minutes. It is the average time required (or experienced) to restore service to the average customer per sustained interruption CAIDI is the average restoration time. As with SAIDI, CAIDI can be used to calculate for different groups of customers from the whole system to parts of a feeder.[97]
- Contribution to System SAIDI is the portion of SAIDI attributable to the customer−minutes of outage time that occurred on a particular part of the system (usually a circuit or a portion of a circuit) divided by the total number of customers served by the entire company (usually per state).[98]
- SAIDI Minutes is the contribution to the SAIDI of a given unit (say a feeder or a district) contributed by a particular outage. It is the customer−minutes interrupted for the outage divided by the total number of customers in the given unit.[99]

Figure 5-46 below shows that between 2011 through 2020, an overall reduction trend in SAIFI is a reflection of an overall reduction in outage events. Since 2011, there has been a significant reduction in SAIFI related to conductor/conductor equipment outages.

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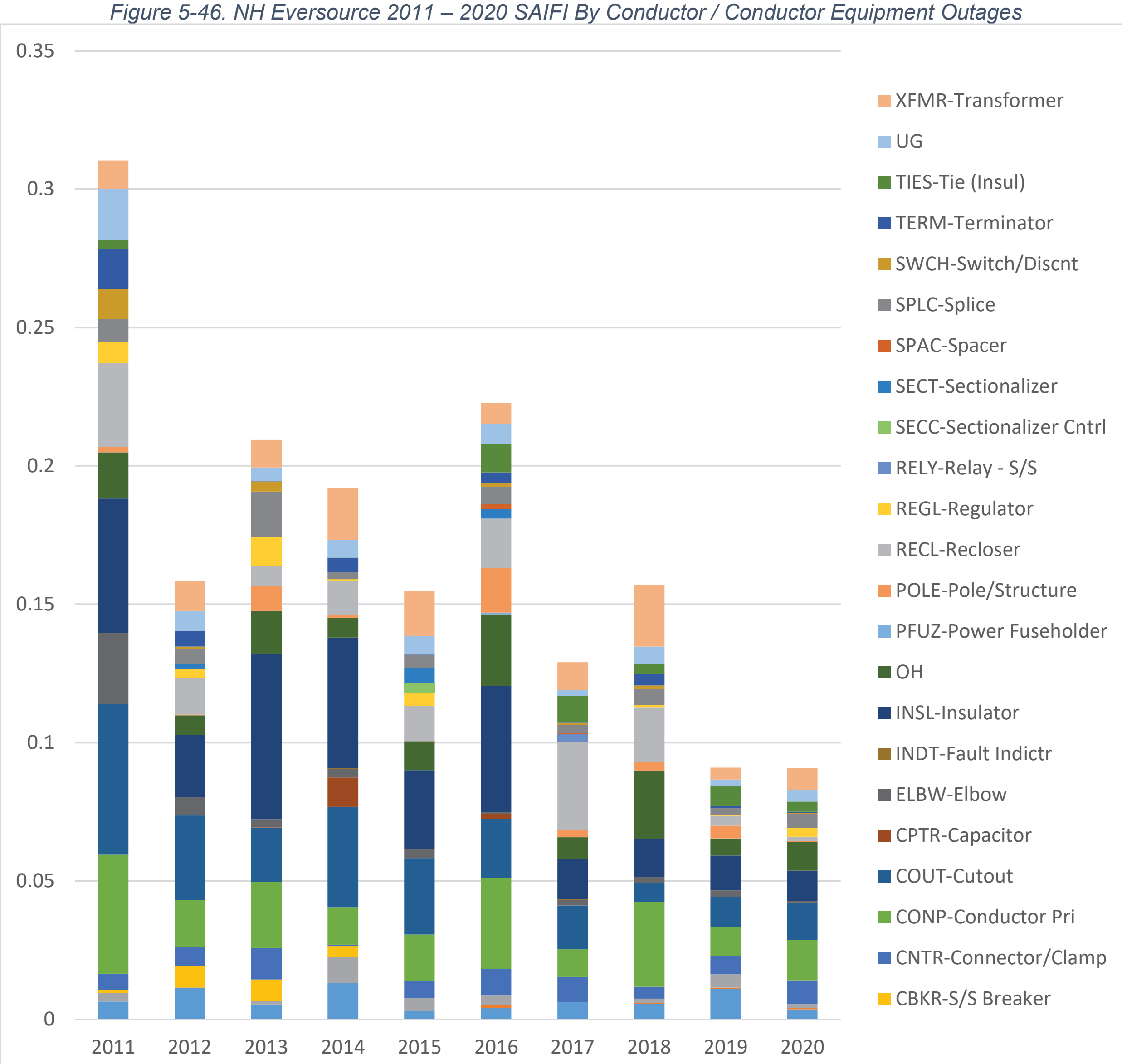
[95] IEEE, Standard 1366-2012 – IEE Guide for Electric Power Distribution Reliability Indices, 2012. https://standards.ieee.org/standard/1366-2012.html
[96] Ibid.
[97] Eversource, Distribution System Engineering Manual, Section 02.11
[98] Ibid.
[99] Ibid.

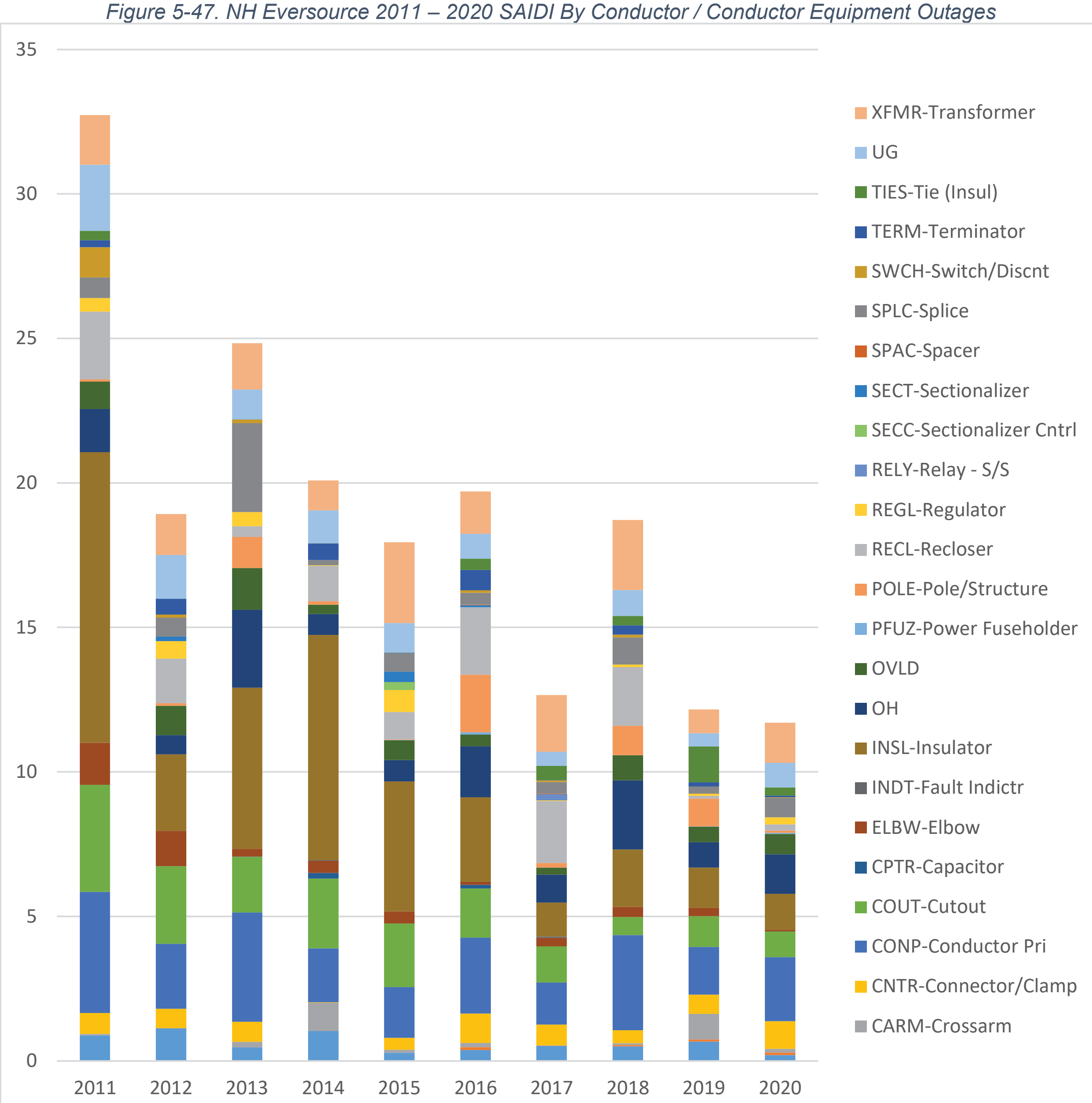
*Figure 5-46. NH Eversource 2011 – 2020 SAIFI By Conductor / Conductor Equipment Outages*




*Source: Eversource internal data*

TRC

*Figure 5-47. NH Eversource 2011 – 2020 SAIDI By Conductor / Conductor Equipment Outages*




*Source: Eversource internal data*

When using SAIDI in calculating average duration for major events and catastrophic days (such as hurricanes and ice storms), this will lead to high SAIDI values since these types of events being that these are considered catastrophic events and therefore have a low probability of occurring.  Large SAIDI values associated to these types of events can linger in a dataset for years causing an upshift in reliability metric trends (IEEE 1366-2012 page 19).

These metrics are designed to measure in seeing if a system is improving (or not improving) over time.  They can also be used in recording major events or planned events separately, be applied to specific equipment for a further insight on areas in need of consideration and can be used for comparing specific areas (system wide, feeder level, substation, etc.) for further insight on areas potentially in need of attention. Overall, the use of metrics administers a better understanding of the overall system health and performance.

The IEEE standard 1366-2012 explains that daily SAIDI values are preferred to daily SAIFI values because SAIDI values are a better measure of the total cost of reliability events, including utility repair costs and customer losses. The total cost of unreliability would be a better measure of the size of a major event, but collection of this data is not practical. (IEEE 1366-2012 page 22)

Duration-related costs of outages are higher than initial costs, especially for major events, which typically have long duration outages. Thus, a duration-related index will be a better indicator of total costs than a frequency-related index like SAIFI or MAIFI. Because CAIDI is a value per customer, it does not reflect the size of outage events. Therefore, SAIDI best reflects the customer cost of unreliability, and is the index used to identify Major Event Definitions (MEDs). SAIDI in minutes/day is the random variable used for MEDs. (IEEE 1366-2012 page 24).

**Mitigations to Lower SAIDI/SAIFI**

To mitigate the circuits with high SAIDI/SAIFI values, reconductoring or relocating a circuit can be considered. Eversource engineers have developed a data base for all circuits so that troublesome circuits can be addressed. Reconductoring should be with standard spacer cable construction. Other actions may include moving the circuits from forested areas in ROW to roadside when feasible.

Investments made towards relocating circuits to more accessible areas may create safer working conditions and allow the opportunity for updating aged facilities to current construction standards. In either case where relocation results in parallel to roadway or road-side construction, this allows for rapid restoration, straight forward trouble shooting, and simplified maintenance. This will improve resiliency, save time, money, and reduce overall length of outages. Overall expenditures in relocating facilities will develop a more robust and secure system that outweighs the potential costs and repercussions of operating and managing an aged system.

Analysis of the data in Figure 5-46 and Figure 5-47 allow for targeting existing problem areas in tracking improvements related to conductor and conductor equipment failures over a timespan where replacements may be made and further addressed wherever possible. The overall intention is to address equipment replacement where the most cost-effective impact can be made and continuing the trend until replacement based on cost effectiveness has been maximized.

Other reconductoring can be recommended due to increase loading when the load grows as found during annual studies. Reconductoring is also justified to increase capacity and to reduce line losses. Costs need to be considered to when providing this option as the cost can outweigh the benefit.

### Conductor Size Selection

The conductor size selection problem involves determining the optimal conductor configuration for the distribution system, using a set of types of conductors. The objective is selection of conductor's size from the available size in each branch of the system which minimizes the sum of depreciation on capital investment and cost of energy losses and reliability while maintaining the voltages at different buses within the limits. Eversource has developed standard conductor sizes and types per General Section 05.131.

### Outage Prevention

TRC recognizes Eversource is already in line with many good utility and industry operational and outage prevention practices. These include:

- Regular inspections and maintenance
- Veg management/tree trimming
- Animal guards
- Incorporating L/A’s
- Thermal imaging inspection
- Use of Insulated wire (spacer or tree wire)
- Designing for proper transformer loading

### System Operation

The way a system is built and operated can also have an impact on system reliability. This can include the types of equipment used for indicating faults, relay and recloser settings (duration or number of operations to close), fusing philosophy (fuse save, fuse blow, or hybrid) maintenance programs, and regular testing,

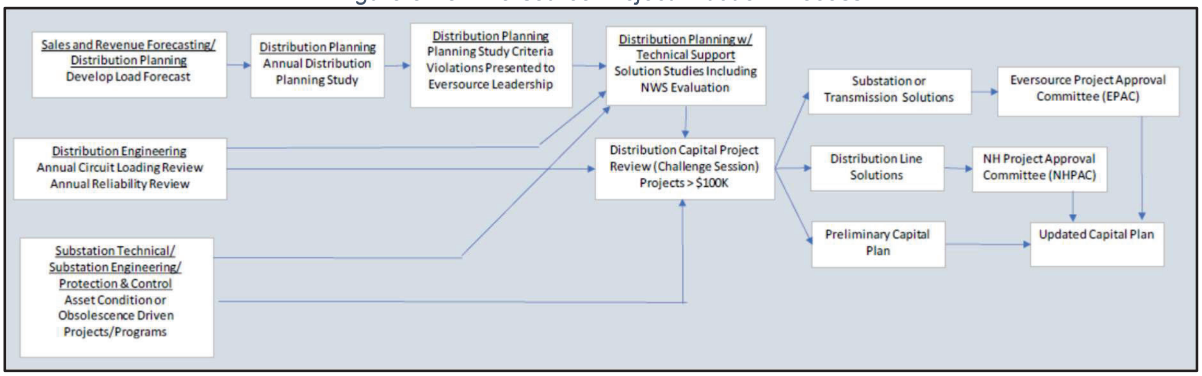
### ROW and Maintenance

Having the ability to exercise and maintain rights-of-way and utility easements can further increase the effects of reliability, to include:

- Right to construct, maintain, operate, replace, upgrade, or rebuild pole lines or underground cable and appurtenances thereto
- Right of ingress and egress
- Right to trim and remove all trees on or adjacent easement necessary to maintain proper service
- Right to keep easement free of any structure or obstacle which deems a hazard to the line
- Right to prohibit excavation within 5 feet of any buried cable, or any change of grade which interferes with the cable

As engineers start their study process, they follow the Project Initiation Process below and develop their study models.

*Figure 5-48. Eversource Project Initiation Process*




*Source: Eversource*

Model Development is a critical piece in the study process. Required models include summer or shoulder period minimum and peak load, as well as winter period minimum and peak load. The loads are extracted from GIS or other sources to get the loads for the substation or substations under study. Additionally, because of growing DER within the Eversource service area, engineers must factor in the Gross Load and DER on the system during the model development process. The Guide describes this in detail. From here, a Peak Forecast Load Model, Minimum Forecast Model, and Scenario Forecasts are developed for up to 10 years out.

Eversource historically produces both a 'normal' and an 'extreme' peak load forecast for each operating company. The normal peak load is based on average historical weather data, and the extreme peak is based on the 90th percentile of that historical weather data. The extreme peak is also referred to as a 90/10 forecast and it assumes a 10% chance that the peak load would be exceeded. Put another way, the forecast will be exceeded on average only once every 10 years.

After loads are determined, the Planning Model is developed using the GIS extraction and the study software to develop the load flow model with the current topology for the substation feeders. This includes the base case, probabilistic and standard load models, and 5- and 10-year yearly increase models.

Eversource conducts these studies on an annual basis for possible reporting to New Hampshire's PUC. During the study, the engineer examines the following for each scenario.

- Substation Normal and Contingency
  - Distribution System Planning will use the Appropriate model to identify violations affecting Distribution Bulk Substations and backbone feeder sections involved in the calculation of the Substation Load Carrying Capability (LCC):
  - To identify violations under Normal (N-0) system conditions the Planning Base Case models will be used to verify that all substation transformers and backbone feeder sections operate under normal thermal ratings, voltage limits, and acceptable load phase balance, as per Section 2.2 of the Guide.

- To identify violations under Contingency (N-1) conditions the Planning Base Case models will be used, together with the guidance provided in Section 4.6 below to verify that all substation transformers and backbone feeders' sections operate under the appropriate Thermal Loading criteria specified in Section 2.2 of the Guide.

- Substation LCC Capability:
  - Distribution load transfer schemes used in the calculation of the LCC, will be modeled and verified by Distribution System Planning for Bulk Distribution Substations that fall within the following criteria:
    - Above 95% of nameplate under normal (N-0) conditions within the next 5 years
    - Above 95% of LCC under emergency (N-1) conditions within the next 5 years
- Contingency Conditions (N-1) Operational Assessment is conducted to determine if any criteria violations are found.
- Contingency Analysis
  - For Distribution Station in which LCC is equal to Firm:
    - For distribution stations where a single event at the transmission level corresponds to a single event at the distribution station, not exceeding N-1 conditions:
    - An N-1 contingency can be modeled at the distribution station by taking the largest transformer out of service and closing the appropriate bus breaker to transfer the load to the remaining transformers.
  - For distribution stations where a single event at the transmission level corresponds to an event at the distribution station that exceeds N-1 conditions:
    - The Distribution station contingency shall be modeled based on the transmission contingency that results in the worst contingency condition for the Distribution Station.
  - For Distribution Station in which LCC is not equal to Firm:
    - For distribution stations where a single event at the transmission level corresponds to a single event at the distribution station, not exceeding N-1 conditions. An N-1 contingency can be modeled at the distribution station by taking the largest transformer out of service and closing the appropriate bus breaker to transfer the load to the remaining transformers.
    - For distribution stations where a single event at the transmission level corresponds to an event at the distribution station that exceeds N-1 conditions. The Distribution station contingency shall be modeled based on the transmission contingency that results in the worst contingency condition for the Distribution Station.

**Allowed System Adjustments to Mitigate Capacity and Power Quality Violations**

Upon performing the study process, the probability for encountering criteria violations at the substation and feeder backbone level may include thermal, phase imbalance, and voltage, as outlined in Section 2.4 of the Guide. System improvements for addressing violations may include:

- Thermal violations:
  - Reduce load by load transfers or non-wires solution (as per Section 4.8 of the Guide).
  - Increase system capacity by upgrading existing equipment or installing new equipment.
  - Phase load imbalance: reduce phase loading by distribution circuit reconfiguration
  - Substation Secondary bus load thermal violations: reduce load by load transfer, or increase equipment capacity
  - Voltage Violation:
    - Reduce load by load transfers or non-wires solutions
    - Applying capacitor or voltage regulation.
    - Upgrading or installing new equipment

Finally, the engineer documents any system constraints with a detailed study report with the study findings. The report considers:

- The substation current configuration/capacity along with transformer ratings
- The historical peak and actual loads, actual/planned load transfers and most recent 10-year load forecast
- Assessment of DG connected to each transformer's feeders and any load adjustments made because of these facilities
- System Review Summary, including:
  - Identification of Non-Standard Bulk Distribution Substations and associated violations
  - Non-Bulk Distribution Substation configuration/capacity and potential violations
  - System reinforcements or mitigating measures to plan or investigate further

Based on the violation type (Capacity, Power Quality, and Reliability) the System Planning report should include:

- Substation name
- Substation Summary
- Description of Problem (if applicable)

- Description of Violation (if applicable)
- Substation Equipment Rating and Limit
- Actual Peak Load (Observed year)
- System Review Summary
- Possible Mitigation Actions

**Solution Development**

When the system capability does not meet forecasted loads, Planning Engineers must resolve projected violations prior to the violation year as per Section 4.8. Once a list of violations is compiled, Distribution System Planning engineers will identify potential solutions to address those violations affecting:

- Bulk Distribution Substations
- Non-Bulk Distribution Substation
- Feeder Backbone Sections required for substation LCC capacity

The solution development method adopted by Eversource is a complex and iterative process which addresses the system needs in conjunction with the capital budget. This approach balances the safe and reliable service provided by the Company with the need to control cost for their customers. The solutions may include the following:

- Distribution Bulk Substation Solution Development
- Distribution Feeder and Non-Bulk Substation Solution Development
- Application of Non-Wires Solutions (NWS)
    - The process for identifying NWS is complicated and the steps are listed in the Guide.

**Planned and Proposed Upgrades**

During the annual development of the transmission and distribution capacity and power quality plans, Eversource shall design long term solutions (Traditional and NWS) that will address capacity and resiliency needs of all distribution substations. Planned projects, identified in the Low Load and Medium Load Planning Scenarios, that address immediate substation capacity and resiliency needs shall designed and prioritized to be included in the 5-year capital plan as approved projects. Proposed projects, identified in the Long-Term Planning Scenario, that address long term capacity and resilience needs shall be developed but not submitted for approval. Figure 5-49 provides a high-level breakdown for an ideal project planning schedule.

*Figure 5-49. Eversource Project Planning Schedule*

| Constraint Type | Timeframe | Status | Planning Scenario |
|---|---|---|---|
| **Planned** | 1-5 years | Full development & approval | Low and Medium Load Growth |
| **Planned** | 5 -10 years | Partially developed | Medium and High Load Growth |
| **Proposed** | 10 years and above | Conceptual Design | Medium and High Load Growth |

**Relocation Project Example:**

Newport Circuit 317/3410 was originally built in 1937 and has maintained many of its original poles, crossarms, insulators, and conductor. A large portion of 317/3410 has been budgeted for 2021-2025 to remove the line from its existing ROW and relocated adjacent to the roadside with construction starting in 2021. Approximate cost is $1M/mi to rebuild with steel poles and spacer cable. Figure 5-50 shows the line as is today in standing water.

*Figure 5-50. Eversource Line 317 Line Relocation*

*Source: TRC Field Inspection*

**Reconductoring with spacer cable example**

Circuit 3139X had multiple tree related outage and was a poor performing circuit. A capital project was implemented to improve the circuit backbone which included upgrading 3.5 miles of open wire conductor in Heather-lite configuration to covered spacer cable along Highway 63. There were six distribution automation devices installed, all with single phase tripping. There was also a distribution automation device installed just outside of Chestnut Hill Substation to create single phase tripping capability. Following the completion of this work, circuit reliability improved. Figure 5-51 displays a completed segment of the circuit backbone.

*Figure 5-51. Eversource Line Reconductored to Spacer Cable*

*Source: Eversource*

*Figure 5-52. Eversource Line Reconductored to Spacer Cable*

*Source: Eversource*

**Cost Analysis**

TRC evaluated the Eversource project justification processes listed in the Guide's references in section 1, which notes that "Projects that are required within the next 6 years of the Observed Year should be fully developed and approved using the latest version of the Capital Project Approval Process, refer to Section 7.1. A Distribution System Planning Substation Review form should be completed by the responsible System Planning Engineer."

TRC found the project costs to be within industry standards, and from the documentation presented, TRC did not observe evidence of project scope changes due to consecutive reviews.

**Recommendations**

TRC recommends Eversource set up a tracking program to compare historical outage data for line segments for 3-5 years (as data is available) and then report annually on that segment post-improvement. Such a system will document the improved reliability and resiliency delivered by relocation and reconductoring projects. TRC recommends reducing the number of radial feeds to allow for increased networking and load pickup throughout the system. Eversource should also maintain awareness for project cost increases that may arise as projects are delayed.

# 6. Conclusion and Summary of Recommendations

This section summarizes TRC's findings for the Eversource distribution system assessment and aggregates the study recommendations across the topic areas surveyed in this research. Finally, TRC presents areas for potential future research based on the research and findings.

## 6.1 Summary of Findings

Eversource's recent or proposed enhanced standards and activities for distribution system hardening have been designed to maintain and improve the reliability and resiliency of the distribution system. These changes are driven by an increased recurrence of major storm events since 2008 that have cause prolonged and widespread outages, at times impacting over 40% of customers. The proposed investments in a more resilient system align with a growing trend among utilities around the country that have faced similar weather (or other external) threats to their operations. It is important to not view individual standards or activities targeted toward resiliency or reliability in isolation, but rather as a package of tools that can be deployed when rebuilding or when making targeted improvements to the system.

Below are key findings related to each of the components of this distribution system assessment research:

**Industry Resiliency Planning**

As noted above, the utility industry is grappling with the need for accelerated planning and investments in resiliency, driven by climate-change induced increases in severe weather events. Despite the increase in interest and planning around resiliency, few utilities or regulators have developed a clear path to plan for costs and benefits, given the low-frequency, high-impact nature of resiliency-focused major events. These and other key findings include:

- Increased resiliency and hardening investment and planning activity across most states is driven by an increase in severe weather events that can significantly impact outage durations.
- Resiliency planning frameworks stress assessment of local climate risks to identify tailored solutions for each utility.
- Evaluating cost-effectiveness of resiliency investments remains a critical challenge for utilities and regulators, as the benefits are difficult to monetize.
- Shifts in the traditional utility business model are impacting investment decisions. The move away from a cost-plus ratemaking approach and moving to a performance-based structure (e.g., New York and Massachusetts) has allowed regulators to incorporate metrics around grid hardening and provides greater flexibility to utilities in their system investment.
- Cost recovery remains central to the ongoing industry debate. This research identifies various approaches currently being advanced, presented later in this chapter. These approaches demonstrate the range in considerations and fragmented nature of the responses across the country.

**System Condition**

Key findings related to the overall condition of Eversource New Hampshire's electric distribution system include:

- A substantial number of wood poles, primary conductor circuits, substation breakers and substation transformers are at the end of their useful life.
- Wood poles are physically overloaded due to their age and number of attachments.
- Many circuit lines in the ROW are inaccessible, due to their locations, and difficult to maintain.
- Trees and canopy are in close proximity to the distribution system, making the lines vulnerable.

**Steel Poles**

Eversource has specified the use of steel poles in the off-road right-of-way due to the difficulties in accessing these line sections in the event of a failure. Steel poles are stronger, less prone to catastrophic failure, lighter and thus easier to deploy, and require less maintenance than their wood counterparts. Key findings include:

- A number of utilities, including several in the South and West have implemented steel poles as the standard for distribution construction. Eversource has used steel structures in the ROW for many years.
- The useful lifespan of a steel pole is estimated to be twice as long as a wood pole.
- While upfront costs can be 250-400% higher for steel poles, the total lifecycle cost of steel poles is lower due to the escalation in material and installation costs of wood poles that must be replaced sooner than a steel pole.

**Class 2 Wood Poles**

Eversource has implemented a standard of using stronger Class 2 wood poles, instead of Class 3 or 4, for distribution primary poles due to the ability to better withstand wind, ice, and other severe weather events. Eversource designed its stands to meet NESC guidelines for severe wind and ice loading. Key findings include:

- Pole failure is the least desirable outcome in an outage event due to the cost and complexity in repairing (compared to failure of conductor, crossarms, or other components).
- Class 2 wood poles, with a wider circumference, can withstand 60% greater force than smaller, Class 4 poles.
- Installed costs of Class 2 wood poles are marginally (2-4%) higher than the cost of a comparable Class 3 wood pole.

**Spacer Cable**

Eversource has made spacer cable its standard for three-phase primary distribution as part of resiliency guidelines to reduce faults from tree and animal contact and survive larger tree strike. Key findings include:

- In addition to ability to withstand tree and animal interference, spacer cable requires less clearance than open wire, reducing ROWs and vegetation management requirements.
- Spacer cable costs approximately 200% more than open wire per mile installed, with higher costs equally driven by labor, materials, and overhead costs.

**Fiberglass Crossarms**

Similar to the components listed above, Eversource has standardized the use of fiberglass crossarms for new construction or replacements as needed. This standardization was driven by the improved longevity, strength, and predictability of fiberglass components considering increasing severe weather events.

Key findings include:

- Modeling shows that fiberglass cross arms pass the heaviest ice loading with heavy tree contact and high wind test simulations where wood crossarms failed.
- Fiberglass crossarms are commonly paired with steel distribution poles, given both have superior longevity to wood material equipment.
- Fiberglass crossarms weigh one-third as much as equivalent wood cross arms and do not require braces, making installation of fiberglass crossarms easier.
- The lifecycle costs of dead-end and tangent fiberglass crossarms are 38-44% of the total lifecycle costs of wood crossarms, due to the need for replacing a wood crossarm at 25-30 years.

**Vegetation Management**

Eversource operates a portfolio of vegetation management activities designed to reduce high-risk vegetation around lines (ETT, ETR, and ROW) and then maintain improved clearances through regular 5-year maintenance (SMT). Key findings include:

- Vegetation management activities since 2011 have led to a significant improvement in tree related SAIFI and SAIDI performance. Inside-zone caused outages have been reduced tenfold for both SAIDI and SAIFI, while outside-zone caused outages have trended slightly downward over the las decade.
- Modeling shows that reductions in vegetation management spending can lead to a disproportionate increase in cycle-time to return to each circuit. For example, a 20% reduction in spending can nearly double the cycle from 5 to 9 years.
- Similarly, deferring SMT can lead to increased costs per mile. A 1-year delay can increase per-mile costs by 20%, while a 3-year deferral can increase costs by 51%.

**Substation Transformers**

Eversource has designed criteria for designing substation components to minimize length and impacts of outages during contingency events. Key findings include:

- Standardizing substation transformer sizes can provide benefits for streamlining inventory and reducing event response time.

**Distribution Planning**

Eversource conducts distribution planning to maintain system operations within established operating criteria. Key findings include:

- Engineers develop solutions to address capacity, power quality, and reliability concerns based on historical performance data and forward-looking forecasts.
- Line relocation and reconductoring are two options to address reliability issues.

## 6.2 Recommendations

TRC recommends the following practices, based on the research and findings of this assessment:

1) Consolidate current resiliency/hardening efforts into an overarching program following the decision framework outlined by the Department of Energy.
2) Establish a systematic asset replacement program to replace wood poles on an age basis, that support three phase lines, over the next 5 years. Beginning with poles 70 years and older poles, with priority on the smaller class 4, 5 and below, then address the 60- and 50-year-old poles. There are about 42,000 wood poles aged 50 years and older that will need to be identified and prioritized for replacement. It is estimated that 20% (8,400) of those poles support three phase lines, requiring approximately 1,700 poles/year of the poles in this age group be replaced in conjunction with the other pole replacement efforts.
3) Poles that are identified as structurally loaded at 90% or greater, be replaced with the correct sized poles to carry the mechanical load under the mandated NESC design conditions. To accomplish this, TRC also recommends that 10% (approx. 4,500) of the overloaded poles, be replaced on an annual basis. Priority should be given to the poles that are overloaded by the greatest amount and/or most critical to the system. It is also essential that all new poles that are installed have pole loading analysis completed to ensure the design criteria is met. Individual pole loading analysis will need to be performed on all new and replacement corner, junction, and dead-end poles. Typical tangent pole analysis can be modeled to promote efficient design.
4) Continue the practice to use a minimum of Class 2 wood poles for all applications and ensure that NESC pole loading requirements are met for both the heavy loading and extreme wind scenarios. Based on analysis of the representative data, Class 2 wood poles are half as likely to be overloaded with attachments compared to Class 3 poles.
5) Identify candidate lines for ROW line relocation to roadside and develop a multi-year plan to address the most critical and least accessible lines. The plan needs to coordinate with efforts to reconductor open wire to spacer cable and the overloaded and aged pole projects.
6) Increase vegetation management and spacer cable installation for vulnerable lines.

7) For distribution engineering materials and equipment, Eversource should continue to plan reliability and hardening standards and investments from a system perspective, rather than a series of individual components:
    a) Given lower lifecycle costs and difficulty patrolling and replacing more remote ROW assets in the event of a failure, continue to use steel poles as the standard in these environments when not able to move roadside.
    b) Continue to use Class 2 wood distribution poles for the added strength in high wind and ice loading scenarios. Perform pole loading analysis on all new and replacement corner, junction, and dead-end poles, to ensure the design criteria is met.
    c) TRC recommends adding a proactive program to replace wood poles or obsolete steel lattice towers in the ROW with steel poles on a planned basis. The plan should include a minimum of five circuit-miles of off-road ROW, three phase rebuilds, including rebuilds that are part of the inaccessible line relocation projects. Line projects need to be prioritized by reliability performance and susceptibility to damage or failure from trees.
    d) Follow the spacer cable program as outlined in the Eversource 2016 Resiliency Guidelines. As part of the capital planning process, accelerate the rebuilding/reconductoring of the open wire, three phase lines that are the most susceptible to outages in heavily treed and narrow ROW areas over the next 5-years. Work in conjunction with the inaccessible line relocations to the roadside and steel pole installation projects in the steel pole section.
    e) Continue to use fiberglass crossarms as specified, given their longevity, improved strength, and resulting lower lifecycle costs. These components also pair better with the proposed use of steel poles due to similar useful lives.
8) Vegetation Management:
    a) For SMT, address an average 2,440 miles annually to follow the 60-month clearing cycle. This will focus on the Inside Zone vegetation and maintain the level of tree caused outages at current levels as indicated by Figure 5-23. Deferral of this work for a year or more will risk erasing the progress on tree-related reliability improvements achieved over the last decade and lead to increasing costs per mile and physical resource needs. This will likely have an impact on the budget.
    b) Accelerate ETT to 80 miles per year to address the remaining 500 miles of the backbone circuits within the next seven years. This will likely have an impact on the budget and be subject to availability of physical resources.
    c) Continue ROW clearing at the current pace to allow for the restoration of the full original easement where vegetation has encroached.
    d) For ETR, target approximately 19,000 hazard tree removals annually following the current identification and prioritization practice. Evaluate additional strategies to drive improvements in outside-zone tree-related outage performance.
9) Standardize substation transformer sizes wherever possible based on voltage class to allow for greater efficiency in maintaining stock of fewer transformer sizes and flexibility in responding to contingency events and coordination with neighboring state service areas.

10) Establish a tracking program to compare historical outage data for line segments for 3-5 years (as data is available) and then report annually on that segment post-improvement. Such a system will document the improved reliability and resiliency delivered by relocation and reconductoring projects.
11) Continue to reduce the number of radial feeds to allow for increased networking and load pickup throughout the system.
12) Maintain awareness for distribution project cost increases that may arise as projects are delayed.

# BUSINESS PROCESS AUDIT

OF

# EVERSOURCE

&

# Public Service Company of New Hampshire

# DISTRIBUTION CAPITAL PROJECTS

JULY

2023

FOR

THE NEW HAMPSHIRE

DEPARTMENT OF ENERGY

DIVISION OF REGULATORY SUPPORT

ELECTRIC DIVISION

PREPARED BY

RIVER CONSULTING GROUP, INC.

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# Executive Summary

The business process audit of Eversource's PSNH distribution capital project (CapEx) processes was procured by the New Hampshire Department of Energy's Division of Regulatory Support - Electric Division (Division), pursuant to the terms of a rate case Settlement Agreement approved by the New Hampshire Public Utilities Commission (PUC or Commission) in Docket No. DE 19-057, Order No. 26,433 dated December 15, 2020.

RCG understands that the genesis of this action involved communication concerns expressed by the Division covering PSNH's approach to project planning and management and the submittal of detailed Capital Projects information in the rate case.

As part of the recent PSNH rate case in Docket DE 19-057, the Division requested documentation for all distribution capital projects and associated estimates. PSNH delivered to the Division the requested information but did not provide complete and clear definitions for the multiple individual project estimates.

In this business process audit, RCG witnessed some communication issues with PSNH. RCG experienced communication issues resulting from PSNH responses to RCG data requests (DRs) including data provided in a format different from what was requested. Based on our process audit experience, RCG recognizes some DRs can take up to a month to prepare but taking three or more months is beyond the norm. Eversource did notify RCG when response times were expected to exceed the agreed upon response time.

DRs are designed to obtain and facilitate the review of standard information that a well-managed utility will use in its ordinary course of business. Specifically, the policies, processes, and procedures should be in place to create the information for successfully managing CapEx projects and tracking them for accounting, engineering, and regulatory purposes. The quality of internal or external communications is often indicative of systemic management control issues that are not part of a typical business process review and will require further efforts on the part of Eversource (see the discussion below).

As part of this audit assignment, RCG undertook an extensive interview process of PSNH and Eversource management personnel and we can report that PSNH arranged interviews consistent with RCG's expectations and appeared to be forthcoming in answering all questions.

A utility's capital planning process is expected to answer the following high-level question: "How much distribution system reinforcement is essential to provide the expected reliability and system resilience?" This question seems straightforward but is incredibly complex, with many variables impacting the final answer.

PSNH is part of a tri-state operation (New Hampshire, Massachusetts, and Connecticut) with different circuit configurations and voltages in each state. PSNH's distribution system is reasonably complex with three primary voltages (34.5kV, 12kV, and 4kV). Notably, some of the critical distribution equipment is older and, in some cases, potentially near the end of its life.

RCG reviewed Eversource/PSNH's functions that impacted the CapEx project process, including accounting and management policies and processes. In addition, RCG conducted a review of engineering policies and practices applicable to load forecasting, system planning, study methods, engineering tools, decision processes, and standards. The results are documented as they apply to core management and engineering functions: organization, engineering project control processes, energy forecasting, system planning criteria, system planning studies, reliability analysis, and the impact of distributed energy resources (DER). In RCG's opinion, these engineering functions, including their attendant processes, are well designed, but their execution, in some cases, was found to need improvement. This conclusion also applies to the policies and processes used to track individual projects.

RCG identified recommendations for the most significant improvement opportunities:

- ***Communications*** – The most significant issue is written and verbal communications, and consistent application of certain terms used by Eversource/PSNH to describe documents and processes. RCG believes Eversource generally understands the terminology, but outside entities may not. For example, some of the terms and definitions used by PSNH, which appear to have common usage, are used, and interpreted differently by other Eversource functional areas, for example "Supplemental" for an additional funding request or "Total" in a Projects' Excel spreadsheet. Communication issues also exist in the CapEx engineering processes, and in the language used in responses to data requests. Also, delays in providing requested information in data requests is a related issue; and
- ***Project management oversight*** – certain project plans as originally designed, were not effective during construction, as design flaws were discovered during troubleshooting and quality control phases of construction and rose to the attention of the Division during the rate case.

Another area reviewed by RCG involved "Third-Party Claims" costs associated with capital projects resulting from third-party damage to the distribution system. PSNH has no control over when third-party damages occur, which puts PSNH in a reactive situation.

While PSNH has formal Third-Party Claims collection policies and processes in place, the pace of collection is partially out of PSNH's control due to the state's lack of a mandatory auto insurance requirement and the inability of entities to promptly repay the repair costs. Third-Party Claims are included in this Business Process Audit because they represent a component of capital project total annual costs, and this issue was specifically highlighted for review by the Division.

RCG's review of the CapEx processes resulted in recommendations designed to improve communications and various processes to improve the overall flow of information within PSNH and for external stakeholders:

**Capital Project Processing, Documentation, and Oversight**

R.1 RCG recommends the Company retain and document higher cost and/or infeasible alternatives that were considered that could be provided to third parties during the regulatory process to aid in explaining the Company's decisions.

R.2 Ensure that all three Eversource oversight functions Internal Audit, Enterprise Risk Management, and Capital Budgeting annually review an appropriate sample of capital projects over $250,000.

R.3 Introduce formal peer reviews into the overall CapEx project development early in the process to support enhanced decisions and training for design engineers.

R.4 Enforce proper use of the term *Supplemental* consistent with APS-1 throughout the entire CapEx project process, including engineering.

R.5 Develop easy-to-understand examples illustrating the before-and-after impact of DSPG 2020 system planning criteria changes on system performance (reliability and resiliency) for all PSNH customer classes (residential, commercial, and industrial). The examples also need to clearly illustrate how superseded standards ED-3002 and SYSPLAN-010 will be used in conjunction with DSPG 2020.

R.6 Develop a formal process to communicate the latest industry activities, including lessons-learned and technology advancements, between departments and potential external parties (other utilities and suppliers).

R.7 Include person hours on all planned project work orders to support crew performance management.

R.8 Develop and test (as a joint effort between System Planning and Distribution Engineering) detailed Synergi feeder models, taking full advantage of System Planning's familiarity with Synergi to facilitate the process.

R.9 Perform an in-depth/rigorous analysis of the data-checking and conversion process for new software platforms (e.g., DistriView to Synergi data sets) independent of the Grid Mod group's conversion verification process to ensure that data continuity and integrity are maintained throughout.

R.10 Develop detailed documentation to maintain data integrity as data conversions are made from one software platform to another, e.g., DistriView to Synergi, Storms to Maximo. This is especially true for Synergi, where individual phase models for distribution circuits are being developed, i.e., converting from 3-phase balanced distribution line models to 1-phase unbalanced distribution line models.

R.11 Investigate the potential benefits of retro-filling power transformers with the latest technology insulating fluids, e.g., extending transformer life (without compromising reliability) and deferring capital investments. Include guidelines for identifying candidate transformers.

R.12 More clearly explain and illustrate with examples why the best overall solution alternatives are not always the least-cost solution alternatives. It is not sufficient to simply state that all criteria violations have been resolved. In addition, consistently document all alternatives considered in the formal project paperwork. Include a formal statement on NWA solution considerations (even if the statement says NWA solutions were not applicable) and reasons why.

R.13 Compare how the traditional solution alternatives are developed and priced against how NWA solution alternatives are developed and priced. Identify areas that disadvantage NWA solutions, e.g., how projected O&M costs are treated. Document key drivers that contribute to the cost differences between traditional and NWA solutions.

R.14 Develop and conduct in-house training programs for New Hampshire DER hosting map development engineers. Lessons learned from Eversource CT, and MA should be integral parts of this training.

R.15 Continue to investigate Conservation Voltage Reduction (CVR) potential energy/demand savings for PSNH, given the relatively high portion of residential system load --- 44% kWh residential sales: 50% kW residential peak demand.

R.16 Conduct a protection and coordination study in conjunction with System Planning at the distribution circuit level to better understand and anticipate how 2-way power flows can be safely accommodated.

R.17 Take more aggressive actions to correct chronic problem feeders by implementing one or more of the following:

- Reduce COSAIDI targets or other reliability targets to encourage more aggressive distribution automation and sectionalizing schemes; and
- Find locations where alternate feeds can be feasibly constructed for long radial circuits, i.e., create circuit loops, not just segmented customer groups; and
- Apply localized NWA solution options, where suitable, when looping feeders is not a feasible alternative and the solution exceeds the NWA threshold. Subsequent revisions to the NWA Framework may be required.

**Third-party Claims Processing**

R.18 PSNH should develop a formal method to track the status of third-party claims in process but not yet completed at the operating center level.

R.19 PSNH should create an accurate job description for the Administrator position that reflects the importance of the third-party claim's preparation process.

R.20 PSNH should revise the third-party claims process to have the Claims group review incidents where no responsible party is identified or when the operating center management has closed an incident without generating a claim.

R.21 PSNH should develop a flowchart and process narrative to define and illustrate the entire third-party claim process in one document.

R.22 PSNH should correct the software which improperly allocates reimbursements to Account 107 instead of Account 108.

**Data Request Processing**

R.23 If PSNH cannot complete a response to a data request and transmit the data response within ten business days, an estimated completion date should be formally transmitted by the tenth business day.

R.24 In its data responses, PSNH should highlight its ongoing and planned responses to issues and the impact of third parties' actions, rather than embedding the issue within the data.

R.25 To facilitate and clarify data requests and responses, PSNH and DOE should consider adding technical conferences before and after data requests are requested and responded to.

## Communications Recommendations

Of the 25 recommendations developed by RCG, 10 recommendations focus in some manner on communications (R1, R4, R5, R6, R12, R14, R21, R23, R24, and R25). While each of these recommendations can be implemented on their own, Eversource should consider taking steps to improve its communications with external parties. These steps might include:

Eversource should convene, before the filing of Eversource's next rate case, a joint working group to understand external parties' needs and the impact of the present data transfer process on those external parties.

Eversource should develop a standard project documentation package that addresses the needs of all major parties in a rate case. One aspect would be to demonstrate the breadth of alternatives that were considered (including NWA) and why the lowest cost alternative may not have been adopted.

Eversource should ensure the terminology used in major documents such as APS-1 is sufficiently defined at a level that all parties (internal and external) consistently understand.

Eversource should host a technical session for external parties to illustrate the impact of the Distribution System Planning Guide 2020. This session would be focused on a non-engineering perspective using easy to understand terminology.

Eversource should invite external parties to regularly scheduled sessions to communicate the latest industry activities, including lessons-learned and technology advancements.

Implementation of these recommended actions will be challenging for Eversource and external parties and will require commitment from all parties to make the necessary structural and attitude changes.

# Introduction

This process review of the Eversource, and its subsidiary Public Service of New Hampshire (PSNH), distribution capital project (CapEx) processes was procured by the New Hampshire Department of Energy's Department of Regulatory Support Division, Electric Division (Division) pursuant to the terms of the Settlement Agreement approved by the PUC in Docket DE 19-057. In accordance with Appendix 2 of the rate case Settlement Agreement in Docket No. DE 19-057, the following scope was adopted by RCG as the primary objective of the business process audit:

1. Review and assessment of the Company's capital planning, budgeting, approval, and management oversight, including:

   a. Company's budgeting and approval process for capital expenditures.
   b. Company's information systems used in work planning, tracking, and accounting.
   c. Initial project design and development of budgets, cost estimates, revised budgets and budget variances.
   d. Internal accounting for capital projects and administrative support.
   e. Decision making by project managers involving design changes, engagement and hiring of outside contractors and the Company's oversight of contractors.
   f. Decision making by project managers in addressing and controlling project costs including factors that necessitate the involvement of upper management.
   g. Reviews by upper management of project costs and cost overruns and the application of cost controls.
   h. Compliance of the above-listed items with good utility practices.

2. Review and evaluation of capital project documentation, including:

   a. Compliance with documentation policies and filing requirements.
   b. Initial project assessment and analysis in the PAF including consideration of known and foreseeable costs and risks.
   c. Use of Supplement Requests, including root cause analysis and lessons learned.
   d. Source documentation and supporting documentation.
   e. Recommendations for improving and enhancing the above documentation process.

3. Selective Project Review: The consultant will select a sample of capital projects for 2020 and 2021 to be included as a part of its examination and testing involving the above listed processes.

Based upon discussions with the Division at the beginning of the engagement, it is RCG's understanding that the genesis of this portion of the settlement was the result of the Division's review of PSNH's project planning and management processes and the unintentional failure of parties to communicate clearly.

RCG's investigative process cannot give specific weight or confirmation to actions or outcomes that occurred during the rate case, as the conduct of that case was not within the scope of this business process audit.

The Division also asked RCG to review PSNH's wood pole replacement practices including the application of steel poles on the distribution system, the rebuilding of distribution lines with 34kv hardware, and distribution substation maintenance and upgrading practices. These topics are addressed within the body of the report.

The following is RCG's audit philosophy and Covid response as expressed in our proposal for this review:

- Develop an assessment through a positive process that captures the perspectives and needs of all interested parties.
- Deliver a final report that provides a clear, independent, and objective evaluation of Company processes.
- Perform this audit in a COVID-19-safe manner as agreed to with NHPUC Staff. While all RCG team members are fully vaccinated, we also expect judicious video conferencing to help manage expenses.

RCG's consistent ability to meet the commitments of its audit schedules and produce effective results relies on the following approach/steps.

- Develop a formal work plan with clearly defined deliverables.
- Use experienced professionals who possess the combination of professional maturity, specific functional utility knowledge and audit work experience.
- Use both quantitative/qualitative data and information obtained through a structured data request process to evaluate the actual performance of the capital process.
- Develop conclusions consistent with generally accepted auditing standards which require thorough documentation of stated *facts* that support the findings/conclusions. Facts will include direct statements from PSNH/EE personnel, policy and procedures, physical observations, and other relevant data.
- Understand how RCG conclusions reached in one audit area may impact other areas. Determine how overall performance is improved through a clearer understanding of these connections and interactions.

- Use a tracking and retrieval system for work papers in a manner that supports documentation of the findings. On several assignments, the utility has had a format tracking tool that RCG will use to facilitate the smooth transfer of data and information.
- Use an editor to ensure draft and final reports are clear and consistent.
- Assure NHPUC Staff concerns are addressed.

RCG used a five-stage process that includes planning and orientation, fact-finding and analysis, conclusion and report construction, recommendation development and final report creation.

RCG brought together several disciplines to fully understand the situation, identify the root causes of identified issues, and provide an overall objective opinion of PSNH's actions relative to the state of their distribution system. Each RCG team member has over 40 years of utility or power engineering and operations experience. RCG has previously participated in other capital project development reviews and has captured what it believes to be the leading practices in this process area.

This process review of PSNH capital projects looked objectively at those engineering and management processes associated with identifying, planning, and executing distribution capital projects. RCG took a deep look into PSNH's engineering function and practices surrounding capital projects.

RCG understands that there must be a healthy dialog between PSNH and external parties to ensure PSNH customers are adequately represented and charged a fair price for the electric services they receive now and in the future. Further, PSNH must continue to provide the expected quality and continuity of service at a reasonable cost.

The specific elements this report will address include:

- Project management process
    - Project funding approval and oversight
- Project planning and engineering
    - Capital project identification
    - Technical capital project challenges
    - Capital project execution
    - Project closeout
- Third-party damage to capital equipment and the approach to managing the treatment of the associated capital spend

# Project Management Processes

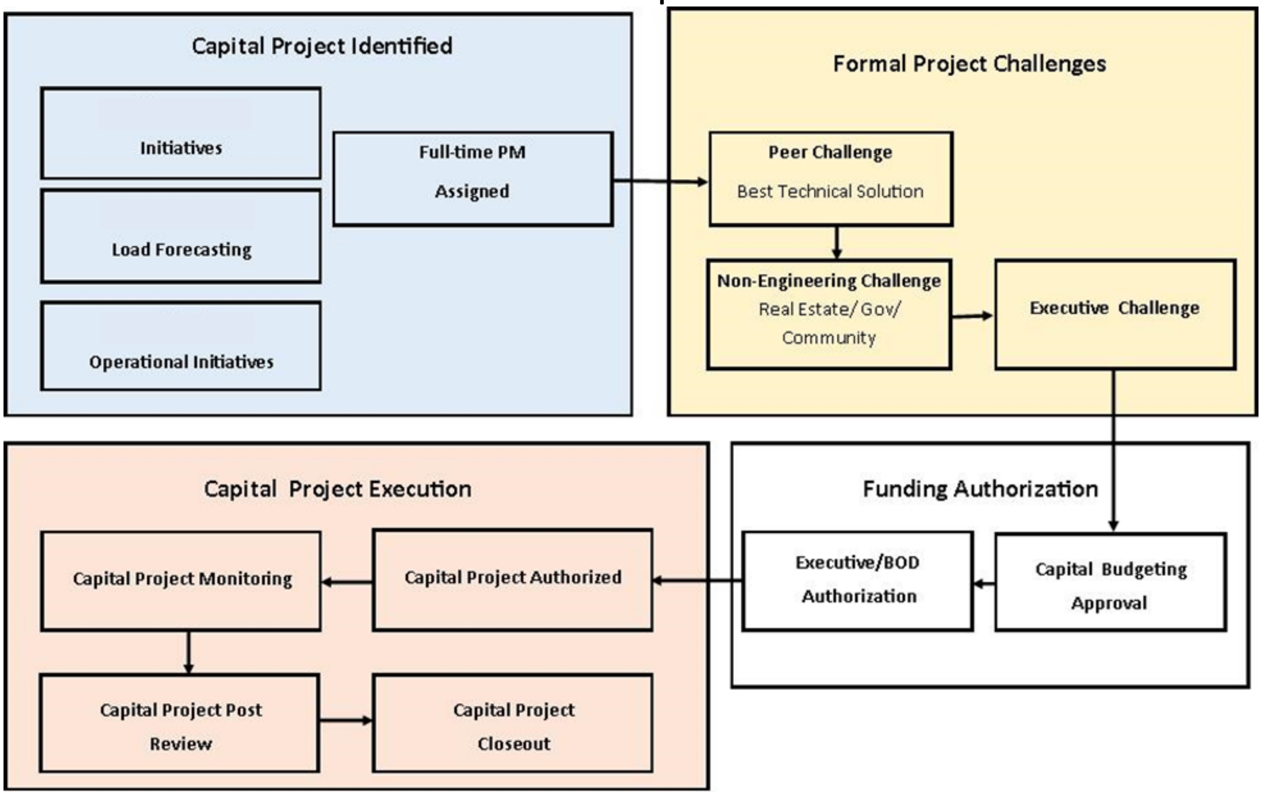
Before analyzing PSNH's CapEx program, RCG will introduce our model of the CapEx process developed over similar assignments, which led to the design of this CapEx process flow. The approach focuses on the capital dollar components of CapEx, but we will introduce several other critical processes which are part of any well-thought-out utility capital program.

## 2.1. RCG developed a Capital Projects process model, incorporating leading policies and practices for CapEx project identification, design, authorization, and oversight processes in the utility space.

This high-level CapEx process model represents the leading practices used in client companies. It reflects minor modifications to streamline the flows and not unduly tax the company personnel responsible for implementing the process. Exhibit 1, on the following page, shows RCG's general process flow for CapEx projects. Notably, the model addresses the approval process, not the detailed engineering process, since that can vary between utilities. As mentioned earlier, the engineering process reviewed in the coming chapters addresses another of the Division's questions. Further, the internal oversight functions are not included in the RCG CapEx process flow but are critical to ensuring all company policies and procedures are performing as designed.

This report will review the processes and actions shown in Exhibit 1 and include other tangential elements identified as critical to the process to clearly understand PSNH/Eversource's process approach to capital projects' life cycle and the state of the NH distribution system. RCG uses the term "Projects" in this document to refer to both stand-alone CapEx projects and programs. Programs are a catalog of similar distribution and substation projects routinely performed across PSNH's service territory over several years.

**Exhibit 1 - RCG CapEx Model**




The blue box, *Capital Project Identified*, shows the sources of Distribution CapEx projects. The first sub-box, Initiatives, indicates corporate policy and standards. Here Eversource sets the guidelines for how systems will be built and maintained, along with equipment specifications and typical designs. Distribution engineering also continually evaluates the system against the standards selected by the utility while ordering system enhancements to keep the system operating within PSNH's set parameters. The second sub-box, Load Forecasting, identifies the future growth patterns and the impact of customer conservation activities and third-party distributed generation. Forecasting looks at peak load (kW) and energy usage (kWh) requirements to determine when and where to expand the system's capacity. As noted in the Engineering chapter, several design and policy concerns were evaluated, along with deciding if PSNH/Eversource evaluated alternatives. It is important to note here that in New Hampshire, distribution companies do not own generation other than for emergency power situations. PSNH operational initiatives deal with unique distribution system situations which will impact system performance. The final sub-box is the assignment of a non-engineer project manager to shepherd the project from inception to project closeout, where the project is moved into the company's capital base. This individual is not responsible for engineering the project but reports progress to management and is responsible for explaining any anomalies or cost variations that might occur during the project. The project manager function provides checks and balances within the project structure with engineering and construction. This individual is the continuity link for the entire project.

The yellow box, *Formal Project Challenges*, is critical to ensure a project is well thought out and prepared for unexpected contingencies. Further, it helps define the best alternative solution for the final project. In this manner, the project team considers the impact on local reliability, including reliability around the specific location, e.g., other substations and feeders, identification of potential impediments to the construction, and alternative cost comparisons. This also offers an opportunity for peer design engineers to challenge the selection of the design engineering team, which also supports learning opportunities while providing valuable insights into the project from various positions. Next, it allows non-engineering personnel to review the project from community, municipal, and state requirements that could impact the design and execution choices. Finally, the executive challenge looks at the project from a needs aspect and consistency with corporate policy.

The white box, *Funding Authorization* ranks the project against other projects competing for the same finite funding. If selected, the budget is approved, and the project moves forward. The critical point is that the project may receive capital funding over several years, or annual CapEx cycles, until completed.

The tan box, *Capital Project Execution*, specifies where the fully engineered project is built, inspected, put into service, and officially closed out from an accounting perspective. The entire process can take several years to complete for substation projects and significantly less time for some distribution line projects.

**2.2. Eversource recently recognized the issues in the capital project process and made changes, however, alternative designs were deleted once management selects the most appropriate design.**

It is RCG's understanding that PSNH/Eversource recognized issues in their capital project budget and estimating processes approximately four years ago and began making substantive changes in the 2017-2018 timeframe. However, an issue discovered by RCG remained unaddressed which PSNH is now addressing because of RCG's early investigation efforts during this audit assignment. RCG noted after observing a PSNH project review session, that once a decision was reached on which alternative project design would move forward, the remaining alternatives appeared to be deleted. RCG also noted that there is a certain degree of informality imbedded in PSNH's communication involving language and detail that non-employees may find difficult to understand. This issue involves spoken and written formats, including a lack of consistent use of definitions and the prompt delivery of essential information as requested in regulatory proceedings. In addition, RCG found that certain project plans, as originally designed, were not effective, as design flaws were discovered during the troubleshooting and quality control phases of construction.

Eversource and PSNH appear to have the appropriate engineering and operational policies, procedures, and processes for managing and maintaining a reliable distribution network in New Hampshire. Still, the written and verbal communications encompassing these efforts are less than what RCG would expect from a company of the size and stature of PSNH/Eversource. While PSNH/Eversource personnel and the management team understand most of what is being said and written inside PSNH, external communications with parties outside the internal process, such as Division Staff, are oftentimes confusing for those parties. This review uncovered several communication issues, which confused our team of utility experts at first glance. These issues will be covered in the appropriate sections of the report and should lead the reader to the same set of conclusions RCG reached during the process review. Specifically, RCG found both written and verbal statements that, on their surface, could be interpreted differently than initially intended. Further, RCG, in performing this process review, identified several issues, which, if not explored more deeply, could lead non-PSNH/Eversource personnel in different directions if the appropriate "next" questions are not asked to achieve clarity. Specifically, RCG found:

- The length of time to respond to some of RCG's data requests exceeded what RCG has experienced in prior process audit reviews. The Division indicated that it has experienced this same issue. This outcome led RCG to conclude that the customarily expected information is not routinely maintained and archived in some instances.
- Standard PSNH terms are not consistently applied across the processes or results. One example was using the PSNH/Eversource word "Supplemental," which was used on several Company spreadsheets as a "total" inconsistent with its formal definition.
- Some information that should be maintained is either discarded or not documented once a design is selected. One example witnessed by RCG is the discarding of alternative solutions once there is a selected project approach. RCG does not infer anything unethical about eliminating this information but assumes it is likely attributable to an effort by PSNH to merely simplify the remaining documentation. Additionally, this action fails to recognize the future need for this solution information by other outside parties such as the Division.

These issues will be reviewed in the appropriate sections of the RCG report.

## 2.3. Eversource and PSNH have done a reasonable job of estimating projects.

Before moving into the formal review of the processes, RCG will present the results of our study of completed project' estimates vs. actuals for 2012-2020.

**Exhibit 2 – Project Estimate to Actuals**

| Year | Percent of Projects Under Estimated | Under Estimated >20% | Total Projects | Over Estimated >20% | Percent of Projects Over Estimated |
|---|---|---|---|---|---|
| 2012 | 100% | 1 | 1 | 0 | 0% |
| 2013 | 33% | 1 | 3 | 0 | 0% |
| 2014 | 56% | 5 | 9 | 1 | 11% |
| 2015 | 52% | 15 | 29 | 4 | 14% |
| 2016 | 57% | 13 | 23 | 4 | 17% |
| 2017 | 29% | 7 | 24 | 2 | 8% |
| 2018 | 21% | 5 | 24 | 4 | 17% |
| 2019 | 30% | 7 | 23 | 0 | 0% |
| 2020 | 22% | 5 | 23 | 4 | 17% |

Exhibit 2 shows a reasonably balanced comparison of under- to over-estimated project costs by year. Except for 2015 and 2016, PSNH made a reasonable effort of estimating projects when compared to actual project cost. This result is essential for the following general reasons:

- Underestimating project costs could produce too many projects not being completed within the annual CapEx budget cycle due to a lack of funding. Consistent underestimating could indicate challenging estimating practices or an inadequate effort to assess project risk factors.
- Overestimating project costs can produce an annual plan with fewer projects due to funding limits. If most projects are overestimated, RCG would be concerned about the potential to pad projects to meet estimating goals. This is not the case here as there are few projects by percentage in this category.

From Exhibit 2, PSNH has more difficulty under-estimating CapEx for projects than overestimating. Although in the last four years, PSNH appears to be doing a better job of estimating. Overestimating seems to be less of an issue for PSNH. Recent efforts appear reasonable when considering the pandemic and its negative impact on the supply chain.

The industry standard is to accept projects completed based on the budget if they are within plus or minus ten percent, which is PSNH's target. RCG has moved the target to twenty percent (20%) to account for recent supply chain issues.

Exhibit 2 indicates a reasonable balance between the over/underestimating except for two years.

## Recommendations

**R.1 RCG recommends the Company retain and document higher cost and/or infeasible alternatives that were considered that could be provided to third parties during the regulatory process to aid in explaining the Company's decisions.**

# Internal Management Oversight

## 3.1. Three separate functions provide independent internal oversight.

The three different functions providing independent internal oversight essential to managing corporate processes are Internal Auditing, Enterprise Risk Management, and Capital Budgeting; however, at PSNH, the first two are conspicuously limited from the PSNH Distribution Capital Line Projects due to Company threshold guidelines.

The internal and independent oversight of all PSNH/Eversource-approved CapEx processes is essential to monitor the integrity of all company processes. Having an internal oversight function of the distribution CapEx process (separate and apart from the engineering/operations function) allows for independent validation of the procedures and policies application. This instills confidence in the processes and attendant outcomes. Within Eversource, internal but independent reviews are performed for substation projects via three separate functions:

- *Internal Auditing (IA)* – Looks at the Company's process controls and in specific projects to ensure compliance with Eversource policies and procedures or where management has concerns over project outcomes for projects. Audit of specific projects generally consist of large dollar/complex risk projects generally over $50,000,000. From an accounting perspective, the oversight of the capital approvals and management is a critical, required set of activities.
- *Enterprise Risk Management (ERM)* – ERM participates during the early development of all substation projects to ensure that all reasonable potential risks are identified. It also impacts the final *Pre-Constructability Estimate and schedule.* Participation is limited to projects greater than $25,000,000.[1]
- *Capital Budgeting* – begins with project development and design. The PowerPlan tool tracks the project's initial conceptual engineering estimate through the development of additional engineering "building block" estimates. Project post-completion responsibility is to compare the total actual engineering and construction costs against the authorized final *Pre-Constructability Estimate*. It is the final estimate in a series of evolving estimates that reflect the project's engineering development stages. Eversource engineering prefers this approach to tracking engineering CapEx distribution projects so that all engineering parties and management can understand the evolution of the project's final *Pre-Constructability Estimate.* The *Pre-Constructability Estimate* once approved becomes the *Full Funding* amount for the specific project. The last and consequential *Pre-*

[1] Interview #35

*Constructability Estimate* is used in the Company's formal capital budgeting process to communicate between the parties as defined in the APS-01 process. The APS-01 is Eversource's project authorization policy. Until January 1, 2022, APS-01 required the estimators to use only direct labor and material costs, omitting the indirect costs associated with labor, supervision, and administration, when determining if a supplemental authorization request was necessary if actual (total) project costs were expected to exceed authorized (total) project cost estimates. This prior approach would generally guarantee that the final (total) project cost would be off by the value of the indirect adders, which could have been in excess of an acceptable threshold. This was changed as of the first day of 2022 and will lead to more projects being evaluated on whether a supplemental cost authorization form is needed when all actual costs are compared to all cost estimates to determine if they exceed the acceptable threshold.

**3.2. Internal Auditing (IA) works with an annual audit target of fifty audits/reviews for their official annual auditing plan across Eversource businesses. This yearly plan's number of audits driven by IA staff size precludes IA from evaluating lower risk/value projects and therefore limits the number of New Hampshire business audits, including the New Hampshire distribution line function.[2]**

The Institute of Internal Auditors defines internal auditing as "an independent, objective assurance and consulting activity designed to add value and improve an organization's operations." IA helps an organization accomplish its objectives by bringing a systematic, disciplined approach to evaluating and improving financial risk management, process controls, and governance processes.

RCG only evaluated IA's function concerning its ability to provide adequate independent oversight of the NH Eversource distribution capital processes. IA is tangential to the CapEx Process but critical to monitoring the process from a control perspective. RCG conducted two interviews on IA organizational structure and reporting lines, responsibilities, experience, training, audit planning and execution, post-audit follow-up, and best practices. We are not commenting on the function but only on its support of the PSNH Distribution CapEx projects.

IA is positioned correctly within Eversource to provide independent assessments of selective Eversource's processes and controls. It appears to be professionally staffed with individuals who meet the requirements of IA auditors. The audit planning process is

[2] Interview #10 and Interview #9

appropriately risk-based, and audits are identified and prioritized based on input from the organization.

Eversource's Internal Auditing has four sections[3]:

- The operational audit group performs process audits across:
  - Electric Distribution,
  - Gas,
  - Water, and
  - Transmission functions.
- Information technology audits, supported by contractors, and
- Sarbanes-Oxley compliance, and
- Environmental, Customer Care, and Corporate (CFO, HR, and General Counsel).

IA has a formal plan to conduct approximately fifty (50) audits annually[4] for the entire Eversource organization. Most annual audits are pre-planned as opposed to reactive audits. The Vice President of IA is proud that when his organization is compared to other Northeast utility's IA organizations, they are slightly smaller in staffing size but achieve a significant amount of work. The annual audits are conducted by a total staff of approximately twenty (20) people, including the four managers reporting to the Vice President of Internal Audit & Security. IA's staffing design makes it challenging to conduct additional audits across all business units within the Eversource family. According to IA, of the 50 planned audits conducted annually only, 18 to 20[5] are within Eversource operations that would include CapEx distribution projects, which would be across the entire Eversource family of operating companies.[6] The remaining 30 plus audits include IT, Environmental, Customer Experience, Corporate Services and CFO function.

IA uses a formal risk rating system that rates all key risks categories including financial, operational, external, technical, strategic, and historical. However, the dollar amount is only tied to the physical project's cost when considering auditing CapEx projects. It does not include the potential harm/risk to Eversource financials caused by the possible rate disallowances that might occur during a rate case due to an issue with a specific project.[7]

The IA formally tracks open audit recommendations made in previously conducted audits, demonstrating that follow-through exists in IA.

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[3] Interview #9
[4] Interview #9
[5] Interview #9
[6] Interview #9
[7] Interview #10

The group monitors and compares itself to industry best practices. It participates in regional peer reviews[8] and adheres to the Institute of Internal Auditors Standards and the Code of Ethics.

**3.3. Enterprise Risk Management (ERM) works within a minimum project/program spend limitation of twenty-five million dollars. There are not enough resources to cover all the projects and programs, so the focus is on the high dollar efforts which preclude PSNH line distribution capital projects. It will have the most significant impact in Exhibit 1's yellow Box, *Formal Project Challenges*, as this function will test the design team's risk assessment evaluation from several different directions.**

ERM is critical to supporting RCG's CPPM, as it helps identify all potential project risks outside the project's design to protect project budgets and schedules. Eversource ERM generally does not review projects valued at less than twenty-five million dollars.[9] Specifically, in RCG's Exhibit 1, the early peer reviews involve other co-workers working in different disciplines, e.g., real estate, governmental and customer affairs, and others. Much of these are covered via ERM.

PSNH's "Regional Barns" or local operations centers, personnel appear to informally provide local knowledge of the design and unique conditions, reducing a portion of risk and allowing for additional project costs. But here, due to project size, there is no outside group evaluating the distribution design and its potential risks. It is important to note ERM has helped create lists of likely project risks based on past experiences, which are available to the designers and management.

This function will test the design's ability to withstand several risk areas, including government imposed issues, environmental and permitting, customer issues, regulatory requirements, and potential geological issues. These risks can add significant costs to the project while potentially impacting the construction schedule. In one example, RCG inspected a distribution line construction site that traversed wetlands and required a substantial level of environment mitigation using an extensive level of matting and a unique pole foundation design which increased the cost of the line installation significantly. Specifically, on this one project, PSNH had to pay for the installation, removal, and rental fees for the period the matting was installed in this marsh area. PSNH performed the necessary walk-down of the site, which allowed them to identify the wetlands, design changes, and incorporate the required additional expense into the

[8] Interview #10
[9] Interview #35

estimate. In the past, RCG has seen several utilities which allowed their engineers to design from their desks and this approach would have missed the need for matting. PSNH/Eversource supports engineers going to the field during the design efforts, a practice RCG supports.

RCG is always concerned, in these types of studies, that these risks can be used to cover poor estimating practices or to ensure that projects are not overestimated to prevent projects from coming in well over the estimates. Based on our review of the requested CapEx projects, this doesn't appear to be an issue. There are several overestimated projects which appear to be within acceptable parameters. In comparison, there were a much higher number of projects underestimated.

**3.4. Capital Budgeting is correctly responsible for overseeing the capital budgeting for projects and adherence to Eversource's *APS-01* policy and process, in addition to managing Engineering's use of *PowerPlan*. The group monitors and oversees a capital project's estimating, funding, and spending processes. The group ensures procedures are followed from determining the specific project capital budget through total spending on projects, including reports on the accuracy of the approved constructability estimates. This group is responsible, along with project management, for monitoring and reporting on the project financials.**

A critical element to understand is that from a financial/accounting perspective, both the *PowerPlan* and *APS-01* are managed under the capital budgeting function, which allows for an independent review of capital budgeting components of a project throughout its life. The process provides for monitoring project estimates and expenses regardless of where or when they occur. *APS-01* establishes the evaluation, decision-making, and approval process of all projects -- per this policy. More importantly, it defines how PSNH will define, manage, and perform quality control of CapEx projects.

> "*A project is defined as a commitment by Eversource of internal and/or* external *resources to accomplish an initiative that will have economic impact to the Company, its customer and/or is required by policy or regulatory standards. The overall policy objective is that projects should be evaluated and approved in accordance with the DOA prior to the commitment of company resources.*"[10]

[10] DR BPA-1-12, Att. B p3

Importantly, PSNH, like other utilities, provides initial funding dollars for the physical initial scoping and engineering of the project. This early *Conceptual Estimate* should *not* be used to compare with the project's as-built final cost as the initial *Conceptual Estimate* does not contain expenses associated with equipment, construction labor, property procurement, overheads, etc.

In concert with the capital budgeting process and *ASP-01*, but integral to the approval process, the PSNH/Eversource's formal *Delegation of Authority* (DoA) policy clearly defines the management approval required for the total project value. The higher the project value, the higher up the management chain for approval is required. Ultimately this can lead to the Board of Directors' approval requirement. DoA is an accepted standard industry policy and practice allowing the appropriate management levels to oversee project approvals actively. The CFO organization is the corporate sponsor for these two policies.

Supplementing APS-01 and the DoA are the following related policies and procedures: [11]

- *Capital Project Approval Process Job Aide,* (JA-AM-2001-A, Rev 5 6/1/2020)
- *Engineering Deliverables Administrative* Procedure (M7-EN-2000, Rev. 0, Eff. 7/1/2020)
- *Power Plan Procedures Manual and Users Guide*
- *Integrated Planning and Scheduling Process Playbook (IP&S Playbook*) (Revision: 0.1, November 30, 2017)

The *Capital Project Approval Process Job Aid* provides instructions and guidance on the process. It identifies the organizations responsible for the capital program project review and approval process following the *APS-01* policy. The *Business and Quality Assurance, Transmission Organization*, is responsible for administering the *Job Aid*. RCG found using a *Job Aid* to provide detailed instructions for creating a project is consistent with industry practices.

*Engineering Deliverables Administrative Procedure*[12] provides the detailed responsibilities and specific actions engineering personnel (PSNH/Eversource and contractors) must follow in the capital project development and approval process. Specifically, this procedure offers guidance for each design phase of a project. Additionally, it provides a complete list of deliverables to be considered by the engineer in developing the design packages for all transmission and substation projects. Most

[11] DR BPA-1-012
[12] DR BPA-5-007

importantly, it allows the project sponsor to validate the design against the need statement and the accuracy of the project estimates and budgets.

RCG found this procedure to be consistent with industry practices. However, RCG found many instances where the design packages did not include and/or retain sufficient documentation of the alternative solutions that had been considered. Additionally, one substation project designed by a contract engineering firm did not receive a good review from the project sponsor. It resulted in the need for considerable rework and additional capital costs. See specific examples in the Engineering Section of the report.

*Power Plan Procedures Manual and Users Guide*[13] provides detailed instructions on using the *Power Plan* software in the capital budget, project development, and approval process. Included are specific instructions for developing the project funding request and creating the work order. These recently updated procedures clarified the requirements for the attachment of project documents including the *PAF*s. RCG found these procedures consistent with utility industry practices and supports the documentation filing practice improvement.

*Integrated Planning and Scheduling Process Playbook* (IP&S Playbook) [14] provides detailed steps for the following:

- An annual work plan,
- The weekly "work order plan", and
- The schedule for field and station operations, electric service, and response specialists.

The annual work plan process covers work identification, budget and resource balancing, and the development of project scope details. The work order planning process lists the prerequisites required for a work order to move into the scheduling window. Once in the scheduling window, the weekly and daily scheduling is developed. This planning results in a weekly work plan targeting 80% of the available hours, with the remaining hours focused on emergency and emergent work. However, the associated work orders for each project do not include targeted work hours to enable supervision to assess individual crew performance.

RCG found the processes and practices described in Eversource's IP&S playbook to be, with the exception noted above, consistent with utility industry practices and found it implemented consistently across PSNH.

[13] DR BPA-11-012 Att. A and b
[14] DR BPA-12-016

The above policies and procedures are combined into PSNH's annual capital budget and project development processes.[15] The PSNH Capital Budget starts with reviewing and updating the *Long-Range Plan* and associated five-year budget forecast early each year. The capital budget development for the upcoming year follows later (in the year) with the annual executive challenge session. At this session, Distribution Line Projects are discussed, including:

- Peak load and reliability-driven projects,
- Line upgrade projects associated with meeting distribution planning criteria, and
- Any distribution ROW rebuild projects, where the scope of the work is a project rather than the $100K limited ROW annual program.

Further, projects in process, including pole-top distribution automation, oil filled circuit breaker replacements, animal protection, obsolete relay replacements, and annual projects such as transformer purchases, new services, and municipal driven work will require budget funding forecasts. Collecting all projects with forecasted estimates leads to a preliminary annual budget.

PSNH leadership then reviews the preliminary annual budget. If approved, it becomes the basis of the capital plan and is presented to Eversource Executive Leadership and the Board of Trustees for approval. Adjustments to the following year's capital budget are based on actual project costs, schedule adjustments, and emergent system needs. The decision on whether to fund a project currently unidentified in the capital budget is made monthly at the Capital Budget Review Meeting, chaired by the President of NH Electric Operations.

Since most distribution line project development takes place before the Challenge Session (described above,) preliminary design work is already underway (provided budget approval has been received.) However, the specific line projects cannot move forward to construction without first being approved by the NH Project Approval Committee (NH PAC). At this point, the *Project Approval Form* (PAF) is submitted to the NH PAC for review once the design is complete. The decision to use internal or external resources is then selected, ensuring the best estimate is available at the time of the NH PAC review. Distribution line projects are then prepared and presented by the organization that initiated the project.

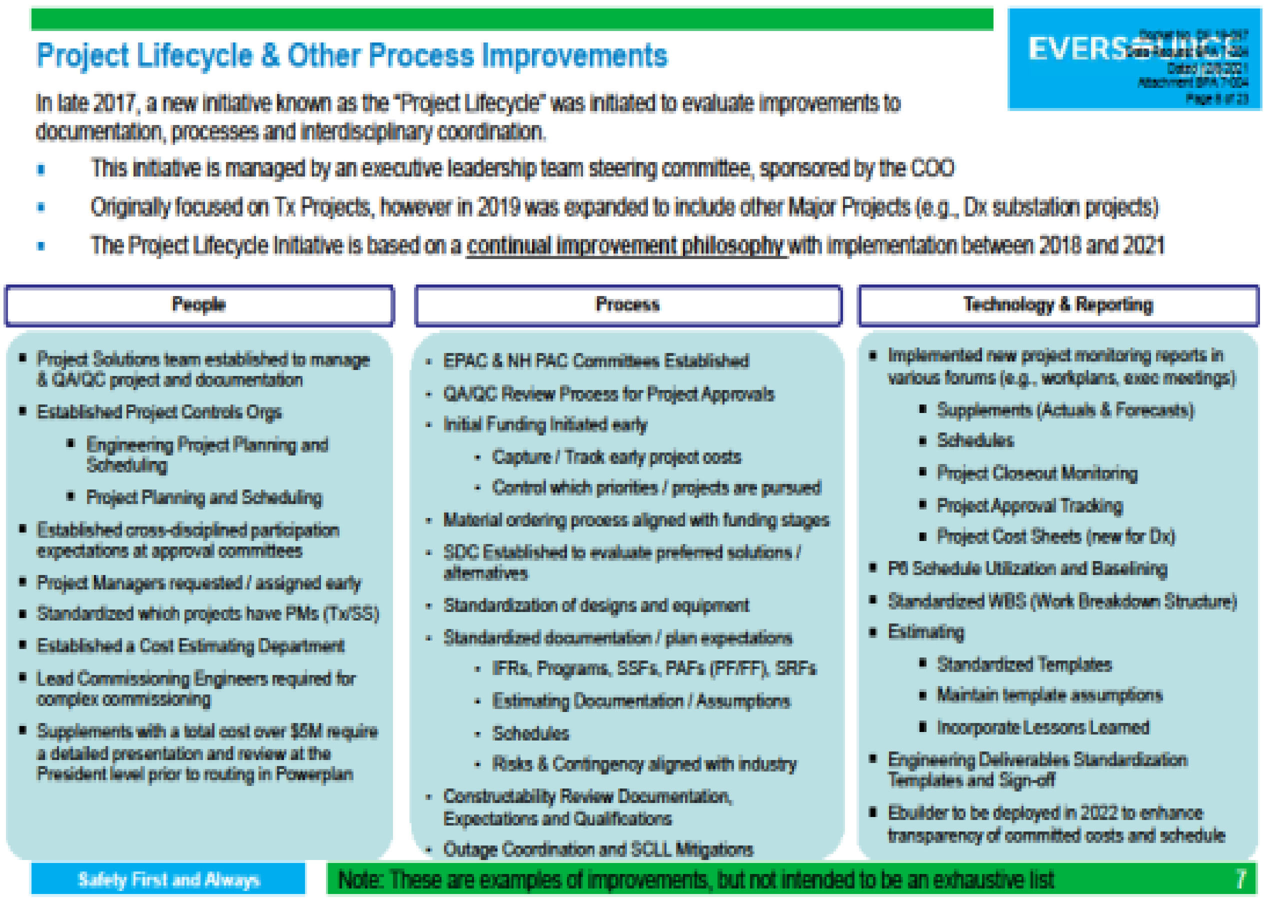
[15] DR BPA-8-029

Similarly, substation projects are developed based on the priorities outlined in the annual capital budget and presented to the *Eversource Project Approval Committee* (EPAC). Since the duration of substation projects is typically longer and more complex than distribution line projects, initial funding and partial funding are requested regularly to support detailed design deliverables. Full funding authorization, approved by EPAC, is required before a substation project can move to construction. Distribution substation projects are also prepared and presented by the initiating organization.

RCG found PSNH/Eversource's capital budget and project development process consistent with industry practices. However, as previously discussed, there are limited opportunities for proposed distribution line projects to undergo peer-to-peer challenges to design alternatives.

PSNH/Eversource has updated its capital budget and project development policies and procedures during this BPA to reflect Eversource's improvements in cost estimate documentation, alternative solution development, and document retention. A number of these improvements were a direct result of interview discussions. The following exhibit reflects improvements Eversource has made in its capital business process:

**Exhibit 3 - Life Cycle and Improvements**[16]




In 2021 changes were implemented regarding the Distribution Line Capital Project Process. The "*pre-construction final estimate*" is now the estimate that the NH PAC will approve, and the construction organization will be held accountable for delivering the project's final cost.[17]

However, two components of the budgeting process contribute to the confusion experienced by outside parties, in particular the Division, involving estimates and additional costs added to the original estimate.

- The term *Supplemental* funding is defined in *APS-1* but has been misapplied. "*Should additional, unexpected costs to the project materialize, **the formal process described as the "Supplemental" attaches those costs to the original***

[16] DR BPA-7-004 Att. p9
[17] DR BPA-12-014

***authorized pre-constructability Estimate.***"[18] RCG understands that *these "Supplementals"* go through a rigorous review by the engineering organization for substation projects. For line distribution projects outside the substation fence, any supplementals are approved by the Director of New Hampshire Distribution Engineering after a thorough vetting. During RCG's review of the CapEx projects data request (DR) form, the RCG team found that the term *"supplemental"* could become confused with total project cost (combining the original authorized amount with the additional supplemental dollars and called the *supplemental*.) This set of conditions could create a point of confusion for anyone not familiar with the form and the process.

- In one project, PSNH pointed out that the extra cost was due to an unforeseen change in the contractor selected and included in *the Pre-Constructability Estimate* because the work had not yet started. We agreed, subject to Eversource's accounting department approving the policy definition until the metaphorical "shovel hits the ground." These unforeseen cost changes would not be supplementals for this report but included in the *Pre-Constructability Estimate*. In Eversource's 3rd Step Adjustment filing, the term "*supplemental*" was used in the supporting spreadsheets as the heading title for the total expenditure column, including any *supplemental* funding. This approach has continued to contribute to confusion on what data PSNH is presenting and does not contribute to clear communication of the overall PSNH position.

*PowerPlan* may indirectly create another point of confusion for outsiders reviewing the CapEx project estimates from two aspects, the number of estimates produced during the project's development and the use of the term "*supplemental*." This issue is reviewed further in the Engineering section of this report. During a review of one of RCG's requested CapEx projects, one project led to significant discussion between RCG and several members from distribution operations. The discussion focused on when a *supplemental* is genuinely a part of the initial *Pre-Constructability Estimate* and, therefore, not treated as an additional unplanned expense. The project was not in construction, but the estimate increased due to a change in contractors. The Company argued that since the winning vendor had not been identified during the final efforts of the *Pre-Constructability Estimate*, the additional cost resulting from a change in construction contractor should not be held against the project estimator as an oversight cost. Without formal input from the Eversource accounting department, RCG would consider any additional cost as part of the *Pre-Constructability Estimate* for this process review.

[18] APS-1

The first two independent oversight reviews appear to work well for those substation projects due to the high dollar value of the projects exceeding the minimum threshold. The distribution line projects are typically below this predefined value and not subject to these two oversight review processes. The reasoning behind these limits is reviewed below, along with a short definition of each function.

| | |
|---|---|
| **3.5.** | **Many current substation capital projects under construction may not have fully benefited from the post-2018 CapEx process and policy changes.** |

Substation projects can span years between need identification and completion due to completing critical sub-project elements, including detailed engineering, acquiring properties, obtaining licenses and permits, conducting environmental assessments, approvals, and significant equipment production lead times. Therefore, many existing substation projects could have started five or more years ago, preceding the current policy and process changes surrounding CapEx projects.

Substation projects covering multiple years have added to the complexity of RCG's evaluation of these large capital projects against our CPPM. Eversource CapEx projects' processes and policies were changed around 2018. However, several current projects under construction were designed before 2018, meaning they were designed and engineered under the previous policies and processes, which lacked the benefits of the new process elements and potentially impacted their accuracy. In addition, some system design standards have been modified, either by policy or upgraded distribution system standards. These concerns are discussed in the engineering chapter. All of this can cause explainable and acceptable variances. Further, some projects had significant issues resulting from not having the benefits of the new policies and procedures. Several of these will also be addressed in the Engineering chapter.

# Recommendations

**R.2** **Ensure all three Eversource oversight functions Internal Audit, Enterprise Risk Management, and Capital Budgeting review an appropriate sample of capital projects over $250,000 annually.**

**R.3** **Introduce formal peer reviews into the overall CapEx project development early in the process to support enhanced decisions and training for design engineers.**

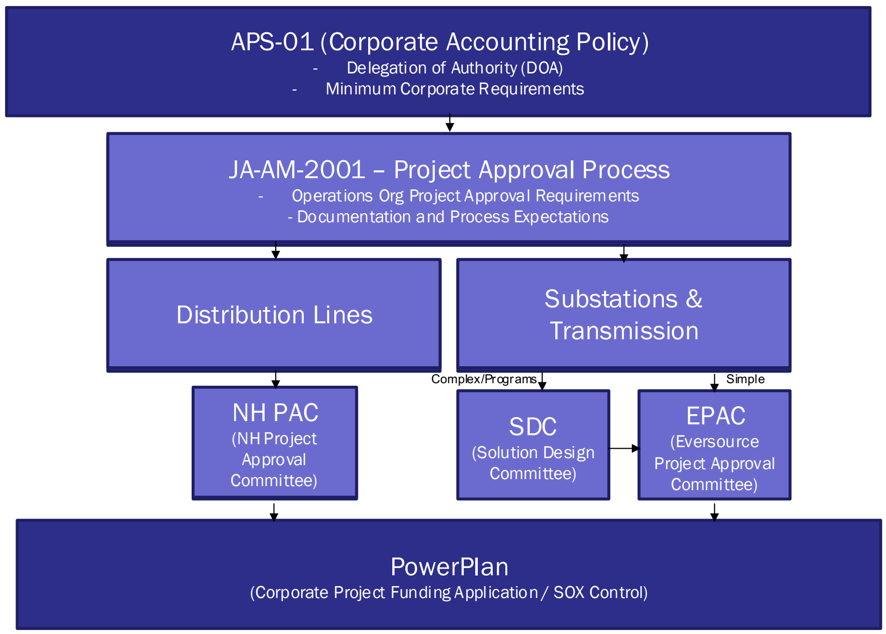
**R.4** **Enforce proper use of the term *Supplemental* consistent with APS-1 throughout the entire CapEx project process, including engineering.**

# Engineering Capital Project Approval Process

**4.1. The capital project approval process is well designed, but its complexity varies with the project class. Further, formal initial peer reviews are not formally included.**

Exhibit 4, provided to RCG during the Kickoff session, shows the hierarchy of the capital projects approval process and the two different process versions.

**Exhibit 4 - High-Level CapEx Project Approval[19]**




*APS-01* is Eversource's formal and governing accounting policy and process. This document includes the traditional definition of the *Supplemental*. *Supplemental* is additional capital funds added to the original authorized CapEx project's budget, initially referred to as the *Pre-Constructability Estimate* by Engineering after their design process is finalized. *Pre-Constructability Estimate* is critical as it signals the end of the engineering phase and becomes the number used in the *Full Funding Request* approved at the *Eversource Project Approval Committee* (EPAC) or *New Hampshire Project Approval Committee* (NHPAC). Any *Supplemental* applied to either substation or distribution line projects are formally reviewed by the appropriate leadership team.

Importantly, all substation design engineering work is managed through Eversource's Substation Engineering function regardless of whether it is for transmission

[19] Capital Project Approval Process, JA-AM-2001-A, Rev 5 Job Aid

or distribution. Further, it encompasses all Eversource distribution companies regardless of distribution voltage variations. This design centralization is expected in the electric utility industry. It promotes consistent design results for specific substation types, minimizing the potential for errors while promoting design consistency across PSNH by primary voltage combinations. Further, it allows operations to better use their resources and engineering personnel across the PSNH system. The voltages may differ, but the protection and switching procedures can be the same, reducing the potential for field-induced operating errors.

RCG discovered one flaw in the CapEx estimating process; it required the project estimators or managers to consider only the direct costs associated with the project when determining whether a supplemental authorization (additional funding request) is required. RCG identified this early in our discovery effort. Since then, Eversource has changed the *APS-01* policy as of January 1, 2022, to require total cost (direct and indirect costs) be considered when determining whether an additional funding request is needed.[20]

The *JA-AM-2001 – Project Approval Process* takes the overall Distribution CapEx project approval to a more technical and granular level of actions and approvals during the needs assessment and engineering design. It is here where a critical distinction occurs between substation and distribution Line projects. As shown in Exhibit 4, the substation projects must first go through the *Solutions Design* Committee (SDC) and, with their approval, advance on to the EPAC, which must approve the CapEx for substation and transmission projects from across the Eversource family of companies. Both committees can return the project to the designers for additional design and requirement efforts. The SDC committee, which tends to be a technical review, will work with the designers before the SDC presentation to ensure that the required forms are correctly completed and that the selected design meets the PSNH's expectations.

**4.2. The Distribution Substation Approval process is detailed and permits close tracking of the project's budget development through a series of evolving estimates in *PowerPlan* that reflect Engineering's efforts. But the process appears to lack sufficient formal peer-level reviews.**

The process appears to lack sufficient formal peer-level reviews that allow alternate designs to be considered earlier in the process and function as a learning tool for engineers. In addition, it provides for the use of the term *Supplemental* before an authorized capital project is designated, potentially creating a point of confusion for

[20] DR BPA 12-015 and Interview #43

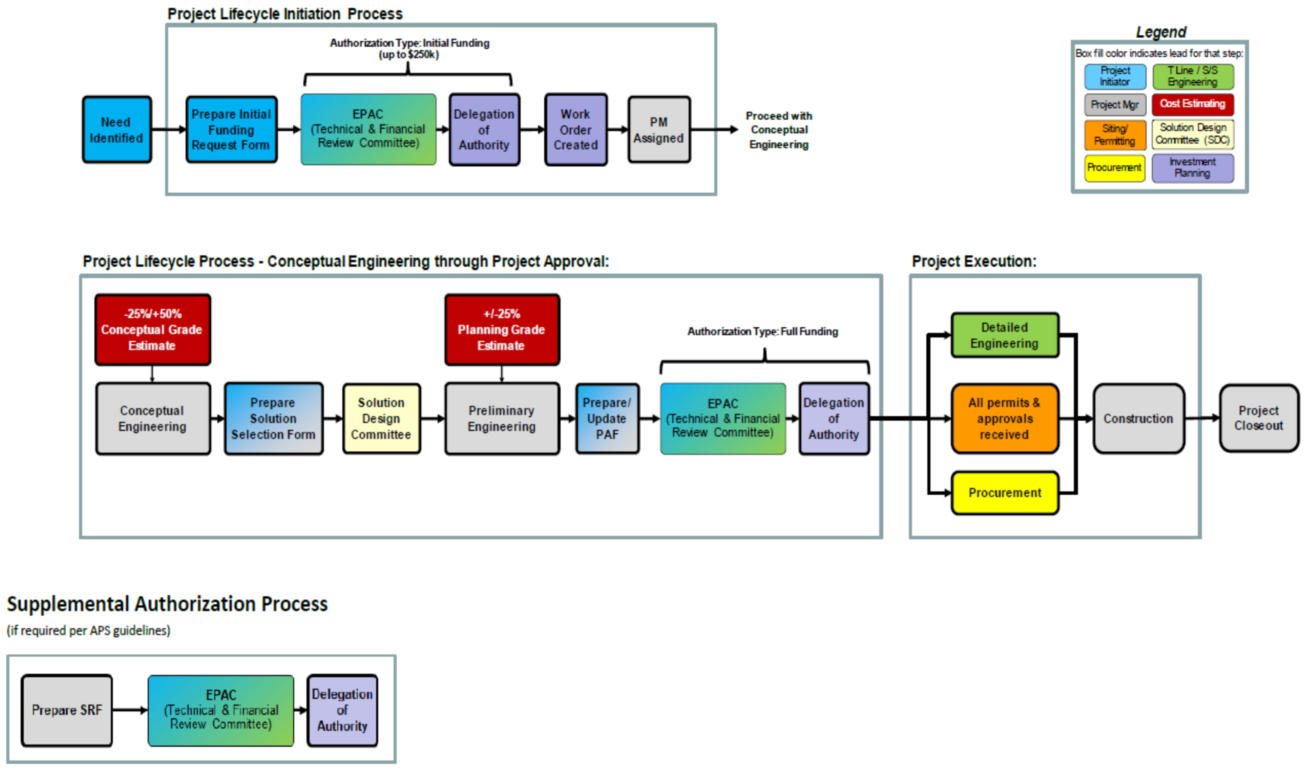
outside parties', in particular the Division, not having the benefit of the list of estimates' definitions, selects and reviews the wrong estimate for comparison with the project's final installed cost. This situation is the result of the Company not providing adequate definitions on each of the different estimates prepared.

Exhibit 5 shows Eversource's Substation Project Approval process, including the Supplemental Authorization process. An important distinction is that substation engineering is positioned in Eversource for all three states. The process is complex in its flow but appears to provide Eversource with most tools RCG deems appropriate and necessary for NH Substation-type projects. It does not, to our knowledge, have a rigorous formal peer review. The reviews are performed by management in the two large-format meetings conducted twice monthly and on the same day. The EPAC session involves many participants from across the Eversource family of companies and appears to be financially focused. Several members of the SDC meeting attend the EPAC session as well.

Exhibit 5 includes a subprocess for *Supplemental* increases during the engineering efforts. This use of *Supplemental* at this project stage is one of those communications-definitional issues raised earlier. According to *APS-1*, the use of *Supplemental* is reserved for projects having *Full Funding Authorization*. In other words, they have achieved the *Pre-Constructability Estimate* status and are authorized to proceed. This use is not the case for the engineering estimates that precede this part of the process.

### Exhibit 5 - Substation Project Approval Process

Attachment D, Transmission and Substation Project Approval Process Flow Charts




Capital Project Approval Process - JA-AM-2001-A, Rev. 5

Because of the number of participants at the EPAC meeting, 70 or more employees from across all Eversource operating companies, these meetings are held via Microsoft Teams. Given the medium, RCG could not determine the participant's level of individual engagement during the session observed by RCG. Further, the SDC meeting is held similarly without as many participants.

Our review shows that the engineering line management structure for the engineering and operations functions is dedicated to robust oversight of the Substation CapEx projects. More on this is provided in the Engineering chapter of the analysis. Further, there is a significant level of person-hours devoted to reviewing projects at multiple levels.

Based on the management interviews and observation of two formal committee sessions involving a significant number of personnel beyond voting members, this process involves a considerable time commitment to review CapEx projects and programs. The two formal bi-weekly meetings occur at the Eversource SDC and (EPAC) levels for substations and New Hampshire PAC for distribution lines. An important point here is some projects will not clear these sessions and will be tabled until they meet the standard design/financial requirements. RCG did not witness extensive questioning on projects in either meeting. Given the size of the EPAC meeting and the number of projects being reviewed, this was not surprising, but RCG would be remiss if we didn't comment on this format. Having such a large forum at EPAC with an unexpectedly lower participant involvement seems counterproductive and may not be supportive of a learning exercise.

SDC reviews the substation engineering projects' technical readiness to move to the EPAC. At this committee, the primary focus is completing the PAC forms and a review of alternatives. RCG considers this to be a pre-screening activity. In addition, before this meeting, SDC team members meet with the project designers to evaluate the worthiness and the technical adequacy of the preparation of documents required by the two committees. The informal SDC pre-meetings function somewhat as an informal peer review described in RCG's CapEx Process but not entirely, since the principal effort of the pre-SDC meetings is to ensure forms are adequately completed.[21]

The purpose of these committees is to move forward those engineering projects to be included in the formal authorized capital plan for PSNH in the form of a *Full Funding Request*. Once approved, the project receives the necessary management signatures consistent with the *Delegation of Authority* policy.

Before full substation project authorization, the engineering of projects is tracked using *PowerPlan*, which follows the project's engineering development estimates through the final *Pre-Constructability Estimate*. *PowerPlan* provides management with critical insights into the formation of the final estimate. However, *PowerPlan* creates several interim "Building Block" estimates as a project moves toward the final *Pre-Constructability Estimate*. When the DOE requests all the estimates associated with a given project, PSNH/Eversource must provide those building block numbers generated from the conceptual engineering estimate through the *Pre-Constructability Estimate*. This can create another point of confusion for third-party reviewers, as PSNH must comply with the request even if the intermediate estimates are only building blocks used to achieve the *Pre-Constructability Estimate*. This situation is aggravated when the estimates provided are not accompanied by appropriately detailed documentation explaining each intermediate estimate's purpose.

[21] Interview #34

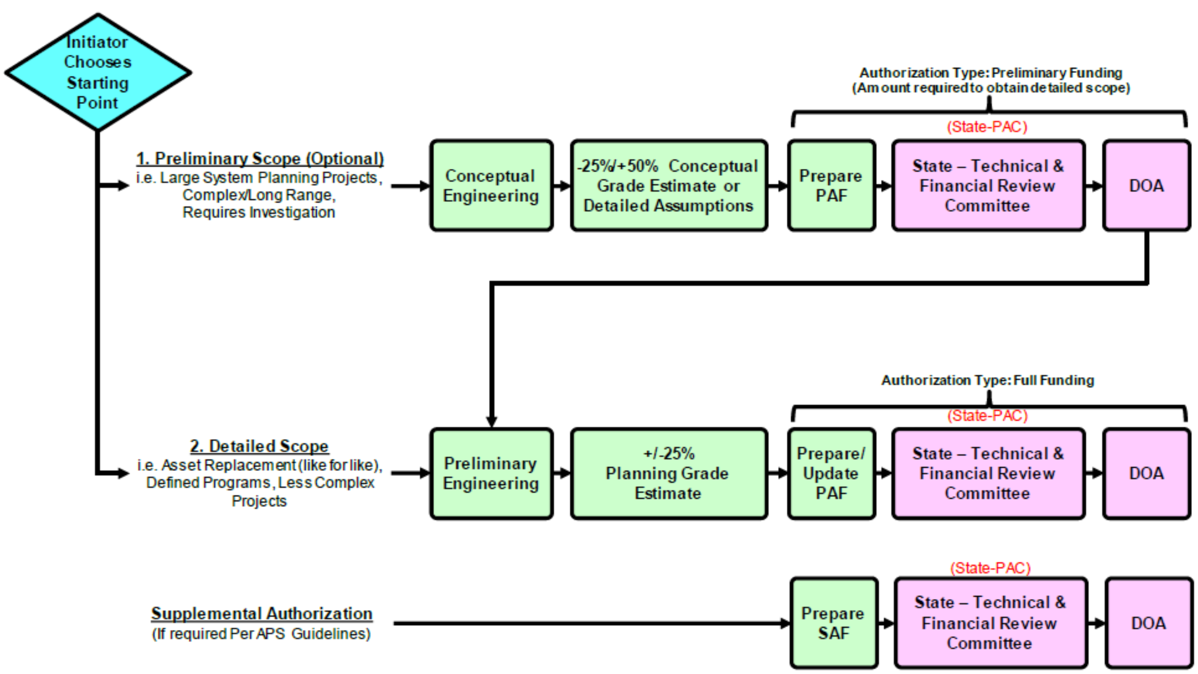
**4.3. The Distribution Line projects follow a less complex process but still contain the same concerns related to clear communication and terminology definition.**

The Distribution Line Projects process, Exhibit 6, only involves one approval committee, the *NH Project Approval Committee* (NHPAC). Further, the final arbiter is the Director of Distribution Engineering, who also serves on the committee. Projects can be tabled and resubmitted after the identified issues are satisfactorily addressed. RCG learned from the Director that this is a highly iterative process.

As with the substation projects' flow, Supplemental is also used in this engineering process flow. The NHPAC committee is different from the two substation approval committees in that it approves the project technically and financially.

**Exhibit 6 - NH Distribution Line Project Approval Process**

**Attachment F, Distribution Project Approval Process Flow Chart**




Capital Project Approval Process - JA-AM-2001-A, Rev. 5

Since these projects are less complex and have a significantly lower dollar value, the need for the same level of rigorous review as the substation design process is less critical. RCG agrees with this determination. Once again, the term "*Supplemental*" surfaces as shown in the above Exhibit and is used similarly as with the substation approval leading to the same type of confusion if the estimate is not the *Pre-Constructability*. Regardless of the project type, either substation or distribution line, the project is managed using *PowerPlan*, which tracks the project's engineering development cost estimates through the final *Pre-Constructability Estimate*. As before, it creates another point of confusion for third-party and regulatory reviewers, even though the Company must comply with regulatory requests. This is particularly true when the estimates lack the appropriate documentation explaining each intermediate estimate's purpose.

The distribution line projects still have a risk component that should be understood and accounted for during the design. Several issues are generally reviewed before a project is approved and the final budget is incorporated into the annual PSNH capital plan. Specifically, these include:

- Soil conditions, rock ledge that could require more time, and the use of special digging equipment,
- Water table depths, where appropriate, could impact the installation process by requiring water mitigation efforts,
- Other in-ground obstacles that would potentially require the relocation of poles or trenches in the case of underground cables,
- Obtaining rights-of-way over private property,
- Tree trimming and removal can, in some locations, be complicated due in part to landowner concerns,
- Municipal roadway requirements, and
- Soil removal and disposal requirements.

Generally, line projects have fewer unique components. PSNH/Eversource has recently changed several design requirement policies to replace worn/aged equipment to improve reliability. In addition, the recent policy changes will improve the purchasing leverage of PSNH/Eversource in general, which in the coming years will lead to better management and predictability of material unit costs for line equipment. Further, it will reduce inventory carrying costs and the overall level of stores by eliminating the need to maintain many different voltage types of the same components. One line hardware component has a side benefit, moving from three other voltage class insulators to standardizing on 34.5kV units will increase the voltage creep distance customarily required for the 12kV and 4kV systems and potentially reduce the need for insulator cleaning on the two lower voltages caused by natural contamination from air-born materials like dirt and salt.

PSNH's tree trimming policy and approach appear adequate for the geography. Issues with tree trimming tend to surface in population centers where property owners live. They have genuine concerns regarding the impact of tree trimming on the aesthetics of their property, which could lead to a perceived lowering of property value. The issue of aesthetics is shared across the electric utility industry, and the solutions can be complicated.

The final approval for distribution line CapEx projects rests with the Director of New Hampshire Distribution Engineering (DoNHDE). The DoNHDE has the final approval and performs any necessary follow-up with the distribution designers, particularly when additional costs exceed the originally authorized CapEx dollars. These overages are tracked by a meeting with the Director to explain the overages.

A pole's typical useful life is dependent on the local climate and soil conditions. Pole loading conditions are another potential issue as well, but this can be managed by the size and type pole used. Several recent storm events brought to light the fragility of some of this inventory, so management changed the policy concerning outcomes from post-third-party inspections. Instead of repairing poles with modest ground line rot issues, the new policy requires that poles be replaced with stronger Class 2 poles***. It is important to stress that the replacement policy is based on potential for pole failure concerns and not on a wholesale pole replacement.*** Interestingly, the Division raised the concern that several poles were replaced in one area that didn't appear to need replacement. RCG investigated the specific situation and learned that a communication company requested the pole changeout to provide better working clearances for their personnel. The communications company paid for this requested work.

Another difference between the substation and line projects is that line projects have a shorter "working" period (from engineering to completed construction). Because line materials don't require the production lead times that substation transformers need, the designs are less complex, and installation is more straightforward. However, we have found that distribution line equipment can occasionally experience supply chain issues.

The above suggests that Line CapEx projects are far simpler and lower cost than substation projects. However, independent oversight of the process and risks should be routinely performed to ensure that operations and management of distribution line projects are carefully following guidelines, and decision-making is within PSNH bandwidths. The defined term "*Supplemental*" is inappropriate for early engineering project design efforts and can create confusion for third-party and regulatory interpretations of the estimates.

**4.4. RCG found that PSNH senior management actively monitors the NH capital budget and the individual capital project costs and schedules.**

In addition to the EPAC, SDC, and NHPAC, periodic meetings focus on monitoring additional aspects of the CapEx process, as reflected in Exhibit 7.[22] Further, the distribution operations organization holds a daily morning briefing to review the overnight system operational issues, switching plans for the day, and any impacts on the scheduled project work.[23] Considering PSNH's continuing improvement effort to refine their estimating process, RCG believes that the number and frequency of meetings focused on capital projects are appropriate in the short term. However, RCG thinks this level of focus could be unsustainable in the future as management shifts its focus on other pressing business issues.

**Exhibit 7 - CapEx Project Process Oversight**

**PSNH CAPITAL PROJECT PROCESS - MEETINGS AND COMMITTEES**

| | Committee/Meeting | Procedure | # of Attendees (a) | Duration (b) | Frequency |
|---|---|---|---|---|---|
| 1 | Project Team | M6-PM-2001 | ~7 | ~1 hour | Weekly/Bi-Weekly |
| 2 | Schedule Review | N/A | ~20 | 2 hours | Weekly |
| 3 | Outage Coordination (T&DCC) | N/A | ~20 | 1 hour | Every 2 weeks |
| 4 | Distribution Engineering Capital Project Status/Tracking | N/A | ~16 | 90 min | Monthly |
| 5 | Joint Planning/Engineering/Operations | N/A | ~15 | 2 hours | Monthly |
| 6 | Distribution Engineering Challenge Session | N/A | ~20 | 2 days | Annually |
| 7 | Capital Budget Review (CBRC) | N/A | ~20 | 2 hours | Monthly |
| 8 | NH Project Approval (NH PAC) | APS-01/JA-AM-2001-A | ~10 | 2 hours | Every 2 weeks |
| 9 | Solution Design (SDC) | JA-AM-2001-A | ~15 | 2 hours | Every 2 weeks |
| 10 | Eversource Project Approval (EPAC) | JA-AM-2001-A | ~22 | 4 hours | Every 2 weeks |

(a) The number of attendees listed above are the attendees that are required to attend. The number of attendees and representatives from different areas of the organization are invited and do attend and will vary depending on the meeting and the the complexity of the agenda topics for that particular standing meeting.

(b) The duration of the meetings listed above is the typical time allotted in the calendar invite. The duration will vary depending on the meeting and the agenda topics for that particular standing meeting. Please refer to the narrative description of each meeting for a more thorough understanding of the duration.

[22] DR BPA-13-007 Att.

[23] Interview #67

**4.5. Using the term *Supplemental* before a CapEx project is fully funded and authorized adds significant confusion to non-Eversource reviewers of CapEx projects.**

The term "*Supplemental*" is defined in *APS-1* as an addition to an already authorized project budget estimate (comparing actuals to the approved *Pre-Constructability Estimate.)* "*Supplemental*" can also specify a project as it moves into the CapEx management process flow with "*Full Funding*" approved. Before this stage of project development, the early estimates maintained in *PowerPlan* are still preliminary estimates that evolve as PSNH/Eversource engineering or contract engineers progress toward the final design and estimate.

RCG believes that using the term "*Supplemental*" during engineering's project development efforts may have helped lead the Division to misinterpret the provided estimates and select an earlier estimate preceding the *Pre-Constructability Estimate* when making comparisons to the actual project cost. This scenario potentially led to the Division's decision to recommend disallowing a significant portion of a rate increase, followed by the need for this process audit. The Division Staff received all the estimates without sufficient definitions, causing them to select an inappropriate early estimate to conduct their analysis, instead of using the actual final *Pre-Constructability Estimate.*

In the future, any estimate created before a *Pre-Constructability Estimate* should be marked as a ***Design Development Pre-estimate*** so that it cannot be repeated. The purpose is to eliminate confusion for the non-Eversource reader. ***Supplemental should not be applied to any of these building block estimates.***

## Recommendations

There are no recommendations for this section.

# Engineering and Systems Analysis Functions

**5.1 PSNH/Eversource's engineering departments are structured properly to provide the appropriate level of attention to maintaining and improving the distribution system, consistent with generally accepted industry practices. However, opportunities exist to enhance these efforts.**

The Division had concerns relative to PSNH's approach to developing capital projects for system improvements, customer expansion, and environmental upgrades and to changes made in PSNH's planning criteria which increased the number of potential capital projects. RCG performed a comprehensive review of engineering practices to understand better the appropriateness of policies and processes governing the Company's actions in identifying, designing, and building a robust distribution system. PSNH's engineering CapEx efforts were compared to industry standards by reviewing a subset of capital projects (Appendix D) to determine if policies and processes were consistently applied. Specific engineering designs were not evaluated as this is out of scope for this process audit.

The findings are presented in the Engineering section of this report according to the following subsections:

- *Organization* - reviews the appropriateness of the engineering function;
- *Engineering Project Control Processes* - outlines project development from identification through design-build;
- *Energy Forecasting* - predicts the growth of customers and attendant energy demand and usage;
- *System Planning Criteria* - describes the system planning criteria and technical design guidelines used to identify potential problem areas in the distribution system and associated substations; included is an assessment of the Distribution Pole Replacement Program (pole testing, selection, and replacement);
- *System Planning Studies* - explains how solution alternatives are identified and developed for projects built before and after changes in the planning criteria;
- *Reliability Analysis* - quantifies historical system performance; included is an assessment of Worst Performing Feeders (a statistical performance measure applied to distribution feeders to assist in prioritizing capital projects) and an assessment of system resiliency practices (the adequacy of future system reliability performance); and
- *Distributed Energy Resources* (DERs) System Impact Studies - evaluates the impact of integrating DER into the NH distribution system and the design, engineering, and equipment application measures taken to resolve potential reliability performance and safety issues.

The two most significant areas for improvement are communications (both written and oral) and management oversight of work being performed. The subsections below will illustrate Eversource/PSNH's work in structuring its engineering efforts, with control centered around two distinct management structures: A substation design function and a distribution line function. Both functions appear to be well designed for their respective areas of responsibility.

Communication and potential management oversight concerns will also be addressed as they apply to distribution system planning criteria, study methods, engineering tools, decision processes, and technical standards based on reliability and resiliency improvement projects. Communication was the single biggest issue throughout the CapEx engineering process.

**5.2 The Engineering Organization is bifurcated between Eversource and PSNH. Complementary organizational responsibilities are accomplished at the Eversource corporate and PSNH levels that encapsulate the core functions of a robust distribution engineering group necessary to design and enhance the distribution system. A relatively new Grid Mod function has become a core part of the engineering operation.**

In certain cases, the Director-level and higher management positions have three-state (CT, MA, NH) responsibilities giving managers the flexibility to assign staff where they are most needed. For processes and technologies to be successful and efficient, each must be interchangeable across all three states[24] (to the extent possible with state-specific voltages and other reasons, including state regulatory commission requirements) and well documented in the Distribution System Planning Guide (DSPG).[25]

In NH, System Planning focuses on substations [distribution, bulk (115kV and above)], non-bulk substations (less than 115kV), and transmission lines (transmission is not directly part of this process review). Responsibilities end at the substation fence (except for transmission and distribution interconnections between substations used to transfer load during a station N-1 event). NH Distribution Engineering is responsible for everything outside the substation fence and works with System Planning on substation feeder connections.[26]

[24] Interview #18
[25] LCIRP, Oct 1, 2020, Appendix D
[26] Interview #13

A *Substation Advanced Analytics Group* was formed by the VP of *Substation & Transmission Engineering* to encourage a forward-thinking atmosphere. When the need for a software tool is identified by engineering, this group will research an outside source or perform an in-house development. This group also ensures that engineers have the best tools for successfully performing their jobs.[27] An example is securing the Electric Power Research Institute's (EPRI) Power Transformer tool (PTX) to support Eversource's power transformer health evaluations. Another example under development is *Smart Inspect*, a machine-learning tool to anticipate pole failures or vegetation encroachment. It has been successfully used in a CT pilot program; MA will be next followed by NH (schedule TBD).[28]

The *Protection & Control* (P&C) group is responsible for:

- All distribution of P&C equipment, application, and settings outside the substation fence (pole-top reclosers, automated switches); and
- All T&D P&C equipment and attendant device settings inside the substation fence (relays, equipment protection, *system control and data acquisition* (SCADA), capacitor bank controls and voltage regulator controls).

The P&C Group designs the protection and control scheme. The Distribution Field Engineering (DFE) group is *appropriately* responsible for managing the distribution pole-mounted voltage regulators and capacitor bank controls & settings. Further, the DFE also correctly handles the fuse sizing or TripSaver application. P&C is responsible for all protection/automation settings (anything that must coordinate), including line reclosers, automated switches, and any communications-related devices.[29]

The *Director of NH Distribution Engineering* is responsible for the NH Distribution system and its five geographic regions. This Director has five managers . . . one for each of the five regions. Each manager has:

- Two or three engineers,
- One supervisor, and
- Eight designers (technicians) reporting to the supervisor.

[27] Interview #15
[28] Interview #15.
[29] Interview #34 and Interview #21

The designers use Maximo (or Storms which Maximo is replacing) to design distribution projects. A "design" includes anything from line extensions, reconductoring for load growth, and pole-top distribution automation down to fused cut-outs. This group designs everything along the streets but is not responsible for day-to-day issues handled by Distribution and Field Engineering by using daily calls to review outages affecting more than 100 customers.

Action plans are prepared if a device has been impacted three or more times in 90 days or if the device has a high customer count.[30] Engineers are responsible for high-level designs, e.g., "We need to run a wire from here to there, or an underground circuit needs to happen." It is then assigned to the designers to complete project design details.[31]

There is also a *Director of Distribution Technical Engineering* (DTE) with three-state responsibilities. Reporting to DTE:[32]

- *A Resiliency Group* that coordinates Distribution Automation (DA) designs;
- Three single-state managers for *GIS* and associated standards; and
- There is one three-state Manager for *Reliability and Resiliency.* The position was vacated in July 2021 due to retirement and was filled in July 2022, which is now reporting directly to the VP of System Planning. The Director of NH Distribution Engineering handled budget and planning issues for NH in the interim, and the Director of DTE was addressing reliability (alongside the Director of NH Distribution Engineering) and resiliency issues in NH through early 2022.

The Manager of *Substation Design Engineering* (SDE) reports to the Director of Substation Design and is responsible for substation asset management in NH. While SDE is not involved with physical testing, SDE is responsible for "Asset Management" (evaluating device conditions and acting on test results). If an asset needs to be replaced, SDE is responsible for the associated design. SDE does not use Storms or Maximo like distribution line engineers and technicians but instead locate stock codes and procure equipment.[33] Asset Condition, System Planning, and SDE groups work closely together.[34] SDE's key concern is having adequate capital funds to complete multi-year programs. Recognizing the capital budget is fixed, SDE competes for annual capital funds for every project and program.

[30] Interview #16
[31] Interview #11
[32] Interview #11
[33] Interview #61
[34] Interview #13

The Manager of Protection & Control Compliance, Standards and Support reports to the Director of Protection & Control Engineering and has three-state responsibilities, including standardizing P&C designs, protection schemes, philosophies, and equipment for the different primary voltages.[35]

## 5.3 Although New Hampshire's Grid Mod's efforts are in the early stages, PSNH is performing needed functions to incorporate Grid Mod into the distribution system.

Grid Modernization (Grid Mod) Programs are rapidly becoming the norm across the industry. Eversource's *Grid Mod Group* was formed to implement Grid Mod programs. Unlike Massachusetts and Connecticut, New Hampshire's Grid Mod efforts are in the early stages.

Groups like PSNH's *Grid Modernization Group* are becoming popular across the electric industry as utilities need to identify better ways to gather system data through enhanced visibility on the grid and to increase automation necessary to provide reliable service in an increasingly decarbonized grid with high DER integration and rising electrification.

The *Grid Mod Group's* strategic goal is to evaluate and implement new technologies and solutions that will benefit system performance/operation, including the following responsibilities:[36]

- *Deploying software solutions*: Collaborating with System Operations and Distribution Engineering to deploy software to control and optimize the grid, using DER to manage peak demand, reduce energy, and control voltage. These software tools establish a flexible DER platform to help facilitate adoption.[37]
- *Facilitating the use of real-time technologies:* Collaborating with engineering to implement new real-time technologies and develop multiple use cases.

[35] Interview #34
[36] Interview #19
[37] Interview #19

In their charter for facilitating new real-time technologies, the *Grid Mod Group* is responsible for delivering the following software solutions:[38]

- *Synergi* (a software tool for steady-state distribution planning and analysis) implementation,
- *Distribution Management System* (DMS) implementation (scheduled for completion in 2022[39]); to add fault location intelligence,
- *Geographic Information System* (GIS) consolidation, and
- *Outage Management System* (OMS) upgrade Storms-to-Maximo.

The Grid Mod Group routinely collaborates with System Planning, Distribution Engineering, and Substation Engineering to accomplish these objectives. This Group is not responsible for system design (circuit ties or DA location/selection, NWA solutions) which is the responsibility of System Planning, Distribution Engineering and Substation Engineering.

A formal Grid Mod Program had been proposed for New Hampshire, but the PUC has yet to approve the funding. In the interim PSNH plans to work with stakeholders and the DOE to identify potential future investment opportunities.[40] So far, PSNH has identified the following program objectives:[41]

- Increase system efficiency and reduce demand;
- Advance penetration of DA and control to the customer meter (grid edge); and
- Facilitate integration of clean energy solutions.

High-potential projects involve the use of new technologies not currently part of PSNH's capital plan. For example, volt-var optimization (VVO) and conservation voltage reduction (CVR) programs are not part of existing PSNH capital budgets but are included in Eversource plans to improve operating efficiency, reduce costs, and enable DER.[42]

Eversource supports grid modernization programs managed by the Grid Mod Group to justify the accelerated deployment of microprocessor relays with advanced distribution automation on primary feeders. This would facilitate more extensive use of automated controls and advanced protection schemes, enhanced use of existing resources, and reduced technical barriers to DER integration.

[38] DR BPA 6-004, page 2
[39] Interview #16
[40] DR BPA 6-004 and Interview #19
[41] Id
[42] Interview #19

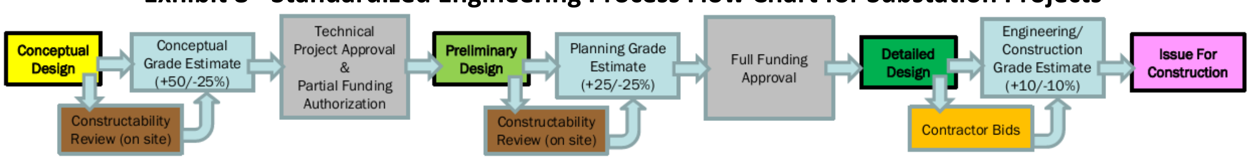
## 5.4 Engineering and Project Control Processes are well thought out and reflect elements found in other leading utility engineering organizations.

In 2018, Eversource implemented standardized processes and controls for Connecticut, Massachusetts, and New Hampshire for project engineering and project management to improve communications between departments and to facilitate/improve the capital approval process. Eversource recognized incomplete or poorly written design documentation could lead to projects being rejected or underfunded. Section 5.7 - below will review and comment on these processes.

## 5.5 Eversource's Substation Design and Engineering has a formal process for project development and design that is divided into four distinctive phases. This overall design process is excellent and consistent with industry practices.

The exhibit below shows the standardized process flow chart for substation engineering projects.[43]

**Exhibit 8 - Standardized Engineering Process Flow Chart for Substation Projects**




| Engineering Packages | Alignment with Project Authorization Process |
|---|---|
| Conceptual Design | For each alternative as required to support cost/benefit analysis of solutions. Typically for partial funding authorization |
| Preliminary Design | Required for all projects seeking full funding. |
| Detailed Design | Supports RFPs for outsourced construction services. Bids received for outsourced construction and materials (based upon Detailed design) are used to complete +10/-10% level estimate. The Engineering grade estimate is typically used to obtain subsidiary board approval for large complex projects. |
| Issue For Construction | Final conformed drawings reflecting all details, final mfg. drawings, construction sequencing, etc. included in +10/-10% estimates and final conformed construction contracts. |

Four phases of engineering design are identified and used throughout the Capital Project Engineering process. As the design progresses, assumptions and estimates become more complete, and specific design details emerge. The four engineering design phases, descriptions, and deliverables are described below.[44]

- *Conceptual Design* – Uses historical site-specific data and conservative assumptions; satellite images; typical physical design/layout drawings; existing electrical drawings; and assumed capacity requirements. Conceptual

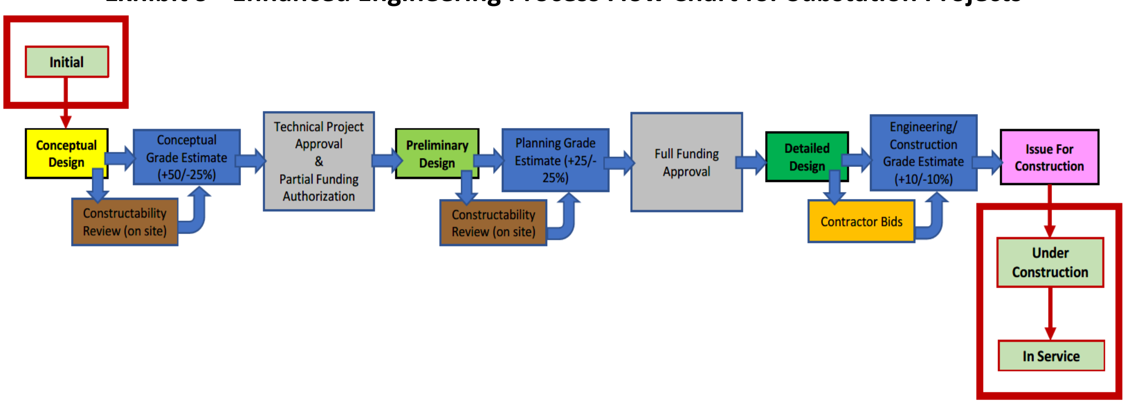
[43] Eversource NH Business Process Audit Kick-off Meeting, November 4, 2021, slide 9
[44] Eversource NH Business Process Audit Kick-Off Meeting, November 4, 2021, slides 10-11

constructability reviews are conducted by engineering and operations to provide initial preliminary design feedback. Conceptual layout drawings: electrical one-line diagrams and long-lead-time material lists are created.

- *Preliminary Design* – Preliminary site development requires above/below grade site-specific testing/analysis to mitigate potential cost impacts due to soil contamination, rock/ledge removal, and other unknown below-grade issues. Historical data begins to replace estimates and assumptions. Preliminary conceptual design constructability reviews are conducted by engineering and operations to provide more detailed feedback for the detailed design. These design elements include preliminary line routings, structural calculations, evaluation of DC battery system and loading impacts, AC station service analysis to produce a preliminary site and layout drawings; and major material lists.
- *Detailed Design* – Detailed final plans include physical site drawings; line routings; structural drawings; detailed bill of materials, electrical connection details; one-line metering & relaying diagrams; relay setting plans; AC and panel drawings; wiring diagrams; cable schedules; certified manufacturers drawings; construction plans; outage/energization plans; testing requirements; and site-specific constraints/risks.
- *Issue for Construction* – Final constructability review takes place; contractor bids are issued/reviewed, and drawings are issued for construction (IFC).

Three additional project phases do not appear in the above process flow chart but are added in the flow chart below and are circled in red to highlight their placement. These phases are Initial, Under Construction, and In-Service. [45]

**Exhibit 9 - Enhanced Engineering Process Flow Chart for Substation Projects**




[45] Eversource NH Business Process Audit Kick-Off Meeting, November 4, 2021, slide 13

Systematically moving from the initial design phase to the final in-service phase produces a defensible design, replacing unknowns with actual, site-specific information. RCG believes this to be a solid approach generally followed by the industry.

## 5.6 The number of project cost estimates can cause confusion.

The substation CapEx process can be overly complex and potentially overwhelming to those not intimately involved, leading to misunderstandings, communication problems, and unrealistic expectations, specifically for non-Eversource entities. This is especially true when engineering produces several different cost estimates. For example, the following five phases have been given specific cost estimating guidelines: [46]

- Initial Phase: -50% -to- +200%;
- Conceptual Phase: -25% -to- +50%;
- Preliminary Phase: -25% -to- +25%;
- Issue For Construction Phase: -10% -to- +10%; and
- Under Construction Phase: -10% -to- +10%.

If the cost estimates are not associated with the appropriate design phase and corresponding deliverables, miscommunications and unrealistic expectations can quickly occur. RCG suggests the following estimates could be enough:

- Initial Phase estimate;
- Preliminary Phase estimate; and
- Issue for Construction Phase (Pre-Constructability) estimate, the precursor to Full Funding Authorization.

Written communications are often unclear, e.g., "Issue for Construction" is also referred to as the "Pre-Construction Estimate." RCG believes this level of inconsistency exists within Eversource and serves to add confusion to the process and estimating practices.

The Distribution Project Approval Process is less complex than for substation projects. While the overall process is good, communications (especially terminology) both inside and outside the Company could be improved. The Distribution Project Approval Process Flow Chart and related observations are provided in earlier sections of this report.

[46] Eversource NH Business Process Audit Kick-Off Meeting, November 4, 2021, slide 12

## 5.7 Enhanced documentation and communication elements are needed to ensure clarity of the Standardized Process Flow Chart for Project Controls, as both are critical for a successful project.

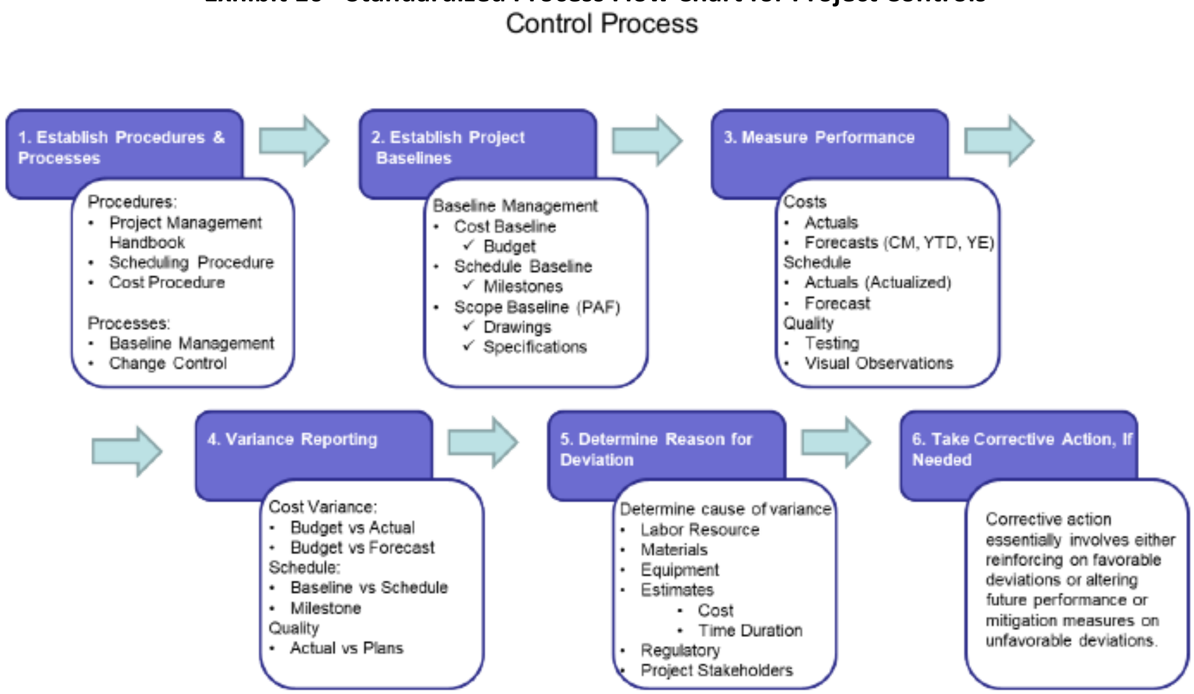
The standardized process flow chart used by Eversource for Project Controls is summarized in the Exhibit 10 below.[47]

The six process elements shown are consistent with responsible actions for any project. However, the following should also be an integral part of the flow chart and prominently identified even if included in the *Project Management Handbook* (control process element 1):

- Documentation - How information is to be documented and archived for each project element.
- Communication - The approach for information flow within the PSNH/Eversource.

[47] Eversource NH Business Process Audit Kick-Off Meeting, November 4, 2021, slide 15

**Exhibit 10 - Standardized Process Flow Chart for Project Controls**




## 5.8 Project Challenges; Executive Technical challenges documented in earlier sections of this report are central to moving projects forward. However, formal peer challenges were not obvious to RCG.

As noted in earlier sections of this report, executive challenges are well documented. However, formal peer reviews (if they do occur) are not documented. During RCG's data-gathering efforts, especially from an interview, informal peer reviews appear to occur. The regularity of these reviews was not obvious to RCG.

### 5.9 Project alternatives are not maintained once management makes its final selection.

RCG attended an NH-PAC meeting on May 18, 2022, where a project was being discussed, including solution alternatives. Once the preferred solution was agreed upon, the Director of Distribution Engineering, the person keeping minutes deleted alternatives from the project documentation. While this simplifies the resulting documentation, it provides an incomplete formal record of considered alternatives. This act is transactional and not strategic and does not recognize the potential future need for defending the preferred solution. This represents a lost opportunity for improving future communications and facilitating project approvals.

### 5.10 PSNH's load forecast process is consistent with utility practice, the methodology for developing substation level loads is a leading practice and the results are reasonable for distribution planning purposes.

PSNH's peak load forecast methodology is consistent with standard utility practice, and its use of econometric models to establish the forecast for bulk distribution substations is a leading industry practice.

At a utility, an accurate load forecast is the foundation for effective capital planning. Contingencies, criteria violations, and other indicators of the need for changes to existing facilities or the need for additional facilities cannot be established without the load forecast. Utilities routinely produce an annual system peak demand forecast for planning and operational requirements and a sales forecast for financial needs. The utility load forecasting process uses models incorporating relevant aspects of the service territory, such as the number of customers, household income, employment, and other variables established to be relevant often by statistical analysis. End-use models, including appliance saturation and usage parameters, are sometimes relevant to a utility's load forecasts.

PSNH's econometric[48] load forecasting model uses industry-standard inputs.[49] These inputs include weather (prior 10-year information of three-day weighted THI (temperature humidity index)),[50] which is similar to ISO-NE.[51] The forecast of econometric

[48] Interview #38
[49] Interview #38
[50] Interview #38
[51] Interview #38

data inputs is obtained from an independent outside vendor (Moody's Analytics).[52] The variables driving the model are evaluated each year and updated as required.[53] The underlying system peak demand forecast is developed independently from the system and distribution planners.

PSNH's load forecasting model produces a 10-year system peak demand forecast[54] and includes a Weather Normal 50/50 forecast and an Extreme 90/10 forecast, meaning one chance in ten of occurring. The system peak model is considered accurate to within 2% of the weather-adjusted peak[55].

Each bulk substation is forecasted as a portion of the system peak load using an econometric model related to that substation.[56] The bulk substation model is considered accurate to within 4% of the two-year average.[57] The Load Forecasting group works collaboratively with distribution engineers to fine-tune the bulk substation forecasts.[58] For example, load shifts between feeders are recognized in the collaborative process.[59]

Additional inputs to the load forecasts include[60] energy efficiency instigated by PSNH. Account executives provide localized known changes,[61] and other step load increases[62] are incorporated within the bulk substation forecast.

The level of solar generation,[63] including customer scale and larger solar generation installations, is forecast with input from Distribution Planning. However, solar does not materially impact bulk substation peak load without associated storage due to timing (between solar peak and system peak) and variability (weather-related).[64] Electric vehicles[65] are estimated within the load forecasting process, although vehicles are a learning process in the current fleet (non-personal) due to the limited data available[66].

[52] Interview #38
[53] Interview #38 and DR BPA 15-4
[54] Interview #38
[55] Interview #38 and DR BPA 15-5
[56] Interview #38 and DR BPA 15-8
[57] Interview #38 and DR BPA 15-6
[58] Interview #38 and DR BPA 15-9
[59] Interview #38
[60] Interview #38
[61] Interview #38 and DR BPA 15-7
[62] Interview #38
[63] Interview #38
[64] Interview #38
[65] Interview #38
[66] Interview #37

The peak load process starts in October after the summer peak season and is finalized by February.[67] The sales (revenue) forecast, which is financially focused, is completed by September.[68]

**5.11 System Planning Criteria PSNH/Eversource system planning criteria, design standards, and document control are consistent with industry practices. The Engineering Standards Bookshelf implemented by Eversource is an industry-leading practice.**

Electric power systems are expected to reliably supply power to various loads under changing weather conditions. To ensure system designs meet these expectations, system planners use pre-determined performance criteria and digital models to proactively identify system abnormalities or violations (PSNH/Eversource terminology) against one or more criteria. Over the years, the industry (IEEE, EPRI, NREL, DOE, EEI, NRECA, NESA, and others) developed equipment application standards (e.g., ratings) and system metrics (e.g., reliability indices) to be used by system planners and design engineers to quantify system performance.

The *Engineering Standards Bookshelf* implemented by Eversource provides:

- A simplified approach to essential document access for all within PSNH/Eversource, and
- Ensures the latest versions are in one place and easy to access, reducing engineering design/equipment application errors and facilitating training requirements.

PSNH's system planning criteria and design standards are discussed in the following pages.

[67] Interview #38
[68] Interview #38

| | |
|---|---|
| **5.12** | **System planning criteria within the *Distribution System Planning Guide* (DSPG) apply to all three states while respecting state-specific voltages and system conditions. RCG believes this process to be consistent with a well-functioning engineering organization. However, having multiple documents can create a source of confusion in written communications which can be avoided by releasing a more complete (revised and combined) version of DSPG 2020.** |

The *Distribution System Planning Guide* (DSPG 2020)[69] is a standard for all three states to harmonize planning criteria and equipment application guidelines as much as practical. Past practices, existing practices, documentation, and industry practices are referenced in the Guide. State-specific exceptions are defined. Resource sharing is supported across all three states for processes and technologies where interchangeability is appropriate.[70] DSPG 2020 contains the following major elements: [71]

- Detailed system planning criteria;
- Asset rating criteria;
- Planning methodology to avoid capacity, voltage, and reliability violations:
  - Model development guidelines: Data imported from GIS; linked demand and DER data; and daily (24-hr)/yearly (8760-hr) planning scenarios;[72]
  - Study methods/procedures;
  - DER applications including Battery Energy Storage Systems (BESS);
  - Load forecasting (reviewed in an earlier section of this report);
  - Solution development procedures/guidelines;
  - Planned and proposed system upgrades (capital planning process).

Non-Wires Alternatives/Solutions (NWAs or NWSs).

A separate, more comprehensive *DER Planning Guide* is to be published by year-end 2022.[73] PSNH plans to address 90% of the issues at publication time, then revise as needed.

Existing planning criteria for all three states are extensively reviewed by engineering when developing the DSPG. The goal is to reduce the risk of sizable events [single contingencies (N-1) lasting one 24-hour cycle] by making the criteria more stringent so engineers can identify reliability risks and proactively design mitigating solutions.[74] Reliability metrics are tracked on multiple timescales and reported to the NH

[69] LCIRP, October 1, 2020, Appendix D
[70] Interview #62, Interview #18, and DR BPA 13-001, page 2
[71] LCIRP, October 1, 2020, Appendix D, Bates pages 106-109
[72] LCIRP, October 1, 2020, Appendix D, Bates page 72
[73] Interview #62
[74] Interview #18

PUC frequently. The responsible reliability planning group, in collaboration with distribution engineering and operations, analyzes the data to identify potential trends and causes and develops plans to mitigate root causes and update standards and practices that improve reliability (reliability performance will be discussed in a later section of this report).

From PSNH's perspective, for the electric grid to accommodate the increased emerging electrification, it requires careful system planning and associated grid investments for reliability and resilience. Today's customers have transitioned from simple tasks such as lighting, refrigeration, cooking, and water heating to more complex and dependent energy needs.[75] Many customers are now working at home and using computers more intensely than at the turn of the century. Simple mechanical thermostats have evolved and now perform complex control of space conditioning. Typical household appliances now have computer chips that optimize how they operate. Entertainment is no longer a simple television. This evolution is expected to continue as the economy further electrifies with new uses such as electric vehicles. Consumers have a real need for a continuous, high-quality electric power supply. In many respects, this shift has been accelerated by the recent pandemic.

The ability to transfer load between substations during a system contingency is key to reliability. Having transformers not loaded to the nameplate when an event happens makes load transfer possible. For NH, (N-0) bulk transformer criteria were changed from 75% (*SYSPLAN-010*) to 95% (*DSPG 2020*) of nameplate rating, reducing the ability to accept load transfers from neighboring substations. However, this was considered an acceptable risk due to the unique nature of the PSNH system and the ability of the 34.5kV backbone distribution lines to carry the additional load.[76]

In addition, legacy guidelines allowed bulk transformers to be loaded to their long-term emergency (LTE) ratings under normal (base case) (N-0) conditions. The new criteria limit loadings to 100% of the nameplate (i.e., the LTE load-ability rating was lowered), leading to more guideline violations.

The comprehensive Exhibit 11 summarizes new *DSPG* planning criteria for bulk/non-bulk transformers and distribution lines for normal (N-0) and contingency (N-1) conditions and compares them to the old criteria. *ED-3002* was issued initially on January 10, 2003, as the primary guidance document for NH system planning until *SYSPLAN-010* was created in 2014. In 2018, the three states' planning criteria were combined into a single revised *SYSPLAN-010* document that was to supersede *ED-3002*.

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[75] RCG's anecdotal experience indicates customer's tolerance of outages (even during major storms) has markedly decreased over time.

[76] Interview #18

The primary guidance document (*SYSPLAN-010*) was revised again in September 2020, creating the new *DSPG 2020* document used today. Updated system planning criteria, equipment ratings, and planning methods/guidelines are included in *DSPG 2020* which was intended to supersede *SYSPLAN-010* and *ED-3002*. However, not all items were moved to *DSPG 2020* creating the need for *SYSPLAN-010* and *ED-3002* to act as supplements (despite both being superseded) until a more comprehensive *DSPG* can be written.[77]

The adoption of *DSPG 2020* coincides with the PSNH's transition to Synergi as a load flow planning tool with abilities to incorporate probabilistic simulation approaches and new DER modeling capabilities.[78] As PSNH organic DER penetration levels increase, the modeling features of this tool are expected to facilitate DER hosting/integration studies which are addressed in *DSPG 2020*.

In the NH *July 2020 Load Flow Study Report*,[79] the following violations were identified for bulk transformers and connected distribution lines:

- 2020: 3 xfmrs on N-0 3 ckts on Voltage 23 subs on N-1
- 2021: 1 xfmrs on N-0 0 ckts on Voltage 0 subs on N-1
- 2022: 0 xfmrs on N-0 0 ckts on Voltage 2 subs on N-1
- 2023: 0 xfmrs on N-0 0 ckts on Voltage 0 subs on N-1
- 2024: 0 xfmrs on N-0 0 ckts on Voltage 0 subs on N-1

While the criteria change from 75% top nameplate rating to 95% will reduce the number of transformer design violations, the considerable variation in the year 2020 compared to the years 2021-2024 can be attributed to an PSNH criterion not discussed above. Before the change, 30 MW of load could be dropped for up to 24 hours for any single contingency condition (e.g., a bulk station transformer failure).[80] Mobile transformers were then relied on to restore power within 24 hours.

In the new criteria, all loads must be immediately restored (i.e., can no longer drop 30 MW) using automatic bus switching schemes. (Note - no capital projects were initiated from 2018-2020 under *SYSPLAN-010*).[81] Bus-tie breakers allow this to occur by connecting the primary bus's live section to the primary bus's dead section, restoring supply across the entire substation primary bus. This use of the bus-tie breaker scheme shows its innate

[77] DR BPA 10-005, pages 1-2
[78] DR BPA 13-001
[79] 2020 to 2029 Load Flow Study Report, July 1, 2020, LCIRP Appendix B-1
[80] ED3002
[81] LCIRP, October 1 2020, p23 of 45

value in protecting the system. The faulted circuit or transformer is separated, via another breaker, from the bus until repaired.

Exhibit 11 - System Planning Criteria – Comparison of Old vs. New DSPG 2020[82]

| Document: | ED-3002 | SYSPLAN-010 | DSPG 2020 |
|---|---|---|---|
| Jurisdiction: | NH | CT-MA-NH | CT-MA-NH |
| Primary Criteria Document: | 1/10/2003-8/1/2018 | 8/1/2018-9/22/2020 | 9/22/2020-Present |

| Bulk Transformers (115kV and above) | | | |
|---|---|---|---|
| (N-0) Normal Operation (Base Case) - Violations Criteria | | | |
| | ED3002 | SYSPLAN-010 | DSPG 2020 |
| Bulk Transformer Loading | 115% - 150% top nameplate rating (TFRAT) | > 75% top nameplate rating | CT-MA: > 75% top nameplate rating<br>NH: > 95% top nameplate rating |
| Voltage, Unregulated Load | < 97.5% | n/a | n/a |
| Voltage, Regulated Load | < 95% | n/a | n/a |
| Voltage, Service | n/a | < 95% | < 95% |
| Load Block Transfer Limit | n/a | n/a | n/a |
| Remaining Isolated Load | n/a | n/a | n/a |
| (N-1) Contingency - Violations Criteria | | | |
| | ED3002 | SYSPLAN-010 | DSPG 2020 |
| Bulk Transformer Loading | 115% - 150% top nameplate rating (TFRAT) | > 100% LTE | > 100% LTE |
| Bulk Substation Loading | n/a | > 100% $STE_{N-1}$ | > 100% $STE_{N-1}$ |
| Voltage, Unregulated Load | < 95% | n/a | n/a |
| Voltage, Regulated Load | < 92.5% | n/a | n/a |
| Voltage, Service | n/a | < 95% | < 92% |
| Load Block Transfer Limit | 3 | 3 | 3 |
| Remaining Isolated Load | 30MW load out for up to 24 hrs | > 0 MW (no loss of load) | > 0 MW (no loss of load) |
| Transmission Supply N-1 | 30MW load out for up to 24 hrs | > 0 MW (no loss of load) | Single Transmisison N-1 shall not cause greater than a single Distribution N-1 condition. |

| Non-Bulk Transformers (below 115kV) | | | |
|---|---|---|---|
| (N-0) Normal Operation (Base Case) - Violations Criteria | | | |
| | ED3002 | SYSPLAN-010 | DSPG 2020 |
| Non-Bulk Transformer Loading | 115% - 150% top nameplate rating (TFRAT) | 115% - 150% top nameplate rating (LTE) | > 100% top nameplate rating |
| (N-1) Contingency - Violations Criteria | | | |
| | ED3002 | SYSPLAN-010 | DSPG 2020 |
| Non-Bulk Transformer Loading | > LTE rating for 1 load cycle; mobile transformer to be installed within 24 hrs if circuit ties not available | > LTE rating for 1 load cycle; mobile transformer to be installed within 24 hrs if circuit ties not available | > LTE rating for 1 load cycle; mobile transformer to be installed within 24 hrs if circuit ties not available |

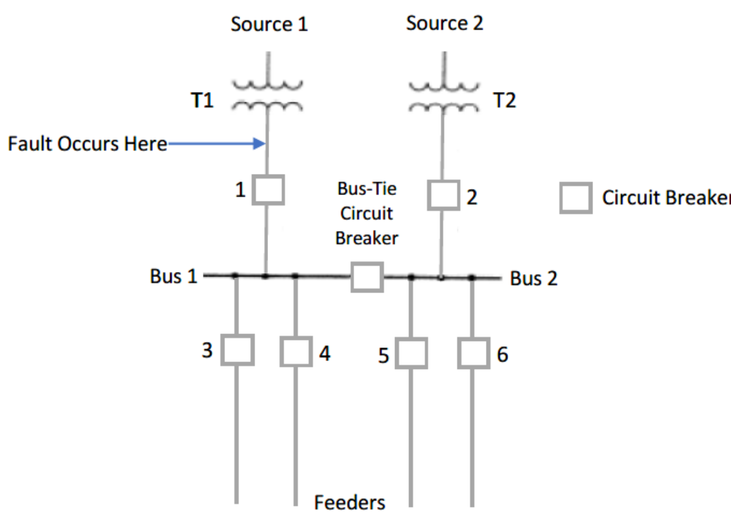
| Distribution Lines | | | |
|---|---|---|---|
| (N-0) Normal Operation (Base Case) - Violations Criteria | | | |
| | ED3002 | SYSPLAN-010 | DSPG 2020 |
| Line Loading | > 100% normal | n/a | n/a |
| Line Loading, Overhead | n/a | > 100% normal | > 100% normal |
| Line Loading, Underground | n/a | > 100% normal | > 100% normal |
| (N-1) Contingency - Violations Criteria | | | |
| | ED3002 | SYSPLAN-010 | DSPG 2020 |
| Line Loading | > 100% emergency | n/a | n/a |
| Line Loading, Overhead | n/a | > 100% emergency | CT-MA: > 100% normal<br>NH: > 100% emergency |
| Line Loading, Underground | n/a | > 100% normal | > 100% normal |

[82] DR BPA 10-004, Attachment BPA 10-004.xls

In addition, PSNH added a single-contingency (N-1) transmission requirement to minimize the impact on the distribution system (i.e., shall not cause more than one distribution N-1 condition) resulting from outages on the transmission system. This policy change means a contingency condition on the transmission system shall not cause more than one contingency condition on the distribution system.

The bus fault criteria specified in *DSPG 2020* is a standard industry practice. A bus or busbar is a connection point for power systems, transmission lines, and distribution feeders. If a fault occurs electrically close to a busbar (e.g., on the T1 low voltage terminal in the exhibit below), all circuits supplying fault current (source side) to the busbar must be tripped (disconnected) to isolate the fault and prevent damage to the system (CB1).

**Exhibit 12 - Bus Tie Example**




A series-bus-tie breaker connects two buses (Bus 1 and Bus 2) and is normally open (for this example). This design improves reliability in that if a fault occurs on one bus (Bus 1), the normally open series-bus-tie breaker is closed (after confirmation CB1 is opened), and loads (feeders) are then transferred from the faulted bus (Bus 1) to the unfaulted bus (Bus 2), maintaining service continuity (limited only by equipment ratings). For loads that can be restored in less than five minutes, SAIDI (duration) reliability performance statistics are not impacted.

As a result of using this new criterion to perform the annual 10-year load flow study, 2020 saw the potential for an increase in violations. With forecasted load growth at only 0.38%, potential capacity violations were expected to substantially decrease in the years 2021-2024.

Despite the relatively large number of 2020 violations, only the highest priority capital projects were submitted in 2020 to avoid exceeding the total annual capital budget of $140M.[83] As a result, Distribution Engineering is working with Distribution Planning to prioritize the violations and corresponding project solutions. The prioritization process considers several factors (for example, asset condition). The highest priority projects are identified in the 5-year capital plan along with the selection rationale. RCG believes this set of actions shows the Company's commitment to maintaining approved annual capital budget limits.

PSNH believes the criteria changes have created a point of disagreement and an atmosphere of distrust with the Division. PSNH is of the opinion that Division believes PSNH should take more risk, not less, to control capital dollars and resulting rate structures. PSNH also believes consumer advocates are also pushing for more risks to be taken to keep rates low. [84]

From PSNH's perspective, PSNH is working on providing reliable electric service to its customers, as needed in a changing grid with electrification trends and climate change related extreme events. These two emerging trends require continuous grid investments with careful utility system planning.

**5.13 PSNH's use of tree wire is appropriate. RCG supports the *selective* use of tree wire (covered wire) in areas with a high frequency of tree–wire contacts leading to outages.**

PSNH strongly believes it is essential to anticipate future conditions and take proactive planning measures before reliability becomes a significant problem. An example would be the selective application of covered tree wire in areas prone to multiple faults due to tree limb contact (but not falling trees).[85] Division Staff have interpreted this use of tree wire as indicative of an overbuilt system. However, selective use of covered wire in highly treed areas with frequent tree contact issues is consistent with leading industry practices.

[83] Interview #20
[84] Interview #20
[85] Interview #11

**5.14 PSNH's change in planning criteria should be better explained. RCG believes PSNH did not sufficiently explain the rationale behind changing the planning criteria to the Division.**

Another RCG concern was the change from allowing a 30-MW load loss over 24 hours to a 0-MW load loss which was interpreted by the Division as going too far and believing more risk should be taken (i.e., some MW load loss is OK), which led to a different philosophy between PSNH and Staff.[86]

This difference in philosophy leads to differing views on what qualifies as a violation. Eversource believes PSNH is "incredibly frugal" in the design and build of the distribution system[87], which is why the system is designed around a 34.5kV distribution backbone (i.e., transformed directly from 345kV transmission to 34.5kV distribution) and why projects are evaluated/prioritized on a cost-per-customer-saved-minute basis.

PSNH did include in its 2019 LCIRP filings an explanation for why criteria changes were needed.[88] A settlement agreement with Staff was reached and approved in October 2019 that included language about criteria change disagreements, stating investments made solely based on these changes could continue subject to prudency reviews. Those disagreements were ultimately settled in PSNH's subsequent rate case whereby PSNH agreed to return to less conservative criteria.

**5.15 PSNH appears to be complying with industry accepted design practices.**

Standard designs have been adopted across all three states as much as practical, recognizing state-specific requirements apply. Standard substation designs are modified to fit need/cost targets, e.g., more expensive breaker-and-a-half schemes will not be used if less expensive straight-bus designs satisfy design/performance criteria.[89]

Most (90%) substation engineering work occurs at existing brownfield sites where standard designs typically do not apply. Instead, existing design alternatives are considered when developing solution alternatives. Selecting the preferred alternative (best overall solution) involves evaluating a matrix of weighting factors (pros/cons, criteria, maintenance costs, logistics, overall costs). Suppose the least-cost solution creates future maintenance concerns (e.g., equipment no longer supported by the

[86] Interview #20
[87] Interview #20
[88] Interview #20
[89] Interview #21

manufacturer) or comes with specific reliability concerns (e.g., animal protection). In that case, a higher initial-cost solution option may be selected instead.[90]

Replacing old transformers at existing substations is possible, even with space limitations, because new transformer designs tend to be physically smaller. However, with older substations, there are usually other issues that need attention resulting in the need for a substation rebuild (e.g., aging equipment, obsolete technologies, eliminating equipment with hazardous fluids, and difficulty obtaining spare parts).[91]

Standard distribution transformer designs are included in Storms/Maximo according to the *Distribution System Engineering Manual* (DSEM). Standard substation designs, including transformers, are in the Substation Design Manual (SDM). Both DSEM and SDM are part of the *Engineering Standards Bookshelf* shown in the exhibit below. When designing distribution lines, field design engineers/technicians use DSEM-published designs. For PSNH distribution step-down transformers, for example, there are 28 unique design configurations.[92]

**Exhibit 13 - T&D Engineering Standards Bookshelf - Contents*[93]***


DSEM does not address every situation. Decisions can incorporate project-specific requirements that may impact the best overall solutions, e.g., conditions set forth by state regulatory bodies.[94] DSEM contains 19 sections covering distribution system design (e.g.,

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[90] Interview #21

[91] Interview #73

[92] DSEM, November 2015, Section 14.34, Table 5.

[93] DR BPA 15-001, Attachment BPA 15-001(a)

[94] DR BPA 9-001

reliability, power quality, overhead, underground, protection) and equipment application (e.g., conductors, arresters, capacitors, transformers, regulators). *DSEM* also addresses safety, voltage regulation, reliability, flexibility, capacity, and economics.[95] Sections are succinctly written and to be used in conjunction with other, more detailed standards (e.g., *DSPG*).

**5.16 PSNH's use of substation feeder protection standards are appropriate. Substation feeder protective device application standards/guidelines, and bulk and non-bulk distribution supply transformer overcurrent protection standards/guidelines appear well written, appropriate, and complete.**

Eversource uses protection standards and guidelines developed internally by the Protection & Control (P&C) Department. They describe the protection philosophy, type of protection, and applicable industry standards. Protection documents are periodically reviewed and revised as protective device technology evolves and improved protection schemes are adopted.[96] The two example documents reviewed by RCG (*Substation Feeder Protective Device Application Methodology*[97] and *Bulk and Non-Bulk Distribution Supply Transformer Overcurrent Settings*[98]) appeared to be well written, appropriate, and complete from an engineering point of view.

Eversource participates in the following industry meetings/conferences: IEEE; NESC; EPRI; NATF; AEIC; IEEE Power System Relay Committee (PSRC); North American Transmission Forum Protection System Working Group; local IEEE; and NPCC. However, meeting highlights are not consistently shared within the engineering organization,[99] creating missed opportunities for professional development and pointing to another example of missed communication.

All changes to T&D procedures are controlled by TD001 in the Document Control Process managed by T&D Standards Engineering.[100]

Hardware is standardized to increase overall efficiency when possible. For example, 34.5kV pole line hardware is also used on 12kV and 4kV systems to simplify the

[95] DR BPA 4-02, Attachment 1, DSEM link
[96] DR BPA 1-029
[97] DR BPA 1-029, Attachment A
[98] DR BPA 1-029, Attachment B
[99] Interview #61
[100] DR BPA 15-001, Attachment BPA 15-001(c)

supply chain, stocking, and construction processes.[101] However, native voltages remain the same.

Blanket agreements are in place with suppliers to streamline supply chain issues and control costs. For example, a blanket agreement is in place to supply standard recloser controls.[102]

Standard ***bulk*** transformer ratings:[103]

- 115-34.5 kV 62.5 MVA
- 115-12.47 kV 30 MVA
- 34.5-12.47 kV 12.5 MVA
- 34.5-4.16 kV 12.5 MVA
- 115-12.47 kV 30 MVA
- 345-34.5 kV 140 MVA
- 44.8 MVA (outdated standard to be replaced with 62.5 MVA units)

Standard ***non-bulk*** transformer ratings:

- Included in the DSEM manual along with application guidelines.[104]

Eversource purposely avoids deviating from equipment standard designs to prevent expensive "specials." In all cases, IEEE standards are met or exceeded.[105]

Eversource has adopted a relatively new (within the last two years) substation design standard: Installing metal-clad switchgear to the low side of substation transformers.[106] (Use of metal-clad and metal-enclosed switchgear is common in industrial /commercial facilities.) No live bus is exposed when the breaker is opened, offering an important safety feature.[107] Metal-clad switchgear reduces on-site installation/testing costs and engineering time since the breakers, relays, wiring, and metering are all contained in standard cubicles that lend themselves to more modular designs. The T&D Standards group developed a detailed metal-clad switchgear procurement standard (detailed specifications) in conjunction with the Substation Design Engineering group that includes comprehensive requirements and drawings[108] for use within the engineering organization. There was a PSNH perception that metal-clad

[101] Interview #11
[102] Interview #19
[103] Interview #61, Interview #73
[104] DR BPA 4-02, Attachment 1, DSEM Manual, November 2015, Section 14
[105] Interview #73
[106] Interview #73
[107] IR-60, page 4
[108] DR BPA 15-002, Attachment BPA 15-002(a)

switchgear was more expensive than open-air construction, but the perception is changing.[109]

**5.17 The supply chain is well integrated. PSNH's Supply Chain organization appropriately changed its normal procurement practices to allow for impacts associated with the international disruption in the materials, services, and contractor availability.**

RCG performed a limited review of Eversource's Supply Chain practices as they relate to capital project processes. A supply chain organization is needed to support capital and maintenance requirements. The procurement and store's function must purchase necessary materials and services; store; pre-packages; and issue when needed. Customers, regulators, and shareholders expect a cost-effective and efficient process. Supply chain personnel must manage the inventory and availability of materials and ensure stocking levels are adequate and consistent with capital programs, emergency response, and future demand needs.

Eversource's supply chain personnel are an active partner in the capital project cost-control process.[110] The corporate purchasing function is multi-state and focused on commodity buyers for substation power transformers and major substation components, distribution standard equipment, and standard step transformers. Eversource bids all purchases and services from prequalified strategic vendors referred to as "Contractor or Vendor of Choice". Strategic vendor performance is monitored, evaluated, and fed back regularly through a supplier relationship management program and a third-party vendor risk management program. Purchasing is responsible for initiating and managing warrantee claims against vendors and/or suppliers. Poor contractor/supplier performance will result in their removal as a strategic partner. Purchasing seeks to have multiple sources for either contracted services or vendor-supplied materials. In rare cases where a unique service or material can only be supplied by a single source, senior management approval is required.

Purchasing creates a pre-approved list of contractors/vendors with established rates/pricing. Competitive bidding takes place using the approved Contractor or Vendor of Choice listing. This approach ensures pre-established master services agreements, terms of the contract, etc. are approved upfront so related negotiations do not adversely impact the capital project process.[111]

[109] Interview #73
[110] Interview #11, Interview #12, and Interview #27
[111] Interview #27

Purchasing is proactively involved in the front-end of capital project development. Purchasing engages with strategic vendor and contractor partners to confirm material and service availability. Additionally, Purchasing seeks input from strategic partners on alternatives to current products and/or services to help identify additional design or solution options.

Purchasing decisions are made based on the "lowest lifetime cost of ownership" and not the initial price, which is a leading industry practice. For example, for power transformers, the lowest cost is a balance between the total cost of ownership, operating cost (losses), and maintenance cost (life-cycle cost). PSNH also looks at the life of the unit, purchase price, delivery, and any additional, value-added services that may be offered by the supplier. This evaluation takes place as part of the commercial and technical review process.

Purchasing has sought out and implemented additional options to expand the availability of distribution transformers, including step transformers. New vendors have been evaluated and selected to provide refurbished and certified transformers. Transformers removed from service are being tested, repaired, and refurbished in-house by the substation testing lab employees, depending on transformer conditions.

Supply disruptions/delays have caused Stores to discontinue the "just-in-time" automated delivery process. Under this former industry standard program, material and equipment inventory levels were kept to a minimum (emergency response levels). Usage, project and maintenance needs, and replenishment delivery times were monitored, adjusted, and ordered electronically. Buyers delt with delivery time updates on an exception basis (reported electronically).

However, since COVID-related supply disruptions, replenishment delivery times have become unpredictable. Purchasing and Stores have responded by putting in place a new process, managed by the Stores personnel, that adjusts inventories based on current needs and material availability/delivery schedules. Now Stores routinely monitors material delivery lead times and recommends purchasing schedules to meet inventory requirements and project schedule and/or routine business material needs. In the case of long lead-time materials, such as power transformers, Purchasing has advanced 2023 purchases. To date, this change has been successful in meeting business needs. There has not been any identifiable impact on PSNH's ability to meet customer needs. In the short run, capital spending should not be impacted since adequate materials and equipment are on hand to satisfy the current year's capital plan. Advanced buying of power transformers has also been included in the current year's capital budget. However, it is still too early to assess the longer-term impact on capital project planning and associated spending.

**5.18 PSNH's Stores function operates consistent with industry practices. PSNH's Stores operation practices are consistent with industry practices and a positive contributor to capital project construction schedules, development, and execution.**

Stores participates in weekly distribution line schedule and planning meetings. Stores confirm all materials are available prior to a project being scheduled for construction. Additionally, Stores identifies operation's delivery requirements. Stores pre-packages all materials for a project and stage it for operations and/or contractor use. Due to space limitations, they do not pre-load material onto the line trucks. Where project logistics permit, Stores can pre-load materials on trailers or have material delivered directly to construction sites. Since Stores participates in the scheduling process, there have been very few construction delays resulting from material availability issues.

**5.19 PSNH makes appropriate use of system planning software. Commercial software tools in use by Eversource are standard industry packages in common use by electric utility companies in the United States. Eversource supplements these software tools with in-house developed/customized software to improve internal operations. Using commercial and in-house developed/customized software tools is consistent with industry best practices.**

Appendix B of this report provides a list of Eversource's in-house software. A few examples are mentioned here.

Synergi was selected as the preferred engineering software package for distribution system studies using Python scripts to automate the simulation/analysis process (e.g., load flow, short circuit, harmonics). In addition, Synergi will be used to simulate 10-year, 8760-hour operating scenarios (including DER integration impacts).[112]

The Grid Mod Group is responsible for implementing the transition from the DistriView engineering analysis package (in use in NH) to Synergi (first deployed in PSNH June 2021). The Grid Mod Group is also responsible for in-house software training and first-line user support.[113]

[112] Interview #13
[113] Interview #19

**5.20 PSNH uses compatible units in estimating work. The use of compatible units (CUs) is an industry standard, but the individual units defined for specific work need to be updated regularly to ensure the accuracy of the downstream estimates.**

Compatible Units (CUs) for Maximo are developed and managed by the Standards Group. CUs are state-specific (labor rates, voltages, etc.); however, three-state standards are set whenever possible.[114] It is worth noting that CUs have been an industry-standard practice for several decades. However, in RCG's experience, CUs require significant maintenance, including regular updating, to be an accurate cost-estimating tool (PSNH agrees). Despite the required maintenance, CU is a valuable tool if kept current.

**5.21 NWA screening tools are being incorporated. The in-house NWA screening tool is a step in the right direction.**

Eversource requires system-wide screening of potential NWA solutions against traditional system-upgrade solutions using an in-house developed, Excel-based, NWA Screening Tool to identify viable NWA alternatives suitable for more detailed engineering analysis by System Planning.[115]

An NWA Framework document was also developed that details all assumptions and modeling methods used by the NWA Screening Tool in the screening process.[116]

Eversource's use of the NWA Screening Tool and NWA Framework document are discussed elsewhere in this report.

[114] Interview #11
[115] LCIRP, March 31, 2001, Supplement, Appendix A
[116] Ibid

| | |
|---|---|
| **5.22** | **Eversource customized a PTX tool. The Eversource-customized PTX tool is appropriate for tracking and evaluating transformer asset conditions and alerts Eversource to emerging power transformer issues.** |

The customized PTX software tool uses a rule-based expert system to assess transformer conditions using readily available asset condition data and nameplate information that provide insights into the likelihood of failure and associated causes. A *health index* is then calculated based on the following factors: overall condition, operating temperature, electrical condition, core condition, oil quality, and age.[117]

| | |
|---|---|
| **5.23** | **The Pole Replacement policy has been modified. PSNH's Pole Replacement Program is well documented, managed, and consistent with general industry practices. Given Eversource's annual pole purchases across all three companies, there could be savings due to volume purchasing leverage. Changing the size (diameter) of the pole from class 4 to class 2 is reasonable for PSNH.** |

The wooden pole has been the standard in the electric utility industry since its inception. Poles' composition, size, class, and height have and continue to be dictated by the pole's application: transmission, distribution, service, or support, and whether it will have other joint uses, such as by the local communications companies and municipalities.

Pole composition can be wood, steel, composition, or concrete. Pole diameter dictates the class of a wood pole. Pole class and height combine to dictate the strength of a wood pole. Typical distribution wood poles used for services and street lighting would be a minimum of Class 6, 30 ft pole. A wooden distribution line pole typically would be sized at a minimum of Class 4 and 35-to-40 ft. However, with the additional height and loading requirements dictated by third parties' joint use of poles, the minimum industry norm for distribution poles has increased to a Class 2, 45-or-50 ft pole. The additional height is to accommodate adequate safety clearances required by all users of the poles.

Which poles "Class" to use is determined by the Standards Group using a pole-loading-analysis program that considers wind and ice to determine the required pole class.[118]

[117] DR BPA 8-004, pages 1-5
[118] DSEM, Reliability Section 02.50, page 02.501, June 2021.

PSNH has a program (consistent with its affiliates at Eversource) of reinforcing its distribution lines to minimize the potential of future outages caused by a combination of tree, wind, and ice damage. This revised thinking is supported by a report produced by TRC, an engineering consulting firm. The study led to several PSNH distribution policy changes, including:

- Moving from Class 4 and 5 poles to stronger Class 2 poles when existing poles are deemed damaged and unsafe; and
- Replacing wooden cross arms with stronger composite cross arms; and
- Upgrading of 12kV and 4kV *pole hardware* to 34.5kV hardware.

The pole policy change was initiated by changing PSNH's long-standing maintenance policy of conducting third-party pole inspections and repairing those with minor ground line rot or replacing them with a new pole of the same class if the existing pole was beyond repair. This inspection and alternative actions practice has been an industry-standard practice for decades. PSNH's new policy affects the latter two options with a required replacement using stronger Class 2 poles, allowing the newer poles to better withstand tree limb impacts (an issue in several recent storms where pole failures occurred.)[119]

Eversource determined that standardizing pole hardware would offer cost savings and improved reliable service in several areas. Eversource reduced the number of items in inventory while improving purchasing leverage by eliminating the variety of similar distribution pole hardware. RCG has learned in recent years that the 4kV line equipment costs were rising due to most distribution line developments focusing on higher voltages, thereby reducing the demand for 4kV equipment. This trend increased the price for 4kV pole hardware. The new Eversource policy includes using 34.5kV insulators and pins on all primary distribution voltage classes and reducing truck and storeroom stocking requirements. This policy change was stated in formal testimony but written in a way that could be interpreted as converting lower primary voltages to 34.5kV voltage, not PSNH's intended position.[120]

Specific to PSNH, the "*TRC System Assessment Report"*[121] commissioned by PSNH in compliance with Section 11.1 of the October 9, 2020, Settlement Agreement in Docket No. DE 19-057 addressed several distribution system reliability criteria and the

[119] Direct Testimony of Joseph A Purington and Lee G LaJoie, DOCKET NO. DE 19-057
[120] Direct Testimony of Joseph A Purington and Lee G LaJoie, DOCKET NO. DE 19-057
[121] May 28, 2021, PSNH Letter Docket No. DE 19-057

standardization of distribution pole applications.[122] The TRC Report's pole recommendations are listed below:

> *"1) Establish a systematic asset replacement program to replace wood poles on an age basis, that support three phase lines, over the next 5 years. Beginning with poles 70 years and older poles, focusing on the smaller class 4 and 5, then address the 60- and 50-year-old poles using the same class criteria. There are about 42,000 wood poles aged 50 years and older that may need to be identified and prioritized for replacement. It is estimated that 20% (8,400) of those poles support three phase lines, requiring approximately 1,700 poles/year of the poles in this age group be replaced in conjunction with the other Company pole replacement efforts.*
>
> *2) TRC recommends poles that are identified as structurally loaded at 90% or greater, be replaced with the correct sized poles to carry the mechanical load under the mandated NESC design conditions. To accomplish this, TRC also recommends that 10% (approx. 4,500) of the overloaded poles, be replaced on an annual basis. Priority should be given to the poles that are overloaded by the greatest amount and/or most critical to the system. It is also essential that all new poles that are installed have pole loading analysis completed to ensure the design criteria is met. Individual pole loading analysis will need Eversource NH Distribution System Assessment 30 to be performed on all angle, tap and dead-end poles. Typical tangent pole analysis can be modeled to promote efficient design.*
>
> *3) Continue the practice to use a minimum of Class 2 wood poles for all applications and ensure that NESC pole loading requirements are met for both the heavy loading and extreme wind scenarios. Based on analysis of the representative data, Class 2 wood poles are half as likely to be overloaded with attachments compared to Class 3 poles."*[123]

RCG's review of pole installations through project reviews and field observations found poles installed for new lines and replacements were consistent with the TRC recommendations. Pole inspection and replacement programs have been an industry-leading practice for decades.

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[122] Eversource's TCR System Assessment, pgs. 20-29

[123] Eversource's TRC System Assessment, pgs. 29

Wood poles continue to be the predominant distribution line pole. As such, utilities inspect wooden poles for deterioration from insects, birds, ground line rot, and external damage. Current utility practice is to inspect distribution wood poles independently or in conjunction with a distribution line inspection based on a formal schedule. The inspection schedule varies based on historical inspection results and environmental factors such as climate, soil conditions, and exposure to physical damage. Typically, 10% of a utility's poles are targeted for inspection annually.

The inspection will identify poles that require further investigation, repair, or replacement. Typically, a specialized professional contractor performs analysis, assessing the extent and damage, type, and whether the deterioration can be treated with chemicals for insect infestation, reinforced at the ground line, or patched with an epoxy mixture. These measures are designed to extend the pole's useful life. However, over the past ten years, the public's reaction to environmental impacts from chemically treated poles or chemical treatments of poles, steel reinforcement of poles along roadways, and the effects to the environment from regular access to poles in wetlands has limited application of historical life-extension methods. As a result, more moderately damaged poles are replaced, and the pole material is considered based on environmental concerns (wetlands, storm exposure, ability to guy, etc.). The pole type most considered for such specialized needs are steel poles in difficult-to-access off-road RoWs (both directly buried and in conjunction with a foundation/casing) and concreted poles for storm-prone or high-congestion areas.

Eversource/PSNH recently changed its formal pole inspection and outcome approach for Class 4 and Class 5 wooden poles. If a Class 4 or Class 5 pole is found to have ground-line rot, the pole will be replaced with a new and more resilient Class 2 pole. This departure from industry practice is being done out of concern for the age of installed poles and their ability to withstand adverse weather events. Normally, RCG would have concerns with this change. However, RCG believes the change to be reasonable for the following reasons.

- Many installed Class 4 or Class 5 poles are near or at end-of-life expectancy.[124]
- New Hampshire (like other New England states) experiences periods of significant ice formation, adding weight to the lines and placing additional stress on poles and pole-line hardware.
- Large limbs and tree failures can take down physically compromised poles.
- Many RCG client utilities have standardized on Class 2 poles.

[124] Direct Testimony of Joseph A. Purington and Lee G. LaJoie, DOCKET NO. DE 19-057

PSNH's pole replacement policies and practices require poles to be periodically inspected, with the results dictating subsequent actions. Formal annual pole inspection programs are well defined and documented as described below:

> *"On average, 10% of Eversource owned poles are inspected annually by town location. Non-Eversource-owned poles in the towns identified for pole inspection also receive a visual inspection. Poles are visually inspected based upon age and type of pole preservative. Sound and bore inspections are performed on poles older than those to be visually inspected. The detailed program on Eversource owned poles is summarized in the following excerpt from Eversource's Maintenance Program EMP 5.61 and shown in the Exhibit below:"*[125]

**Exhibit 14 - Pole Inspection Criteria**[126]

**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

As shown in the notes above, pole inspection results fall into three categories: 1) Passed; 2) Normal reject (pole must be replaced within one year), and 3) Priority reject (field supervisor must field-check within 48 hours to ensure no immediate safety concerns). The pole must be made safe within 10 days and replaced within one year.

[125] DR BPA-6-009

[126] DR BPA-6-009. CCA = Chromated Copper Arsenate

The following exhibit shows the targeted and actual pole inspections for the past five years:[127]

**Exhibit 15 - Historical Pole Inspection Targets and Actuals**

| *Year* | *Target* | *Actual* |
|---|---|---|
| *2017* | *25,493* | *31,873* |
| *2018* | *43,816* | *42,399* |
| *2019* | *45,666* | *44,097* |
| *2020* | *41,319* | *38,477* |
| *2021* | *47,914* | *42,897* |

Poles that fail inspection are replaced under the PSNH's Reject Pole Replacement Project. Projects are broken down into annual work orders to improve annual budget management and control.[128]

PSNH's Pole Replacement Project results are shown in the exhibit below. Just looking at the most recent rejection rate for 2021 of 42,897 poles, only 136 were rejected, or 0.3 percent of installed poles.

This Reject Pole Replacement Project has funded pole replacements, over the past five years as follows:[129]

**Exhibit 16 - Annual Rejected Poles & Replacements**

| *Year* | *Reject Count* | *Completed* |
|---|---|---|
| 2017 | 270 | 270 |
| 2018 | 514 | 514 |
| 2019 | 358 | 358 |
| 2020 | 165 | 165 |
| 2021 | 136 | 136 |

The above exhibit shows PSNH's commitment to keeping the distribution system safe and resilient. PSNH is keeping up with both the identification and replacement of poles deemed unacceptable.

[127] DR BPA-6-009
[128] Interview #43, Power Plan Panel
[129] DR BPA-7-009

## 5.24 Steel poles are used judiciously.

Steel poles are a viable solution under specific circumstances. RCG reviewed PSNH's use of steel poles in non-transmission applications. PSNH has recently expanded its use of steel poles beyond transmission structures in RoWs, consistent with the following observations from the TRC report:

> *"… steel distribution poles are an investment that provide a long-term solution for safe, reliable, and cost-effective service to the customer. This investment is one component of improved distribution line resiliency. Steel poles used in off-road right-of-way settings provide additional resiliency benefits to guard against what would be a longer duration outage, given the difficulty in patrolling and replacing these more remote assets in the event of a failure during a severe weather event."*[130]

Additionally, in response to industry environmental concerns for treated wood poles in wet environments and the increasing cost of wood matting to access RoWs, the use of steel poles is specified (excerpts below) by PSNH's policy. RCG did physically inspect one location considered wetlands. The PSNH was required to temporarily install extensive matting, consisting of multiple 8x8 timbers, to protect the wetlands environment from equipment damage during line installation. When matting is temporarily installed, it adds significant expense to the project. The matting cost includes installation, removal, and a rental fee for the time it is installed. PSNH's steel pole policy follows:

> *"New poles installed in Eversource three phase lines in distribution Rights-of-Way are to be direct embedded self-weathering steel poles, class, and height to be determined by the Transmission Line Engineering group.*
>
> *The use of steel poles in other situations, such as for single phase lines, jointly owned facilities, or other special situations, is by exception only and requires approval from managers or above in Operations and Engineering.*
>
> *Steel poles shall not be used for service poles."*[131]

Along with this wooden pole policy change was PSNH's further decision and accompanying policy change to use steel poles for more difficult-access locations in distribution rights-of-way (RoWs). This action minimizes the frequency of bringing large,

[130] Eversource's TCR System Assessment, p. 38
[131] DR BPA-4-002 Att. 2

heavy line trucks into these difficult off-road locations. Internal to PSNH, some personnel initially misunderstood this policy due to inadequate communications, causing some distribution engineers to misinterpret the directive and use steel poles in locations other than the intended difficult access RoWs. PSNH identified the issue and clarified the instructions to personnel.[132]

RCG believes the expanded use of steel poles is a reasonable policy that will provide the additional benefit of significantly extending the life expectancy of these poles while reducing the frequency of inspections.

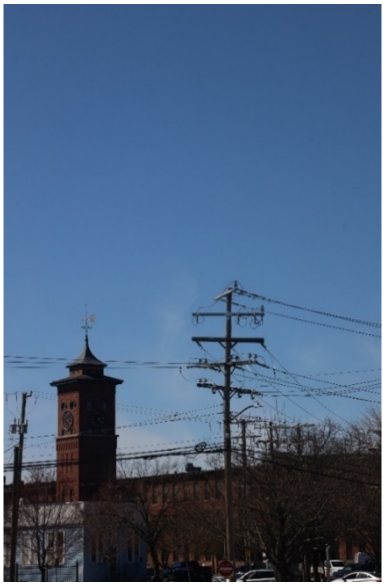
**5.25 Capital Project Hours can be more accurately specified. Capital project execution appeared to be appropriate but lacked crew project-hour targets, thereby reducing efficiency target expectations.**

While RCG had limited time to evaluate field construction practices, several field crews were visited during the audit process. Crews typically include a non-union working foreman which is unique in the industry, making the foreman accountable for crew quality and productivity. As a result, crews appeared to be well informed on their work assignments.

Electronic work orders did not set time-to-perform expectations but set more macro-level expectations by scheduling 80% of a workweek, leaving 20% to cover unexpected customer needs and/or emergencies. RCG has no issue with this scheduling approach but believes setting specific project completion goals will yield tighter schedule adherence and may allow more work to be completed within the same timeframe.

RCG witnessed PSNH crews responding to a pole hit by a vehicle that took down a single-phase and neutral along a heavily trafficked road. Communication during the clearing and restoration effort was impressive. Crew personnel continually communicated with each other to rapidly clear the roadway and restore power in a safe/timely manner. This suggests crews are well-trained with strong supervision and attention to detail.

[132] Interview #67, Field Visit



The above pictures show some of the typical PSNH Distribution construction and a line crew replacing a pole hit by a third party. As seen in the picture, the crews must navigate the distribution pole installation around the resident tree population. PSNH schedules their crews at 80 percent of the work week on scheduled projects, the remaining 20 percent is for emergency work like what is shown in one of the pictures. An important point is since emergency work is unscheduled the actual work time may take longer than a planned project where all the logistics are planned. As a result, emergency-work wait times for several other reasons beyond the crew's control may include material delivery, public safety, clearances, traffic, etc.

## Recommendations

**R.5** **Develop easy-to-understand examples illustrating the before-and-after impact of *DSPG 2020* system planning criteria changes on system performance (reliability and resiliency) for all PSNH customer classes (residential, commercial, and industrial). The examples also need to clearly illustrate how superseded standards *ED-3002* and *SYSPLAN-010* will be used in conjunction with *DSPG 2020*.**

**R.6** **Develop a formal process to communicate the latest industry activities, including lessons-learned and technology advancements, between departments and potential external parties (other utilities and suppliers).**

**R.7 Include person hours on all planned project on work orders to support crew performance management.**

## 5.26 System Planning Studies

PSNH's system planning policies, procedures, design guidelines, and processes for evaluating/selecting alternatives (when resolving planning criteria violations) are consistent with industry-standard practices. However, opportunities for improvement exist to address communication/documentation processes to mitigate confusion and misunderstandings when the PSNH interfaces with external entities like the Division.

Planning and designing an electric power system requires ongoing comprehensive analyses to evaluate system performance, determine the effectiveness of expansion alternatives, and identify and, most importantly, proactively resolve problems that might impact system reliability.

System performance projections are created using digital system planning studies based on system performance criteria defined by planning and design criteria/guidelines determined by the standards department that incorporate industry standards and best practices. Issues can be proactively resolved, and alternative solutions can be identified and tested using these digital tools (Appendix B).

As explained in later sections of this report, reliability indices are used to identify worst-performing distribution feeders based on historical outage data and asset condition assessments. System planning studies assess the ability to meet specific design criteria/guidelines. When studied together, solution alternatives can be evaluated, and the best overall alternatives (preferred alternatives) identified.

There is a distinction between a system "plan" and system "planning." A plan is the output of a planning process driven by criteria, policy, and process to develop solutions to problems. Planning is a dynamic process requiring updates to processes and procedures used to create specific plans/solutions.[133] Both "plans" and "planning options" are developed by System Planning.

All transmission and 34.5kV systems are studied using *PSS/E* software and balanced three-phase models.[134] Larger generators are modeled in detail. Load is allocated (not modeled in detail). If a distribution planning project involves the high side (transmission side) of a substation transformer, the Transmission Planning group will

[133] Interview #18
[134] Interview #16

assist Distribution Planning with the study.[135] RCG considers this overall approach to be consistent with industry best practices.

Starting in 2022, Synergi will become the standard software package for modeling the NH distribution system.[136] DistriView had been the standard.[137] Models will be 3-phase (individual phases) instead of the existing single-phase (assumes balanced 3-phase) when fully implemented. The critical point is that detailed load flow modeling is not currently done on 12kV and 4kV systems and will have to be developed, complicating full Synergi implementation.[138]

Distribution Engineering conducts all short circuit and protection coordination studies for everything other than three-phase recloser and relayed circuit breakers done by the Protection & Control (P&C) group using the Aspen OneLiner software package. Single-phase reclosers and TripSaver (electric recloser for cutout applications) coordination studies are conducted by Field Engineering. Even though Synergi has Protection & Control (P&C) capabilities, there are no plans to migrate P&C from the more specialized Aspen OneLiner.[139]

As mentioned above, detailed models of distribution feeders in Synergi do not currently exist.[140] RCG believes System Planning's expertise with the Synergi package can greatly benefit Distribution Engineering when scoping, modeling, and testing new individual phase distribution feeder models. Once these models are completed, full unbalanced phase modeling to the customer meter will be possible, greatly enhancing "what-if" capabilities and better positioning the PSNH to handle DER integration studies.

For substation asset condition issues (inside the fence), Substation & Transmission Engineering alerts System Planning and the seriousness and urgency for resolving the issue. System Planning then develops alternatives from which the best overall solution is selected.[141] Distribution Engineering follows a similar process for asset condition issues outside the substation fence.

*PSCAD* are transient studies and generally more critical for transmission. *PSCAD* is also used in DER planning to study transients caused by DERs on the distribution system.[142]

[135] Interview #62 and Interview #16
[136] Interview #62
[137] Interview #16
[138] Interview #62
[139] Interview #62
[140] Interview #18
[141] Interview #61
[142] Interview #62

Simulations involving 10-year, 8760-hour data sets create data "nightmares" when managing data integrity. As Eversource is moving toward multi-year time series analysis, the evaluation of simulation results becomes a challenge. To this extent, Eversource is exploring cloud storage solutions. Furthermore, as the simulation models increase in complexity, the requirement for data quality increases. Eversource has showcased this ability in its 10-year study in Cambridge, MA and is working to enable these abilities in all jurisdictions through the Modeling Team.[143] The Grid Mod group is responsible for data verification during the conversion[144] to maintain data integrity. RCG acknowledges the benefits of cloud storage and recognizes other utility companies have successfully used the cloud. However, in so doing, proactive cyber security measures must also be taken to ensure data security and overall system integrity. Lessons learned from the successful East Cambridge implementation should prove to be a valuable resource for this effort.

System studies are based on planning criteria/guidelines specified in the *DSPG* 2020.[145] "What-if" simulations identify potential violations. "What-if" simulations assess potential solutions. For example, PSNH has many substations with two transformers connected on the low side with solid, straight busbars. A disadvantage of this design is that bus faults can trip both transformers. The traditional fix (and accepted industry standard) is to insert a bus-tie breaker. Before/after System Planning conducts simulations to verify the solution. This example represents a typical system study. PSNH has submitted and approved several capital projects with this reliability fix.[146]

PSNH has a number of aging transformers.[147] Age alone is only one of several factors considered by Eversource's PTX transformer assessment tool when calculating a transformer health index.[148] Depending on the system need and associated transformer health index (if transformer adequacy is to be part of the solution), simulations are performed by System Planning to identify feasible solutions to meet the need.

Replacing transformers for capacity reasons is done as a last resort.[149] Alternative solutions include load transfer, NWA (or at least evaluating the possibility), reconfiguration, and combining substations. Sometimes, capacity cannot be met (including backup capacity) without changing or adding a transformer.[150] Potential transformer replacements for asset-condition reasons are summarized in the *2020 Design*

[143] Interview #13
[144] Interview #19
[145] LCIRP, October 1, 2020, Appendix D
[146] Interview #13
[147] Interview #61 and Interview #73
[148] Interview #15
[149] Interview #18
[150] Interview #18

*Violations Summary Report* for the period 2020-2029.[151] Results indicate very few transformers were replaced solely for health reasons. Results also indicate very few transformers were replaced solely for capacity reasons. (*Note*: Projects proposed in the *2020 Design Violations Summary Report* have yet to be approved by SDC, EPAC, and NH PAC.)

Mobile transformers are available for emergency use, but logistics can be challenging. Transporting and connecting a mobile unit takes 24 hours or more[152] which is too long to have customers without power. As a result, mobile units are typically used for planned outages or to relieve transformer overloads until a more permanent solution can be implemented.[153] (Mobile units are stored in an enclosed area out of the weather at the Mobile Wood facility in Bow, NH, for state-wide use.[154])

Mobile units are often used to restore customer load at non-bulk substations (4.16kV, 12.47kV, or 13.8kV) where alternative supply sources do not exist. The exhibit below summarizes PSNH's available mobile transformer voltages and sizes.[155]

**Exhibit 17 - Inventory of Mobile Transformers**

| Quantity | Nameplate Data | | |
|---|---|---|---|
| | Primary Voltage (kV) | Secondary Voltage (kV) | MVA |
| 3 | 115 | 34.5 | 35 |
| 1 | 115 | 12.47 | 30 |
| 1 | 46 or 34.5 | 13.09 | 14 |
| 2 | 34.4 | 4.36 or 13.09 | 10 |
| 1 | 34.4 | 4.36 or 13.08 | 7 |

Mobile units include a high-side disconnection device (e.g., circuit breaker) and a transformer. Cable rails are included to connect the low side if an overhead connection is impossible. The largest units (115-34.5kV 35MVA) require three trailers. The smallest units (34.5-4.16kV, 5MVA) require only one trailer.[156]

[151] DR BPA 1-006, Attachment BPA 1-006, 2020 Design Violations Summary Report – NH Distribution System, revised March 18, 2021
[152] DRs BPA 10-006 and BPA 12-009 1
[153] Interview #18 and Interview #61
[154] Interview #61 and DR BPA 12-009, page 2
[155] DR BPA 10-006
[156] Interview #61

### 5.27 Proposed bulk and non-bulk substation solutions for all regions (Central, Eastern, Northern, Southern, and Western) appear reasonable and not overdesigned or overbuilt.

RCG reviewed the October 1, 2021, *2020 Design Violations Summary Report – New Hampshire Distribution System Planning*, revised on March 18.[157] The number of proposed capital project bulk and non-bulk transformer replacements by region/area due solely to unhealthy transformers (i.e., no other planning criteria violations) are shown in the exhibit on the following page. All but one replacement required at least one other planning criteria violation before solution alternatives were considered.

**Exhibit 18 - 2020 Design Violations Summary Report - Xfmr Replacement Projects**

| Substation | Existing | | | | | | Solution | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Voltage (kV) | MVA | Install Yr | MW Load 2020 | # Fdrs | Violation | Voltage (kV) | MVA | MW Load 2029 | # Fdrs | Other |
| Cocheco Street (Dover) | 115-34.5kV | TB22 - 44.8<br>TB55 - 44.8 | 1972<br>2001 | 80.00 | 4 | Unhealthy transformer TB22; N-1 STE violation; N-1 bus fault | 115-34.5kV | TBxx - 62.5<br>TBxx - 62.5 | 82.00 | 4 | Replace with larger transformers; add series bus tie breakers |
| Great Bay | 115-34.5kV | TB171 - 44.8 | 2002 | 45.00 | 2 | N-0 base case load violation | 115-34.5kV | TB171 - 44.8 | 45.00 | 2 | Transfer load to Timber Swamp |
| Madbury | 115-34.5kV | TB65 - 44.8<br>TB74 - 44.8 | 1971<br>1976 | 70.00 | 4 | Unhealthy transformer TB65; N-1 STE violation; N-1 bus fault | 115-34.5kV | TBxx - 62.5<br>TBxx - 62.5 | 80.00 | 5 | Replace with larger transformers; add series bus tie breakers; add new feeder |
| Mill Pond | 115-12.47kV | TB171 - 44.8 | 2014 | 10.00 | 4 | N-0 base case load violation | 115-12.47kV | TB171 - 44.8 | 13.00 | 4 | Replace transformer at Cutts Street Substation; upgrade distribution lines |
| Rochester | 115-34.5kV | TB53 - 44.8<br>TB57 - 44.8 | 1968<br>2002 | 60.00 | 4 | N-1 STE violation | 115-34.5kV | TB53 - 44.8<br>TB57 - 44.8 | 65.00 | 4 | Transfer load to Tasker Farm Substation |

The total number of proposed capital projects by region/area in the *2020 Design Violations Summary Report* required to resolve all identified planning criteria violations are summarized in the Exhibit below. DSPG 2020 provides the following guidance for planning criteria:

> *"The planning design criteria are intended to maintain safe, reliable operation of the power system. Projected violations that are not within the planning design criteria are not tolerated. When these criteria are violated, the system must be reinforced, reconfigured, or upgraded to eliminate the constraints by the forecasted violation year."*[158]

[157] All proposed solutions are tentative and subject to further study by System Planning and SDC review; and are based on yet-to-be-approved planning criteria outlined in DSPG 2020 per Attachment BPA 1-006, October 1, 2021, 2020 Design Violations Summary Report – New Hampshire Distribution System Planning, revised March 18, 2021.

[158] LCIRP, October 1, 2020, Appendix D, Section 4.8.2, page 38

The exhibits below (All Projects and Bulk Subs) were tabulated from a detailed spreadsheet developed by RCG from the *Violations Summary Report* included in Appendix A. The Eastern Region bulk-substation-violations section of the detailed spreadsheet was extracted and presented in the Exhibit to serve as an example of what can be found in the detailed spreadsheet for proposed bulk and non-bulk capital projects.

**Exhibit 19 - 2020 Design Violations Summary Report - All Projects**

| Region / Area | ALL Capital Projects Multiple Violations | Region / Area | ALL Capital Projects Multiple Violations |
|---|---|---|---|
| **BULK Transformers (115kV and above)** | | **NON-BULK Transformers (below 115kV)** | |
| Central | 6 | SE Corner | 7 |
| Eastern | 5 | SE Center | 3 |
| Northern | 12 | Center | 2 |
| Southern | 8 | | |
| Western | 6 | | |
| **TOTAL** | **37** | **TOTAL** | **12** |

**Exhibit 20 - 2020 Design Violations Summary Report – Bulk Subs – Eastern Region**

| Region / Area | Capital Projects Due Solely to Unhealthy Transformers | Capital Projects Unhealthy Transformers Plus at Least One Other Violation | Region / Area | Capital Projects Due Solely to Unhealthy Transformers | Capital Projects Unhealthy Transformers Plus at Least One Other Violation |
|---|---|---|---|---|---|
| **BULK Transformers (115kV and above)** | | | **NON-BULK Transformers (below 115kV)** | | |
| Central | 0 | 3 | SE Corner | 1 | 4 |
| Eastern | 0 | 2 | SE Center | 0 | 2 |
| Northern | 0 | 6 | Center | 0 | 1 |
| Southern | 0 | 2 | | | |
| Western | 0 | 5 | | | |
| **TOTAL** | **0** | **18** | **TOTAL** | **1** | **7** |

The substation report summarizes planning violations for each region (bulk) and area (non-bulk) in Appendix A. Details are provided for both "existing" and "solution" system conditions. The "Solutions" column summarizes "preferred alternative solutions" (sometimes referred to as "best overall solution alternative" per earlier definitions). (*Note*: All solutions are based on the *yet-to-be-approved* planning criteria outlined in DSPG 2020[159] and, as a result, are subject to further study by System Planning and a critical review by the SDC.[160]) Project solutions are to collaborate between System Planning, Design Engineering, and Distribution Engineering (for inside-the-fence connections to distribution feeders).[161]

All existing transformers in the above exhibit (Bulk Subs) are 44.8MVA (older units no longer included in the transformer design standards). The new standard specifies 62.5MVA. Based on asset condition assessments and the ability to meet system design needs, strategic plans call for these older units to be systematically replaced. This is the case for Cocheco Street and Madbury Substations. The proposed solution calls for the 44.8MVAs to be replaced with 62.5MVAs to resolve unhealthy transformer issues and multiple (N-1) violations. For both substations, series-tie breakers are proposed to increase reliability and provide load transfer capability options should a transformer fail. Engineering simulations verified all system requirements would be met and planning criteria violations resolved.

At the distribution substation level, Eversource follows accepted industry maintenance and replacement practices of inspecting substations and testing power transformers on a schedule. This policy allows PSNH/Eversource to determine when to replace older, potentially failing transformers consistent with PSNH/Eversource's (and industry) updated asset management policies and procedures. Eversource changed its PSNH policy of power transformer sizes to several specific MVA sizes and voltage ratings to reduce required inventory. This policy shift allows PSNH to order these long-lead-time units without incurring the additional capital expense involved when making a unique procurement on short notice, requiring the Company to "buy in" to the existing manufacturers' transformer production schedule. Having spares of these standard transformers now cover a broader number of installed distribution power transformers and reduces the overall number of spares in inventory.[162]

Another program replaces old oil circuit breakers with newer vacuum breakers, which offer better controls, are environmentally friendly, and are far safer to operate. In the past, there have been industry-wide incidents where the oil breakers have failed and

[159] LCIRP, October 1, 2020, Appendix D

[160] DR BPA 1-006, Attachment BPA 1-006, *2020 Design Violations Summary Report – New Hampshire Distribution System,* revised March 18, 2021, page 4 of 158

[161] Interview #21

[162] Interview #61 and Interview #73

caused damage. Further, the industry, for decades, has been moving to eliminate hazardous oils that, when spilled, cause ground environmental contamination.[163]

Transformer rewinding/rebuilding is an option to purchase new units depending on transformer condition, time to rebuild, and cost. However, Eversource has not found many circumstances where rewinding is a feasible alternative.[164] RCG understands and agrees with this position.

Environmentally friendly alternatives to mineral oil can be used to retro-fill power transformers and extend useful life. An example is FR3® which is derived from 100% renewable vegetable oils for use in distribution and power generation transformers of all voltage classes. FR3 transformers can operate $15^0$C to $20^0$C warmer than conventional mineral-oil transformers without sacrificing reliability or life expectancy, allowing for increased load capacity.[165] Eversource has briefly considered the FR3 technology but believes more investigation/evaluation is needed before applicability decisions can be made.[166]

**5.28 Eversource routinely implements industry-accepted design practices, following a set of guidelines detailed in DSPG 2020, supplemented by a comprehensive set of documentation maintained in the Engineering Standards Bookshelf. RCG agrees with this process.**

One example is installing feeder ties to create multiple sources to improve service reliability and create load-transfer options, making more efficient use of capital. Another is making good use of enhanced checklists in Eversource's enhanced capital review/approval process to improve design quality by focusing attention on engineering and pricing details. However, an area of concern is the low priority PSNH places on integrating DER technologies which could create planning problems down the road if DER penetration rates significantly exceed growth forecasts.

PSNH's distribution voltage classes and corresponding installed miles are given in the exhibit below.[167]

[163] Interview #61
[164] DR BPA 12-012
[165] IEC 60076-14 Part 14: Liquid-immersed power transformers using high-temperature insulation materials. Edition 1.0. September 2013; IEEE C57.154 Standard for the Design, Testing, and Application of Liquid-Immersed Distribution, Power, and Regulating Transformers Using High-Temperature Insulation Systems and Operating Elevated Temperature. October 30, 2012.
[166] Interview #16
[167] DR BPA 1-025

**Exhibit 20 - Miles of Distribution Lines by Type**

| Voltage Class | Overhead (Miles) | Underground (Miles) | Total (Miles) |
|---|---|---|---|
| 4kV | 2,733.29 | 215.43 | 2,948.72 |
| 8.32kV | 352.38 | 36.05 | 388.43 |
| 12.47kV | 5,486.63 | 570.45 | 6,057.08 |
| 13.8kV | 8.69 | 8.36 | 17.05 |
| 34.5kV | 3,599.82 | 1,191.23 | 4,791.05 |
| **Total** | **12,180.81** | **2,021.52** | **14,202.33** |

System one-line diagrams are of good quality, well-marked with legends, and appear comprehensive, categorized by "*Electric System Control Center*" and "*System Operations Center*." A PSNH map highlights major portions of the distribution system.[168] (A reduced version of this map is included in the Reliability section of this report.)

PSNH's 34.5kV system is 60+ years old and unique to the three-state area (CT, MA, NH).[169] The above exhibit shows 3600 miles of 34.5kV, 5487 miles of 12kV, and 2733 miles of 4kV. Expanding the 34.5kV system where other voltages already exist and satisfy system planning criteria "makes no sense, and it is not done." 34.5kV lines are tapped to meet specific load growth demands, but PSNH has no system-wide plans to upgrade to 34.5kV.[170]

Voltage upgrade decisions (4kV, 12kV, 13.2kV, 34.5kV) are based on the best technical/financial solutions to service the loads. Considerations include the cost-per-saved-customer-minute and the number of customers affected.[171] A case in point is the 4kV system which is reliably operating and meeting the needs. Nashua is an example of where it would cost too much to upgrade the 4kV infrastructure. Currently, the PSNH has no plans to expand/replace the 4kV system.[172]

Another example might be a projected overload of a 4kV substation transformer triggering possible conversion to 12kV. If there is no benefit to converting, the overloaded substation may be retired, and the load transferred to a step transformer. The decision is on the extent to which the substation transformer is forecasted to be overloaded.[173]

[168] DR BPA 1-026 and Confidential Attachments
[169] Interview #11
[170] Interview #13, Interview #16, and Interview #20
[171] DR BPA 7-006
[172] Interview #11, Interview #16, and Interview #20
[173] DR BPA 7-006

Taps taken off 34.5kV lines in RoWs could have one or 1000 customers per circuit. As a result, there is an effort to use distribution automation to create circuit taps or segments that will limit outage exposure to 500-count customer blocks while creating load transfer options. For radial lines, 500-count blocks do not mean only 500 customers will be affected by upstream faults; it simply means the ability now exists to isolate customers into blocks of 500. An important point to make is the following: On a radial circuit with in-line fault protect (breakers), faults occurring closer to the head-end or substation side of the line will affect all customers beyond the point of failure. The radial line must be looped or tied to another independent generation source to overcome this.

Eversource is an industry leader in implementing IEC 61850 technology. The Eddie Substation in NH is the first such T&D installation which serves as an example for future facilities. To keep the focus on substation installations, IEC 61850 will not be applied to the distribution system (reclosers) until some future date is determined.[174]

Bare wire can no longer be installed on distribution circuits unless a phase is added or extended. Covered wire and spacer cable (optional) is used instead but only on a per-case basis, with justification.[175] PSNH believes tree trimming along the distribution backbone is adequate, especially over the last ten (10) years. However, PSNH recognizes vegetation management will continue to be an ongoing challenge. One of the most significant problems is scenic roads, where it is difficult to secure tree-trimming approvals (34.5kV RoWs are maintained by transmission maintenance and construction).[176]

In support of distribution automation, more than 1700 smart devices are installed in PSNH. Currently, there is no peer-to-peer communication between smart devices because PSNH did not want to duplicate DMS (Distribution Management System) communication logic. Instead, data is brought back to a central location for processing. Local device control is still operational.

Looped (backup) feeder-tie connections exist around the system. Multiple ties exist fed from different substations and circuits in the Southern, Central, and Eastern areas. In the Northern and Western regions, there are far fewer looped connections. Even so, there are enough connections to use DA to achieve the 500-customer segmenting target mentioned earlier.[177] DMS will automatically switch ties based on pre-programmed priorities to minimize customers out of service.[178]

[174] Interview #34
[175] Interview #16
[176] Interview #16
[177] NOTE: projects to loop circuits using feeder-tie connections, and projects designed to achieve 500 customer segmentation are two different efforts.
[178] Interview #19

**5.29 The use of greenfield substation sites is discouraged, but when needed, PSNH looks to set a 5-acre minimum land parcel requirement. RCG concurs with this for the reasons stated below.**

Minimally sized green-field substation sites may not be large enough to allow mobile-transformer use. RCG believes this to be a good policy. When evaluating substation development solutions, PSNH avoids trying to "fix" substations with significant maintenance issues as cost-saving measures will likely cause more extensive problems and incur additional costs down the road, resulting in unplanned outages that could have been avoided.

If physical space permits, new substations will be built on greenfield sites next to old substations, then switched over to minimize customer downtime. When looking to secure property, PSNH sets a minimum 5-acre requirement, often being able to purchase more land. Eversource considers the incremental cost (e.g., $150K) to be minimal compared to overall project costs, and the extra space provides a means for building around obstacles (e.g., wetlands), offers multiple orientation design options, provides larger buffer areas from neighbors, and makes future expansion possible.[179]

A typical substation design is the Twombly Street Substation (DR 9-018). The design process uses 3D software to facilitate standardization by using similar designs as starting points, then making modifications as needed. Double-ended substation designs (two transformers) are not standard due to overcapacity versus reliability concerns. This approach is consistent with PSNH's policy of "only doing what is necessary." [180]

There is an external perception that substation overdesigns tend to happen when more than the minimum amount of greenfield land is purchased. Eversource does not believe this to be the case, contending it saves capital dollars in the long run for the reasons explained above.[181] When coupled with the efficient application of metal-clad switchgear (discussed in the Design Standards section of this report), dollar savings can be even more significant.

[179] Interview #73
[180] Interview #61
[181] Interview #61

**5.30 PSNH's Protection philosophies and equipment used are consistent with industry-standard practices.**

Regarding system protection, the distribution system at the substation level consists of bulk-connected transformers and buses configured with high-speed differential protection. Distribution feeder breakers use time overcurrent protection schemes to coordinate with downline reclosers and fuses.[182] For radial circuits, the fuse closest to the fault opens first. If the fault is between the fuse and the upstream recloser, the recloser operates first. If the fault is between the substation feeder breaker and downstream recloser, the substation feeder breaker operates first. This process is referred to as *selectively coordinated fault protection*. RCG agrees with this approach.

There are no planned changes to this overall approach. However, equipment upgrades are often made as part of asset-replacement capital projects. Examples include replacing electromechanical relays with microprocessor-based devices, adding redundant relaying; replacing fuses with reclosers (e.g., cutout-mounted recloser); and adding high-speed instantaneous or differential protection.[183]

Changes in protection schemes and equipment are also required when DER technologies are applied to distribution feeders to accommodate two-way power flows safely. This DER-related scenario is used on an as-needed basis.

**5.31 More data-centric discussions are needed with the Division. Not enough data-centric discussions are being held between PSNH and the Division to demonstrate/explain why the best *overall* solution alternative is not always the least-cost solution alternative.**

There are five broad categories of capital projects:

1) Basic business (customer connections);
2) Grid modernization;
3) Equipment obsolescence;
4) Distribution line work; and
5) Distribution substation work.[184]

[182] DR BPA 1-034
[183] DR BPA 1-034
[184] Interview #13

For project development, it is essential to understand the terminology being used by Eversource when presenting solution alternatives. Eversource definitions for each type of alternative follow:[185]

- *Alternative Solutions* – All *reasonable* solutions that address specific identified needs.
- *Feasible Alternative Solutions* – Viable solutions that have no identifiable constraints precluding construction or implementation.
- *Technically Feasible Alternative Solutions* – Viable solutions that have no technical constraints precluding construction or implementation.
- *Least-Cost Alternative Solutions* – Solutions that have the least cost. As outlined in RSA 378:37, it is New Hampshire's energy policy that "least-cost planning" requires the selection of solutions that represent the "*lowest reasonable cost*" based on consideration of factors other than cost, including reliability and diversity of energy sources; to maximize the use of cost-effective energy efficiency and other demand-side resources; and to protect the safety and health of citizens, the physical environment of the state, and the future supplies of resources, with consideration of the financial stability of the state's utilities.
- *Best Overall Alternative Solutions – Eversource refers to these as "Preferred Alternatives."* Solutions with the best combination of electrical performance, cost, future expandability, and feasibility to comprehensively address all the identified needs in the required timeframe.

Sometimes, "do nothing" is listed as an alternative on the PAF forms. While discouraged, it is an acceptable alternative if a case can be made that more maintenance, increased observation, or operational workarounds can satisfactorily resolve the issues.[186]

**5.32 More complete documentation is required for NWA solutions. Not enough attention is given to documenting potential NWA solutions, even though NWA evaluations are integral to the Eversource project selection process. To date, no NWA solutions have been implemented in NH.**

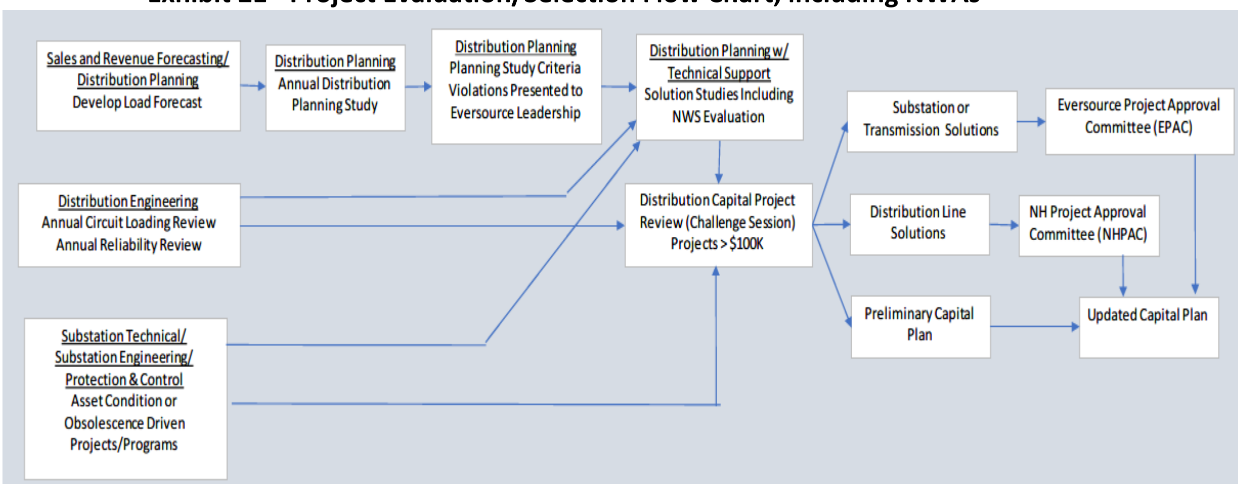
Even though progress is being made in developing/applying tools to streamline the NWA evaluation process, more out-of-the-box thinking is required to create feasible alternatives. For example, only two NWA solutions were proposed (Loudon 31W2 and

185 DR BPA 14-007
186 Interview #34

Hanover Street 16W3, both non-bulk substations) in the *2020 Design Violations Summary Report*[187] out of 37 bulk substation projects and 12 non-bulk substation projects.

The exhibit below provides a high-level flow chart of the project evaluation/selection process for both traditional and NWA solutions. For all substation planning criteria violations, "potentially suitable" NWA solutions must be considered. If a project is a specific size and there is adequate timing (enough time to implement the solution), then NWAs are considered potentially "suitable." NWAs must then pass a revenue requirements impact evaluation to determine which solution will, in the short or long-term, impact customers the least.

**Exhibit 21 - Project Evaluation/Selection Flow Chart, including NWAs[188]**




Sometimes, NWAs are a sound deferral strategy for more traditional solutions. In the end, a solution must pass a benefit-cost analysis, i.e., the value of the NWA solution divided by the value of the conventional solution must be greater than or equal to 1 for an NWA to pass the benefit-cost analysis threshold. An NWA also has a "fit" criteria, e.g., an NWA is considered not applicable when there is an asset health issue due to failing equipment.[189]

If an NWA does not apply (e.g., equipment failure), it must be noted on the PAF forms.[190] However, this policy/guideline is *not* being consistently followed, another failure in communications. PAF forms do not always include statements regarding potential NWA

[187] DR BPA 1-006, Attachment BPA 1-006 dated 10/01/2021
[188] DR BPA 15-017; LCIRP, March 31, 2021, Supplement, Appendix A, NWA Framework
[189] Interview #18
[190] Interview #62

solutions, good or bad, as was discovered in a May 5, 2021, NH-PAC meeting. An NWA status statement should be included on all distribution line project NH-PAC forms. It can be as simple as, "Due to the immediate need (less than six months) of the project, no NWA investigations were conducted as forth in the rules of the NWA Framework."

The NWA Framework[191] (and NWA Screening Tool) places a value on environmental benefits (e.g., emissions), but these benefits are not rigorously analyzed. In NH, no NWA solution has been approved and implemented. Even though no NWA incentives are currently in place, discussions have been held with some municipalities for potential use.[192]

System Planning developed the NWA screening tool over a six-month period (2019-2020) for all three states to screen NWA alternatives based on cost and technical merits. Factors considered include energy efficiency profiles, CVR, demand-side management, behind-the-meter generators, diesel generators, battery storage, battery storage plus solar, solar, and combined heat & power (CHP). The cost of the traditional and NWA solutions is calculated using the latest approved rate making mechanisms to ensure accurate revenue requirement impacts. Costs are synthesized over a five/six-year period. Results are compared to avoided deferral costs for traditional solutions.[193]

The cost threshold for NWA to be competitive is around $3 M, e.g., a 2MW, 5MWh battery storage installation costs around $5M. PSNH believes going through the motions for anything less does not make sense.[194]

**5.33 Conduct in-house training programs for NH hosting capacity map developers and system planning personnel, especially if lessons learned from Eversource CT and MA are included in the training will be productive.**

DER hosting capacity maps show the best potential interconnection locations. In MA and CT, hosting capacity maps were developed using Synergi software. In NH, hosting maps do not yet exist[195] but are expected to be released early 2023. When detailed Synergi planning models are completed for NH, individual phase circuit modeling and DER technology models (PV, wind, energy storage) will be possible. More complete what-if studies can then be performed when investigating DER integration capabilities (including the impact of electric vehicle charging stations) and associated system performance

[191] LCIRP, March 31, 2021, Supplement, Appendix A-1
[192] Interview #18
[193] Interview #13
[194] Interview #13.
[195] Interview #13

(including how to safely address two-way power flows), especially when advanced load forecasting algorithms (future scenario modeling) are used.

System Planning is responsible for DER interconnection strategies, including meeting hosting capacity limitations and 2-way power flow constraints (1-way radial now). Protection & Control (P&C) is responsible for DER system protection and associated device settings (e.g., transfer trip, relays). The NH DER integration strategy was initially part of an NH Grid Modernization Program (GMP) not yet approved by the PUC. Integral to the Plan was a systematic conversion of the distribution system to handle two-way power flows from one-way radial designs. The nightmare scenario is if DER penetration quickly increases, significant changes in system design/protection will be needed in a relatively short time to meet hosting capacity and two-way power flow requirements.[196]

**5.34 CVR is not being investigated adequately. Consideration should be given to more aggressively investigating and implementing Conservation Voltage Reduction (CVR) for peak demand and energy savings.**

Given the relatively high content of residential system load --- 44% of kWh residential sales; 50% of kW residential peak demand. CVR potential in PSNH has *not* been evaluated.

CVR hasn't been incorporated in PSNH but is part of a planned volt-var optimization (VVO) implementation to interface SCADA with DMA with controllable capacitor banks, line voltage regulators, and micro-capacitors (connected to the 240-volt side of distribution transformers).[197]

CVR can reduce peak load demand (kW) and energy use (kWh) by as much as 3%, depending on the system. Opportunities exist on distribution feeders serving loads where normal operating voltages can be reduced without impacting the end-user, e.g., resistive loads, which generally occur for residential loads. Industrial/commercial loads typically contain large motors where voltages cannot be adjusted without impacting the end-user; this results in minimal CVR opportunities. The Exhibit below summarizes the residential versus industrial/commercial make-up for PSNH. *The percent residential load is large enough to justify investigating CVR potential*.

[196] Interview #34
[197] Interview #19

Due to a significant shift in interior residential lighting in NH towards LED lighting (50% in 2020 versus less than 1% in 2009),[198] CVR opportunities may be reduced (LEDs use far less energy). It is further recognized that the load profiles of residential customers in northern NH are different from load profiles in southern NH. Nevertheless, a more in-depth investigation of CVR potential is justified.

CVR is considered an NWA solution and, as such, is included in the NWA screening tool. Eversource's rationale is that CVR is one of the easiest and most cost-effective NWA alternatives for reducing energy use and lowering peak demand. When evaluating energy efficiency, the (N-1) design guidelines no longer apply to CVR or PV behind the meter because the controlling devices are located at different locations.[199]

**Exhibit 22 - Residential, Industrial, and Commercial 2020 Load Totals for NH**

| Customer Class | # Customers 2020 | % | kWh Sales 2020 | % | Customer Class | kW Coincident Peak Demand 2020 | % |
|---|---|---|---|---|---|---|---|
| Residential | 446,612 | 84.9% | 3,373,392,618 | 43.9% | Residential | 864,068 | 49.8% |
| Commercial | 75,849 | 14.4% | 3,003,670,859 | 39.1% | Small Commercial/Ind | 321,512 | 18.5% |
| Manufacturing | 2,719 | 0.5% | 1,294,235,314 | 16.8% | Medium Commercial/Ind | 340,270 | 19.6% |
| Public Streetlighting | 753 | 0.1% | 12,400,749 | 0.2% | Large Commercial/Ind | 207,947 | 12.0% |
| Other | 12 | 0.0% | 5,880 | 0.0% | | | |
| | ------- | ------ | -------------- | ------ | | -------------- | ------ |
| | 525,945 | 100.0% | 7,683,705,420 | 100.0% | | 1,733,797 | 100.0% |
| | Reference: BPA 15-019 | | Reference: BPA 15-020 | | | Reference: BPA 15-021 | |

[198] New Hampshire Residential Baseline Study submitted by Itron to the New Hampshire Evaluation, Measurement, and Verification Working Group, June 11, 2020, pages ES-2 and ES-3
[199] Interview #13

# Recommendations

**R.8 Develop and test (as a joint effort between System Planning and Distribution Engineering) detailed Synergi feeder models, taking full advantage of System Planning's familiarity with Synergi to facilitate the process.**

**R.9 Perform an in-depth/rigorous analysis of the data-checking and conversion process for new software platforms (e.g., DistriView to Synergi data sets) independent of the Grid Mod group's conversion verification process to ensure data continuity and integrity are being maintained throughout.**

**R.10 Develop detailed documentation to maintain data integrity as data conversions are made from one software platform to another, e.g., DistriView to Synergi, Storms to Maximo. This is especially true for Synergi, where individual phase models for distribution circuits are being developed, i.e., converting from 3-phase balanced distribution line models to 1-phase unbalanced distribution line models.**

**R.11 Investigate the potential benefits of retro-filling power transformers with the latest technology insulating fluids, e.g., extending transformer life (without compromising reliability) and deferring capital investments. Include guidelines for identifying candidate transformers.**

**R.12 More clearly explain and illustrate with examples why the best overall solution alternatives are not always the least-cost solution alternatives. It is not sufficient to state all criteria violations have been resolved. In addition, consistently document all alternatives considered in the formal project paperwork. Include a formal statement on NWA solution considerations (even if the statement says NWA solutions were not applicable) and reasons why.**

**R.13 Compare how the traditional solution alternatives are developed and priced against how NWA solution alternatives are developed and priced. Identify areas that disadvantage NWA solutions, e.g., how projected O&M costs are treated. Document key drivers that contribute to cost differences between traditional and NWA solutions.**

**R.14 Develop and conduct in-house training programs for New Hampshire DER hosting map development engineers. Lessons learned from Eversource CT, and MA should be integral parts of this training.**

**R.15 Continue to investigate Conservation Voltage Reduction (CVR) potential energy/demand savings for PSNH, given the relatively high content of residential system load --- 44% kWh residential sales; 50% kW residential peak demand.**

# System Reliability Performance

PSNH's Distribution System consists of 17,600 miles of distribution lines; and 139 substations in a heavily treed state, creating operational challenges to maintain a reliable overhead Distribution system. Recent reliability metrics indicate PSNH's progress in improving system reliability.

Major components of PSNH's electric distribution system are summarized in the following Exhibit:[200]

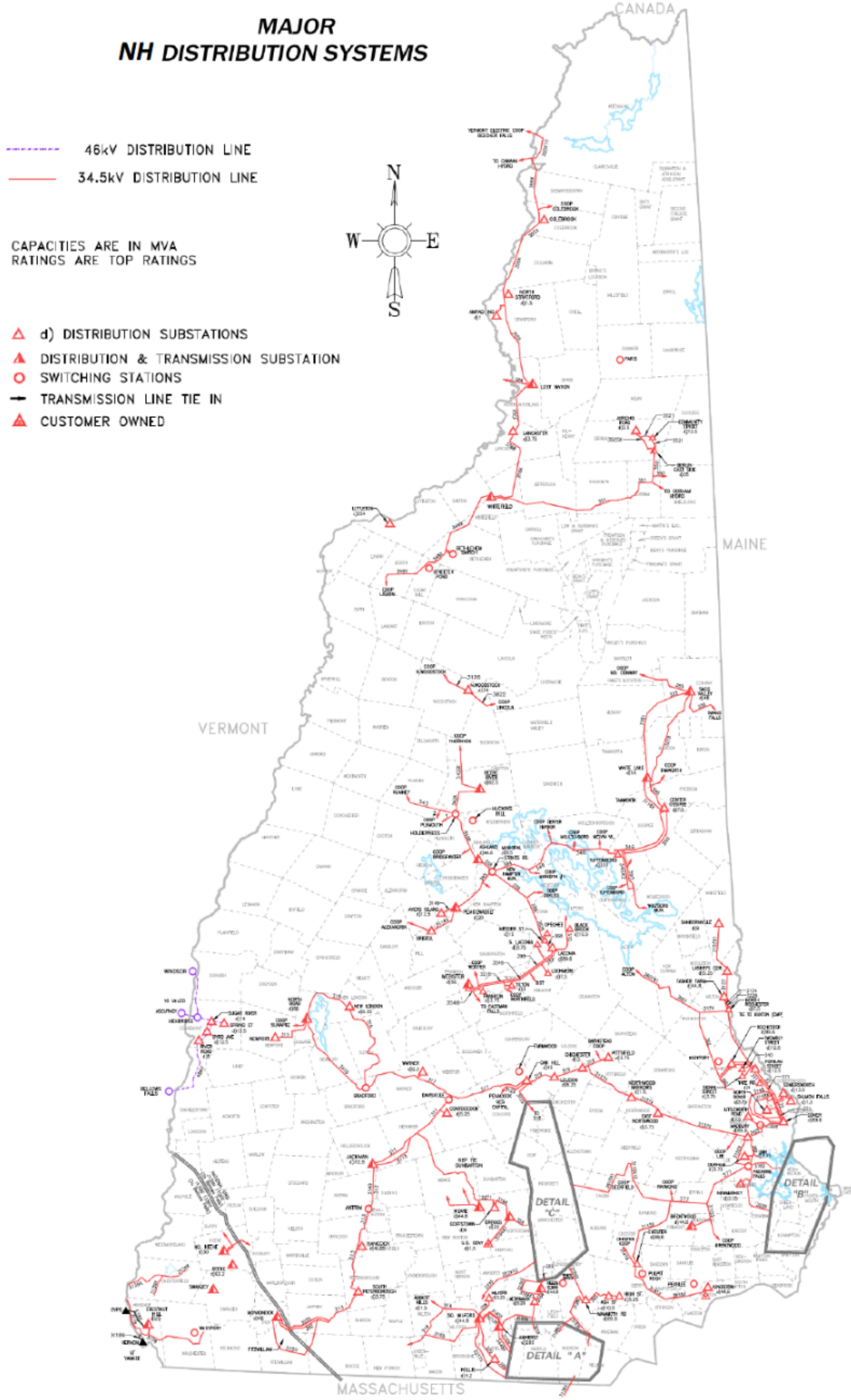
**Exhibit 23 - PSNH Distribution System Components**

| | | |
|---|---|---|
| 12,200 | mi | Overhead Distribution Lines |
| 3,000 | mi | Road-Side Distribution Lines |
| 600 | mi | Off-Road Distribution Lines |
| 1,800 | mi | Underground Distribution Lines |
| 17 | % | Distribution Lines - Backbone |
| 83 | % | Distribution Lines - OH Lateral Circuits from the Backbone |
| 139 | | Distribution Substations |
| 184 | | Substation Transformers (1.5 MVA to 140 MVA) |
| 179,000 | | Jointly-Owned Poles |
| 276,000 | | Solely-Owned Poles |

The exhibit below shows a state-wide overview map of the distribution system.[201] Red lines signify 34.5kV circuits and dashed lines are 46kV circuits. The map suggests higher load densities in the state's southern portion, especially the southeast region. Also, while not apparent from the map, it should be noted NH is a heavily treed state which creates challenges in constructing and maintaining the overhead portion of the distribution system.

[200] Docket 19-057, Testimony of Joseph A. Purington and Lee G. Lajoie, May 28, 2019, Bates page 397
[201] DR BPA 1-026, Attachment BPA 1-026 C

**Exhibit 24 - PSNH Major Distribution Systems Map**



**6.1. Eversource closely monitors reliability performance using industry-recognized reliability metrics. Eversource has proactively identified, prioritized, and implemented distribution automation projects that have consistently resulted in annual reliability performance improvements. Eversource has also defined complementary resiliency program initiatives to maintain and further improve reliability performance.**

Distribution reliability falls into the following two categories:[202]

- *Feeder level* - The goal is to minimize both the duration and the frequency of outages due to a fault. The new policy target for customers impacted by a line fault is 500 customers. The desired results are being achieved by segmenting the feeders via switching that started with the Reliability Enhancement Program (REP) using distribution automation to achieve the target.
- *Substation level* - The goal is to develop strategies for load pick-up should a power transformer, or feeder circuit fail. System Planning is responsible for making this happen through substation configuration, bus configuration (e.g., ring bus or breaker-and-half schemes), and equipment selection.

Historical reliability statistics are the quantitative basis for sound decision-making and come in many forms. Overall reliability statistics are excellent for self-evaluation. Utility-to-utility comparisons are made, but differences in each electrical network (weather conditions, number of customers served, customer willingness to pay for reliability, and equipment used) must be considered. While such comparisons have benchmarking value (e.g., utility ranking against its peers), the metrics are most valuable for a single utility system when relative comparisons are examined from period to period (week, month, or year). The data can help make the best decisions considering the utility's system-specific circumstances.

Reliability indices (metrics) indicate system performance and individual circuit conditions, i.e., if the system or circuit reliability improves or worsens over time. Reliability indices are situational and reflect different baselines depending on system-specific designs and operational philosophies. *IEEE Guide for Electric Power Distribution Reliability Indices (Standard 1366[203]) facilitates uniformity in distribution service reliability indices and aid in consistent reporting practices related to distribution systems,*

[202] Interview #34

[203] IR-57 IEEE-1366-Reliability-Indices-2-2019 - NGRID

*substations, circuits, and defined regions. The standard is universally used (including by Eversource) to characterize distribution system reliability.*[204]

In times of extreme events, it may be unreasonable or difficult to track customer outages. As a result, Standard 1366 accounts for major storms separately to assist in tracking severe weather outages (e.g., tornados, thunderstorms, and the like) leading to unusually long outages. In NH, accumulated ice and wind make for significant reliability problems on overhead distribution circuits. A utility can either include planned interruptions/outages (PIs) or keep them separate to measure downtime caused by operations. A utility typically reports reliability metrics with and without storms so that restoration can be a measurable performance objective.

Capital programs require the justification of system improvement projects based on the need to improve overall system reliability and at specific points in the system. To this end, annual system-wide statistics, individual distribution line statistics, and specific components (e.g., transformers, poles, etc.) are collected—annual results aid in determining if reliability improvement initiatives are needed.

Distribution system interruption data and IEEE performance indices can provide data-driven insights when considering reliability improvement measures. Indices most often referenced are the following:

- ***SAIDI*** - System Average Interruption Duration Index (>5 min typically) (CMI ÷ CS) - Number of minutes of interruption average customer experiences.
- ***MAIFI*** - Momentary Average Interruption Frequency Index (<5 min typically) - How often the average customer experiences power quality disturbances.
- ***SAIFI*** - System Average Interruption Frequency Index (SAIDI ÷ CAIDI) (or CI ÷ CS) - How often the average customer experiences an interruption (>5 min).
- ***CAIDI*** - Customer Average Interruption Duration Index (SAIDI ÷ SAIFI) (or CMI ÷ CI) - Average time required to restore service.

[204] IR-58 Understanding Distribution Reliability Metrics

Additional reliability metrics used by Eversource are the following:

- ***COSAIDI***[205] - Contribution to PSNH (system-wide) SAIDI - Used to rank individual circuit performance, considering cost-per-saved-customer minute (primary consideration), number of customers impacted, frequency of interruptions, exposure to lengthy outages due to access issues, and the impact on critical customers.
- ***MBI*** - Months Between Interruptions (months ÷ SAIFI, e.g., 12 ÷ 0.9654 = 12.4 MBI)
- ***CI*** - Customers Interrupted/Impacted
- ***CS*** - Customers Served
- ***CMI*** - Customer Minutes Interrupted
- ***CIII*** - Customers Interrupted per Interruption Index (CI ÷ # events) - This metric is used primarily at the circuit level to help identify the need and location for additional protective devices or automation to reduce the number of customers impacted by a single event.[206]

Important industry norms and definitions follow:[207]

- ***IEEE Criteria*** - Reliability performance without MEDs.
- ***MEDs*** - Major Event Days - Calculated reliability metric based on five years of performance data (including storms and planned & scheduled interruptions), resulting in a daily-SAIDI-threshold-value-per-year. MEDs equate to days exceeding this threshold.
- ***Eversource Reportable Criteria*** - IEEE criteria without planned interruptions. This indicator is the main criterion used within the Eversource organization.
- ***Without*** Storms IEEE Quartile Rankings - This represents the range of reliability metrics respondents experienced during non-major storm days but includes minor storm data.
- ***With*** Storms IEEE Quartile Rankings - It represents the range of reliability metrics respondents experienced during all days. This ranking includes all-in data, MED days, and minor storm data.

[205] DR BPA 1-36
[206] DR BPA 14-005
[207] Id.

## 6.2. PSNH's reliability performance shows a consistent improvement based on key reliability indices, suggesting system reliability investments are working.

Year-to-year system-wide reliability performance is a vital indicator of the ability to minimize customer outage minutes when expected or higher frequency/probability of occurrence events happen. PSNH's performance over ten years is summarized in the two exhibits presented below based on the following reliability metrics: CI, CMI, SAIDI, CAIDI, SAIFI, and CIII. Both exhibits show a steady, consistent improvement in these indices over ten years (2011 to 2021). (Note: The number of "Parent Events" in the first exhibit represents the sum of the "Parent Events" in the two exhibits that follow.)

**Exhibit 25 - NH Reliability Statistics 2011-2021 – ALL Events[208]**

| Year | # Parent Events | CI | CMI | SAIDI | CAIDI | SAIFI | CIII |
|---|---|---|---|---|---|---|---|
| 2011 | 14,025 | 1,420,678 | 1,121,114,669 | 2,250 | 789 | 2.852 | 101 |
| 2012 | 11,363 | 875,435 | 298,949,392 | 598 | 341 | 1.751 | 77 |
| 2013 | 10,067 | 774,073 | 106,693,930 | 213 | 138 | 1.544 | 77 |
| 2014 | 11,713 | 939,411 | 440,781,256 | 874 | 469 | 1.864 | 80 |
| 2015 | 8,548 | 573,772 | 60,883,395 | 119 | 106 | 1.124 | 67 |
| 2016 | 11,012 | 826,837 | 105,678,322 | 202 | 128 | 1.584 | 75 |
| 2017 | 16,808 | 1,018,158 | 509,073,382 | 969 | 500 | 1.939 | 61 |
| 2018 | 15,196 | 1,014,800 | 207,455,653 | 392 | 204 | 1.920 | 67 |
| 2019 | 12,013 | 639,783 | 122,747,595 | 231 | 192 | 1.204 | 53 |
| 2020 | 13,761 | 808,823 | 249,991,929 | 467 | 309 | 1.512 | 59 |
| 2021 | 8,883 | 451,936 | 82,054,948 | 152 | 182 | 0.839 | 51 |

**Exhibit 26 - NH Reliability Statistics 2011-2021 – excludes MEDs[209]**

| Year | # Parent Events | CI | CMI | SAIDI | CAIDI | SAIFI | CIII |
|---|---|---|---|---|---|---|---|
| 2011 | 8,968 | 624,920 | 77,932,762 | 156 | 125 | 1.254 | 70 |
| 2012 | 9,323 | 609,069 | 70,958,452 | 142 | 117 | 1.218 | 65 |
| 2013 | 8,614 | 581,827 | 69,062,920 | 138 | 119 | 1.160 | 68 |
| 2014 | 9,599 | 623,637 | 61,912,845 | 123 | 99 | 1.237 | 65 |
| 2015 | 8,295 | 538,776 | 54,177,931 | 106 | 101 | 1.055 | 65 |
| 2016 | 9,862 | 720,704 | 72,391,329 | 139 | 100 | 1.380 | 73 |
| 2017 | 11,789 | 578,995 | 62,146,242 | 118 | 107 | 1.102 | 49 |
| 2018 | 10,361 | 565,301 | 63,373,060 | 120 | 112 | 1.069 | 55 |
| 2019 | 8,875 | 393,465 | 43,907,584 | 83 | 112 | 0.740 | 44 |
| 2020 | 8,866 | 431,001 | 51,239,298 | 96 | 119 | 0.805 | 49 |
| 2021 | 6,892 | 321,961 | 35,531,699 | 66 | 110 | 0.598 | 47 |

[208] Id.
[209] DR BPA 1-35-1, Attachment. MEDs = Major Event Days (Storms)

**Exhibit 27 - NH Reliability Statistics 2011-2021 – includes only MEDs[210]**

| Year | # Parent Events | CI | CMI | SAIDI | CAIDI | SAIFI | CIII |
|---|---|---|---|---|---|---|---|
| 2011 | 5,057 | 795,758 | 1,043,181,907 | 2,094 | 1,311 | 1.597 | 157 |
| 2012 | 2,040 | 266,366 | 227,990,940 | 456 | 856 | 0.533 | 131 |
| 2013 | 1,453 | 192,246 | 37,631,010 | 75 | 196 | 0.383 | 132 |
| 2014 | 2,114 | 315,774 | 378,868,411 | 752 | 1,200 | 0.626 | 149 |
| 2015 | 253 | 34,996 | 6,705,464 | 13 | 192 | 0.069 | 138 |
| 2016 | 1,150 | 106,133 | 33,286,993 | 64 | 314 | 0.203 | 92 |
| 2017 | 5,019 | 439,163 | 446,927,140 | 851 | 1,018 | 0.836 | 88 |
| 2018 | 4,835 | 449,499 | 144,082,593 | 273 | 321 | 0.850 | 93 |
| 2019 | 3,138 | 246,318 | 78,840,011 | 148 | 320 | 0.464 | 78 |
| 2020 | 4,895 | 377,822 | 198,752,631 | 371 | 526 | 0.706 | 77 |
| 2021 | 1,991 | 129,975 | 46,523,249 | 86 | 358 | 0.241 | 65 |

**6.3. PSNH reliability quartile rankings have consistently improved over the last five years when compared to peer utilities (other northeast utilities), placing PSNH in the 1st and 2nd quartiles. However, reliability performance consistently lags Eversource CT and MA, suggesting there may be room for improvement.**

Another key indicator is how well a utility performs compared to its peers. Multiple reliability indices (defined above) are typically used when developing quartile rankings.

The exhibit below summarizes PSNH's reliability performance over five years based on PSNH (ES) reportable criteria (IEEE criteria without planned interruptions and MEDs) representing the range of reliability metrics respondents experienced during non-storm days. The quartile data is based on 17 (varies slightly by year) Northeast and Mid-Atlantic medium-sized companies to provide reasonably comparative data and are based on a three-year historical average of the data; e.g., 2021 quartiles are based on 2018-2020 average data.[211]

PSNH consistently ranked in the 1st and 2nd quartiles against its peers for 2017-2021 (highlighted in green below).[212] Being in the 1st quartile for both SAIDI (system outage minutes) and SAIFI (outage frequency) is excellent and the goal of most utilities. The PSNH believes the interconnected nature of NH substations is key to this reliable performance.[213] For SAIDI and SAIFI, low and decreasing numbers are good. Sometimes,

[210] Id.
[211] DR BPA 12-013
[212] DR BPA 14-005, page 3
[213] Interview #18

simply maintaining existing numbers is good enough. RCG agrees with these observations.

**Exhibit 28 - PSNH Reportable Criteria**[214]

NH - IEEE Criteria - Without IEEE MED Storms

| | | | | | | | | | IEEE Quartiles SAIDI | | | IEEE Quartiles CAIDI | | | IEEE Quartiles SAIFI | | | IEEE Quartiles MBI | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | # Parent Events | CI | CMI | Cust Served | SAIDI | CAIDI | SAIFI | CIII | Q1 | Q2 | Q3 | Q1 | Q2 | Q3 | Q1 | Q2 | Q3 | Q1 | Q2 | Q3 |
| 2017 | 11,735 | 581,568 | 62,285,406 | 525,227 | 119 | 107 | 1.11 | 50 | 108.1 | 138.1 | 160.2 | 98.4 | 109.5 | 139.2 | 1.03 | 1.13 | 1.34 | 11.6 | 10.6 | 8.9 |
| 2018 | 10,303 | 565,301 | 63,373,060 | 528,668 | 120 | 112 | 1.07 | 55 | 97.1 | 120.3 | 148.2 | 94.8 | 105.3 | 125.8 | 1.01 | 1.12 | 1.25 | 11.9 | 10.7 | 9.6 |
| 2019 | 8,821 | 393,556 | 43,913,997 | 531,399 | 83 | 112 | 0.74 | 45 | 96.8 | 116.9 | 139.0 | 94.9 | 103.8 | 122.5 | 0.98 | 1.10 | 1.21 | 12.2 | 10.9 | 9.9 |
| 2020 | 8,830 | 431,124 | 51,247,908 | 535,095 | 96 | 119 | 0.81 | 49 | 81.3 | 118.5 | 139.6 | 94.7 | 108.2 | 124.6 | 0.93 | 1.06 | 1.20 | 12.9 | 11.3 | 10.0 |
| 2021 | 9,370 | 448,477 | 52,107,413 | 531,916 | 98 | 116 | 0.84 | 48 | 84.8 | 121.4 | 149.7 | 95.3 | 109.7 | 129.6 | 0.92 | 1.06 | 1.26 | 13.0 | 11.3 | 9.5 |

CAIDI (customer outage minutes) performance was not as strong as SAIDI and SAIFI, mainly in the 2nd quartile. When both SAIDI and SAIFI are decreasing (which they are), both the average frequency and the average duration of outages are reduced. However, CAIDI, as the ratio of SAIDI to SAIFI can increase while SAIDI and SAIFI both decrease, if the rate of decrease of SAIDI is lower than the rate of decrease of SAIFI. If reducing CAIDI is an important objective, System Planning can suggest solution alternatives to minimize the occurrence/lengths of these outages.

MBI (months between interruptions) (MBI = months ÷ SAIFI) performance is shown in the Exhibit below.[215] The MBI results for all years place the PSNH in the 1st quartile, which is excellent. For MBI, higher numbers indicate more months between major interruptions, which is consistent with the above CAIDI discussion, i.e., having fewer outages but longer duration.

**Exhibit 29 - PSNH Quartile Performance – MBI**

NH - ES Reportable Criteria - (IEEE Excl PI) - With Targets

| | | | | | ES Reportable Actuals/Targets | | | | | | | | MBI | Over 12 Months | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | SAIDI | | CAIDI | | SAIFI | MBI* | | CIII | NH - ES Quartiles MBI | | |
| Year | # Parent Events | CI | CMI | Cust Served | Actual | Target | Actual | Target | SAIFI | Actual | Target | CIII | Q1 | Q2 | Q3 |
| 2017 | 8,949 | 502,996 | 56,981,288 | 525,227 | 108 | 104 | 113 | 99 | 0.96 | 13 | 11 | 56 | 12.0 | 11.0 | 9.4 |
| 2018 | 8,164 | 475,763 | 56,822,365 | 528,668 | 107 | 107 | 119 | 107 | 0.90 | 13 | 12 | 58 | 12.5 | 11.1 | 9.9 |
| 2019 | 6,033 | 296,872 | 36,594,457 | 531,399 | 69 | 102 | 123 | 115 | 0.56 | 21 | 14 | 49 | 13.2 | 11.2 | 10.0 |
| 2020 | 7,455 | 367,108 | 45,916,873 | 535,095 | 86 | 95 | 125 | 117 | 0.69 | 17 | 15 | 49 | 13.9 | 11.6 | 10.3 |
| 2021 | 7,615 | 361,472 | 45,162,030 | 539,189 | 84 | 93 | 125 | 122 | 0.67 | 18 | 16 | 47 | 13.8 | 11.9 | 9.8 |

214 DR BPA 14-005, page 2; DR BPA 12-013, Attachment to BPA 12-013
215 Id.

When all events (PI[216] & MED) are included (exhibit below), the PSNH ranks in the lower portion of the 3rd quartile for SAIDI, CAIDI, and SAIFI (highlighted in green), i.e., doing worse than many of its peers. However, in 2021, all three indices moved from the 3rd to the 1st quartile. Even though all PSNH indices (SAIDI, CAIDI, and SAIFI) increased over previous years, this shift indicates there were more events and longer-duration events that caused the numbers to increase and that this occurred for all respondents. PSNH's numbers increased less than its peers, causing a quartile shift. Specific details on how this happened require additional investigation.

**Exhibit 30 - NH – ES Reportable Criteria – Quartile Performance with PI & MED[217]**

| NH - With Storms - All-In | | | | | | | | | All-In Quartiles SAIDI | | | All-In Quartiles CAIDI | | | All-In Quartiles SAIFI | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | # Parent Events | CI | CMI | Cust Served | SAIDI | CAIDI | SAIFI | CIII | Q1 | Q2 | Q3 | Q1 | Q2 | Q3 | Q1 | Q2 | Q3 |
| 2017 | 16,436 | 991,058 | 488,857,780 | 525,227 | 931 | 493 | 1.89 | 60 | 158.2 | 238.0 | 732.0 | 122.6 | 199.1 | 446.2 | 1.19 | 1.50 | 1.85 |
| 2018 | 14,903 | 990,643 | 200,596,779 | 528,668 | 379 | 202 | 1.87 | 66 | 123.5 | 166.8 | 256.0 | 109.9 | 137.5 | 192.4 | 1.12 | 1.25 | 1.54 |
| 2019 | 11,785 | 623,614 | 118,360,911 | 531,399 | 223 | 190 | 1.17 | 53 | 119.8 | 155.0 | 217.7 | 110.5 | 125.4 | 157.9 | 1.08 | 1.22 | 1.48 |
| 2020 | 13,485 | 785,235 | 240,072,600 | 535,095 | 449 | 306 | 1.47 | 58 | 118.4 | 149.7 | 217.9 | 110.9 | 132.4 | 161.7 | 1.00 | 1.18 | 1.46 |
| 2021 | 11,217 | 562,999 | 94,270,738 | 539,189 | 175 | 167 | 1.04 | 50 | 143.5 | 199.7 | 388.2 | 120.5 | 156.8 | 235.8 | 1.10 | 1.31 | 1.56 |

Since Eversource sets reliability goals for three states (NH, CT, and MA) (considered peer utilities), it may be appropriate to compare NH targets (performance *expectations*) against CT and MA targets. This exercise can be done by comparing SAIDI, CAIDI, and MBI targets in the exhibit below based on 2017-2021 ES reportable criteria (IEEE excluding Planned Interruptions [Pi's]). (Note: MBI is a key metric used by Eversource.)

Reliability targets are set by Eversource in January for all three states[218] based on the following considerations: historical reliability performance; technology investments, system hardening initiatives; improvements in customer service feeds (i.e., alternate feeds); and improvements in restoration procedures.[219] As seen in the exhibit below, CT and MA targets stayed essentially the same (only minimal change) for 2017 through 2021, suggesting performance expectations were met with existing performance goals; i.e., reliability indices were acceptable as-is.

[216] PI is an abbreviation for Planned Interruptions.
[217] DR BPA 14-005, page 3; DR BPA 12-013, Attachment to BPA 12-013
[218] DR BPA 8-021
[219] DR BPA 12-010

For PSNH, the targets are set to be more challenging each year, i.e., reduced SAIDI (outage duration) and MBI (months between interruptions) increased. Since MBI is inversely proportional to SAIFI (months ÷ SAIFI), an increasing MBI means SAIFI (frequency of interruptions) decreases. If this trend in setting NH reliability targets continues, NH's targets will eventually meet or surpass CT and MA's.

**Exhibit 31 - Reliability Targets for NH, CT, and MA**[220]

| Year | Location | Measure | Target | Measure | Target | Measure | Target |
|---|---|---|---|---|---|---|---|
| 2017 | Electric Field Ops **CT** | SAIDI (ES) | 76.45 | CAIDI (ES) | 105.05 | MBI (ES) | 16.45 |
| 2018 | Electric Field Ops **CT** | SAIDI (ES) | 77.75 | CAIDI (ES) | 107.55 | MBI (ES) | 16.55 |
| 2019 | Electric Field Ops **CT** | SAIDI (ES) | 75.05 | CAIDI (ES) | 110.05 | MBI (ES) | 17.55 |
| 2020 | Electric Field Ops **CT** | SAIDI (ES) | 74.75 | CAIDI (ES) | 112.05 | MBI (ES) | 17.95 |
| 2021 | Electric Field Ops **CT** | SAIDI (ES) | 73.45 | CAIDI (ES) | 115.05 | MBI (ES) | 18.75 |

| Year | Location | Measure | Target | Measure | Target | Measure | Target |
|---|---|---|---|---|---|---|---|
| 2017 | Electric Field Ops **MA** | SAIDI (ES) | 65.55 | CAIDI (ES) | 90.05 | MBI (ES) | 16.45 |
| 2018 | Electric Field Ops **MA** | SAIDI (ES) | 72.05 | CAIDI (ES) | 99.65 | MBI (ES) | 16.55 |
| 2019 | Electric Field Ops **MA** | SAIDI (ES) | 68.25 | CAIDI (ES) | 100.05 | MBI (ES) | 17.55 |
| 2020 | Electric Field Ops **MA** | SAIDI (ES) | 68.05 | CAIDI (ES) | 102.05 | MBI (ES) | 17.95 |
| 2021 | Electric Field Ops **MA** | SAIDI (ES) | 66.45 | CAIDI (ES) | 104.05 | MBI (ES) | 18.75 |

| Year | Location | Measure | Target | Measure | Target | Measure | Target |
|---|---|---|---|---|---|---|---|
| 2017 | Eversource Electric **NH** | SAIDI (ES) | 104.25 | CAIDI (ES) | 99.05 | MBI (ES) | 11.35 |
| 2018 | Eversource Electric **NH** | SAIDI (ES) | 107.05 | CAIDI (ES) | 107.05 | MBI (ES) | 11.95 |
| 2019 | Eversource Electric **NH** | SAIDI (ES) | 102.25 | CAIDI (ES) | 115.05 | MBI (ES) | 13.45 |
| 2020 | Eversource Electric **NH** | SAIDI (ES) | 94.95 | CAIDI (ES) | 117.05 | MBI (ES) | 14.75 |
| 2021 | Eversource Electric **NH** | SAIDI (ES) | 92.75 | CAIDI (ES) | 122.05 | MBI (ES) | 15.75 |

Eversource uses monthly scorecards to track performance against targets. Results are distributed to the PSNH Electric Operations management team and included in the monthly Executive Performance Review Package. It is reviewed in the PSNH President's biweekly staff meeting and monthly work plan meetings attended by all PSNH officers, directors, and managers. All reported metrics use the following color codes: Blue (means 10% or more *above* target); Green (means *on* target); Yellow (means *below* target); and Red (means 10% or more *below* target). The portion of the operations scorecard dealing with reliability performance for Jan-Nov 2021 is shown in the exhibit below.[221]

[220] DR BPA 12-010, Attachment to BPA 12-010
[221] DR BPA 8-021

**Exhibit 32 - New Hampshire Ops Performance Scorecard Jan-Nov 2021**[222]

| | Actual | Target | | |
|---|---|---|---|---|
| MBI | 19.2 | 15.5 | B | MBI is the 2nd highest in 8 years. Compared to 2020 YTD, minor storms have impacted ~32k fewer customers YTD. |
| CAIDI | 121.1 | 121.9 | G | CAIDI continues to recover following the March storms, in part due to less minor storm activity and non-storm CAIDI being lower. |
| SAIDI | 69.5 | 86.5 | B | SAIDI came in at its second lowest level since 2013. SAIDI YTD is 10.7 minutes lower than 2020 YTD. |

SAIDI and MBI are both Blue (10% or more above target), while CAIDI is Green (on target), suggesting that as of November 2021, PSNH was exceeding reliability performance expectations. In 2011 (per an earlier exhibit), SAIDI exceeded 150 min; in November 2021, SAIDI was only 70 min, a significant improvement. CAIDI remains a challenge even though performance against the target is considered good. [The CI metric (customers impacted per event) was shown in an earlier exhibit and has also been downward (i.e. improving) for ten years.[223]]

PSNH understands spending capital dollars on reliability when targets are being met or exceeded is a hard sell. However, reliability is a historical performance metric. PSNH's concern is with issues that could result in significant customer outage minutes. The main issues may be restoration speed and criticality of load, which are most often dealt with at the circuit or substation level. (A standard reliability measure is *worst performing feeders* which will be addressed later in this report.) Resiliency and reliability improvement initiatives are interconnected, i.e., resiliency needs cannot be evaluated or met without first assessing and meeting reliability needs.[224] (Resiliency is mentioned below and will be addressed in a later section of this report.)

**6.4. With this level of reliability performance, it is difficult to justify additional capital spending to "improve" reliability. However, when resiliency is considered, future/continued reliability becomes a focus for proposed capital projects.**

To understand PSNH's reliability improvement investments, one must understand the Reliability Enhancement Program (REP) initiated as part of the 2006 rate case (Docket No. DE 06-028). REP provided PSNH with additional capital to improve reliability through enhanced capital system programs and equipment upgrades.

[222] DR BPA 8-021
[223] Interview #16
[224] Interview #62

The REP transitioned to REP II in 2010 following PSNH's 2009 rate case completion. While the original program focused on vegetation management, REP II included additional system improvement projects.[225] REP transitioned again in 2015, creating REP3, including everything in REP plus REP II, and adding projects like distribution automation and circuit ties. The REP program was scaled back in 2018 and ended in 2019.[226]

While not identified as REP, REP reliability/resiliency programs are embedded in today's capital budget program. Example projects/programs include the following:[227]

- Distribution Automation Program,
- TripSaver Program,
- Line Sensor Program,
- Circuit Ties Program,
- Direct Buried Cable Replacement Program,
- Pole Inspection Program,
- Oil Circuit Breaker (OCB) Replacement Program,
- Capacitor Switch Replacement Program,
- PLC Automation Scheme Replacement Program,
- Electromechanical Relay Replacement Program,
- Substation Animal Protection Equipment Program, and
- RoWs Hardening/Reconductoring Program.

Each program is considered a project requiring a PAF and associated justification. Each project is evaluated and authorized annually before being included in the approved capital budget. A core tenet of Eversource is to adhere to the approved yearly capital spend limit, which forces management to prioritize capital projects for any given year.

**6.5. PSNH's most significant asset-related condition assessment issues involve power transformers, PCB-containing equipment (transformers, circuit breakers, bushings), and animal protection. In each case, systematic replacement plans are implemented consistent with capital budget constraints. RCG agrees with this approach.**

Asset management deals with two types of aging: First, due to years in service; and second, due to loading. For transformers, the EPRI-based PTX tool addresses both

[225] DR BPA 3-3, Table on page 2
[226] DR BPA 3-3
[227] DR BPA 4-15

types of aging along with other factors to determine the optimal replacement schedule. (See this report's System Planning Criteria-Technical Standards/Guidelines section for more on the PTX tool.) Storm conditions can ultimately be the last straw to failure.

The goal is to extend transformer life as much as reasonably practical through regular maintenance programs and major overhauls while anticipating the conditions for potential transformer failure before a storm hits. Maintenance could involve rebuilding a transformer as a cost-saving measure over buying new ones. However, rebuilds are often not viable solutions due to conditions or cost constraints.

PSNH has more than 80 power (bulk) transformers that are 50+ years old. They believe these older transformers cannot be replaced fast enough to stay out of the high-risk category. So, as a precautionary measure, spare transformers are maintained in the" warm" state for the different voltage classes and strategically located by region in each state.[228] Concurrently, PSNH management recently decided to standardize on four power transformers (62.5MVA, 30MVA, 12.5MVA, and 140MVA) to meet system requirements while reducing the number of spares. RCG believes this to be a sound approach.

Environmental concerns must also be addressed. One of the more significant environmental issues involves replacing PCB equipment with non-PCB equipment. Regulatory requirements for PCB use and disposal must be considered, as well as the financial risks if PCBs are released into the environment. Timely replacement/disposal of PCB-containing dielectrics is key to preventing future expensive liabilities.[229] The most significant source of PCBs is U-type bushings used to connect power transformers. Another source is oil circuit breakers used to connect the transformers to lines and buses. These components are usually replaced as part of a substation rebuild project.[230] For Eversource, PCB replacement program strategies are developed by the Director of Quality Assurance T&D.[231]

Another potential risk is aggressive animal behavior, requiring more sophisticated animal protection. Ravens have been an "unbelievable problem in vandalizing substations," according to one of the interviewees.[232] Even though animal protection had been installed per industry standards, the ravens found a way to bypass the protection. After meeting with utilities dealing with similar animal issues, Eversource decided to install lasers as the most promising way to alleviate the problem. Time will tell if more

[228] Interview #21 and Interview #16
[229] Bench, Dan. "Identification, Management, and Proper Disposal of PCB-Containing Electrical Equipment used in Mines." Page 10 of 11, date unknown but estimated to be early 2000's.
[230] Interview #61
[231] Interview #61
[232] Interview #61

actions are needed. RCG believes this approach to problem-solving is consistent with industry best practices.

**6.6. PSNH appears to be following current standard industry practices when identifying and resolving power quality issues (primarily voltage related).**

Customer power quality (PQ) expectations are high, driven by more home offices and sophisticated and temperamental electronics. Industrial and commercial customers demand the same and, in some cases, higher levels of power quality. Voltage complaints are monitored, and not many are received in NH.[233] Some customers classify momentary interruptions (<5 min) as PQ problems even though PQ refers to perceptible voltage and current fluctuations, which can adversely impact electronic equipment.

Per DSPG 2020, System Planning is addressing the following power quality issues:[234]

- Steady-state thermal and voltage criteria guidelines,
- DER impact on voltages,
- Voltage flicker issues,
- Transformer reverse power capabilities, and
- Unbalanced voltage (3V0) for high impedance ground fault issues.

**6.7. Worst performing feeders are monitored and ranked on an annual basis. Some feeders are classified as the worst performers year after year due partly to two major North-South 34.5 kV lines not being looped (creating alternate feeds). When faults occur on these circuits, all customers downstream of the faults will experience an outage.**

Utilities continually develop and maintain a list of worst-performing feeders annually based on a consistent reliability performance metric. Eversource uses COSAIDI [Contribution to PSNH (system wide) SAIDI], which weights radial circuits with large customer counts more heavily than other circuits. As a result, the same circuits can appear on the worst-performing circuits list year after year.[235] For example, a 150-mile circuit

[233] Interview #11
[234] LCIRP, October 1, 2020, Appendix D, page 9
[235] DR BPA 1-36, Attachment to BPA 1-36

with 8000 customers will have more exposure than a 75-mile circuit. Some circuits have been in the top 10 for a decade.[236]

Efforts are underway to apply SCADA-controlled pole-top devices (e.g., reclosers) to break distribution lines into customer blocks of 500 customers or less (discussed earlier in this report). This cost-effective program can improve a worst-performing circuit and prevent a circuit from making the list.[237] However, the best solution is to find locations where alternate feeds can be feasibly constructed for long radial circuits, i.e., create circuit loops with alternate feeds, not just segment lines into customer groups. Looping is often not feasible due to cost or physical constraints. In these cases, localized NWA solution options should be considered.

PSNH is willing to accept higher costs-per-saved-customer-minutes for projects that benefit large numbers of customers.[238] Unfortunately, this runs counter to the goal of "treating all customers equally" since customers at the end of radial circuits will always be impacted by upstream faults, i.e., these customers will be continually disadvantaged because of where they live. Recognizing radial circuits can be challenging to manage, RCG believes every reasonable attempt should be made to minimize the disparity. As PSNH continues to loop more of the remaining radial circuits, this problem will continue to dissipate.

PSNH evaluates each circuit, determines where reasonable, cost-effective solutions can be applied and includes them in the capital plan. However, the ten worst-performing feeders do not automatically appear on the plan but must be evaluated and prioritized along with all other proposed projects. As a result, PSNH does not proactively develop a worst-performing-feeder-improvements project schedule since it must compete with all other system needs during each budget cycle. In addition, the list of worst-performing circuits is based on a single year's performance, meaning new circuits and potentially more cost-effective projects will be proposed and reviewed each year.[239]

[236] Interview #16
[237] DR BPA 1-36
[238] DR BPA 1-36
[239] Id.

**6.8. Resiliency is another cornerstone to building a reliable distribution system. Given PSNH's heavily treed/ice environment, RCG believes PSNH is pursuing a reasonable course of action by looking for systematic opportunities to improve at-risk circuits and substations incrementally. Investing in resiliency programs to preserve reliable performance and meet customer expectations is consistent with industry-standard practices.**

Reliability and resiliency are often mistakenly used interchangeably. However, they are different. *Reliability* is most simply defined as the power is either ON or OFF. IEEE summarizes the more commonly applied industry definitions (from NERC, US DOE, IEEE, and NATF) in Technical Report PES-TR83.[240] In this report, US DOE defines reliability as "the ability of the system to deliver expected service through both planned and unplanned events."

For *Resiliency*, there is no universally acceptable industry definition despite attempts by organizations worldwide to do so. PJM (Pennsylvania-New-Jersey-Maryland) Interconnection came up with the following simplistic definition for resiliency: "It is about the power system's ability to withstand extreme or prolonged events."[241] The author goes on to say, "You cannot be resilient if you are not first reliable." Reliability is the historical performance of a system or circuit, while resiliency is the future performance of a system or circuit under potentially extreme conditions. The industry currently categorizes resiliency projects into (a) mitigation, (b) preparedness, (c) response, and (d) recovery.[242]

Eversource defines *Reliability* as the ability of the electric power system to deliver electricity to the end-user.[243] When evaluating reliability performance, Eversource applies standard industry-accepted reliability metrics (SAIDI, SAIFI, CAIDI) discussed elsewhere in this report.

Eversource defines *Resiliency* as "the ability (of) the electric power system to withstand and recover from low probability, high impact, extreme and damaging conditions, including weather and other natural causes."[244] Or, put another way, the ability

[240] IEEE Power & Energy Society Industry Technical Support Leadership Committee Task Force. "Resilience Framework, Methods, and Metrics for the Electricity Sector," Technical Report PES-TR83, October 2020.
[241] Ott, Andy (President and CEO). "Reliability and Resilience: Different Concepts, Common Goals," PJM Inside Lines, December 17, 2018.
[242] IEEE Power & Energy Society Industry Technical Support Leadership Committee Task Force. "Resilience Framework, Methods, and Metrics for the Electricity Sector," Technical Report PES-TR83, October 2020.
[243] DR BPA 14-006
[244] *Id.*

to withstand a storm and other significant events, and recover from them in a reasonable amount of time.[245]

While Eversource does not have a formal documented process for triggering resiliency projects,[246] resiliency initiatives have been set as follows:[247]

- Tree Trimming
- Electrical Hardening
- Structural Hardening
- Equipment Automation

When the industry evaluates reliability performance and calculates metrics, it is usually done with and without major events. Major events are excluded to focus on the day-to-day performance of the system. Major events, typically weather-related, have a low probability of occurring, but they can have significant ramifications. Electric utilities must prepare the system for such events and have active plans to respond. Although PSNH ranks in the 1st and 2nd reliability quartiles excluding major events (see Reliability section), that PSNH only ranks in the lower portion of the 3rd reliability quartile when major events are included[248] suggests there are potential opportunities for improving resiliency to reduce the impact of storms and improve restoration capabilities post-storm, especially when considering the observable increase in frequency/intensity of storms in New England.[249] (While not part of this business process review, RCG believes it would be advantageous for PSNH to review/update its emergency response plans.)

Examples of resiliency-based capital projects initiated by PSNH include the following:

- Upgrading distribution poles, shown to have ground line rot issues, to stronger class 2 wood poles or more resilient steel poles in areas of difficult access;
- Replacing cross arms with composite ones;
- Reconductoring to more resilient conductors such as covered wire and spacer cable in areas where tree damage is more prone; and
- Installing distribution automation (automated switching) to reduce the impact of customer outages by isolating faulted feeder sections.

[245] Interview #16
[246] DR BPA 9-019
[247] Eversource. "Improving Electric Reliability: Eversource's System Resiliency Program," www.eversource.com
[248] DR BPA 7-007, Attachment pages 10-12
[249] DR BPA 14-006

The question always is, "When is reliability/resiliency good enough?" Or, put another way, how can capital funds be best allocated to meet reliability targets and satisfy resiliency goals? Some in PSNH contend resiliency has not been a problem;[250] others say improvements are needed.[251] The ultimate answer lies in which projects get approved. Today's submittals must follow the latest Eversource capital-approval process, including technical and cost justification components. The more compelling the case, the more likely the approval. Distribution Engineering collaborates with System Resiliency & Reliability group to identify potential resiliency projects.[252]

PSNH's core capital distribution investments are primarily in overhead equipment and facility upgrades to make the system more resilient to major events while preparing a platform for integrating advanced technologies (e.g., DER) at virtually any point on the system, including the ability to accommodate two-way power flows on distribution lines.[253]

Since conditions change yearly, the assumption that "reliability is good enough" is not acceptable. There will always be risks and corresponding needs for corrective actions. Investments in resiliency measures are needed to prevent/minimize catastrophic events. PSNH looks to the industry for guidance on how far to go and when to stop.[254] Two important PSNH system characteristics are the significant number of trees present and the system's high probability of ice buildup on the lines, which places PSNH in a high risk position.

PSNH believes investments in reliability and resiliency are necessary to remain in the 1st quartile (preferably) or 2nd quartile (at worst) peer reliability performance categories.[255] The nightmare scenario is an ice storm with the wind causing tremendous damage from falling trees and bringing down power lines and poles. When protective devices (switches) try to operate to clear faults, the devices cannot because contacts are frozen shut. Worse yet, feeds from either end may be cut off by system faults. There is a need to protect against 60-70 mile/hour winds which seem to be occurring more frequently.[256] Ice, ice loading, and wind are ongoing concerns, even for well-trimmed RoWs.[257] For these reasons, PSNH has placed a high priority on reliability- and resiliency-related investments.

[250] Interview #61
[251] Interview #16 and DR BPA 7-007
[252] DR BPA 9-019
[253] DR BPA 1-005
[254] Interview #11
[255] Interview #16
[256] Interview #16
[257] Interview #11

PSNH believes operations does a very good job of maintaining substation equipment. However, there is a concern (this has not happened yet) that failure events will start to increase due to aging infrastructure. For example, several 62.5MVA and 44.5 MVA transformers are 50+ years old.[258] The oldest 140MVA transformer is 36+ years old. In response to these concerns, PSNH is taking measures to quantify and prioritize actions using the EPRI-based PTX transformer assessment tool (discussed in earlier sections of this report).

A substation reliability program in process for several years is the oil circuit breaker (OCB) replacement program, which focuses on replacing aging and PCB-containing equipment. If a substation OCB fails, many customers can be affected. If the OCB contains PCBs, potentially significant environmental cleanup will be required.[259]

PSNH believes the biggest obstacle for reliability-based projects is getting them scoped, engineered, approved, and included in the capital plan. Three active distribution substation projects (White Lake, Dover, and Monadnock); and seventeen (17) additional distribution substation projects were identified in the *2020-2029 Load Flow Study* as having (N-1) contingency violations (based on the DSPG revised planning criteria).[260] 14 of the 17 projects were due to STE (Short Term Emergency) rating violations, bus faults, bus-tie breaker issues, and single-contingency transmission issues (causing a double-contingency condition on the distribution system). (Refer to Appendix A for a complete list of projects and respective violation summaries.)

These 20 substation projects total $225 M based on conceptual engineering estimates. PSNH believes all 20 are needed. However, that would exceed the annual capital budget. According to PSNH, "The challenge (then) becomes prioritizing and spreading them over a reasonable period of budget cycles to get them all done prudently."[261] The updated capital approval process is expected to facilitate this process.

PSNH determined NH's pole inspection program meets today's needs but is concerned about future resiliency needs. 35% of the pole population is 40+ years old. The concern centers around what the former inspection program did not do, proactively replacing the oldest poles. The inspection program looks for imminent replacement needs (<10 years). PSNH believes better pole integrity/replacement metrics are needed from an asset management perspective, which is the position taken in recent rate cases.[262]

[258] Interview #61
[259] Interview #61
[260] Interview #62
[261] Interview #62
[262] Interview #11

Customer expectations are changing, and according to one interviewee, "We don't want to fail 400-4,000 poles in the same storm." Add to that the changing nature of weather and the concern is magnified. Customers could be out for eight or more days in worst-case scenarios. PSNH believes the pole replacement target should be closer to 1,000 poles/year rather than the relatively small number done today. PSNH believes replacing poles in clusters rather than one at a time is the most cost-effective approach from a resiliency point of view.[263]

PSNH does not believe a resiliency program can be based on the following position: "In the last five years, we have not had a storm that resulted in more than a two-day outage for customers." Customers, regulators, and politicians are not going to accept two-day outages. So, resiliency is essential in meeting and maintaining reliability expectations.[264]

## Recommendations

**R.16 Conduct a protection and coordination study in conjunction with System Planning at the distribution circuit level to better understand and anticipate how 2-way power flows can be safely accommodated.**

**R.17 Take more aggressive actions to correct chronic problem feeders by implementing one or more of the following:**

- **Reduce COSAIDI or other reliability targets to encourage more aggressive distribution automation and sectionalizing schemes; and**
- **Find locations where alternate feeds can be feasibly constructed for long radial circuits, i.e., create circuit loops, not just segmented customer groups; and**
- **Apply localized NWA solution options, where suitable, when looping feeders is not a feasible alternative and the solution exceeds NWA thresholds. Subsequent revisions to the NWA Framework may be required.**

[263] Interview #11
[264] Interview #62

# Third-Party Claims

| | |
|---|---|
| **7.1.** | **Within the external constraints of third-party damage recovery, PSNH has a reasonable process to track and recover the costs associated with third-party damages to the distribution system and transfer the net costs into ratebase. However, the process is not fully documented in writing which could create opportunities for varying interpretations of how to execute the process and any decisions required.** |

In RCG's experience, when a third-party entity damages a typical utility's property (generally already included in ratebase) the utility must repair or replace the damaged equipment to ensure reliable and safe service. As the damage is unpredictable, the financial impact can vary from period to period. All or a portion of the capital expenditure (and maintenance expenses) may be offset by recoveries from the responsible party causing the damage or the responsible party's insurance coverage.

A typical utility estimates an annual amount for capital expenditures within its capital budgeting process. That amount is reconciled to the actual cost of repairing the damage less the recovery of those costs from the responsible party causing the damage. The costs of repairs would typically enter ratebase (less the recovered costs) during a rate case or tracker mechanism as authorized by the regulatory scheme.

During PSNH's request for its first step adjustment pursuant to the settlement reached in Docket DE 19-057, treatment of its post-rate decision capital costs prompted questions from the Division over how PSNH accounted for the capital costs and the associated recovered costs. At that time, PUC Staff (now the Division) conducted an audit of the initial 2019 Step adjustment, and the audit report was submitted at the time of the second step adjustment (2020) filing and third-party claims became an issue in that proceeding. Cross-examination covering the issue took place, and the Commission decided to include the issue within the Business CapEx Process Audit.

> *"Eversource discussed its treatment of costs related to replacing plant in service when a third-party damages utility property. Eversource explained that once the Company knows that the damage was caused by a third party, and the third party is identified as responsible for payment, the Company will bill the individual or insurance company for the damages. Once Eversource generates the bill for damages, Eversource credits the work order within the annual project in the calendar year that the Company actually bills the third party. Eversource argued that it would be inappropriate to assume recovery of damaged plant is a given and stated*

*that this topic should be addressed during its upcoming business process audit."*[265]

The Division audit (February 1, 2021) states, "To date, PSNH has not responded sufficiently. Audit Issue #1"" PSNH included $1,789,400 in the current 2019 Step adjustment. This figure does not account for the anticipated contributions of $(1,189,200)." [266]

The Division audit process includes two opportunities to potentially resolve differences through the discovery process and the comment period provided to the utilities. As a result, drafts and input were exchanged between the Division auditors and PSNH. The audit was issued, and PSNH provided comments.[267] According to PSNH, there was limited discussion. The Division audit group concluded that it could not confirm or trace the expected reimbursement offset based on its review of PSNH's filings.[268] The Division's audit report was entered into the case as an exhibit in the 2020 Step adjustment hearings by the Division with the subsequent cross-examination of PSNH on the issue.[269]

**7.2. Third-party damage presents PSNH with some unique challenges as the incidence and timing of damage are beyond the PSNH's control.**

While third-party damages are a small part of PSNH's annual capital expenditures, all, or some portion of those expenditures (the amount not reimbursed by the responsible party or its insurance coverage) will eventually enter ratebase and become a cost of doing business and thus increase rates paid by customers.

Unlike standard PSNH-initiated capital projects, third-party damage is not initiated by PSNH, and the work scope and timing are only under PSNH's limited control. While the total capital amounts are accumulated into a budgetary line item, they consist of many independent incidents. The exhibit below indicates the number of incidents.

[265] Order No. 26,504 Page 3
[266] DR BPA 5-004, Attachment Page 3
[267] Claims Panel #1
[268] DR BPA 5-004, Attachment Page 5
[269] Claims Panel #1

**Exhibit 33 - Annual Number of Events and the Number of Identified Offenders**

| Year[270] | Number of Incidents[271] | Total Costs Before Recovery[272] | Responsible Party Identified[273] |
|---|---|---|---|
| **2017** | 1,197 | $ 2,172,199 | 515 |
| **2018** | 1,421 | $ 2,560,753 | 594 |
| **2019** | 1,584 | $ 2,467,492 | 640 |
| **2020** | 1,231 | $ 2,929,850 | 448 |
| **2021** | 1,308 | $ 3,106,301 | 478 |

Typically, PSNH is notified of damage to its facilities by the police as they respond to and investigate an accident. In other incidents, third-party damage may be caused by a contractor damaging PSNH's facilities that require a response by PSNH. During routine inspections of PSNH's facilities, third-party damage may be detected.

**7.3. PSNH's responders immediately document the site in written form, photographs of the site and identification of the responsible party (if available); together create a formal record of the event.**

Depending on how the incident is reported and the severity of the damage, the initial work and investigation are performed by a Response Specialist[274] or a line crew.[275] PSNH on-site responders may take a photo of the responsible party's license plate at the scene.[276] That information is embedded within the electronic record of the work order.[277]

Reimbursement for third-party damages can take a substantial effort and take significant time to resolve. PSNH's collection for third-party damages is hampered by the state of New Hampshire's not requiring mandatory auto liability insurance, the responsible party's ability to pay compared to the cost to collect, the availability of police reports, and unreported (hit and run) incidents. However, the collection is aided by the NH DMV license suspension process.

[270] Incidents and amounts may be out of synch due to date of recording the various aspects of the incident.
[271] DR BPA 8-013
[272] DR BPA 5-003
[273] DR BPA 8-013
[274] Interview #71 and Claims Panel #1
[275] Interview #72
[276] Claims Panel #1
[277] Claims Panel #1

### 7.4. While PSNH has a process for discovering, tracking claims,[278] and accounting for the costs of third-party damages, that process is not formally memorialized in a written policy that spans the entire process.

PSNH does not have a detailed flowchart or process document for the entire third-party claims process[279]. Although PSNH provided a narrative in response to a data request[280] the third-party process is not recognized in a distinct Sarbanes Oxley (SOX) accounting process, rather controls fall within separate functional areas.[281]

Conceptually there are three types of major damage claims. (The "Type" designation has been created by RCG solely for clarity.)

- Type 1 – The responsible party cannot be identified (hit and run event).[282] *No potential offset of costs is expected.*
- Type 2 – The responsible party is identified and has liability insurance. *Reasonable expectation of payment:*
  - Payment may not be for the amount originally billed due to insurance negotiations related to the asset's depreciated cost.[283]
- Type 3 – The responsible party is identified but has no insurance. *Extended time to receive payment (if any) due to*:
  - Payment plans,
  - No assets,
  - Costs of recovery (legal fees) are expected to exceed repair costs, and
  - The final payment status (none or partial) may take years depending on the processes involved. [284]

Due to the timing of the repair compared to the eventual recovery of none, all, or a portion of the costs from the responsible party, a reconciliation process is needed to recognize and confirm accounting for the actual payment level compared to the amount billed to the entity.

[278] DR BPA 16-001
[279] Claims Panel #1
[280] DR BPA 5-005 and Claims Panel #1
[281] Claims Panel #1 1:34:09
[282] DR BPA 8-013 and Claims Panel #1
[283] Claims Panel #1
[284] Claims Panel #1

**7.5. The Administrators, who are the designated employees responsible for capturing, validating, and monitoring the costs of third-party damage, appear to be functioning well and are appropriately managed.**

RCG interviewed two Administrators (a position located at the regional operating centers) who described PSNH's process to determine if an incident has occurred and then create a claim. Daily, the Administrators monitor activity such as trouble reports from the outage-reporting system to find incidents. The priority of this monitoring is considered second only to payroll. The Administrator will create an individual work order for each incident.[285] The initial preparation of the claim is handled by an Administrator[286] at the local operating center. The work order contains backup information including incident photos.[287] The costs of the incident are retrieved from PSNH work order records and time reporting. Some inherent time delays are attributed to all until other costs are entered into the work order, such as environmental response contractor and material costs.[288]

The Administrator will search for the responsible party within the records entered by the PSNH responder. The Administrator will use the Lexis-Nexis document database and if necessary, make personal contact with local police to obtain a police report.[289] The identification of the responsible party may be difficult as not all damage is reported to the police, such as hit and run incidents[290] and damage found later during routine inspections by PSNH. Further, obtaining police reports has been complicated by COVID-19 and freedom of information issues.[291] In some cases, long delays have occurred.[292]

If an Administrator is unavailable due to absence, such as vacation or illness, there is a backup procedure in place to ensure that the monitoring for incidents continues.[293]

285 Claims Panel #1
286 Interviews #71 and Interview #72
287 Claims Panel #1
288 Interview #71
289 Interview #71 and Claims Panel #1
290 Claims Panel #1
291 Interview #71 and Interview #72
292 DR BPA 12-005(d)
293 Interview #72

**7.6. The job description for the Administrator function does not include the third-party damage function and therefore is out of date.**

As part of RCG's investigation, the Administrator's position description was requested. RCG found that the duties within the provided job description[294] did *not* include the third-party incident discovery and claim creation functions.

**7.7. The description of the initial portion of the claim process performed within the operating center was detailed in a narrative provided however, the checks and balances are unclear.[295] Combined with the lack of a detailed process flowchart or other similar definitions, RCG is concerned that the claim development process is not well defined, and therefore subject to possible misinterpretation.**

The Operations Supervisor determines when to close out a work order[296] and reviews construction work in progress to determine if incidents have not been processed.[297] During a panel interview conducted by RCG, a PSNH participant noted if a claim is not generated, it "*does not percolate in our system.*"[298]

It is unclear to RCG, who is responsible for confirming that no third party can be identified. This would be a control issue as the Operating Center management could circumvent the claims process. RCG found no evidence of this occurring.

## Recommendations

**R.18 PSNH should develop a formal method to track the status of third-party claims in process but not yet completed at the operating center level.**

**R.19 PSNH should create an accurate job description for the Administrator position that reflects the importance of the claim's preparation process.**

**R.20 PSNH should revise the third-party claims process to have the Claims group review incidents where no responsible party is identified or when the operating center management has closed an incident without generating a claim.**

[294] DR BPA 11-002
[295] Interview #72 and BPA 12-1 Attachment Page 5
[296] Claims Panel #1
[297] Claims Panel #1
[298] Claims Panel #1

**7.8. The process to administer and resolve claims with the responsible party is defined, appears to be functioning well and is appropriately managed.**

Once the incident cost is established by the Administrator and approved by Operating Center management, the information is forwarded to the Claims Department, which processes the claim. The Claims Analyst contacts the responsible party and seeks payment[299] based on information in the police report or contact with the responsible party. Supported by a tracking system to follow up on the claims billed[300], the Claims Analyst may make multiple follow-up contacts, negotiate payment arrangements, and, if necessary, request the NH DMV to suspend the responsible party's license for failure to pay for the damage.

Payments are tracked monthly as payment plans extend over time and therefore are monitored.[301] If the responsible party fails to pay after four months, a "14-day letter", which is a notice of the possibility of license suspension, is sent to the responsible party.[302] The Claims Analyst typically allows 30 days for a response and then will request the NH DMV to suspend the license of the responsible party.[303] The possibility of license suspension has proved a good tool for the claims process.[304] When suspension cannot be achieved, the claim will typically be sent to collections.

**7.9. While not specifically documented but detailed through RCG's interviews and PSNH's responses to RCG data requests, accounting for third-party damage and the offsetting reimbursement is a defined and managed process.**

Once the claims process has begun, the accounting for the claim takes place. Costs are moved from FERC Account 107 Construction Work in Progress to Account 106 Work Completed but Not Classified. Charges are classified according to FERC accounting conventions,[305] and costs are apportioned between capital and O&M accounts[306].

[299] Claims Panel #1
[300] DR BPA 12-008, 16-001 and Claims Panel #1
[301] Claims Panel #1
[302] Claims Panel #1
[303] Claims Panel #1
[304] Claims Panel #1
[305] Claims Panel #1
[306] DR BPA 12-005

**7.10. PSNH customers are protected by the PSNH's immediate recognition of potential reimbursement from responsible parties (the Sundry Bill process) while the collection process is underway. The amount recognized is reduced by the reserve analysis.**

At the same time, the potential (but not yet collected) Sundry Bill to the responsible party is recognized as an offset in Account 108 Accumulated Depreciation. PSNH provided the FERC accounting guideline that suggests the reimbursement be credited to Account 108 as a recovery from insurance.[307]

The actual level of the reimbursement for an incident is often different than the initial bill, which will decrease the amount credited to Account 108 in a later period. The difference may result from negotiations with the insurance carrier, negotiations with the responsible party, non-payment by various parties, or differences in overhead percentage charges, which may change monthly.[308]

**7.11. The accounting process for establishing reserves for non-payment of billed reimbursement is defined.**

Periodically PSNH will review the status of reimbursements (Sundry Bills as a whole) and adjust the reserve amounts to reflect the potential for non-payment of the Sundry Bills that have previously been rendered. While the analysis of uncollectible accounts[309] is considered an "art" and uses judgement factors to deal with the "pooled" uncollectible[310], the concept of the uncollectible reserve balance[311] is like the reserve established for customer receivables[312]. PSNH provided the process used to establish such reserves[313] and an analysis from January 1, 2019, as requested by RCG.[314] This process includes input from the Claims group.

Each year an annual budget for damage is established (project # INS9R).[315] A "supplemental" request will be developed if a budget overrun looks possible.[316] The

[307] DR BPA 12-006
[308] Claims Panel #1
[309] Claims Panel #1
[310] Claims Panel #1
[311] Claims Panel #1
[312] Claims Panel #1
[313] DR BPA 15-013
[314] DR BPA 15-014
[315] Claims Panel #1
[316] Claims Panel #1

overrun is not a result of PSNH actions as the damage is caused by third parties, whether identified or not.

**7.12. A programming error leading to a misclassification of credits is in the process of correction, and a temporary mechanism is being used in the interim.**

A programming error in the implementation of a new software system that interfaces into accounting system resulted in reimbursement credits assigned to FERC Account 107 Construction Work In Progress instead of FERC Account 108 Accumulated Depreciation in the mapping process. This was disclosed in a footnote to a data response rather than during an interview or the body of the response.[317] On follow-up, PSNH indicated that it is transferring the amounts quarterly to correct this misclassification[318] and that a consultant has been engaged to correct the erroneous classification process within the software[319].

## Recommendations

**R.21 PSNH should develop a flowchart and process narrative to define and illustrate the entire third-party claim process in one document.**

**R.22 PSNH should correct the software which improperly allocates reimbursements to Account 107 instead of Account 108.**

[317] DR BPA 12-005(c)
[318] DR BPA 16-002
[319] Claims Panel #2

## Communications

In any regulatory filing, including an application for rate relief, the typical utility has the burden of proof. Implicitly the utility also has a burden to reply in a timely fashion according to the norms in that regulatory jurisdiction.

To facilitate the review of the third-party claim process, PSNH suggested using a Claims interview panel. Ultimately, there were two Claims interview panels. Using interview panels permitted a wide-ranging positive discussion that explained the functions of the involved PSNH groups and their interactions, rather than piecing together details from several interviews.

**7.13. Relevant items were not disclosed clearly or in sufficient detail by PSNH in data responses, sometimes to its detriment by not highlighting positive information or actions.**

A misclassification by a new software program of reimbursements was disclosed within a footnote to a data response rather than directly disclosed in that data response.[320] Although PSNH had both a short and long-term resolution of the issue, PSNH did not highlight the ongoing, positive actions taken by PSNH.

The extended time to release a third-party claim work order due to a late police report was apparent when comparing various dates within the documents provided as a data response.[321] PSNH did not highlight information that would document a delay beyond PSNH's control due to delayed availability of police reports.

In response to a data request for the Administrator's job description, the response did not highlight that the job description provided was outdated and therefore not useful for the purposes that RCG requested.[322] Only after RCG's informal questioning of PSNH was this situation confirmed.

[320] DR BPA 12-005(c)
[321] DR BPA 12-005(d)
[322] DR BPA 11-002

**7.14. PSNH's overall communications, in the context of the review of the third-party damage process review by RCG, was not timely.**

The requests to schedule interview panels have taken well over a reasonable two weeks (ten business day) expectation, and no estimated date to schedule the interview panel was provided in the interim period.

Many data responses have taken well over a reasonable two weeks (ten business day) expectation, and no estimated date of delivery was provided in the interim period. In RCG's experience with management and process audits, we have not seen such response times (up to 45 calendar days).

## Recommendations

**R.23 If PSNH cannot complete a response to a data request and transmit the data response within ten business days, an estimated completion date should be formally transmitted by the tenth business day.**

**R.24 In its data responses, PSNH should highlight its ongoing and planned responses to issues and the impact of third parties' actions, rather than embedding the issue within the data.**

**R.25 To facilitate and clarify data requests and data responses, PSNH and the Division should consider adding technical conferences before and after data requests are requested and responded to.**

# BUSINESS PROCESS AUDIT
# OF PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE d/b/a
# EVERSOURCE ENERGY'S NEW HAMPSHIRE
# DISTRIBUTION CAPITAL PROJECTS
# JULY 2023

# APPENDICES

**REQUESTED BY**

**THE NEW HAMPSHIRE**

**DEPARTMENT OF ENERGY'S**

**DDIVISION OF REGULATORY SUPPORT**

**ELECTRIC DIVISION**

**PREPARED BY**

**RIVER CONSULTING GROUP, INC.**

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# Appendix A

## 2020 Design Violations Summary Report

## Bulk Substations

## Non-Bulk Substations

RCG RIVER CONSULTING GROUP, INC.

## Appendix A: 2020 Design Violations Summary Report - Bulk Substations

| Substation | Region | Existing | | | | | | Solution | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Voltage (kV) | MVA | Install Yr | MW Load 2020 | # Fdrs | Violation | Voltage (kV) | MVA | MW Load 2029 | # Fdrs | Other |
| Bedford | Central | 115-34.5kV | TB164 - 44.8<br>TB191 - 44.8 | 2004<br>2004 | 61.00 | 7 | N-1 STE violation; N-1 bus tie violation | 115-34.5kV | TBxx - 62.5<br>TBxx - 62.5 | 65.00 | 7 | Replace with larger transformers |
| Eddy | Central | 115-34.5kV | TB26 - 44.8<br>TB81 - 44.8 | 1978<br>1968 | 61.00 | 6 | Unhealthy transformers TB26 and TB81; N-1 STE violation; N-1 bus tie violation | 115-34.5kV | TBD | 72.00 | 6 | Solution TBD - depends on Bedford and Huse Road substations final configuration |
| Garvins | Central | 115-34.5kV | TB39 - 67.2<br>TB51 - 67.2 | 1974<br>1974 | 69.00 | 7 | Unhealthy transformer TB39; N-1 bus fault violation | 115-34.5kV | TB39 - 67.2<br>TB51 - 67.2 | 75.00 | 7 | Add series bus tie breakers |
| Huse Road | Central | 115-34.5kV | TB46 - 44.8<br>TB58 - 48.0 | 1987<br>1969 | 72.00 | 5 | Unhealthy TB58; N-1 STE violation; N-1 bus fault violation | 115-34.5kV | TBxx - 62.5<br>TBxx - 62.5 | 80.00 | 5 | Replace with larger transformers; add series tie breakers |
| Pine Hill | Central | 115-34.5kV | TB118 - 44.8<br>TB161 - 44.8 | 2003<br>1968 | 59.00 | 4 | N-1 STE violation; N-1 bus tie violation | 115-34.5kV | TBD | 60.00 | 4 | Solution TBD - depends on Bedford and Huse Road substations final configuration |
| Rimmon | Central | 115-34.5kV | TB26 - 44.8<br>TB81 - 44.8 | 2015<br>2015 | 65.00 | 7 | N-1 STE violation | 115-34.5kV | TBD | 69.00 | 7 | Solution TBD - depends on Bedford and Huse Road substations final configuration |
| Cocheco Street (Dover) | Eastern | 115-34.5kV | TB22 - 44.8<br>TB55 - 44.8 | 1972<br>2001 | 80.00 | 4 | Unhealthy transformer TB22; N-1 STE violation; N-1 bus fault violation | 115-34.5kV | TBxx - 62.5<br>TBxx - 62.5 | 82.00 | 4 | Replace with larger transformers; add series bus tie breakers |
| Great Bay | Eastern | 115-34.5kV | TB171 - 44.8 | 2002 | 45.00 | 2 | N-0 base case load violation | 115-34.5kV | TB171 - 44.8 | 45.00 | 2 | Transfer load to Timber Swamp Substation |
| Madbury | Eastern | 115-34.5kV | TB65 - 44.8<br>TB74 - 44.8 | 1971<br>1976 | 70.00 | 4 | Unhealthy transformer TB65; N-1 STE violation; N-1 bus fault violation | 115-34.5kV | TBxx - 62.5<br>TBxx - 62.5 | 80.00 | 5 | Replace with larger transformers; add series bus tie breakers; add new feeder |
| Mill Pond | Eastern | 115-12.47kV | TB171 - 44.8 | 2014 | 10.00 | 4 | N-0 base case load violation | 115-12.47kV | TB171 - 44.8 | 13.00 | 4 | Replace transformer at Cutts Street Substation; upgrade distribution lines |
| Rochester | Eastern | 115-34.5kV | TB53 - 44.8<br>TB57 - 44.8 | 1968<br>2002 | 60.00 | 4 | N-1 STE violation | 115-34.5kV | TB53 - 44.8<br>TB57 - 44.8 | 65.00 | 4 | Transfer load to Tasker Farm Substation |
| Ashland | Northern | 115-34.5kV | TB5 - 44.8 | 2005 | 36.00 | 2 | N-1 transformer violation; N-1 bus fault violation | 115-34.5kV | TB5 - 44.8<br>TBXX - TBD | 38.00 | 2 | Add second transformer; add third and fourth feeder to Meredith and Ashland Municipal to utilize increased capacity; solves violations at other substations |
| Beebe River | Northern | 115-34.5kV | TB62 - 44.8 | 1974 | 21.00 | 2 | Unhealthy transformer TB62; N-1 transformer violation; N-1 bus fault violation | 115-34.5kV | TB62 - 44.8 | 21.00 | 2 | Add second transformer at Ashland Substation |
| Berlin (Eastside) | Northern | 115-34.5kV | TB83 - 15.0<br>TB115 - 20.0 | 1954<br>1947 | 17.00 | 3 | Unhealthy transformers TB83 and TB115; N-1 bus fault violation | 115-34.5kV | TBD | 21.00 | 3 | Solution TBD - voltage support along 34.5kV line |
| Laconia | Northern | 115-34.5kV | TB24 - 44.8<br>TB125 - 44.8 | 1977<br>2002 | 61.00 | 5 | Unhealthy transformer TB24; N-1 STE violation; N-1 bus fault violation | 115-34.5kV | TB24 - 44.8<br>TB125 - 44.8 | 69.00 | 5 | Transfer load to Webster/Daniel Substation; add series bus tie breakers |
| Lost Nation | Northern | 115-34.5kV | TB033 - 28.0<br>TX129 - 44.8 | 1961<br>2017 | 10.00 | 4 | Unhealthy TB033; N-1 bus fault violation | 115-34.5kV | TB033 - 28.0<br>TX129 - 44.8 | 11.00 | 4 | Replace manual load-break switch with SCADA-controlled device to restore load on radial feeder |
| North Woodstock | Northern | 115-34.5kV | TB67 - 44.8 | 1986 | 9.00 | 2 | N-1 transformer violation; N-1 bus fault violation | 115-34.5kV | TB67 - 44.8 | 12.00 | 2 | NH Electric Coop to add D-SCADA to 34.5kV |
| Oak Hill | Northern | 115-34.5kV | TB15 - 44.8<br>TB84 - 45.0 | 2003<br>1991 | 68.00 | 4 | N-1 STE violation; N-1 bus fault violation; N-1 bus tie violation | 115-34.5kV | TB15 - 44.8<br>TB84 - 45.0 | 69.00 | 4 | Transfer load to Garvins Substation |
| Pemigewasset | Northern | 115-34.5kV | TX88 - 62.5 | 2018 | 25.00 | 3 | N-1 transformer violation; N-1 bus fault violation | 115-34.5kV | TX88 - 62.5 | 25.00 | 3 | Add second transformer at Ashland Substation. **[Note: 20 MVA TB88 was replaced with a new 62.5 MVA TX88, Q4 2020.]** |
| Saco Valley | Northern | 115-34.5kV | TB60 - 44.8 | 1976 | 20.00 | 3 | N-1 transformer violation; N-1 bus fault violation | 115-34.5kV | TB60 - 44.8 | 23.00 | 3 | Replace manual load-break switch with SCADA-controlled device to restore load on radial feeder |
| Webster and Daniel | Northern | 115-34.5kV | TB43 - 44.8<br>TB59 - 44.8 | 2016<br>2016 | 39.00 | 3 | N-1 bus fault violation; N-1 bus tie violation; N-1 transmission violation | 115-34.5kV | TB43 - 44.8<br>TB59 - 44.8 | 41.00 | 3 | Replace manual load-break switch with SCADA-controlled device to restore load on radial feeder |
| White Lake | Northern | 115-34.5kV | TB76 - 28.0<br>TB82 - 28.0 | 1964<br>1963 | 49.00 | 4 | Unhealthy transformers TB76 and TB82; base load violation; N-1 transformer violation; N-1 STE violation; N-1 bus fault violation | 115-34.5kV | TBxx - 62.5<br>TBxx - 62.5 | 50.00 | 4 | Replace both transformers; add series bus tie breakers |
| Whitefield | Northern | 115-34.5kV | TB89 - 44.8 | 1966 | 20.00 | 3 | Unhealthy TB89; N-1 bus fault violation | 115-34.5kV | TB89 - 44.8 | 25.00 | 3 | Replace manual load-break switch with SCADA-controlled device to restore load on radial feeder |
| Amherst | Southern | 345-34.5kV | TB68 - 140.0<br>TB85 - 140.0 | 1987<br>2003 | 105.00 | 5 | N-1 bus fault violation; N-1 bus tie violation | 345-34.5kV | TB68 - 140.0<br>TB85 - 140.0 | 110.00 | 5 | Replace and add a 2nd transformer at South Milford Substation; replace both transformers at Bridge Street Substation |

## Appendix A: 2020 Design Violations Summary Report - Bulk Substations

| Substation | Region | Existing | | | | | | Solution | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Voltage (kV) | MVA | Install Yr | MW Load 2020 | # Fdrs | Violation | Voltage (kV) | MVA | MW Load 2029 | # Fdrs | Other |
| Bridge Street | Southern | 115-34.5kV | TB45 - 44.8<br>TB52 - 44.8 | 1973<br>1973 | 55.00 | 5 | Unhealthy transformers TB45 and TB52; N-1 STE violation; N-1 bus fault violation; N-1 transmission violation | 115-34.5kV | TBxx - 62.5<br>TBxx - 62.5 | 59.00 | 5 | Replace both transformers; solution TBD for N-1 transmission violation |
| Bridge Street 4kV | Southern | 115-4.16kV | TB15C - 10.5 | 2007 | 7.20 | 6 | N-1 transformer violation; N-1 bus fault violation; N-1 bus tie violation | 115-4.16kV | TB15C - 10.5 | 8.00 | 6 | Deploy mobile 34.5-4.16kV substation in an emergency (typical procedure for non-bulk substations) |
| Hudson | Southern | 115-34.5kV | TB33 - 44.8<br>TB44 - 44.8 | 2005<br>1974 | 43.00 | 6 | N-1 bus fault violation | 115-34.5kV | TB33 - 44.8<br>TB44 - 44.8 | 47.00 | 6 | Transfer load or add series bus tie breakers (study needed to determine best alternative) |
| Lawrence Road | Southern | 345-34.5kV | TB48 - 140.0 | 1995 | 49.00 | 5 | N-1 transformer violation; N-1 bus fault violation | 345-34.5kV | TB48 - 140.0 | 49.00 | 5 | Add transformer breaker to Lawrence Road Substation; study needed to determine if bus tie breaker or additional capacity at neighboring substations will resolve N-1 bus fault violation |
| Long Hill | Southern | 115-34.5kV | TB10 - 44.8<br>TB20 - 44.8 | 2005<br>1969 | 65.00 | 4 | Unhealthy transformer TB20; N-1 STE violation; N-1 bus fault violation; N-1 transmission violation | 115-34.5kV | TB10 - 62.5<br>TB20 - 62.5 | 71.00 | 4 | New transmission line from South Milford Substation; replace both transformers; add series bus tie breakers |
| Scobie Pond | Southern | 115-12.47kV | TB131 - 30.0<br>TB132 - 30.0 | 2011<br>2011 | 33.00 | 6 | N-1 bus fault violation; N-1 bus tie violation; N-1 transmission violation | 115-12.47kV | TB131 - 30.0<br>TB132 - 30.0 | 32.00 | 6 | Enhance 12.47kV distribution to increase line capacity; add series bus tie breakers |
| South Milford | Southern | 115-34.5kV | TB86 - 44.8 | 2014 | 45.00 | 2 | N-0 base load violation; N-1 transformer violation; N-1 bus fault violation; N-1 bus tie violation | 115-34.5kV | TB86 - 62.5<br>TBxx - 62.5 | 50.00 | 2 | Replace transformer; add 2nd transformer; add new feeder; construct new transmission line into South Milford |
| Chestnut Hill | Western | 115-34.5kV | TB87 - 12.5<br>TB98 - 12.5 | 1947<br>1947 | 17.00 | 2 | Unhealthy transformers TB87 and TB98; N-1 transformer violation; N-1 bus fault violation | 115-34.5kV | TB87 - 44.8<br>TB98 - 44.8 | 18.00 | 2 | Replace both transformers with 44.8 MVA or 62.5 MVA; add series bus tie breakers; add 2 feeder breakers |
| Emerald Street (Keene) | Western | 115-12.47kV | TB18 - 12.5<br>TB23 - 12.5<br>TB3 - 22.4<br>TB7 - 22.4<br>TB12 - 22.4 | 1953<br>1954<br>2000<br>1964<br>1969 | 31.00 | 10 | Unhealthy: TB18, TB23, TB7, TB12; N-1 bus tie violation | 115-12.47kV | TB3 - 22.4<br>TBxx - 30.0<br>TBxx - 30.0 | 40.00 | 10 | Replace 12.47kV switchgear; replace 4 unhealthy transformers with 2-30 MVA transformers; solution TBD for N-1 bus tie violation |
| Jackman | Western | 115-34.5kV | TB61 - 28.0<br>TB33 - 44.8 | 1964<br>2008 | 36.00 | 5 | Unhealthy transformer TB61; N-1 bus fault violation | 115-34.5kV | TB61 - 28.0<br>TB33 - 44.8 | 38.00 | 5 | Add series bus tie breakers |
| Monadnock | Western | 115-34.5kV | TB80 - 28.0<br>TB40 - 20.0 | 1965<br>1951 | 35.00 | 3 | Unhealthy TB40; N-1 transformer violation; N-1 STE violation; N-1 bus fault violation; N-1 bus tie violation | 115-34.5kV | TBxx - 44.8<br>TBxx - 44.8 | 40.00 | 3 | Replace both transformers with 44.8 MVA or 62.5 MVA; add series bus-tie breakers; add cap bank to supplement existing |
| North Keene | Western | 345-34.5kV | TB145 - 140.0 | 2015 | 19.00 | 5 | N-1 bus fault violation; N-1 bus tie violation | 345-34.5kV | TB145 - 140.0 | 22.00 | 5 | Replace manual load-break switch with SCADA-controlled device to restore load on radial feeder |
| North Road | Western | 115-34.5kV | TB38 - 44.8<br>TB49 - 44.8 | 1971<br>1971 | 40.00 | 4 | Unhealthy transformers TB38 and TB49; N-1 bus fault violation | 115-34.5kV | TB38 - 44.8<br>TB49 - 44.8 | 42.00 | 4 | Add series bus tie breakers |

Source: **Attachment BPA 1-006**, October 1 2021 --> 2020 Design Violations Summary Report - New Hampshire Distribution System Planning, revised March 18 2021

| | |
|---|---|
| Central | 6 |
| Eastern | 5 |
| Northern | 12 |
| Southern | 8 |
| Western | 6 |
| | ---- |
| Substations | 37 |

**Appendix A: 2020 Design Violations Summary Report - Non-Bulk Substations**

| Substation | Location | Existing | | | | | Violation | Solution | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Voltage (kV) | MVA | Install Yr | MW Load 2020 | # Fdrs | | Voltage (kV) | MVA | MW Load 2029 | # Fdrs | Other |
| Cutts Street 15W4 | SE Corner | 34.5-12.47 | 15W4 - 4.5 | 1956 | 3.80 | 1 | Unhealthy transformer 15W4 | 34.5-12.47 | 15W4 - 12.5 | 4.20 | 1 | Replace transformer with 12.5 MVA unit (solves Mill Pond capacity problem); enhance distribution system with D-SCADA and possible reconductoring and/or reconfiguration |
| Goffstown 27W2 | SE Corner | 34.5-12.47 | 27W2 - 3.0 | 1956 | 1.80 | 1 | Unhealthy transformer 27W2; N-0 base load violation | n/a | n/a | 3.20 | 1 | Remove 27W2 and 45H1 subs (1 feeder each); upgrade distribution line to 34.5kV |
| Goffstown 45H1 | SE Corner | 34.5-4.16 | 45H1 - 1.8 | 1955 | 1.90 | 1 | Unhealthy transformer 45H1; N-0 base load violation | n/a | n/a | 3.10 | 1 | |
| Loudon 31W1 | SE Corner | 34.5-12.47 | 31W1 - 5.25 | 2006 | 4.00 | 1 | N-0 base load violation | 34.5-12.47 | 31Wx - 12.5 | 5.60 | 1 | Replace 31W1 and 31W2 with single transformer; **NWA candidate** |
| Loudon 31W2 | SE Corner | 34.5-12.47 | 31W2 - 3.36 | 1964 | 3.60 | 1 | Unhealthy transformer 31W2; N-0 base load violation | | | 3.80 | 1 | |
| Rye 48H1 | SE Corner | 34.5-4.16 | 15W4 - 3.75 | 1956 | 3.50 | 2 | Unhealthy transformer 15W4; N-0 base load violation | ??? | ??? | 4.10 | 2 | ??? (error in report) |
| Salmon Falls 51H1 | SE Corner | 13.8-4.16 | 51H1 - 1.5 | 1996 | 1.50 | 1 | N-0 base load violation | 13.8-4.16 | 51H1 - 1.5<br>51Hx - 1.5 | 1.70 | 1 | Add second 1.5 MVA transformer |
| Hanover Street 16W3 | SE Center | 34.5-12.47 | 16W3 - 3.36 | 1962 | 3.60 | 1 | Unhealthy transformer 16W3; N-0 base load violation | 34.5-12.47 | 16W3 - 3.36 | 4.00 | 1 | Transfer 12.47kV load to 34.5kV distribution system; **NWA candidate** |
| Meetinghouse Road 3W2 | SE Center | 34.5-12.47 | 3W2 - 5.04 | 1969 | 5.35 | 1 | N-0 base load violation | 34.5-12.47 | 3W2 - 5.04 | 5.85 | 1 | Transfer 12.47kV load to 34.5kV distribution system |
| Suncook 44W2 | SE Center | 34.5-12.47 | 44W2 - 5.04 | 1965 | 4.90 | 1 | Unhealthy transformer 44W2; N-0 base load violation | 34.5-12.47 | 44W2 - 5.04 | 5.10 | 1 | Transfer 12.47kV load to 34.5kV distribution system |
| Opechee Bay TB10 | Center | 34.5-12.47 | TB10 - 2.5 | 1956 | 3.00 | 1 | Unhealthy transformer TB10; N-0 base load violation | 34.5-12.47 | TB10 - 2.5 | 3.20 | 1 | Transfer load to Messer Street |
| Weirs | Center | n/a | n/a | n/a | n/a | n/a | Site of **future** 34.5-12.4 kV substation | n/a | n/a | n/a | n/a | Site of **future** 34.5-12.4 kV substation |

Source: **Attachment BPA 1-006**, October 1 2021 --> 2020 Design Violations Summary Report - New Hampshire Distribution System Planning, revised March 18 2021

| | |
|---|---|
| SE Corner | 7 |
| SE Center | 3 |
| Center | 2 |
| | ---- |
| Substations | 12 |

# Appendix B

## Software Tools

## Commercial

**Aspen OneLiner** – Short circuit and relay coordination software package for electric power system protection engineers from Aspen.

**Cascade** – Asset inventory, maintenance, and condition-tracking software from DNV.

**Clik Field Services Management** – Crew tablet scheduling software from Clik Software. This software is planned to be replaced.

**DistriView**™ – An integrated suite of voltage-drop, short circuit, relay coordination, harmonics, and reliability calculation software for utility distribution systems from Aspen.

**e-Builder** – Construction management software from Trimble.

**GIS** – Geographic Information System for capturing, storing, checking, and displaying geographic position data.

**IBM Planning Analytics** – Enterprise financial planning software tool from IBM designed to implement collaborative planning, budgeting, and forecasting solutions.

**Inventor 3D Design Software** – Professional-grade 3D CAD software for product design and engineering for both solid and surface modeling from Autodesk.

**Jira Software** – Software tool from Atlassian that helps facilitate the agile process, which is an iterative and collaborative approach to managing the work associated with a project.

**Maximo** – Asset management, monitoring, and predictive maintenance software package from IBM. Work orders are created in this software and capture material, contract, and time charges. The project number from PowerPlan links these charges to the plant accounting system.

**Planning Analytics** – Business performance management software suite from IBM. It is designed to implement collaborative planning, budgeting, and forecasting solutions, interactive "what-if" analyses, as well as analytical and reporting.

**PowerPlan** – Integration hub specialty project accounting software that automates key accounting functions, and manages interfaces between sources of transactions, including general ledger, project accounting, plant accounting, and book depreciation from PowerPlan, Inc. Project numbers are initiated within this software and become the link to charges made to specific work orders created in Maximo.

**Power BI Tool** – Dashboard generating tool from Microsoft.

**Primavera P6** – Project management and scheduling software from Oracle.

**PSCAD™** – Power systems EMT (Electro-Magnetic Transient) simulations from PSCAD, a subsidiary of Manitoba Hydro International Ltd.

**PSS/E** – Electric power system analysis software package from Siemens [came with PTI purchase] used for transmission studies.

**PTLOAD** – Power transformer load simulation software package from EPRI.

**PTX Software** – Power transformer condition assessment software (Power Transformer Expert System) from EPRI.

**Synergi Electric** – Power distribution simulation software package from DNV.

**Synergis Adept** – Engineering document (drawings) management software from Synergis Technologies, LLC.

**Teams** – Proprietary business communication platform developed by Microsoft for video conferencing and meetings management.

**WorkDay** – Human Resource Information System (HRIS) software from Workday for data analytics, HR, finance, management, and enterprise planning.

## Custom In-House

**NWA Screening Tool**[1] – An Excel-based Eversource internal document that allows System Planning to screen capacity project needs at specific locations for potential application of NWA solutions. The Tool is designed to enable rapid initial screening of NWA options against traditional system upgrade projects. And will provide appropriate sizing of such locations.

**Custom modifications to EPRI PTX Software tool** – To better focus on transformer health management.

[1] LCIRP, March 31, 2021 Supplement, Appendix A-1, "Non-Wires Alternative Framework, Version 2.0.

# Appendix C

## Abbreviations

| | |
|---|---|
| ABR | Automatic Bus Restoral scheme |
| ADA | Advanced Data Analytics |
| ADMS | Advanced Distribution Management System |
| ADR | Active Demand Response |
| AEIC | Association of Edison Illuminating Companies |
| AFUDC | Allowance for Funds Used During Construction |
| AI | Artificial Intelligence |
| AMF | Advanced Metering Functionality |
| AMI | Advanced Metering Infrastructure |
| AMR | Automated Meter Reading |
| ANSI | American National Standards Institute |
| APPR | Approved (in MAXIMO) |
| APS | Accounting Policy Statement |
| APS-01 | Accounting Policy Statement 01 (corporate accounting policy) |
| ARO | Asset Retirement Obligation |
| AS&E | Administrative Salaries and Expenses |
| ASCE | American Society of Civil Engineers |
| Aspen OneLiner | (Aspen) Software for studying power system protection |
| AVG | Average |
| BCA | Benefit Cost Analysis |
| BES | Bulk Electric System |
| BESS | Battery Energy Storage System |
| BMS | Business Management System |
| BOD | Board of Directors |
| BOM | Bill of Materials |
| BOT | Board of Trustees |
| BP | Best Practices |
| BPA | Business Process Audit |
| BPS | Bulk Power System |
| BTM | Behind-the-Meter |

| | |
|---|---|
| Bulk Distribution Substation | – A collection of equipment and transformers used to step the Transmission source voltage (115 kV and higher) down to a Distribution voltage (usually 34.5 kV and below) |
| Non-Bulk Distribution Substation | – A collection of equipment and transformers used to step the Distribution source voltage (46 kV and 34.5 kV) down to a lower Distribution voltage (usually 12.47 kV and 4.16 kV) |
| BUG | Back-Up Generation |
| CAIDI | Customer Average Interruption Duration Index |
| CAGR | Compound Annual Growth Rate |
| CAM | Cost Allocation Manual |
| CapEx | Capital Expense |
| CBRC | Capital Budget Review Committee |
| CBC | Capital By Category |
| OCA | Office of Consumer Advocate |
| CCA | Chromated Copper Arsenate |
| CCNC | Completed Construction Not Classified |
| CCVT | Coupling Capacitor Voltage Transformer |
| CDG | Community Distributed Generation |
| CEG | Cost Estimating Group |
| CENH | Clean Energy New Hampshire |
| CEO | Chief Executive Officer |
| CESIR | Coordinated Electric System Interconnection Review |
| CFO | Chief Financial Officer |
| CGS | Certificate of Good Standing |
| CHP | Combined Heat and Power |
| CI | Customers Interrupted |
| CIII | Customers Interrupted per Interruption Index |
| C/I or C&I | Commercial/Industrial or Commercial & Industrial customers |
| CIP | Capital Improvement Plan (or Critical Infrastructure Protection) |
| CIO | Chief Information Officer |
| CIS | Customer Information System |

| | |
|---|---|
| CLF | Conservation Law Foundation |
| CMI | Customer Minutes Interrupted |
| CMS | Customer Meter Services |
| CoA | Certificate of Assurance |
| COC | Contractors of Choice |
| CoE | Center of Excellence |
| Company | Public Service Company of NH d/b/a Eversource Energy |
| COO | Chief Operating Officer |
| CO2 | Carbon Dioxide |
| COSAIDI | Company System Average Interruption Duration Index |
| COVID-19 | Pandemic |
| CPP | Critical Peak Pricing |
| CPPM | Capital Project Process Model |
| CRIS | Customer Related Information System |
| CS | Customer Solutions (or Customers Served) |
| CSDBR | Company Sanctioned Data Backup Required |
| CSOC | Cyber Security Operations Center |
| CSS | Customer Service System |
| CU | Compatible Unit |
| CVA | Certificate of Vote/Authority |
| CVR | Conservation Voltage Reduction |
| CY | Calendar Year |
| CYME | International power systems solutions and software provider |
| CYMDIST | CYME distribution system analysis software |
| CYMTCC | CYME over-current protection analysis software |
| DA | Distribution Automation |
| DAL | Drastic Action Limit |
| DAS | Distribution Automation Switching |
| DC | Direct Current |
| DEC | Department of Environmental Conservation |

| | |
|---|---|
| DER | Distributed Energy Resource |
| DERs | Distributed Energy Resources |
| DERMS | Distributed Energy Resource Management System |
| DES | Department of Environmental Services |
| DG | Distributed Generation |
| DIP | Distribution Integrated Planning |
| DistriView | ASPEN DistriView Integrated Software Package |
| Division | Department of Energy Regulatory Support Division (Staff) |
| DLC Program | Direct Load Control Program |
| DLM | Dynamic Load Management |
| DMS | Distribution Management System |
| DoA | Delegation of Authority |
| DOE | NH Department of Energy |
| DoNHDE | New Hampshire Distribution Engineering |
| DP | Distribution Provider |
| DPC | Distribution Planning Criteria |
| DR | Demand Response (Distributed Resource or Data Request) |
| DRWG | IEEE's Distribution Reliability Working Group |
| D-SCADA | Distribution Supervisory Control and Data Acquisition |
| DSINPRG | Design in Progress (in MAXIMO) |
| DSM | Demand Side Management |
| DSOC | Distribution System Operations Center |
| DSP | Distributed System Platform |
| DSPG | Distribution System Planning Guide |
| DSS | Distribution System Supply |
| DTS | Distribution Transfer Switching |
| EAM | Earnings Adjustment Mechanism |
| EBIT | Earnings Before Income Tax |
| EBU | Electric Business Unit |
| EDI | Electronic Data Interchange |

| | |
|---|---|
| E2E | End-to-End |
| E&S | Engineering and Supervision |
| EE | Energy Efficiency (can also mean Eversource Energy) |
| EERS | Energy Efficiency Resource Standard |
| EG | Emergency Generation |
| ELF | Electric Load Forecast |
| EMS | Energy Management System |
| EMT | Electromagnetic Transients |
| ENST | Eversource NWS Screening Toolset |
| EOC | Engineers of Choice |
| EPA | Environmental Protection Agency |
| EPAC | Eversource Project Approval/Authorization Committee |
| EPC | Engineer-Procure-Construct |
| EPRI | Electric Power Research Institute |
| EPS | Electric Power System |
| ERISA | Employee Retirement Income Security Act |
| ERM | Enterprise Risk Management |
| ERP | Enterprise Resource Planning |
| ESP | Electric System Planning |
| ES | Energy Storage |
| E&S | Engineering and Supervision |
| ESCC | Electric System Control Center |
| ESP | Electronic Security Perimeter |
| Esri | Global leader in GIS software |
| ESS | Energy Storage System |
| ETT | Enhanced Tree Trimming |
| EV | Electric Vehicle |
| Event | Single contingency (N-1) lasting one cycle (24 hrs) |
| EWR | Engineering Work Request |
| FC | Fuel Cell |

| | |
|---|---|
| FERC | Federal Energy Regulatory Commission |
| FLISR | Fault Location, Isolation, and Service Restoration |
| FSSP | Financial Simplification and Standardization Project |
| FTE | Full-Time Equivalent |
| FTM | Front of the Meter |
| FWO | Field Work Order (created in MAXIMO) |
| FY | Fiscal Year |
| GAGAS | (Federal) General Accountings Government Auditing Standards |
| GHG | Greenhouse Gas |
| GIS | Geographic Information System |
| GMSG | Grid Modernization Stakeholder Group |
| GOP | Generator Operator |
| GPS | Global Positioning System |
| GridLab-D | Power distribution simulation software from PNNL |
| Grid Mod | Grid Modernization |
| GST | Granite State Test |
| GSU | Generator Step-Up transformer |
| GTEP | Grid Transformation and Enablement Program |
| GW | Gigawatt |
| GWh | Gigawatt-hour |
| HC | Hosting Capacity |
| HCA | Hosting Capacity Analysis |
| HR | Human Resources Organization |
| HRIS | Human Resource Information System |
| IA | Internal Auditing (can also mean Interconnection Agreement) |
| IBM | International Business Machines |
| IDP | Integrated Distribution Plan |
| IEEE | Institute of Electrical & Electronics Engineers |
| IFC | Issued For Construction |
| IFR | Initial Funding Request |

| | |
|---|---|
| IFRF | Internal Funding Request Form |
| IMP | Integrity Management Plan |
| IMS | Incident Management System |
| INIT | Initiate (in MAXIMO) |
| IoT | Internet of Things |
| IOU | Investor-Owned Utility |
| IPE | Independent Professional Engineer |
| IT | Information Technology |
| IS | Information Systems |
| ISO | Independent System Operator |
| ISO-NE | Independent System Operator – New England |
| ISOC | Integrated System Operations Center |
| IT | Information Technology |
| JM-AM-2001 | Corporate project approval process |
| KPI | Key Performance Indicator |
| kV | Kilovolt |
| kvar | Kilovar |
| kW | Kilowatt |
| kWh | Kilowatt-hour |
| LBMP | Locational-Based Marginal Price |
| LCC | Load Carrying Capacity |
| LCE | Lead Commissioning Engineer |
| LCIRP | Least-Cost Integrated Resource Plan |
| LCTA | Least Cost Technically Acceptable |
| LED | Light-Emitting Diode |
| LRP | Long Range Plan |
| LSP | Local System Plan/Planning |
| LSR | Large-Scale Renewables |
| LTC | Load Tap Changer |
| LTE | Long Term Emergency rating |

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|---|---|
| LVA | Locational Value Analysis |
| LVMs | Line Voltage Monitors |
| MADC | Marginal Avoided Distribution Capacity |
| MAIFI | Momentary Average Interruption Frequency Index |
| M&C | Maintenance and Construction |
| MAX | Maximum |
| Maximo | Work and Asset Management System software |
| MBI | Months Between Interruptions (months in period divided by SAIFI) |
| MCOS | Marginal Cost of Service |
| MDEC | Miscellaneous Distribution Expense Capitalization |
| MDM | Meter and Data Management |
| MDMS | Meter Data Management Services |
| MED | Major Event Days/Definition |
| METT | Maintenance of the Enhanced Tree Trimming specification |
| MIN | Minimum |
| MTM | Market to Market |
| MW | Megawatt |
| MWh | Megawatt-hour |
| NARUC | National Association of Regulatory Utility Commissioners |
| NEC | National Electric Code |
| NE-ISO | New England Independent System Operator |
| NEPOOL | New England Power Pool |
| NERC | North American Electric Reliability Corporation |
| NESC | National Electrical Safety Code |
| NH | New Hampshire |
| NHDOT | New Hampshire Department of Transportation |
| NHEC | New Hampshire Electric Cooperative |
| NHPAC | New Hampshire Project Approval/Authorization Committee |
| NHPUC | New Hampshire Public Utilities Commission |
| NPCC | Northeast Power Coordinating Council |

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|---|---|
| NPV | Net Present Value |
| NREL | National Renewable Energy Laboratory |
| NTF | National Transmission Forum |
| NWA | Non-Wires Alternatives |
| NWS | Non-Wires Solutions |
| OCA | NH Office of the Consumer Advocate |
| OCB | Oil Circuit Breaker |
| O&M | Operations and Maintenance |
| OMS | Outage Management System |
| OPAF | Operations Project Authorization Form |
| OpEx or O&M | Operations Expense or Operations & Maintenance Expenses |
| OPGW | Asset Management Programs for Replacements |
| OPM | Operational Performance Management |
| OQ | Operator Qualifications |
| OQ'd | Operator Qualified |
| OT | Operational Technology |
| OTAF | Operations Technical Approval Form |
| PAC | Planning Advisory Committee (or Project Approval Committee) |
| PACT | Protection And Control Test committee |
| PAF | Project Authorization Form |
| P&L | Profit and Loss |
| PCM | Portfolio Calibration Meeting |
| PE | Professional Engineer |
| PEX | Performance Excellence |
| PFR | Partial Funding Request |
| PHEV | Plug-in Hybrid Electric Vehicle |
| PI | Planned Interruption |
| PLC | Power Line Carrier (or Project Life Cycle) |
| PM | Project Manager |
| PMI | Project Management Institute |

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|---|---|
| PMO | Project Management Office |
| PNNL | Pacific Northwest National Laboratory |
| PQ | Power Quality |
| POC | Point of Control |
| POI | Point of Interconnection |
| PowerPlan | Integration hub software from PowerPlan, Inc. |
| PP4 | Planning Procedure 4 |
| PSNH/EE | Public Service Company of NH d/b/a Eversource Energy |
| PSPM | Protection System Maintenance Program |
| PSS/E | Power system software package from Siemens |
| PTF | Pool Transmission Facility |
| PTLoad | EPRI transformer loading software package |
| PTO | Participating Transmission Owners |
| PTX | Power Transformer Expert System |
| PUC/NHPUC | State of New Hampshire Public Utilities Commission |
| PV | Photovoltaic (Solar) |
| QA/QC | Quality Assurance/Quality Control |
| RCG | River Consulting Group |
| Regulated Load | Load that has voltage regulation at a 34.5kV primary voltage beyond the bulk distribution facility/substation |
| RDISP | Ready to Dispatch (in MAXIMO) |
| REP | Reliability Enhancement Program |
| RIDS | Risk Informed Decision Support |
| RFI | Request for Information |
| RFP | Request for Proposal |
| RM | Risk Management |
| ROE | Return on Equity |
| ROW | Right of Way |
| RSA | Revised Statutes Annotated |
| RSP | Regional System Plan |

| | |
|---|---|
| RTU | Remote Terminal Unit |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| SAMP | Strategic Asset Management Plan |
| SCADA | System Control and Data Acquisition |
| SCLL | Single Contingency Load Loss |
| SCT | Societal Cost Test |
| SD | System Design |
| SDC | Solution Design Committee (or Substation Design Change) |
| SDM | Substations Design Manual |
| SEC | Securities and Exchange Commission |
| SFR | Supplemental Funding Request |
| SGIP | Small Generator Interconnection Process |
| SHE | Safety, Health, and Environmental |
| SIR | Standardized Interconnection Requirements |
| SLA | Service Level Agreement |
| Smallworld | Software GIS mapping tool |
| SME | Subject Matter Expert |
| SMT | Scheduled Maintenance Trimming |
| SOC | System Operations Center |
| SPCA | Spacer Cable |
| SRF | Supplemental Request Form |
| SSF | Solution Selection Form |
| Staff | New Hampshire DOE Staff (Regulatory Support) |
| STE | Short Term Emergency rating |
| Sub-T | Sub-transmission |
| SVC | Static VAR Compensator |
| Synergi Electric | Power Distribution System and Electrical Simulation software package from DNV |

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|---|---|
| Synergis Adept | Engineering document (drawings) management software from Synergis Technologies, LLC |
| TAF | Technical Approval Form |
| T&D | Transmission and Distribution |
| T&M | Time and Material |
| TFRAT | Transformer Rating, bulk transformer "loss of life" used historically by legacy PSNH (superseded by SYSPLAN-008) |
| THI | Temperature Humidity Index |
| TO | Transmission Owner |
| TOP | Transmission Operator |
| TOU | Time-of-Use |
| TRC | Total Resource Cost |
| TRS | Trouble Reporting System |
| TVP | Time-Varying Pricing |
| UCT | Utility Cost Test |
| UG | Underground |
| UER | Utility Energy Registry |
| UES | Unitil Energy Systems |
| Unregulated Load | Load that has ***no*** voltage regulation at a 34.5kV primary voltage beyond the bulk distribution facility/substation |
| URD | Underground Residential Distribution |
| USDOE | US Department of Energy |
| USSC | US Sanction Committee |
| VAD | Value Added Data |
| VCB | Vacuum Circuit Breaker |
| VDER | Value of Distributed Energy Resources |
| VP | Vice President |
| VT | Voltage Transformer |
| VTOU | Voluntary Time-of-Use |
| VVO | Volt-VAR Optimization |
| VVO/CVR | Volt-VAR Optimization /Conservation Voltage Reduction |

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|---|---|
| WO | Work Order |
| WTBS | Waiting To Be Scheduled (In MAXIMO) |
| WTHI | Weighted Temperature Humidity Index |
| Yellow Book | Federal General Accountings Government Auditing Standards |
| ZEV | Zero-Emission Vehicle |

# Appendix D

## Projects Review

A sampling of capital projects was reviewed[2] to evaluate adherence to Company processes/guidelines and standard industry practices. Information reviewed included the following: History, planning violations, solution alternatives, preferred solution rationale, and project-specific lessons learned.

**A review of projects indicated an established engineering process was being followed. However, RCG believes more comprehensive and consistent communications and project oversight could have identified/resolved issues earlier in the project development process, including how best to use outside contracted resources.**

The following projects were reviewed *[a representative sample taken from hearings, rate case, data requests, LCIRP, Company website, system planning studies (criteria violations), Staff concerns/questions, and budget variances]:*

I. East Northwood Phase Extension
II. Loudon Station
III. Nashua Millyard Substation
IV. Monadnock Distribution Substation Rebuild
V. Pack Monadnock Distribution Line Rebuild
VI. Pemigewasset Transformer Project
VII. Reconductor New Boston Road, Bedford
VIII. West Rye Substation Rebuild
IX. Viper Replacement Project
X. Rimmon Substation Animal Protection
XI. Goffstown Substation Elimination – Phase 1
XII. Replace Notre Dame Substation with MITS and Dunbarton Road Substation with Pad-mounted Step Transformer

For each project, *summaries and observations* are provided followed by project-specific *lessons learned.*

## I. **East Northwood Phase Extension** (2020-2021)[3]

1 - Planning violations: Low voltages; phase overloads/imbalances; and protection issues.

[2] Process reviews were conducted not technical reviews.
[3] Data Requsts BPA 8-001; BPA 9-010; BPA 9-011; BPA 1-013

2 - Three (3) alternatives were considered.

- Alternatives #1 and #2 were significantly more expensive, did not resolve all technical issues, and were not fully investigated.
- Alternative #3 (preferred alternative): 63W1 Reconductor Drake Hill Road was the lowest cost and resolved all technical issues.

3 - Funding approval process:

- Challenge Session Form: $900,000 - August 24, 2020
- PAF: $1,062,000 - January 21, 2021
- Actual indirect costs were greater than PAF estimated costs because they were based on historical average costs per foot rather than actual project work scope estimates.
- Tree-trimming cost estimates were not obtained for the PAF.
- Competitive bids for line construction contractor labor costs (the largest component of most distribution line projects) were also not obtained for the PAF.

**Lessons learned per the Company:**

- Project-specific unit construction estimates should be used instead of typical estimates when competing PAFs.
- The results of competitive contractor bids should be used when completing PAFs, such as tree trimming, construction oversight, and ledge pole sets.
- Cost estimates developed by engineering personnel need to be based on specific work scopes rather than historical average labor rates when completing PAFs.
- **RCG conclusion**: Overall project documentation was delivered to RCG in pieces, requiring multiple DRs, and complicating the review process.

**II. Loudon Station**[4] (project still under review; no approved PAF as of this writing[5])

1 - Planning violations: N-0 base load violation; and unhealthy transformers.

2 - Five (5) potential traditional solutions were evaluated, and ten (10) potential NWA solutions (using the NWA Screening Tool).

- Preferred traditional solution: Replace 31W1 and 31W2 transformers with a single transformer.
- Preferred NWA solution: Mobile generators (3) operating 3-to-6 days per year as part of a 5-year deferral strategy.

[4] LCIRP Mar 31 2021, Supplement, Appendix A-2; Data Request BPA 1-006, 10/01/21 Attachment

[5] Interview #18

3 - Funding options:

- Traditional Solution -> $6,500,000 (if deferred 5 years, net present value savings would be $1,657,186)
- NWA Solution -> $194,928/year (if implemented)

**Lessons learned per the Company**:

- None was given.
- **RCG conclusion**: The Loudon study was a good example of how the NWA Screening Tool can be used to quantify potential NWA solutions which can serve as an example for future projects.

**III. Nashua Millyard Substation** (2016-2022)[6]

1 - Planning violations: Obsolete equipment (>65 years old); and congested physical site.

2 - Seven (7) alternatives were considered.

  - Alternative #4 was selected as the preferred solution based on receiving the highest total-ranking score, using a decision matrix of 9 weighting factors, 2 of which were operating costs and system-loss savings.
  - Alternative # 4 was not the least-cost solution.

3 - The project was initiated (2016) before the inception of EPAC or SDC and was initially reviewed at CPAC, the predecessor to EPAC. When SDC and EPAC processes were established, the Millyard project was brought before both committees. Full funding was approved by EPAC in 2021.

**Lessons learned per the Company**:

- None was given.
- **RCG conclusion**: The systematic ranking process used to arrive at the preferred alternative (Alternative # 4) was a good, objective way to arrive at and subsequently support the decision even though it was not the lowest cost solution.
- **RCG conclusion**: Project checklists for the new capital approval process are more comprehensive than the forms completed and approved for this project.

[6] Data Request BPA 7-001; BPA 7-002; IR-48a; IR 48b

## IV. Monadnock Distribution Substation Rebuild (2020-2023)[7]

1 - Planning violations: Unhealthy transformer[8]; (N-1) transformer violation; (N-1) STE violation; (N-1) bus fault violation; and (N-1) bus-tie violation.

2 - Two (2) alternatives were scoped in detail by an outside engineering firm.

- Alternative #1 breaker-and-a-half design.
- Alternative #2 was a ring-bus design. Included: Replacement of both transformers; the addition of series bus-tie breakers; and the addition of an additional capacitor bank as a supplement to the existing capacitor bank.
- Alternative #2 was selected because it addressed reliability issues.

3 - Funding approval process:

- An initial Solution Selection Form (SSF) was submitted on March 16, 2021, with no budget estimates since the project was in the early initiation stages. An NWA was not considered since the Company does not evaluate NWA solutions for asset condition issues. A greenfield site was selected to facilitate construction and scheduled outages.
- SDC approved an updated SSF on September 29, 2021, along with conceptual budget estimates (30%-40% engineering completed).
- On November 29, 2021, an outside engineering firm provided detailed project estimates for Alternative #2 totaling $23,399,900 with a range of -25% ($17,550,000) and +50% ($35,100,000).

**Lessons learned per the Company**:

- None was given.
- **RCG conclusion:** More detailed and accurate project estimates are needed for funding approval. The tolerance ranges of -25% to +50% are too large. A more industry-accepted range is +/-10%.

[7] LCIRP Mar 31 2021 Supplement, Appendix E-3; BPA 1-006, 10-01/21 Attachment; BPA 6-008, 11/29/21 Attachment

[8] Data Request BPA 8-004: The following factors are used by the PTX tool to create a health index → Normal degradation, abnormal thermal condition, abnormal electrical condition, abnormal core condition, oil quality, and age.

### V. **Pack Monadnock Distribution Line Rebuild** (2017-2021)[9]

1 - Planning violations: This off-road, 1-phase distribution line, was not up to code and could present a safety hazard to the public following a request by a third-party telecom company to attach equipment to the line.

2 - Multiple alternatives were considered and reviewed with external stakeholders (due to the sensitivity of the site), including overhead and underground options.

- Project plans were revised to incorporate feedback. The Company continued communications with stakeholders throughout the pre-and post-construction phases.
- The best overall solution was to reconductor with tree wire and upgrade with stronger poles to accommodate additional equipment and better withstand adverse weather conditions.
- Potential NWA solutions were not applicable in this case.

3 - In 2020, the Company submitted permit applications. All approvals were secured in time to complete line construction in 2021.

**Lessons learned per the Company**:

- None was given.
- **RCG conclusion**: Maintaining regular communications with stakeholders throughout all project phases (planning, construction, commissioning) was effective on this project and should be a standard process for all projects.

### VI. **Pemigewasset Transformer Project** (2017-2020)[10]

1 - Planning violations: (N-1) transformer violation; and (N-1) bus fault violation.

2 - Five (5) alternatives were considered.

- Alternative #2 was selected as the preferred alternative using a decision matrix with weighting factors.
- Alternative #2 was neither the highest nor the lowest cost but was considered the best overall technical solution since it resolved (N-1) violations at adjacent substations (Ashland and Laconia).
- NWA status is unknown since it was not included in the PAF.

4 - Funding approval process: (details below)

[9] LCIRP Mar 31 2021 Supplement, Appendix F-1;Data Requests BPA 9-009; BPA 9-007; BPA 9-006

[10] Data Request BPA 8-002; DE 19-057 dated 07-19-21; Data Request BPA 5-010

- PAF: $4,063,000 - February 14, 2018 (EPAC approved)
- SFR: $2,754,000 - June 10, 2020 (EPAC approved)
- SFR (revised): $3,700,000 - April 14 2021
- The $4.063M PAF included a "Project Checklist" where the initiator indicated a "field constructability review (had) been completed." However, this was only a cursory review since a detailed site walk-through (constructability review) was not conducted until 2019.
- The $2.754M SFR was to cover a larger control house (the existing control house is too small), bringing the total funding request to $6.817M.
- The $2.754M SFR was replaced with a larger $3.7M SFR to cover engineering costs (internal + outside engineering firm) to correct a transformer issue (synch scope wiring error discovered during initial energization testing), animal protection, smart grid enhancements, and improperly (by the outside engineering firm) accounted for Company overhead costs. The PAF + revised SFR totaled $7.7M (which EPAC approved on 4/14/21). However, a PUC $900,000 disallowance occurred due to PSNH's failure to hold the primary contractor liable for the wiring error.

**Lessons learned per the Company**:

- The legacy authorization process was in place for this project (i.e., prior to 2018 capital approval process changes),[11] meaning PAF completion did not follow the new capital SDC/EPAC approval process which requires engineering to validate major assumptions prior to submitting the PAFs.
- Indirect cost estimates in the original PAF were prepared by an outside engineering firm that did not properly account for Company overheads.
- The Company believes animal protection should have been submitted for separate funding approval since it was not included in the original PAF.
- Better checks and balances and communications were needed throughout this project. Improvements made by the Company due in part to this project include the following:[12]
    - Formation of an Engineering Project Controls Group in late 2019.
    - Creation of an *Administrative Procedure M7-EN-2000 Engineering Deliverables* effective 7/1/20.

[11] DE 19-057, 07-19-21, page 22
[12] Data Request BPA 5-010

- **RCG conclusion**: Better attention to engineering design details and project oversight might have prevented issues with control house size requirements after initial funding approval had been received; e.g., the increased number of switchgear bays should have been an early red flag.
- **RCG conclusion**: The new capital approval process might have reduced or eliminated the need for supplemental funding requests.

## VII. Reconductor New Boston Road, Bedford (2020-2021)[13]

*NOTE: The New Boston Road Project was submitted by the Company as a typical distribution capital project. A comprehensive project timeline was overlaid on the process flow chart provided with Data Request BPA 8-005.*

1 - Planning violations: Major load imbalance; and potential low-voltage issues.

2 - Three alternatives were considered. Only the preferred alternative met all technical requirements.

- Preferred alternative: Replace 1-phase conductor with 3-phase 477 spacer cable. Redistribute load from phase C (1-phase) to two new phases (A & B). Replace the single-phase recloser with the three-phase recloser. Collateral benefits: Contributes to establishing a long-needed circuit tie between circuits 3194X1 and 322X10, improving reliability. Spacer cable improves resiliency.
- NWA status is unknown since it was not included in the PAF.

3 - Funding approval process:

- Challenge Session: September 2, 2020 (delayed from Aug)
- PAF: $825,000 - February 11, 2021 (approved by NH-PAC)
    - Funding estimates were based on historical cost-per-foot values and considered limited risk since the project involved standard overhead construction. The Company's preference moving forward is to have the design completed and actual construction bids in hand (if using contract resources) before presenting full funding requests for approval.
- A preliminary engineering design was completed in January 2021.
- An initial, high-level constructability review with Electric Field Operations was conducted in January 2021.

[13] Data Request BPA 8-005

- A PAF was created in January 2021 (and approved in February as indicated above).
- Detailed engineering constructability reviews were conducted in April 2021 (after PAF approval). While constructability reviews are required for all distribution line projects, *formal constructability documentation was not required at the time. Going forward, the Company intends to make this a requirement.*

**Lessons learned per the Company**:

*No specific lessons learned were recorded by the Company for this project. However, lessons learned (documented on pages 3-4 of BPA 8-005) accumulated from similar projects (per Data Request BPA 8-005) follow:*

- If outside resources are to be used, estimates should be based on results from a competitive bidding process.
- Full funding requests should include contingency amounts for items such as ledge pole sets, Company pole sets in non-Company maintenance areas, and other potential unknown costs.
- Overall project cost estimates should include:
    - Tree-trimming costs from the Vegetation Management Department.
    - Internal labor costs for items such as recloser settings development, equipment testing, commissioning, and project management which are not in the compatible units of the Work Management System (Maximo).
    - Labor costs for construction representatives.

## VIII. **West Rye Substation Rebuild** (2016-2018)[14]

1 - Planning violations: Unhealthy transformers (age, gassing); obsolete equipment[15]; loading issues; and low voltage issues.

2 - Two (2) alternatives were considered. Only the preferred alternative met all technical and environmental requirements.

- Preferred alternative: Replace two 1.5 MVA 34.5-4.16 kV substation transformers with one 10/12 MVA 34.5 - 12.47 kV substation (Eversource standard transformer size). Install 3 reclosers along with RTUs (for distribution automation).

[14] Data Requests BPA 7-005; BPA 11-001; DE 19-057 dated 12-23-19

[15] Replacement parts are no longer available to maintain the equipment.

- NWA status is unknown as it was not included in the PAF.

3 - Funding approval process:

- PAF: $1,303,000 - April 12, 2016
- SFR #1: $286,189 - July 20, 2017
- SFR #2: $712,118 - February 28, 2018
- SFR #3: $364,000 - September 28, 2018
- SFR #4: $524,597 - October 4, 2019
- Total Funding after SFRs = $3,190,715 (245% increase)

4 - **SFR #1**: To include design/materials/construction for mobile transformer tap on 3105X line. More than expected contractor resources were used for design work (an outside consultant was used for all engineering/design). More than expected material costs. Station service, PTs, site expansion, fencing, grounding, and stoning were not included in the original estimate.

5 - **SFR #2**: To cover increased costs for construction, testing, and commissioning based on actual bid pricing. The work scope for line taps was not appropriately defined. Responsible parties were not clearly identified. ROW clearing and environmental monitoring were not considered. Oversights occurred due to SFR #1 not being written by the project manager, but by the engineering lead. The Company indicated this was due to the construction window only being 3 months long, and issues arose after construction had started. Issues also occurred with the closeout and material reconciliation processes.

6 - **SFR #3**: To cover increased costs by the construction company to remedy civil and electrical design issues in the field. The materials ordered differed from the drawing specifications. Other issues included poor materials handling, discrepancies between internal/external designs, discrepancies in stock-coded materials, and wiring discrepancies in pre-wired junction boxes.

7 - **SFR #4:** To cover a scope increase (line work) after the start of new substation construction due to a lack of clarity on the demarcation between line costs tied to the substation and line costs associated with a voltage conversion project. Antenna/radio materials were also not included in the original work scope because the protection and control bill of materials was not available until after the construction contractor had been awarded the job. Animal protection materials were also not included in SFR #3 (only the labor to install the materials was included in SFR #3). Other contributing factors for SFR #4: Materials previously missed by the contractor and Eversource during the bidding process; siting and construction services were higher than expected; testing and commissioning services were needed longer than expected; property taxes were not included in any of the previous SFRs or the original PAF, and indirect costs increased more than expected between 2017 and 2018.

**Lessons learned per the Company**:

- Lessons learned taken from SFR #3 (as submitted):
  - Project managers (PMs) and Engineering groups should work together in the estimating process to ensure checklists and documentation are complete.
  - Cost analysts need to use updated overhead and loader costs.
  - PMs should not submit SFRs before approving any field changes not already in the budget.
- **RCG conclusion**: More detailed documentation, more complete explanations and better communications are needed from project inception through project completion to facilitate "a more administratively efficient review process for Staff and Commission."[16]

## IX. Viper Replacement Project (2018-2018)[17]

1 - Violations: Reliability/safety concerns due to an installed recloser vacuum bottle defect that could result in violent failures. Recloser refurbishment and/or replacement needed ASAP (262 units). The recloser defect was discovered after 15 field failures. "It was kind of scary because we had so many failures in a short amount of time. We were worried about having some major reliability impacts while waiting for vendor repairs."[18]

2 - This project was not a typical reliability improvement or load-driven project due to reliability/safety concerns with defective reclosers and negotiations with suppliers.

3 - Solution alternatives:

- **Alternative #1** - Replace defective reclosers with rebuilt units at zero material costs and minimal protection-and-control engineering costs, temporarily bypassing the defective units until rebuilt units could be delivered and installed (5-week estimate).
- **Alternative #2** (preferred alternative) - The Company's senior management decided to expedite the project due to safety/reliability concerns by acquiring replacement equipment from alternative recloser vendors, substantially increasing material and labor costs. Since it was not possible to determine which defective reclosers would fail, expedited replacement of all affected units was approved by Company management
  - Refurbish and reinstall 165 defective reclosers.

[16] DE 19-057, 12-01-20, page 52, lines 21-23
[17] Data Requests BPA 9-012; BPA 9-013; BPA 9-014; DE-057, DR TS2-056 dated 10/28/19; DE 19-057, DR Staff 12-045 dated 09/20/19, Attachment Staff 12-045 AE
[18] Interview #34

  - Replace 97 defective reclosers with alternative vendor equipment.
  - Refurbished reclosers (165 units) are to be redeployed when needed on the distribution system at $0.00 material cost. Since the defect was known and corrected by the manufacturer, the Company was confident refurbished units would perform reliably.[19]
- **NWA** alternatives were not considered applicable and as a result, were not investigated.

4 - Funding approval process:

- PAF: $950,000 - January 22 2018
- SFR: $8,929000 - February 27 2018
- Total Funding Request after SFRs: $9,879,000
- Total Project Costs: $5,796,925 [approximately $4M lower than SFR due to lower-than-expected defective recloser replacement costs ($7,065 each instead of $13,000); lower-than-expected alternative vendor costs ($61,288 each instead of $75,000); and lower-than-expected indirect costs of $1,100,000].
- The February 17 2018 SFR was submitted immediately after the original PAF to switch the project from Alternative #1 to the highly expedited Alternative #2.

**Lessons learned per the Company**:

- The Viper project occurred prior to the new capital project approval process. Today, this kind of project would be managed by the Director of NH Distribution Engineering and his team working with the Protection & Control (P&C) group and approved by the NH-PAC (since it was a distribution line project). SDC/EPAC approvals would not be required since the project was not a substation project.
- If expedited project scenarios are foreseen as a possibility, the fiscal impacts of these scenarios should be included in the PAFs.[20]
- **RCG conclusion**: The value of reliability and safety should have been quantified on PAF and SFR forms to justify expediting defective recloser replacements at substantially higher costs.

[19] Data Request BPA 9-013
[20] Data Request BPA 9-014

- **RCG conclusion**: The Company should have presented a more rigorous financial analysis to demonstrate due diligence in obtaining the least-cost supplier pricing.
- **RCG conclusion**: The Company should have presented a more rigorous engineering analysis to quantify why only 97 defective reclosers (out of a total number of 262) had to be replaced with alternative vendor equipment.
- **RCG conclusion**: The Company should have provided more detailed and easier-to-understand documentation with the filing[21] to make it easier for Staff to evaluate what had been done and why additional funding was needed/justified.

### X. **Rimmon Substation Animal Protection** (2019-2022)[22]

*NOTE: The Rimmon SS Animal Protection Project was submitted by the Company as a typical substation capital project. A comprehensive project timeline was overlaid on the process flow chart provided with Data Request BPA 8-005.*

1 - Violations: Outages caused by ravens. Ravens damaged traditional animal coverings on insulators by pecking away at them. Eventually, the coverings failed, and outages ensued.[23] The problem began in 2018 with 10 outages caused by ravens.

2 - Eight (8) alternatives were considered. Alternative #1 was initially selected but rejected following an SDC review/challenge. Alternative #6 was ultimately selected (to install lasers as a deterrent) as the preferred alternative.

- NWA is unknown since it was not addressed in the PAF.

3 - Funding approval process:

- SSF #1: no funding request - January 7, 2019 SDC
- IFRF: $100,000 - June 10 2019
- SSF #2: Eight Alternatives - January 21, 2020 SDC
- Alternative #1 was first proposed to the SDC at a cost of $4,500,000. SDC challenges led to a much cheaper alternative (Alternative # 6) at a cost of only $339,000.

4 - Detailed documentation was maintained throughout the funding approval process including detailed budget estimates for all eight alternatives, site drawings, site pictures, completed constructability review forms, control panel layouts, and a project scope document.

**Lessons learned per the Company**:

---

[21] DE 19-057, 10/28/2019
[22] Data Request BPA 8-003; BPA 9-018
[23] Interview #73

- Documentation must be *clear;* justification must be in terms of asset health or maintenance record if asset-based; or must be tied to specific planning criteria if reliability based.
- SDC/EPAC challenges resulted in a more cost-effective solution than would not have otherwise been discovered.
- More detailed cost estimates provided a more accurate basis for comparing alternative solutions which is consistent with the new process.
- Conducting field constructability reviews ***after*** detailed designs are completed validates assumptions and identifies outstanding issues/risks.
- Metal-clad switchgear offers better animal protection than open-air switchgear and is more secure.[24]
- **RCG conclusion**: This project is a good example of how SDC/EPAC challenges can lead to lower-cost solutions while meeting technical and environmental objectives.

## XI. Goffstown Substation Elimination – Phase 1[25]

A full-funding PAF was submitted on 4/27/21 along with two of five alternatives. In a Goffstown System Planning Study published November 2019, five (5) alternatives were evaluated, including an NWA option.

**Lessons learned per the Company**:

- None was given.
- **RCG conclusion**: All five alternatives should have been included in the PAF for completeness.

## XII. Replace Notre Dame Substation with MITS and Dunbarton Road Substation with Pad-mounted Step Transformer[26]

This project was not included in the 2021 capital budget, but the Company plans to submit it for future consideration. Estimated cost: $3,512,000.

The proposed use of MITS (Modular Integrated Transportable Substation) technology in this project is a good example of how engineering and construction costs can be saved by using

[24] Interview #73
[25] Data Request BPA 10-001 and Attachments
[26] Data Request BPA 1-014 and Attachment B

modular substation designs. MITS was also considered for the Milford Substation and there did seem to be potential cost savings, but the MITS option was not selected as a preferred alternative.[27]

**Lessons learned per the Company**:

- None was given.
- **RCG conclusion**: Where feasible and ratings permit, modular substation designs should be more widely considered. Modular substations are rapidly deployable and highly standardized compared to traditional substation designs, reducing engineering and construction costs.

**2020 Design Violations Summary Report - Projects** (Appendix A) (Data Request BPA 1-006)

Thirty-seven (37) bulk substation projects and twelve (12) non-bulk substation projects were identified in the *2020 Design Violations Summary Report*[28]. None have moved through the capital approval process as more study is needed.

**Lessons learned per the Company**:

- None was given.
- **RCG conclusion**: Of the 49 projects (37 + 12) in the *2020 Design Violations Summary Report*, only two were flagged as potential NWA candidates: Loudon 31W1 and 31W2; and Hanover Street 16W3. Per DSPG 2020 requirements, the NWA Framework screening tool is to be used to evaluate potential NWA solutions. However, it is not known if the NWA tool had been used for all projects. Nevertheless, NWA status should be included on the PAF forms, even if it is only a statement that NWA was not applicable due to the project being asset-condition based (for example). This has ***not*** been a Company practice and has led to NWA questions when reviewing PAF forms.

[27] Interview #61

[28] Attachment Data Request BPA 1-006

# Solution Selection Form

| | |
|---|---|
| **Project Title:** | **Project Number:** |
| **Date Prepared:** Click drop-down to enter date | **Company:** Choose an item |
| **Organization:** Choose an item | **Class(es) of Plant:** Choose an item |
| **Project Initiator:** | **Project Category:** Choose an item |
| **Managing Organization:** Choose an item | **Schedule ID#:** |
| **Project Manager:** | **Project Type:** Choose an item |
| **Project Sponsor:** | **Project Purpose:** |
| **Estimated in service date:** | **EJ Community Impact:** Choose an item |
| **Conceptual Grade Cost Estimate (preferred solution):** | |
| **Facility Type** (check all that apply): ☐ PTF ☐ non-PTF ☐ local PTF ☐ Distribution ☐ N/A (General Plant) ☐ BPS ☐ BES ☐ CIP | |

*When completing this form =>*
*Follow instructions contained in 'Solution Selection Form - Guide - 2023-12-07' located here: \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms*

*Consult JA-AM-2001-A Capital Project Approval Process for process guidance.*
*\\nu.com\data\SharedData\EPAC\Administrative*

*For additional support please reach out to solutiondesigncommittee@eversource.com*

## [1] Project Need Statement

# [2] Project Objectives

## [3] Alternatives Considered with Cost Estimates

Environmental Justice Considerations shall be included as part of the alternative analysis.

## [4] Project Scope (Preferred Solution)

## [5] Project Schedule

*Add additional key milestones specific to this project as needed.*

| Milestone | Scheduled Completion Date |
|---|---|
| IFR Approval | |
| SDC Approval | |
| Conceptual Design Completion | |
| EPAC Partial Funding Approval (for applicable projects) | |
| EPAC Full Funding Approval | |
| Start of Construction | |
| Project In-Service Date (ISD) | |
| Project Need Date (for applicable projects) | |

## [6] References

| References |
|---|
| 1. |
| 2. |
| 3. |
| 4. |
| 5. |

## [7] Attachments (One-Line Diagrams, Images, etc.)

*Please make sure all attachments provided here are referenced above in the appropriate section of the PAF with the correct attachment number.*

| Attachments |
|---|
| A. Cost Estimate |
| B. |
| C. |
| D. |
| E. |
| F. |

## [8] Preliminary Project Checklist (Preferred Solution)

| PLANNING | |
|---|---|
| Is a NX-9 required? | Choose an item |
| Is an ISO-NE PAC presentation required? | Choose an item |
| Is a PPA required? | Choose an item |
| Is a TCA Application Required? | Choose an item |
| ENVIRONMENTAL JUSTICE COMMUNITIES | |
| Is any part of this project in an Environmental Justice Community? | Choose an item |
| Was the Equity Framework Checklist completed? | Choose an item |
| Has Project Services established an enhanced outreach plan per State Regulatory requirements? | Choose an item |

# Solution Selection Form

| | |
|---|---|
| Project Title:<br>*Short descriptive title that best describes the project. If project has already received initial or partial funding, project title should remain constant throughout the project lifecycle and match prior authorization documents.* | Project Number:<br>*The Power Plan project number. For assistance securing a project number, send an email to tranEPAC@eversource.com* |
| Date Prepared:<br>*Date SSF submitted to EPAC or state PAC administrator* | Company/ies:<br>*Select the region from the dropdown list– Eversource “CT”, “EMA”, WMA or “NH”. If multiple regions, type in name of additional regions after the dropdown (example “Eversource CT, Eversource NH”).* |
| Organization:<br>*Select the Director’s organization that is preparing the SSF from the dropdown list.* | Class(es) of Plant:<br>*Select the Plant Class identified in the Plant Accounting Manuals (i.e. T SS, T Line, D SS, D Street, Telecomm, or Other) from the dropdown list. If multiple classes of plant, type in name of additional classes after the dropdown (example “T SS, T Line”).* |
| Project Initiator:<br>*Typically engineer level* | Project Category:<br>*See file Project Budget Categories.xlsx in the folder: N:\EPAC\Administrative\ and select the appropriate project budget category from the dropdown list (example System Planning projects to choose “Planning (T)” and Interconnection/Generation Projects to choose “Interconnection/Generation”). If project includes multiple categories, type in the name of additional categories after the dropdown (example, “Stations-Transformer, Circuit Breakers”).* |
| Managing Organization:<br>*Select what organization will own project management responsibilities for the project* | Schedule ID#:<br>*The Primavera P6 schedule ID* |
| Project Manager:<br>*Enter the name of the PM* | Project Type:<br>*Select one of “Specific”, “Annual”, “Prelim Project”, or “Program” from the dropdown list.* |
| Project Sponsor:<br>*Typically the initiator’s director* | Project Purpose:<br>*The type of need the project is solving, capacity, reliability, asset condition interconnection, etc.* |
| Estimated in service date:<br>*Best estimate at least by Quarter – make sure this matches the date in the project schedule table below* | EJ Community Impact:<br>*Does this project impact an Environmental Justice (EJ) Community, select Yes or No* |
| Conceptual Grade Cost Estimate (preferred solution):<br>*Enter Conceptual Grade Cost Estimate for the preferred solution. If multiple project numbers listed, specify request amount for each project number. If project is reimbursable, state what percentage is reimbursable. If multiple facility types, designate by project number (example, 404040 PTF, 404041 non-PTF in the total request cell* | |
| Facility Type:<br>*Check boxes for “PTF”, “Non-PTF”, “local PTF” and/or “Distribution” (check as many as apply). Use General Plant when applicable. Mark and BPS when applicable.* | |

*SSF formatting note: All responses should be black, size 11, Arial font. Paragraphs should be spaced with a 1.15 multiple with 10pt spacing after each paragraph. The SSF header and footer should not be modified unless the SSF document needs to be specially marked for CIP or CEII reasons.*

*General Notes*

- *After submitting a request to solutiondesigncommittee@eversource.com the Project Solutions team will perform a first line review of the request. SSF should be submitted as a word file.*
- *Project Solutions review feedback will be sent back to the initiator embedded as tracked changes and review comments within the originally submitted word document. A deadline to incorporate Project Solutions feedback into the SSF (and attachments) will be included in the Project Solutions feedback email.*
- *Project Solutions team feedback is based on adherence to procedural requirements and general best practices for SSF included information, content and data; formatting, grammar and spelling; etc*
- *For Revised SSFs –the FINAL Word version of the original SSF should be used and tracked changes made to the FINAL WORD version should be submitted to solutiondesigncommittee@eversource.com. If needed, please request the original Word SSF from solutiondesigncommittee@eversource.com. Include any other necessary attachments as well.*

– *Consult JA-AM-2001-A Capital Project Approval Process for process guidance. \\nu.com\data\SharedData\EPAC\Administrative*

– *The information required (need, objectives, scope of preferred solution, cost estimate(s), and alternatives analysis) can be supplemented with attachments (i.e. MS Word, MS PowerPoint, MS Excel, PDF files).*
– *Attachments should be submitted as separate files and not embedded within this form.*
– *Previously approved Initial Funding Request forms or other approved authorizations should be included with the submission of this form as a separate attachment.*

# [1] Project Need Statement

– *Description of the problem that exists which this project is intending to solve.*

– *Detailed explanation of the drivers behind why this project is necessary (i.e. specific planning criteria violations, aging infrastructure/obsolete equipment, regulatory requirement, interconnection requirement, asset condition, etc.).*

– *Provide supporting detail on the existing equipment and conditions: reference recent testing, inspection and maintenance data; note the installation date/age of existing equipment and any lack of available replacement parts; etc.*

# [2] Project Objectives

*What the project objectives are and how achieving the project objectives will effectively resolve the existing problem.*

# [3] Alternatives Considered with Cost Estimates

- *Provide a list of the alternatives evaluated with estimated costs for each alternative (including the preferred alternative).*

- *Environmental Justice Considerations shall be included as part of the alternative analysis.*

- *List and describe all electrical and routing alternatives considered along with their cost estimates.*

- *Include a project scope summary for each alternative. For the preferred alternative save project scope details for the Project Scope section.*

- *Include the pros and cons of each alternative as well as challenges and potential risks.*

- *Explain why the preferred alternative is the chosen solution when weighed against each non-preferred alternative.*

- *Provide a summary of any non-wires alternatives analysis conducted along with reasoning for dispositioning the non-wires alternatives and the cost estimates.*

- *Describe the customer/community impacts of the preferred solution and alternatives.*

## [4] Project Scope (preferred solution)

- *Detail what will be done, how it will be done and when, and by whom.*
- *For projects will multiple locations, lines and/or substations, organize scope information by individual location.*
- *Utilize tables whenever possible to organize scope information.*
- *Detail scope accomplished to this point.*
- *Include material quantity, and details such as make, manufacturer, and model if available, as well as any guidance or restrictions to provide bounds on the scope of the project.*
- *For replacement projects identify current existing equipment that will be removed as well as equipment to be installed.*
- *Include scope from all pertinent disciplines (i.e. Engineering, siting and outreach, environmental, civil and electrical construction, etc.).*
- *Scope should match the scope listed in the backup cost estimate.*
- *Include reference to the constructability review (if completed) with the date of the review and any pertinent information from the constructability review.*
- *For SS project include impacts to station batteries, control house space and noise impact if transformers are involved.*

## [5] Project Schedule

- *Utilize the appropriate list of required milestones for this funding request type.*
- *Reference JA-AM-2001-A for the required milestones listed by funding request type.*
- *Add additional milestones as needed, including engineering, procurement, permitting, construction, partial funding approval milestones to capture the major dates of the project.*
- *If applicable, include dates for milestones/phases already completed or in progress.*
- *Mark non-applicable milestones N/A*
- *Ensure Milestone information contained in this table matches the project P6 schedule, if applicable. Reference the P6 attachment below the milestone table.*

## [6] References

| References |
|---|
| 1. |
| 2. |
| 3. |
| 4. |
| 5. |

- *List any references useful for PAF review, including prior funding authorization forms and any documents or standards referenced in sections above.*

## [7] Attachments (one-line diagrams, images, etc.)

*Please make sure all attachments provided here are referenced above in the appropriate section of the SSF with the correct attachment number.*

| Attachments |
|---|
| A. Cost Estimate |
| B. |
| C. |
| D. |
| E. |
| F. |

- *Identify multiple cost estimate attachments as A1, A2, A3 etc. Use same methodology for other attachments as well.*
- *Explain why standard attachments are not included*
- *Include any applicable previous submittals for this project and program submittals as attachments.*

# [8] Preliminary Project Checklist (for the preferred solution)

| PLANNING | |
|---|---|
| Is a NX-9 required? | Choose an item |
| Is an ISO-NE PAC presentation required? | Choose an item |
| Is a PPA required? | Choose an item |
| Is a TCA Application Required? | Choose an item |
| **ENVIRONMENTAL JUSTICE COMMUNITIES** | |
| Is any part of this project in an Environmental Justice Community? | Choose an item |
| Was the Equity Framework Checklist completed? | Choose an item |
| Has Project Services established an enhanced outreach plan per State Regulatory requirements? | Choose an item |

**PLANNING**

| | |
|---|---|
| Is a NX-9 required? | Identify if a thermal ratings update is required, including cable sizing, conductor length, limiting element changes, etc. |
| Is an ISO-NE PAC presentation required? | Identify if criteria are met to prepare a presentation for the ISO-NE Planning Advisory Committee. Note if the project has already been presented to ISO-NE. |
| Is a Proposed Plan Application (PPA) required? | Identify if a Proposed Plan Application is needed. |
| Is a Transmission Cost Allocation (TCA) Application Required? | Identify if an ISO-NE transmission cost allocation application is required. |

**ENVIRONMENTAL JUSTICE COMMUNITIES**

| | |
|---|---|
| Is any part of this project in an Environmental Justice Community? | Yes or No<br>Equity and Environmental Justice team will confirm |
| Was the Equity Framework Checklist Completed? | Yes or No<br>Equity and Environmental Justice team will confirm |
| Has Project Services established an enhanced outreach plan per State Regulatory requirements? | Yes or No<br>Include details of what community impacts may result from the project and any mitigations to be made to minimize those impacts in the Regulatory Approval section. |

# Operations Project Authorization Form

| | |
|---|---|
| **Project Title:** | **Project Number:** |
| **Date Prepared:** Click drop-down to enter date | **Company:** Choose an item |
| **Organization:** Choose an item | **Class(es) of Plant:** Choose an item |
| **Project Initiator:** | **Project Category:** Choose an item |
| **Managing Organization:** Choose an item | **Schedule ID#:** |
| **Project Manager:** | **Project Type:** Choose an item |
| **Project Sponsor:** | **Capital Investment part of original Op Plan:** Choose an item |
| **Estimated in service date:** | **Emergency Related Request?** Choose an item |
| **Eng./Constr. Resources Budgeted?** Choose an item | **Facility Type** (check all that apply)**:** ☐ PTF ☐ non-PTF ☐ local PTF ☐ Distribution ☐ N/A (General Plant) |
| **EJ Community:** Choose an item | **Authorization Type:** Choose an item |
| **Total Capital Request:** | |

## [1] Executive Summary

*When completing this form =>*

*Follow instructions contained in 'Project Authorization Form - Guide - 2022-01-01' located here: \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms*

*For additional support please reach out to tranepac@eversource.com*

# [2] Project Costs Summary

*Note: Dollar values are in thousands and rounded to nearest thousand*

| Line item Category | Prior Authorized | Actuals to Date | 2023 to Go | 2024 | 2025 | 2026 | 2027 | 2028 | Total Request |
|---|---|---|---|---|---|---|---|---|---|
| 1. ROW / Easements / Land Acquisition | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 2. Environmental Approvals / Permits | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 3. Outreach | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 4. Siting Approvals / Permits | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 5. Engineering / Design | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 6. Materials (Eversource purchased) | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 7. Construction (incl materials by contractors) | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 8. Testing / Commissioning | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 9. Project Mgmt Team | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 10. Removals | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 11. Other | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 12. Risks | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| **SUBTOTAL DIRECTS W/ RISKS** | **$** | **$** | **$** | **$** | **$** | **$** | **$** | **$** | **$** |
| 13. Indirects/Overhead | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 14. AFUDC | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| **PROJECT TOTAL – BASELINE BUDGET** | **$** | **$** | **$** | **$** | **$** | **$** | **$** | **$** | **$** |
| 15. Contingency | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| | | | | | | | | | |
| **TOTAL CAPITAL REQUEST** | **$** | **$** | **$** | **$** | **$** | **$** | **$** | **$** | **$** |
| 16. Reimbursables/Customer Contribution | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| | | | | | | | | | |
| **PROJECT TOTAL (LESS REIMBURSABLES)** | **$** | **$** | **$** | **$** | **$** | **$** | **$** | **$** | **$** |
| O&M | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| **TOTAL REQUEST** | **$** | **$** | **$** | **$** | **$** | **$** | **$** | **$** | **$** |

Detail other costs, project risk items and their allocations:

| Risk | Allocation |
|---|---|
| 1. -*Enter First Risk Item Here-* | $ |
| 2. | $ |
| 3. | $ |
| 4. | $ |
| 5. | $ |
| **Total** | $0 |

**Explain unique payment provisions, if applicable:**

**Identify and detail any unique O&M impacts resulting from this project:**

# [3] Technical Justification

## Project Need, Objective and Justification

## Project Scope

## Substation Equipment *(use as applicable, delete if N/A)*

| Station | Device Position / Nomenclature | Device Removals *include manufacturer* | Device Additions *include manufacturer* |
|---|---|---|---|
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |

## Line Inspection Report *(use as applicable, delete if N/A)*

| XXXX Line Report | |
|---|---|
| Total structures | 0 |
| Steel lattice structures | 0 |
| Steel monopole structures | 0 |
| Wood structures | 0 |
| Planned Replacements or Removals | 0 |
| Original structures remaining | 0 |

| XXXX Inspection Report | |
|---|---|
| Priority A | 0 |
| Priority B | 0 |
| Priority C | 0 |
| Priority D | 0 |
| **Priority Rating** | |
| Priority A | No defects found |
| Priority B | Minimal defect; Repair as needed |
| Priority C | Moderate defect. Repair or replace under next scheduled maintenance |
| Priority D | Severe defect; Replacement recommended |
| | |

## Background

# [4] Alternatives Considered

*Environmental Justice Considerations shall be included as part of the alternative analysis*

# [5] Project Schedule

*Include required milestones as outlined in Capital Project Approval Process Job Aid JA-AM-2001-A. Add additional key milestones specific to this project as needed.*

| Milestone | Scheduled Completion Date |
|---|---|
| IFR Approval | |
| SDC Approval (for applicable projects) | |
| Conversion of Tx development costs, 183 to 107 (applicable to projects that require SSF approval and/or ISO preferred alternative selection) | |
| EPAC Partial Funding Approval (for applicable projects) | |
| Preliminary Design Completion (or latest pre-full funding design phase) | |
| EPAC Full Funding Approval | |
| Siting Approval (for applicable projects) | |
| Start of Construction | |
| Project In-Service Date (ISD) | |
| Project Need Date (for applicable projects) | |
| ISO Related Milestones: (for applicable projects) | |
| • ISO Preferred Alternative Selected | |
| • PAC Presentation | |
| • TCA Submittal | |

# [6] Regulatory Approvals

### EJ Community Considerations:

*For projects requiring environmental justice community considerations per required state regulatory requirements, detail what community impacts may result from the project and any mitigations to be made to minimize those impacts.*

# [7] Risk and Risk Mitigation Plans

### Contingency:

### Risk Mitigation:

| Risk | Mitigation |
|---|---|
| 1. *-Enter First Risk Item Here-* | |
| 2. | |
| 3. | |
| 4. | |
| 5. | |
| **Total** | |

## [8] References

| References |
|---|
| 1. |
| 2. |
| 3. |
| 4. |
| 5. |

## [9] Attachments (One-Line Diagrams, Images, etc.)

*Please make sure all attachments provided here are referenced above in the appropriate section of the PAF with the correct attachment number.*

| Attachment | Included in Submittal? |
|---|---|
| A. Cost Estimate | *YES / NO / N/A* |
| B. P6 Schedule | *YES / NO / N/A* |
| C. Constructability Review | *YES / NO / N/A* |
| D. System and Station One-Lines | *YES / NO / N/A* |
| E. | *YES / NO / N/A* |
| F. | *YES / NO / N/A* |

**INSTRUCTIONS:**
It is the responsibility of the initiator to contact the subject matter experts in the listed area disciplines to determine if the project considerations contained in this list are applicable to their project. They should fill out the checklist and determine a transition plan for the purpose of project execution. See the PAF Guide for additional instruction.

| **Project Checklist - Transmission & Substation Capital Project** | | | |
|---|---|---|---|
| **Project Name:** | **Project Number:** | | |
| **Facility Type:** ☐BPS ☐BES ☐PTF ☐local PTF ☐non-PTF ☐CIP ☐Distribution ☐General Plant ☐CONVEX ☐SCADA | | | |
| PLANNING | | | |
| Is a NX-9 required? | Choose an item | | |
| Is an ISO-NE PAC presentation required? | Choose an item | | |
| ISO-NE Presentation Date (if completed): | Enter Date | | |
| Cost in ISO-NE Presentation ($M) (if completed): | Enter Cost ($M) | | |
| Is a PPA required? | Choose an item | | |
| ISO-NE Approval Date (if completed): | Enter Date | | |
| Is a TCA Application Required? | Choose an item | | |
| TCA Submittal Date (if submitted): | Enter Date | | |
| Cost in TCA Submittal ($M) (if submitted): | Enter Cost ($M) | | |
| Enter ISO-NE RSP / Asset Condition ID, if assigned: | Enter ISO-NE ID | | |
| PLANNING/PROTECTION & CONTROLS | | | |
| Are RAS/SPS/UVLs affected? | Choose an item | | |
| OPERATIONS | | | |
| Outage Required? | ☐ Primary Equipment (Power Transfer) | ☐ Secondary Equipment (P&C only) | ☐ Outage Not Required |
| Do SCLL Conditions Exist? | Choose an item | | |
| Has an outage schedule been approved? | Choose an item | | |
| Are Operations & Maintenance procedures/training required? | Choose an item | | |
| STANDARDS | | | |
| Does the project include standard equipment and designs? | Choose an item | | |
| SUBSTATION ENGINEERING | | | |
| Does this impact Revenue Metering | Choose an item | | |
| Is preliminary short circuit/ breaker duty analysis required? | Choose an item | | |
| Are there any changes to the baseline audible noise? | Choose an item | | |
| Is there an impact to the existing ground grid? | Choose an item | | |
| Is a Transient Over Voltage (TOV) analysis required? | Choose an item | | |

| Project Checklist - Transmission & Substation Capital Project | |
|---|---|
| **Project Name:** | **Project Number:** |
| **P&C ENGINEERING** | |
| OP-22 - Are PMUs and DDR required? | Choose an item |
| If BPS, is an NPCC Directory #4 presentation required? | Choose an item |
| Are ISO-NE OP-24 Appendix B updates necessary? | Choose an item |
| **TRANSMISSION LINE ENGINEERING** | |
| Are there any changes that affect the baseline EMF? | Choose an item |
| Are there any changes that affect the baseline EMI? | Choose an item |
| **SITING** | |
| Has Siting reviewed this project? | Choose an item |
| Name of Siting contact: | |
| Is a Siting filing required? *(If yes, list in regulatory approvals section)* | Choose an item |
| **PERMITTING** | |
| Is there any permitting required? *(If yes, list in regulatory approvals section)* | Choose an item |
| **PROJECT SERVICES (OUTREACH) and ROW WORK COORDINATION** | |
| Has Project Services reviewed this project? | Choose an item Choose an item |
| Name of Project Services contact: | |
| What is the level of outreach expected? | Choose an item |
| Has ROW Coordination reviewed this project? | Choose an item |
| Is this project coordinating with other existing scheduled work? | Choose an item |
| **ENVIRONMENTAL JUSTICE COMMUNITIES** | |
| Has the Equity and Environmental Justice team reviewed this project? | Choose an item |
| Name of Equity and Environmental Justice contact: | |
| Is any part of this project in an Environmental Justice Community? | Choose an item |
| Was the Equity Framework Checklist completed? | Choose an item |
| Has enhanced outreach required per State Regulatory requirements been completed? | Choose an item |
| **INITIATOR** | |
| Has a field constructability review been completed? | Choose an item |

| Project Checklist - Transmission & Substation Capital Project | |
|---|---|
| **Project Name:** | **Project Number:** |
| INVESTMENT RECOVERY | |
| Does the project require development of an Investment Recovery plan? | Choose an item |
| COST ESTIMATING | |
| What team/firm prepared the cost estimate? | Choose an item |
| Name of the person who prepared the estimate: | |
| Was the estimate reviewed by Eversource Estimating? | Choose an item |

# Job

# Aid

**Capital Project Approval Process**

JA-AM-2001-A, Rev. 7

Process Owner:

Effective Date: 06/01/2022

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# 1 Purpose

This job aid provides instructions and guidance on the process for initiating and then obtaining technical and financial approval for capital projects within all three states. This job aid will focus on project initiation, solution vetting by the Solution Design Committee (SDC), and approval of the Project Authorization Form (PAF) by the Eversource Project Approval Committee (EPAC) for transmission and substation projects and by each of the state Project Approval Committees (state PACs) for distribution projects. The authorization forms used by each committee can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms. Completed samples of each form can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms\Sample Forms\. This job aid supports the guidance contained in Accounting Policy Statement 1 (APS01), Operations Project Authorization, which can be found on the Eversource intranet at https://eversourceenergy.sharepoint.com/sites/Accounting/SitePages/Accounting-Policies-%26-Procedures.aspx.

# 2 Affected Groups

As described in Responsibilities and General Instructions, the System Planning, Asset Management, Transmission Interconnections, and Project Management groups, along with the SDC, EPAC, and state PAC committees will have primary responsibility for the project review and approval process. The following general groups will also be affected by this job aid as their participation is critical to the successful initiation, development, review, and approval of capital projects.

- Transmission Line, Substation Design, Substation Technical, Protection and Controls, Grid Modernization and Distribution Engineering
- Construction
- Scheduling
- Licensing and Permitting
- Environmental
- Siting and Project Services
- Procurement
- Investment Planning
- Operations
- Engineering Project Controls
- Transmission Project Controls

# 3 Responsibilities

## 3.1 Project Initiator

In general, Transmission and Substation projects will be initiated by either the System Planning (Reliability, Capacity, Distributed Energy Projects), Asset Management (Asset Condition Projects), Grid Modernization or Transmission Interconnections Department (Interconnection Projects). Distribution street and line projects with no substation scope will be initiated by the Distribution Engineering group. Telecom projects (aside from OPGW projects which will be initiated by the Asset Management group) will be initiated by the Telecommunications Engineering Group.

For Transmission and Substation projects, the project initiator is responsible for establishing a project by securing initial (or in some cases partial) funding. The initiator is responsible for development of the establishing document(s), typically an initial funding request (IFR), a program level PAF with initial funding for early program development or a partial funding request in some cases. The project initiator will be responsible for securing funding from state PAC for Distribution line projects.

For Transmission and Substation projects, a PM will typically be assigned at the time initial funding is procured. As outlined in section 3.2 the PM assumes responsibility for the project budget and schedule as well as organizing engineering, siting, permitting and outreach activities working with the various departments. If a project manager is assigned, the project initiator will support the PM during the engineering phases and PAF development as needed.

For applicable projects (See Section 3.4.1 below for details), the project initiator is responsible for the development of the Solution Selection Form (SSF) and presentation of the project preferred and alternative solutions to the SDC.

For projects that do not have a project manager assigned, the project initiator will be responsible for; coordinating conceptual engineering activities and conceptual cost estimates (-25%/+50%) to support alternatives analysis; coordinating preliminary engineering activities and developing an updated +/-25% planning grade cost estimate. The project initiator will then be responsible for updating the PAF and securing full funding from the EPAC or a state PAC. Once a project is fully approved and funded, project ownership transfers to the project manager for the project execution and closeout phases.

## 3.2 Project Manager (PM)

For projects managed by the Transmission Projects organization a PM will typically be assigned at the time initial funding is procured. The PM will own the project budget and schedule from the time of assignment. The PM is also responsible for; coordinating conceptual engineering activities and conceptual cost estimates (-25%/+50%) to support alternatives analysis; coordinating preliminary engineering activities and developing an updated +/-25% planning grade cost estimate by driving collaboration with the various engineering disciplines and affected departments. The project manager is responsible for overseeing the development of partial and full funding requests. PAFs shall include the financial and technical project details, a detailed backup cost estimate, a project checklist, the current project schedule, a listing of required schedule milestones as shown in Attachment G, and a Constructability Review (CR) Form (CR form required for full funding requests) at least seven working days prior to the next scheduled EPAC meeting for Transmission and Substation projects or three working days prior to the next scheduled state PAC meeting for Distribution projects. For transmission projects, the detailed cost estimate must be in accordance with Attachment D to PP4 (ISO-New England Planning Procedure 4). The estimate should be formatting in-line with Transmission Project Control's Work Breakdown Structure (WBS).

The PM will also be responsible for any required supplemental approval with support from the project initiator, if necessary.

## 3.3 Project Sponsor

Typically, the Project Sponsor will be the director of the project initiator. The Project Sponsor will be responsible for review and approval of project documents before they are submitted to the committees for approval.

## 3.4 Solution Design Committee (SDC)

The SDC will serve as solution development gate keepers to ensure the best solution is selected, ensure guiding principles are followed, and drive standardization. SDC will review project alternatives, scope, and conceptual grade cost estimates during the solution vetting process. The SDC administrators will use the email address SolutionDesignCommittee@eversource.com to communicate with project initiators and for all committee communications. More information on solution vetting can be found in Section 4.4 and the full responsibilities of the SDC are contained in Attachment A, Solution Design Committee Charter.

### 3.4.1 Project Types

The SDC will review and approve solutions for the following Transmission and Substation project types:

- System Planning – Reliability and Capacity Projects
- Asset Management – Programs (OPGW Programs, Breaker Programs, etc.), Rebuilds, Conductor/Cable Replacements, Program releases with significant scope in addition to the program.
- Transmission Interconnection Projects – Projects on track to sign Interconnection Agreements may be reviewed by the SDC at the request of the sponsoring engineering director.
- Other Telecom projects and programs

Like-for-like asset replacement projects and individual releases within defined programs with minimal scope variations will not need to be reviewed or approved by the SDC. EPAC member directors will also have discretion to determine whether a specific project or program will require review and approval by the SDC. In certain cases where there is a quorum of EPAC representatives present at the SDC, an initial or partial funding request may be presented in conjunction with an SSF for the same project at the SDC.

## 3.5 Eversource Project Approval Committee (EPAC)

The EPAC will be responsible for the review and approval of the technical and financial merits of transmission and substation projects. For project and program initiations, the EPAC will review and authorize Initial Funding Request Forms (IFRs) typically up to $250,000, including Program Level PAFs with initial funding. The EPAC may also review requests for initial funding beyond $250,000 if a larger funding amount is required to complete preliminary engineering activities. For previously initiated projects and programs, the EPAC will review partial and full funding PAFs, Program Level PAFs, and Program Release Forms. The EPAC will review conceptual grade cost estimates (-25%/+50%) for projects looking to secure partial funding and will review planning grade cost estimates (+/-25%) for projects looking to secure full funding authorization. The EPAC administrators will use the email address TranEPAC@eversource.com to communicate with project teams and for all committee communications The full responsibilities of the EPAC are contained in Attachment B, Eversource Project Authorization Committee Charter.

### 3.5.1 Project Types

The EPAC will review and approve the following project types:

- Planned Transmission line and/or substation projects (Transmission and Distribution substation over $300,000 total cost)
- Transmission line and/or substation programs (OPGW Programs, Breaker Programs, etc.)
- Telecom projects that impact transmission lines and/or substations
- New or reconfiguration of a distribution substation (regardless of voltage level)
- Substation projects with transmission and distribution components will be reviewed as a package, only by the EPAC
- Customer interconnection requests that require transmission or substation work
- Emergency projects greater than $500,000 total cost (refer to section 6 for further details)
- Any other project per the discretion of the EPAC chairperson(s)

All other distribution projects will be reviewed and approved by the state PAC (see section 3.6.1). See Section 5 for review process for transmission and substation projects less than or equal to $300,000 total cost.

## 3.6 State Project Approval Committees (CT PAC, MPAC, and NH PAC)

The state PACs will be responsible for the review and approval of the technical and financial merits of Distribution projects. There will be three different project approval committees to review and approve the projects; one from each state (CT PAC, MPAC, and NH PAC).

The state PACs will review initial funding requests to develop detailed engineering and to support early establishment of projects in Eversource financial and scheduling systems. Regardless of cost, initial funding requests shall adhere to PAC approval processes and shall include a schedule by which engineering plans to complete detailed engineering, produce a planning grade cost estimate and present for full funding authorization. The state PAC committee chair will track projects that are given approval for initial funding and ensure timely submission, review and approval of PAFs for full funding authorization. Distribution projects looking to secure full funding authorization shall develop PAFs containing a planning grade (+/-25%) cost estimate.

The full responsibilities of the state PACs are contained in Attachment C, State Project Approval Committee (State PAC) Charter.

### 3.6.1 Project Types

The state PACs will review and approve the following project types:

- Overhead distribution projects greater than $300,000.
- Underground distribution and combined overhead-underground distribution projects greater than $1 million.
- Customer interconnection requests with total cost estimates (including indirect costs) greater than $1 million. Customer interconnection projects less than $1 million are reviewed and approved in PowerPlan and typically will not require review and approval by the state PAC.
- DG interconnection request without substation scope that require a new feeder (regardless of cost) or with total cost estimate greater than $500,000. Note that DG interconnection projects with substation scope will be reviewed by EPAC as described in Section 3.5.1.)

Note that per APS01 and Operations executive management, all other underground, overhead, and underground-overhead mixed distribution projects under the dollar thresholds listed above but over $500,000 total cost require PAF documentation. Projects $300K or greater but less than $500K may require PAF documentation at the discretion of the PAC committees, except for emergency projects and standard distribution underground interconnections in EMA, both of which will only require PAFs for projects $500K or greater in all cases. These PAFs will be reviewed and approved directly in PowerPlan. The approving director can use his/her discretion to require any of these projects to be reviewed at the state PAC. All other transmission and substation projects will be reviewed and approved by the EPAC (see section 3.5.1).

## 3.7 Cost Estimating

The Transmission Cost Estimating team will support development of project cost estimates for Transmission and Substation projects. Depending on the complexity of the project, the approximate cost, and other factors the level of support provided by the Cost Estimating team may range from taking the lead in developing the estimate to reviewing an estimate prepared by the project team. To request support from the Cost Estimating team, project teams should complete the Estimate Request Form which can be found at \\nu.com\data\SharedData\Estimating-Shared\2) Estimate Templates\1) Est Request form\Current\ and submit to Cost_Estimation_Request@Eversource.com

# 4 General Instructions

The process to proceed with each successive phase of a capital project is designed to ensure that there is a valid need, the right solution alternatives are evaluated, the technical approach is sound, and resources are budgeted and prudently spent. The overall process flow for Transmission and Substation projects is depicted in Attachment D, Transmission and Substation Project Approval Process Flow Charts. Attachment E, Transmission and Substation Project Approval Process Detailed Flow Chart is a 17”x11” flowchart with more detailed descriptions. The overall process flow for Distribution projects is depicted in Attachment F, Distribution Project Approval Process Flow Chart. The initiation and major engineering and approval phases of the process flow charts correspond to the sections below.

These general instructions are for the project types listed in Sections 3.5.1 and 0. Refer to Section 5 for instructions for planned transmission and substation projects less than or equal to $300,000. Refer to Section 6 for instructions for securing approval of emergent work.

## 4.1 Project Initiation

Following the identification of a project need the initiator will secure a project number. Project initiators can email TranEPAC@eversource.com for assistance securing a project number. Project initiators will then complete an IFR and submit it to EPAC via TranEPAC@eversouce.com. The IFR may be used to request funding per Section 3.5. The form can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms\. The initiator will be required to state the project need and objectives and include an explanation of the funding request amount, including a budget for conceptual and preliminary engineering activities and the required schedule milestones as shown in attachment G. The IFR may include a budget for initial internal siting and permitting preparation activities. The IFR should not include funding for detailed engineering or procurement of any material. The EPAC chairman may decide to approve the request directly or may request that the initiator present the request for input and feedback to the EPAC.

Once an IFR is approved, the EPAC administrator will send the approved form to Investment Planning to create a project and submit it for Delegation of Authority approvals in PowerPlan, the Eversource software tool for financial approval. The initial funding is obtained once delegation of authority has been performed through PowerPlan in accordance with APS01 (See Section 4.5.3 for more information on Delegation of Authority Policy). Once fully approved in PowerPlan a Work Order (WO) will be assigned. The EPAC administer will copy the Project Management on the submittal to Investment Planning so that a Project Manager can be assigned as appropriate. The Project Manager should work with their Investment Planning contact to determine the work order setup best suited for the management and execution of the project. For some projects the Project Manager role may remain with the Project Initiator, be assigned to a lead engineer, or be assigned to an individual in Maintenance and Operations.

## 4.2 Project Initiation for Programs

Initial funding can also be requested at the program level using the Program Level Project Authorization Form. The form can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms. The funding can be used to advance specific project scope under an approved program. Sections 4.5.1 and 4.5.2 contains more information on full approval of programs and program level releases.

## 4.3 Conceptual Engineering

The project initiator should follow the Project Alternative Process in procedure M2-TP-2018 for the identification, development and selection of project alternatives. As described in detail in M2-TP-2018, the project manager with support from the project initiator will coordinate the following activities with input from affected departments:

- Incorporate designs from standards library and develop scope and major equipment lists for all alternatives under consideration.
- Conceptual engineering of all competitive alternatives including early field review and desktop analysis.
- Identification of key project risks with the appropriate level of detail with respect to constructability, routing, outage planning, possible Single Contingency Loss of Load (SCLL) conditions and applicable mitigation actions, siting and permitting, environmental impacts, community and external stakeholder impacts, site control, procurement, etc.
- Identification of any land rights needs.
- Develop project strategies to mitigate identified risks.
- Conceptual grade cost estimates (-25%/+50%) for all competitive alternatives (at least the preferred solution and leading alternative). Order of magnitude cost estimates (-50%/+200) should be provided for alternatives that are not competitive with the preferred solution. The project team should request support from the Cost Estimating team for all estimates.

The project team will then recommend a preferred solution and document the rationale for the choice of preferred solution. For conceptual engineering deliverable requirements refer to procedure M7-EN-2000R0 Engineering Deliverables and a listing of the deliverables found at \\nu.com\data\SharedData\EPAC Project Deliverables.

## 4.4 Solution Vetting

Prior to proceeding with Preliminary Engineering of the preferred solution, more comprehensive projects and asset condition projects at the program level will need to be reviewed and approved by the SDC (See Section 3.4.1 for list of project types the SDC will review). The project team will submit a Solution Selection Forms (SSF) to the SDC via SolutionDesignCommittee@eversource.com at least seven business days prior to the next scheduled SDC meeting. The SDC will review the SSF and confirm that the project team has selected the best solution. The SSF will require a statement of the project need and objectives, documentation of the alternatives analysis, scope and major equipment list for the preferred solution, and a conceptual grade cost estimates for the preferred solution and any competitive alternatives. The form can be found at

\\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms. The full responsibilities of the SDC are contained in Attachment A, Solution Design Committee Charter. Once reviewed and approved by the Solution Design Committee, projects will proceed with Preliminary Engineering.

Certain Transmission and substation projects do not require review and approval by the SDC such as like-for-like asset replacement projects and individual releases within defined programs with minimal scope variations. Questions regarding the need for a project to visit the SDC can be clarified by contacting SolutionDesignCommittee@eversource.com.

Distribution street and line projects without substation components may also require a solution vetting process. The state PAC chairperson may require more complex distribution street and line projects to complete a distribution design review prior to state PAC approval.

## 4.5 Preliminary Engineering

Once the project team has chosen a preferred solution with scope definition, it can proceed with preliminary engineering and development of an updated cost estimate of the preferred solution. In order to receive full funding approval, projects will require planning grade (+/-25%) cost estimates. The cost estimate shall be submitted in the form of the Project Controls work breakdown structure (WBS). The WBS format can be referenced the EPAC PAF template located at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms. The project team should request support from the Cost Estimating team to develop the planning grade cost estimate.

The project team will work with the affected groups listed in Section 2 to complete more in-depth investigations, develop a mitigation plan for project risks, and refine project strategies

For preliminary engineering deliverable requirements refer to procedure M7-EN-2000R0 Engineering Deliverables and a listing of the deliverables found at \\nu.com\data\SharedData\EPAC Project Deliverables. Example preliminary deliverables include:

- Constructability Review
- ROW Environmental Mapping
- Preliminary Three-Line
- SS Control Enclosure Layout
- UG Plan and Profile

If the initial funding is not sufficient to complete preliminary engineering and develop a planning grade cost estimate, then the project team can prepare a PAF and make a request for partial funding at EPAC per Section 3.5. The request should generally be for the budget amount that will be required to fulfill project engineering activities, prepare a full funding request and planning grade cost estimate. For large scale projects multiple partial funding requests may be required. Partial funding may include funds for detailed engineering activities. As with IFRs, partial funding requests may include a budget for internal siting and permitting preparation activities but should not include funding for procurement of any material. The request should also include a listing of required schedule milestones as listed in Attachment G.

After a minimum of preliminary engineering is completed, the PAF will be completed and the project will be presented to either the EPAC or the state PAC for full approval and funding authorization. PAFs that will be reviewed at EPAC should be submitted to TranEPAC@eversource.com at least seven business days prior to the next scheduled EPAC meeting. For the project types listed in Section 3.4.1, the EPAC will not review full funding requests unless the project has already been approved by the Solution Design Committee. The project checklist, a Constructability Review Form, a copy of the current project schedule, a listing of required schedule milestones as shown in Attachment G and a detailed backup cost estimate in accordance with Attachment D to ISO-NE Planning Procedure 4 (PP4) must accompany the PAF.

## 4.6 Full Project Authorization

### 4.6.1 Program Approval

EPAC will review and approve Asset Management programs using the Operations Program Level Project Authorization Form. The form can be found at\\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms. In addition to the information required on the PAF for a regular project (need, objectives, scope, background/justification, etc.) the Program Level PAF will also require a financial evaluation completed on a unit cost basis so that the capital cost of each application of the program can be fully understood. The unit cost is often based on a similar project that has been completed.

- A listing of proposed circuits or substations by state that will be included in the scope of the program.
- An estimate of the program capital investment value by state.
- A proposed schedule for bringing forward and executing the program level releases.
- A description of the investigations that will be needed at each location to develop the scope and cost estimate at a specific site.

As described in Section 4.1.1 Program Level PAFs may also be combined with an initial funding request at the program level so that the initiator will have funds to develop the scope of the program at specific sites and bring forward full funding program release requests. Partial funding may be obtained for individual program release requests when initial funding is not sufficient to complete preliminary engineering and develop a planning grade cost estimate.

### 4.6.2 Program Release Authorization

Once the scope, site-specific cost estimate and constructability reviews are completed for a particular location or circuit, a Program Release Form will be submitted for full funding. The Program Release Form can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms\. Each Release will summarize the scope and cost estimate at a specific location and discuss any variances between the scope or cost estimates from the expected unit costs and scope approved in the Program Level PAF. Once an individual program release is approved at EPAC, any initial funding costs that were originally charged at the program level will be journaled to the specific project, which will allow those costs to be capitalized along with the specific project and also make more budget available at the program level to develop additional Program Release Forms. Once approved, the approval process for a Program Release Form will be the same as stated above for the full funding PAF.

### 4.6.3 Delegation of Authority

Once approved, the EPAC or state PAC administrator will submit the EPAC-approved PAF to Investment Planning for approvals in PowerPlan in accordance with the company Delegation of Authority Policy (DOA). The DOA specifies the capital authorization level of various company positions (manager, director, vice president, senior vice president / subsidiary president, Executive vice president, etc.). The MS Excel file “Power Plan Project Approval Trees” found at N:\EPAC\Administrative\ lists which specific individuals at each authorization level that will be required to approve projects authorized by EPAC. There are separate approval trees listed for transmission line and substation major projects and distribution substation projects. The full project funding is attained once delegation of authority has been performed through PowerPlan in accordance with APS01. PMs should include up to thirty days in project schedules to complete approvals in PowerPlan and sixty days for projects that will require Delegation of Authority approval by the Eversource Subsidiary Board.

Projects must be fully approved in PowerPlan before their scope or cost estimates can be shared publicly. This includes but is not limited to sharing cost estimates with ISO-NE, sharing cost estimates with customers for customer or interconnection projects, filing a siting or permitting application that includes a cost estimate, and conducting project outreach. If a project schedule requires the release of project information prior to full project approval in PowerPlan is possible, then a project team can request approval from EPAC to release the information. If EPAC approval is also not possible, then the project team can seek the SDC’s approval to release the information.

## 4.7 Detailed Engineering, Siting, and Permitting

Once the project is fully authorized in PowerPlan, the project team can proceed with detailed engineering, siting and permitting application filings, project outreach, ordering major material, and other development activities.

## 4.8 Construction and Construction Variance Monitoring

The project manager or lead will manage the project’s execution and construction while monitoring the project’s spend vs. its authorized cost. In cases where the project, totaling greater than $300K for planned work or greater than $500K for emergent work, will exceed its APS-01 tolerances, or there is a significant change to the project’s technical design or a significant change to the project’s scope the project manager shall submit a Revised PAF or Supplemental Request Form (SRF) to the EPAC or state PAC.

A Revised PAF can be submitted under one or more of these conditions, given the listed condition(s) is(are) the primary driver for the change:

1. Revised PAF – Scope [Applicable to all projects]
    - Capital investment for additional units of property that were not previously part of the project scope.
    - Significant change(s) in technical design (i.e. OH vs UG, air vs. GIS, etc.)

2. Revised PAF – Pre-Construction [Applicable to projects yet to begin construction forecasting 5% or greater than their original total full funding authorization]

    - Market conditions cause awarded (or to be awarded) vendor contract amount(s) for labor or material to be higher than the amount(s) for the equivalent labor or material allocation(s) in the approved full funding estimate.
    - An agency, stakeholder or impacted party external to Eversource causes an uncontrollable change to the project resulting in higher project costs.
    - Indirect rate(s) increase from the full funding estimate.

    Projects forecasting 5% or greater than their original total full funding authorization prior to construction should consult PM management to decide if pre-construction revised authorization should be pursued. Projects forecasting over $5M total cost will require a detailed review by Cost Estimating to corroborate the project forecast's cost increase drivers match the intent of Pre-Construction re-authorization. Project that will exceed their APS-01 tolerances must seek reauthorization, either revised or supplemental funding depending on the circumstance.

Additional requests for a Revised PAF can be evaluated on a case-by-case basis by the EPAC committee. The justification for all Revised PAFs is subject to the review and approval of the EPAC committee.

A SRF shall be submitted where the project will exceed its APS-01 tolerances in all other cases than those allowing for revised funding. Supplemental authorization requests should be prepared as soon as it is likely that the project cost is expected to increase and the updated project forecast exceeds the APS01 tolerance for the current authorization. Supplement requests should also be submitted once a scope change is identified. The SRF can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms.

If a supplement is approved by the EPAC or state PAC, the committee administrator will send the approved SRF to Investment Planning for submittal for Delegation of Authority approvals in PowerPlan. When determining when to submit a supplement, PMs should note that attaining full approval in PowerPlan may take up to thirty days and sixty days for projects that will require Delegation of Authority approval by the Eversource Subsidiary Board.

## 4.9 Project Closeout

All project documents will be closed and affected databases updated upon project closeout in accordance with M6-PM-2001, Project Management Process, or applicable local project closeout process.

# 5 Instructions for Planned Projects $300K or less (Annuals) including Capital Tools

Each year annual transmission and distribution substation budgets are approved and funded to support the many small planned projects that will be completed that year. Per APS01 and Operations executive management, planned transmission and distribution substation projects less than or equal to $300,000 total cost and emergency projects less than or equal to $500,000 total cost do not require their own PAFs.

Planned annuals require the initiator to document the work scope, justification, estimated cost and in-service date(ISD). To create a work order that will charge against one of these annual budgets for a small planned transmission or distribution substation project, the project initiator must follow the Capital Annuals Process found at \\nu.com\data\SharedData\EPAC\Administrative. The EPAC Annuals administrative team can be contacted at CapitalAnnualsRequest@eversource.com.

# 6 Instructions for Emergent Work

Each year annual transmission and distribution substation budgets are approved in each region and funded to support the many small projects that classify as emergent work within that year. In the case of emergency projects to fix equipment that failed while in-service or is at high risk of imminent failure that needs to be addressed real-time not allowing for fully planned project development, only those emergency projects exceeding $500,000 total cost will require a PAF.

Emergent annuals require the initiator to document the work scope and justification. To create a work order that will charge against one of these annual budgets for an emergency transmission or distribution substation project, the project lead must follow the Capital Annuals Process found at \\nu.com\data\SharedData\EPAC\Administrative. The EPAC Annuals administrative team can be contacted at CapitalAnnualsRequest@eversource.com.

# 7 Definitions & Acronyms

| | |
|---|---|
| Annuals | Annuals refers to the annual project budgets that are approved to support small projects and small emergent work projects. |
| APS | Eversource Accounting Policy Statement |
| Conceptual Engineering | The project design phase required to obtain a project cost estimate accurate to -25%/+50% and to generate an SSF |
| Conceptual Estimate | A cost estimate with target accuracy of -25% to +50% |
| Construction | The project phase for the implementation of an engineered project |
| DOA | Delegation of Authority |
| Detailed Engineering | The project phase following preliminary engineering. See M7-EN-2000R0 Engineering Deliverables for further details. |
| Emergent Work | Refers to work to fix equipment that failed while in-service or is at high risk of imminent failure that needs to be addressed real-time |
| Engineering Estimate | A cost estimate with target accuracy of +/-10% |
| EPAC | Eversource Project Approval Committee |
| IFC Engineering | Issue for Construction Engineering phase follows detailed engineering. IFC engineering completion is typically required to support an Engineering |

| | |
|---|---|
| | Estimate (+/-10%). See M7-EN-2000R0 Engineering Deliverables for further details. |
| Initial Funding | • Initial Funding provides exploratory early development dollars intended to facilitate refinement of the project concept, particularly the project need, justification and objectives.<br>• Project scope and alternatives as well as a resource loaded, project schedule shall be developed.<br>• Initial funding can support funding up to Preliminary design if the requested dollars are <$250K (Some exceptions may be considered).<br>• Initial Funding is not intended to support complete project design and engineering and should not fund the project beyond the Preliminary design phase.<br>• The core project team should be assembled using Initial Funding. |
| IFR | Initial Funding Request Form required to initiate a project with funding and setup a Work Order, the initiator will complete an IFR and submit it to the EPAC. |
| ISD | In-Service Date |
| ISO-NE | The independent operator of New England's bulk electric power system and transmission lines. ISO-NE manages a comprehensive regional planning process. |
| M2-TP-2018 | The Project Alternative Strategy procedure document published by the System Planning organization. |
| M6-PM-2001 | The Project Management Process procedure document |
| M6-PM-2012 | Constructability Review procedure document |
| M7-EN-2000R0 | Engineering Deliverables procedure document |
| PAF | Project Authorization Form required by Accounting Policy Statement 2 for the purpose of requesting authorization of capital funds for a particular project |
| Partial Funding | • Partial Funding is intended to fund design/engineering for the project as well as project support including site evaluation/prep activities, siting and outreach plans, early procurement activities (in some cases Limited Notice to Proceed for Long-Lead equipment), site testing, outage planning activities, etc.<br>• Partial Funding should not be used to purchase material nor be used for construction activities.<br>• Since Partial Funding typically requests >$250K, a PAF should be completed. |
| Planned Annual | Scheduled capital work costing $300K or less that is <u>not</u> to fix equipment that failed while in-service that needs to be addressed real-time |
| Planning Estimate | A cost estimate with target accuracy of +/-25% |

| | |
|---|---|
| PM | Project Manager |
| PowerPlan | Eversource financial approval tool |
| PP4 | ISO-NE Planning Procedure 4 |
| Preliminary Engineering | The project phase for the engineering needed to obtain a project cost estimate accurate to ± 25% and to generate a PAF |
| Program Level PAF | Authorization document for programs. A program is a substation need that will be addressed at numerous sites (i.e. Oil Circuit Breaker Replacements, Relay Replacements, etc.) or a line need that will be addressed on numerous circuits (i.e. Structure Replacements, Fiber Optic Expansion, etc.) |
| Program Release Form | Authorization form for a specific site or circuit of an approved program. |
| SCLL | Single Contingency Loss of Load |
| SDC | Solution Design Committee is a three-state committee that reviews substation and transmission projects and programs to ensure that the best solution is selected and standardization is implemented across the company |
| SSF | Solution Selection Form – Document that the SDC will review and approve |
| SRF | Supplement Request Form |
| State PAC | State Project Approval Committee. There will be three state project approval committees for distribution projects: MPAC, CT PAC, and NH PAC |
| WBS | Work Breakdown Structure |
| WO | Work Order |

# 8 Revision History

Revision 7 – June 1, 2022

- Updated Attachment G project milestones required
- Added Revised PAF – pre-construction definition to section 4.8
- Updates section 3.6, PAC Project Types
- Other minor updates

Revision 6 – January 1, 2022

- Updated dollar threshold requirements in accordance with Jan 1 2022 APS01 update
- Updated section 5 to reflect modified annuals process
- Updated section 3.6 to include updated state PAC instructions
- Update section 3.7 Cost Estimating instructions
- Updated sections 4.1, 4.3, 4.6 to add schedule milestone requirements
- Added attachment G, PAF Schedule Milestone Requirements
- Added definitions for initial funding and partial funding
- Added IFC Engineering to Attachment D and E
- Other minor updates

Revision 5 – June 1, 2020

- Added Sections 4.1.1, 4.5.1, and 4.5.2 containing description and instructions for initiating programs, Program Level PAFs, and Program Release Forms
- Added Sections 4.5.3 to add additional description of Delegation of Authority Policy
- Added Sections 5 and 6 to include instructions for securing authorization for emergent work and annual projects
- All Sections: Added detail and instructions for distribution line projects, distributed generation interconnection projects, and communications engineering projects.
- Other minor updates

Revision 4 – November 2, 2018

- Updated all sections to align with updated project lifecycle including new Project Initiation Process and Solution Design Committee Process

Revision 3

- Minor updates

Revision 2 – October 27, 2017

- All Sections: Changed from TRC and CPAC to EPAC and state PACs

Revision 1 – December 7, 2016

- 4 General Instructions – Added location of forms
- 4.2 Detailed Engineering Approval – Added requirement to complete TAF Transmission Checklist

- 5 Definitions and Acronyms – Added acronyms used in Attachment F
- 6 Summary of Changes – Added section
- Added Attachment F, TAF Transmission Checklist and Instructions

Revision 0 – August 28, 2016

- Original issue

# Attachment A, Solution Design Committee Charter

**Purpose**

The Solution Design Committee (SDC) will serve as solution development approval committee to ensure the best solution is selected, ensure guiding principles are followed, and drive standardization. SDC will review project alternatives, scope, and conceptual grade cost estimates during the solution vetting process.

**Applicability**

The SDC is responsible for solution selection review of electrical Transmission and Substation projects in all three states of the following types:

- System Planning – Reliability & Capacity Projects
- Asset Management – Programs (OPGW Programs, Breaker Programs, etc.), Rebuilds, Conductor/Cable Replacements, Program releases with significant scope in addition to the program.
- Transmission Interconnection Projects – Projects on track to sign Interconnection Agreements may be reviewed by the SDC at the request of the sponsoring engineering director.

Like-for-like asset replacement projects and individual releases within defined programs with minimal scope variations will not need to be reviewed or approved by the SDC. EPAC member directors will also have discretion to determine whether a specific project will require review and approval by the SDC.

**Objectives**

The objectives of the SDC are as follows:

1. Confirm that the right subject matter experts from affected departments were appropriately involved in the conceptual engineering, alternatives analysis, and solution selection.
2. Confirm project teams identified and considered a robust set of alternatives when selecting the best solution in accordance with M2-TP-2018 Project Alternative Process.
3. Ensure the development of project solutions and alternatives incorporate standardized design and equipment, where practical/possible.
4. Review initial conceptual engineering, scope, and cost estimates for all potential project alternatives. Cost estimates should be of conceptual grade (-25%/+50%) for the preferred solution and competitive alternatives.
5. Review and confirm that project teams identify project risks for the preferred solution and its alternatives with the appropriate level of detail with respect to constructability, routing, outage planning, possible SCLLs, siting and permitting, environmental impacts, community and external stakeholder impacts, land rights needs and site control, procurement, etc.
6. Review and confirm project team's alternatives analyses and choice for preferred solutions and ensure the rationale is appropriately documented.
7. Coordinate with EPAC to initiate any needed process changes on at least a biennial basis.

## Membership

SDC shall consist of an executive sponsor, a chairperson, voting members, an administrator, and non-voting attendees as shown on the below table. The chairperson may designate additional voting members, if required.

***SDC Membership List***

| SDC Role | Company Position |
|---|---|
| Executive Sponsor | VP, Substation and Transmission Engineering |
| Co-Chairperson | Director, Substation Design Engineering |
| Co-Chairperson | Director, Substation Protection and Controls |
| Administrator(s) | As appointed by the Chairperson |
| Voting Member | Director, Transmission Business and Quality Assurance |
| Voting Member | Director(s), System Planning |
| Voting Member | Director, Transmission Line Engineering |
| Voting Member | Director, Substation Technical Engineering |
| Voting Member | Director, Distribution Technical Engineering |
| Voting Member | Director, Engineering Capital Projects |
| Voting Member | Director, Project Performance |
| Voting Member | Director(s), Transmission Project Management |
| Voting Member | Director, Transmission Siting and Project Services |
| Voting Member | Director(s), Station Operations |
| Voting Member | Director, Transmission Project Controls |
| Voting Member | Director, Engineering Project Controls |
| Attendee | Manager of Project Solutions |
| Attendee | Manager of Siting |
| Attendee | Manager of Project Services |
| Attendee | Manager of Estimating |
| Attendee | Manager of Asset Management |
| Attendee | Manager(s) of Substation Engineering |
| Attendee | Manager(s) of Protection and Controls |
| Attendee | Manager(s)/Lead(s) of Transmission Line and Civil Eng. |
| Attendee | Manager(s) of Substation Technical Engineering |
| Attendee | Manager(s) of System Planning |
| Attendee | Manager of Licensing and Permitting |
| Attendee | Manager(s) of Environmental Affairs |
| Attendee | Manager(s) of Procurement |
| Attendee | Supervisor(s)/Manager(s) of Outage and Ops Planning |
| Attendee | Manager of Generation Interconnections |
| Attendee | Manager of Operational Compliance |
| Attendee | Manager(s) of Transmission Line Operations |
| Attendee | Manager(s) of Station Operations/ Field Engineering/ System Dispatch |
| Attendee | Manager(s) of Systems Engineering |
| Attendee | Manager of ISO Policy and Economic Analysis |

**Roles and Responsibilities**

Executive Sponsor

- Provide senior management vision, direction and feedback to the SDC
- Appoint the Chairperson(s)

Chairperson(s)

- Preside at SDC meetings
- Designate a Voting Member as an alternate to preside at meetings in his/her absence
- Solicit Voting Member appointments
- Appoint a SDC administrator
- Determine the meeting schedule and location(s)
- Approve meeting agendas
- Review meeting materials on the agenda prior to the SDC meeting
- Hold votes as required
- Participate in discussions and votes to meet the SDC objectives
- Initiate the biennial review of the SDC process in coordination with EPAC
- Create subcommittees as required

Voting Member

- If required, designate a manager in the same organization as a voting alternate to participate in the SDC
- Review meeting materials on the agenda prior to the SDC meeting
- Participate in discussions and votes to meet the SDC objectives
- Participate in the biennial review of the SDC process as required

Administrator

- Schedule meetings
- Prepare draft meeting agendas
- Quality Screening of Project Documentation
- Distribute meeting materials to attendees five working days prior to a scheduled SDC meeting
- Record the result of any votes
- Prepare and distribute meeting notes
- Record Solution Select Forms presented and their attachments and meeting results
- Attend to and manage the SolutionDesignCommittee@eversource.com email inbox

Project Lead/Initiator

- Complete a Solution Selection Form (including statement of need, project objectives, alternatives analysis, and scope for preferred solution) for any proposed capital project that meets the applicability criteria described above
- Ensure that SDC objectives listed above are fully met, and that subject matter experts from affected departments were included in the alternatives analysis.

- Submit the Solution Selection Form to the SDC administrator via SolutionDesignCommitee@eversource.com at least five working days prior to the next scheduled SDC meeting (ensures document screening and review by committee members)
- Attend the SDC meeting and present the Solution Selection Form to SDC members
- Revise the Solution Selection Form and/or respond to comments from the SDC as required

**Quorum**

The Chairperson(s) (or alternate) plus a minimum of four Voting Members (or alternates) shall constitute a quorum for voting purposes if all appropriate disciplines are present to challenge the merits of the project(s).

**Meeting Schedule and Location**

The SDC shall schedule meetings twice monthly. The Chairperson(s) may cancel a meeting or require more frequent meetings from time to time as required. The location of the SDC meeting will rotate between MA, CT, and NH.

**Voting**

The Voting Members and the Chairpersons, or their designated alternates, are eligible to vote. A vote is carried by a simple majority. Each person has one vote.

**Subcommittees**

The Chairperson may establish standing or ad hoc subcommittees as required to meet the objectives of the SDC. Subcommittees shall be chaired by a voting member of the SDC or their designated alternate.

# Attachment B, Eversource Project Authorization Committee Charter

**Purpose**

The Eversource Project Authorization Committee (EPAC) reviews and approves the technical and financial merits of Transmission and Substation projects, including the selection of preferred solutions that are consistent with Eversource priorities (e.g. safety, reliability, cost efficiency). The EPAC authorizes, monitors and adjusts capital expenditure and resources for projects; prioritizes projects for the capital program and defers projects based on budget and resource availability.

**Applicability**

The EPAC is responsible for the technical review and financial approval of electrical Transmission and Substation projects in all three states.

**Objectives**

The objectives of the EPAC are as follows:

1. Receive, review, and approve Initial Funding Request Forms
    a. Review the need and confirm that a capital project is needed to address the need.
    b. Review and approve the project's objectives.
    c. Ensure the funding request amount, planned development activities, and schedule are appropriate.
2. Receive, review, and approve PAFs for all projects that meet the Accounting Policy Statement No. 1 threshold. A lower threshold may be imposed by the EPAC, if desired.
    a. Ensure that the PAF justification is valid.
    b. Review and approve the project's technical merits.
    c. Ensure that all reasonable alternatives were evaluated and appropriately rejected.
    d. Ensure the scope and cost estimates are reasonable to ± 25% for projects seeking full authorization.
    e. The committee has the ability to review engineering designs, ensuring the proposed work is in accordance with Eversource Standards, evaluate load implications, assess root cause / reliability and vet out all possible alternatives.
    f. Not all projects presented are requesting funding and require a vote – these projects will be noted "FOR DISCUSSION ONLY".
    g. Ensure the PAF project checklist is complete.
    h. Ensure the Constructability Review Form is complete
    i. Ensure the financial analysis is reasonable to the accuracy appropriate to the project phase.
    j. Ensure the project schedule is achievable and reasonable to the accuracy appropriate to the project phase
    k. Ensure risks and mitigation plans are identified.
3. Evaluate project funding and priorities relative to the five-year capital plan.

4. Ensure project approval statuses and DOA progress are reviewed at least monthly.
5. Prioritize projects for deferment or cancellation.
6. Review EPAC process performance and lessons learned and coordinate with the state PACs to initiate any needed changes on at least a biennial basis.

**Membership**

EPAC shall consist of an executive sponsor, a chairperson, voting member directors, an administrator, and non-voting attendees as shown on the below table. The chairperson may designate additional voting member directors, if required.

*EPAC Membership List*

| EPAC Role | Company Position |
|---|---|
| Executive Sponsor | VP, Transmission Projects |
| Co-Chairperson | Director, Transmission Project Controls |
| Co-Chairperson | Director, Transmission Business and Quality Assurance |
| Administrator | EPAC Program Manager |
| Member Director | Director(s), Transmission Project Management |
| Member Director | Director, Transmission Line Engineering |
| Member Director | Director, Substation Design Engineering |
| Member Director | Director, Substation Technical Engineering |
| Member Director | Director, Substation Protection and Controls |
| Member Director | Director, Distribution System Planning |
| Member Director | Director, Transmission System Planning |
| Member Director | Director, Siting and Project Services |
| Member Director | Director(s), Investment Planning |
| Member Director | Director, Sustainability and Environmental Affairs |
| Member Director | Director, Reliability, Compliance and Implementation |
| Member Director | Director(s), Transmission/System Ops |
| Member Director | Director, System Operations |
| Member Director | Director(s), Field Operations Lines |
| Member Director | Director(s), Field Operations Substations |
| Member Director | Director(s), Field Engineering |
| Member Director | Director, Engineering Project Controls |
| Member Director | Director, Engineering Capital Projects |
| Member Director | Director, Project Performance |
| Attendee | Manager of Project Solutions |
| Attendee | Manager of Transmission Siting |
| Attendee | Manager of Project Services |
| Attendee | Manager of Transmission Cost Estimating |
| Attendee | Manager of Licensing and Permitting |
| Attendee | Manager(s) of Procurement |
| Attendee | Manager(s) of Substation Engineering |
| Attendee | Manager(s) of Protection and Controls |
| Attendee | Manager(s)/Lead(s) of Transmission Line and Civil Eng. |
| Attendee | Program Manager- Transmission Capital Program |

| | |
|---|---|
| Attendee | Supervisor(s)/Manager(s) of Outage and Ops Planning |
| Attendee | Manager of Standards |
| Attendee | Manager of Budget and Investment |
| Attendee | Manager of Generation Interconnections |
| Attendee | Manager of Asset Management |
| Attendee | Manager of Operational Compliance |
| Attendee | Manager(s) of Line Operations |
| Attendee | Manager(s) of Substation Technical Engineering |
| Attendee | Manager(s) of System Planning |

## Roles and Responsibilities

Executive Sponsor

- Provide senior management vision, direction and feedback to the EPAC
- Appoint the Chairperson(s)

Chairperson(s)

- Preside at EPAC meetings
- Designate a Member Director as an alternate to preside at meetings in his/her absence
- Solicit Member Director appointments from the leadership team
- Appoint a EPAC administrator
- Determine the meeting schedule and location(s)
- Approve meeting agendas
- Review meeting materials on the agenda prior to the EPAC meeting
- Hold votes as required
- Participate in discussions and votes to meet the EPAC objectives
- Initiate the biennial review of the EPAC process in coordination with the other EPACs
- Create subcommittees as required

Member Director

- If required, designate a manager in the same organization as a voting alternate to participate in the EPAC
- Review meeting materials on the agenda prior to the EPAC meeting
- Participate in discussions and votes to meet the EPAC objectives
- Participate in the biennial review of the EPAC process as required

Administrator

- Schedule meetings
- Prepare draft meeting agendas
- Quality Screening and Quality Measurement of Project Documentation.
- Distribute meeting materials to attendees three working days prior to a scheduled EPAC meeting

- Record the result of any votes
- Prepare and distribute meeting notes
- Record PAFs and SRFs presented and meeting results
- Submit PAFs and SRFs approved to Investment Planning for Delegation of Authority approvals in PowerPlan
- Attend to and manage the TranEPAC@eversource.com email inbox

Project Lead/Initiator

- Complete a PAF (including financial and technical details, cost estimate, project checklist, and Constructability Review Form) for any proposed capital project or change, ensuring that EPAC objective one items are fully met, and obtain any necessary reviews and approvals prior to submittal to the EPAC
- Submit the PAF to the EPAC administrator via TranEPAC@eversource.com at least seven working days prior to the next scheduled EPAC meeting for engineering approval (ensures document screening and review by committee members)
- Attend the EPAC meeting and present the PAF to EPAC members
- Revise the PAF and/or respond to comments from the EPAC as required

**Quorum**

The Chairperson(s) (or alternate) plus a minimum of four Member Directors (or alternates) shall constitute a quorum for voting purposes if all appropriate disciplines are present to challenge the merits of the project(s).

**Meeting Schedule and Location**

The EPAC shall schedule meetings twice monthly. The Chairperson(s) may cancel a meeting or require more frequent meetings from time to time as required.

**Voting**

The Member Directors and the Chairpersons, or their designated alternates, are eligible to vote. A vote is carried by a simple majority. Each person has one vote.

**Subcommittees**

The Chairperson may establish standing or ad hoc subcommittees as required to meet the objectives of the EPAC. Subcommittees shall be chaired by a voting member of the EPAC or their designated alternate.

# Attachment C, State Project Approval Committee (State PAC) Charter

**Purpose**

The State Project Approval Committees (State PACs) review and challenge the technical merit of proposed distribution projects, and approve them as consistent with Eversource priorities (e.g. safety, reliability, cost efficiency).

**Applicability**

This charter applies to the three state PACs in Connecticut, Massachusetts and New Hampshire that are responsible for all Eversource electrical distribution projects originating in their respective states.

**Objectives**

The objectives of a state PAC are as follows:

1. Receive, review and approve Project Authorization Forms (PAFs) for all projects that meet the Accounting Policy Statement No. 1 threshold. A lower threshold may be imposed by the state PAC, if desired.
    a. Ensure that the PAF justification is valid.
    b. Review and approve the project's technical merits.
    c. Ensure the scope and cost estimates are reasonable to ± 25% for projects seeking full authorization and to -25%/+50% for projects seeking initial funding.
    d. Ensure that all reasonable alternatives were evaluated and appropriately rejected.
    e. The committee has the ability to review detailed engineering designs, ensuring the proposed work is in accordance with our Standards, evaluate load implications, assess root cause / reliability and vet out all possible alternatives.
    f. Not all projects presented are requesting funding and require a vote – these projects will be noted "FOR DISCUSSION ONLY".
    g. Ensure risks and mitigation plans are identified.
    h. Ensure the PAF project checklist is complete.
    i. Ensure the Constructability Review Form is complete.
    j. Ensure the financial analysis is reasonable to the accuracy appropriate to the project phase.
    k. Ensure the project schedule is achievable and reasonable to the accuracy appropriate to the project phase.
    l. If CEO or subsidiary board approval is required, ensure project and cost analysis has been reviewed by the Enterprise Risk Management and Financial Planning & Analysis departments.
2. Release engineering labor and funds for detailed engineering on approved PAFs.
3. Review projects authorized for detailed engineering at least monthly to control engineering spend.

4. Review state PAC process performance and lessons learned and coordinate with the other state PACs and the EPAC to initiate any needed changes on at least a biennial basis.
5. Provide a forum for design review for more complex distribution street and line projects. The state PAC chairperson will use their judgement to determine which projects require distribution design review prior to state PAC approval.

**Membership**

Each state PAC shall consist of an executive sponsor, a chairperson, voting member directors, an administrator and non-voting attendees as shown in the below table. The chairperson may designate additional voting member directors, if required.

*State PAC Membership List*

| State PAC Role | Company Position |
|---|---|
| Executive Sponsor | VP, Engineering |
| Chairperson | Director, Distribution Engineering |
| Administrator | Appointed by Chairperson |
| Voting Member | Manager, Distribution Engineering |
| Voting Member | Manager, Investment Planning |
| Voting Member | Manager, Distributed Generation |
| Voting Member | Manager/Supervisor, Field Engineering |
| Voting Member | Manager, Integrated Planning, Scheduling |
| Voting Member | Manager, System Operations |
| Voting Member | Manager, Field Operations |
| Voting Member | Manager, Substation Technical Engineering |
| Voting Member | Manager, Engineering Standards |
| Attendee | Project Manager(s) |

**Roles and Responsibilities**

Executive Sponsor

- Provide senior management vision, direction and feedback to the state PAC
- Appoint the Chairperson

Chairperson

- Preside at state PAC meetings
- Designate a Member Director as an alternate to preside at meetings in his/her absence
- Solicit Member Director appointments from the leadership team
- Appoint a state PAC administrator
- Determine the meeting schedule and location(s)
- Approve meeting agendas
- Review meeting materials on the agenda prior to the state PAC meeting

- Hold votes as required
- Participate in discussions and votes to meet the state PAC objectives
- Release funds on approved PAFs for detailed engineering
- Initiate the biennial review of the state PAC process in coordination with the other state PACs
- Create subcommittees as required
- Determine which projects should complete a design review prior to state PAC approval

Voting Member

- If required, designate a voting alternate to participate in the state PAC
- Review meeting materials on the agenda prior to the state PAC meeting
- Participate in discussions and votes to meet the state PAC objectives
- Participate in the biennial review of the state PAC process as required

Administrator

- Schedule meetings
- Prepare draft meeting agendas
- Distribute meeting materials to attendees three days prior to a scheduled state PAC meeting
- Record the result of any votes
- Prepare and distribute meeting notes
- Record PAFs presented and meeting results in the capital project database

Project Initiator (typically engineer level)

- Complete a PAF for any proposed capital project, ensuring that state PAC objective 1 items are fully met, and obtain any necessary reviews and approvals prior to submittal to the state PAC
- Submit the PAF to the state PAC administrator at least three working days prior to the next scheduled state PAC meeting for engineering approval
- Attend the state PAC meeting and present the PAF to state PAC members
- Revise the PAF and/or respond to comments from the state PAC as required
- Once fully authorized, if costs exceed the approved PAF levels by more than the amounts shown in Accounting Policy Statement No. 1, create a SRF, attach to the previously approved PAF, and resubmit for review and approval.

**Quorum**

The Chairperson(s) (or alternate) plus a minimum of two Member Directors (or alternates) shall constitute a quorum for voting purposes if all appropriate disciplines are present to challenge the merits of the project(s).

**Meeting Schedule**

Each of the state PACs shall schedule meetings at least bimonthly. The Chairperson may cancel a meeting or require more frequent meetings from time to time as required.

**Voting**

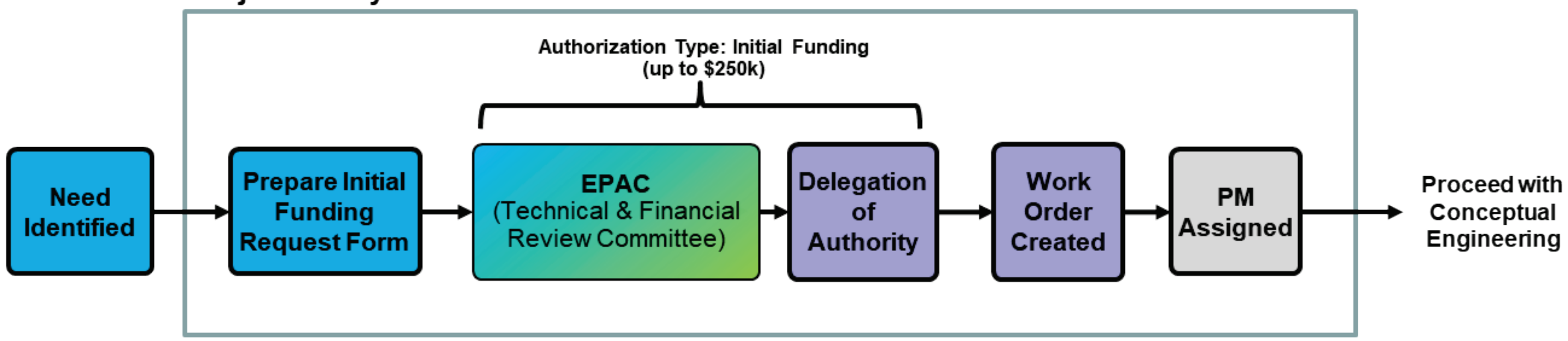
The Member Directors and the Chairperson, or their designated alternates, are eligible to vote. A vote is carried by a simple majority. Each person has one vote.

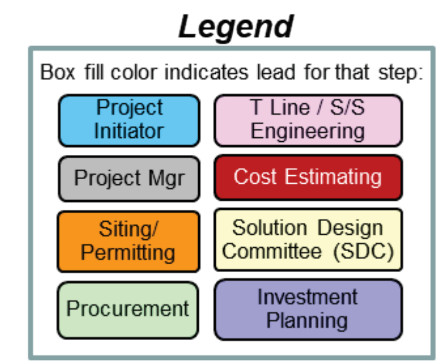
**Subcommittees**

The Chairperson may establish standing or ad hoc subcommittees as required to meet the objectives of the state PAC. Subcommittees shall be chaired by a voting member of the state PAC or their designated alternate.

## Attachment D, Transmission and Substation Project Approval Process Flow Charts

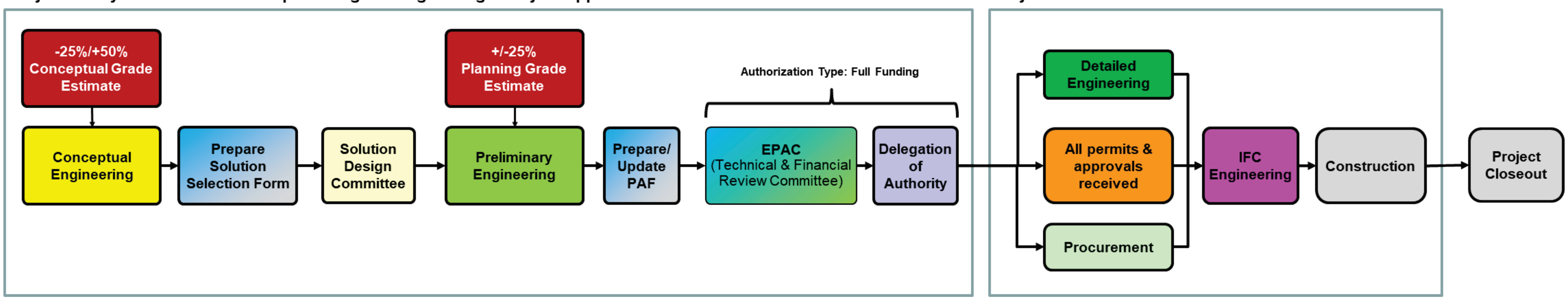
### Project Lifecycle Initiation Process



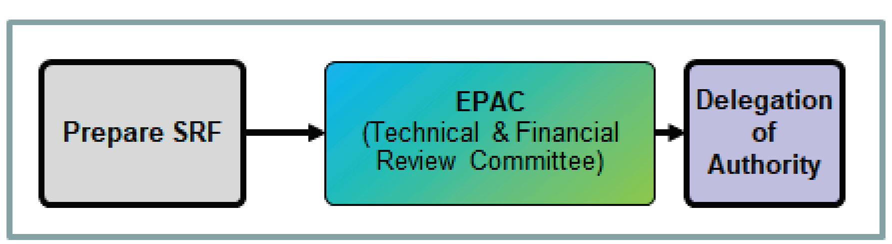

### Project Lifecycle Process - Conceptual Engineering through Project Approval:

### Project Execution:

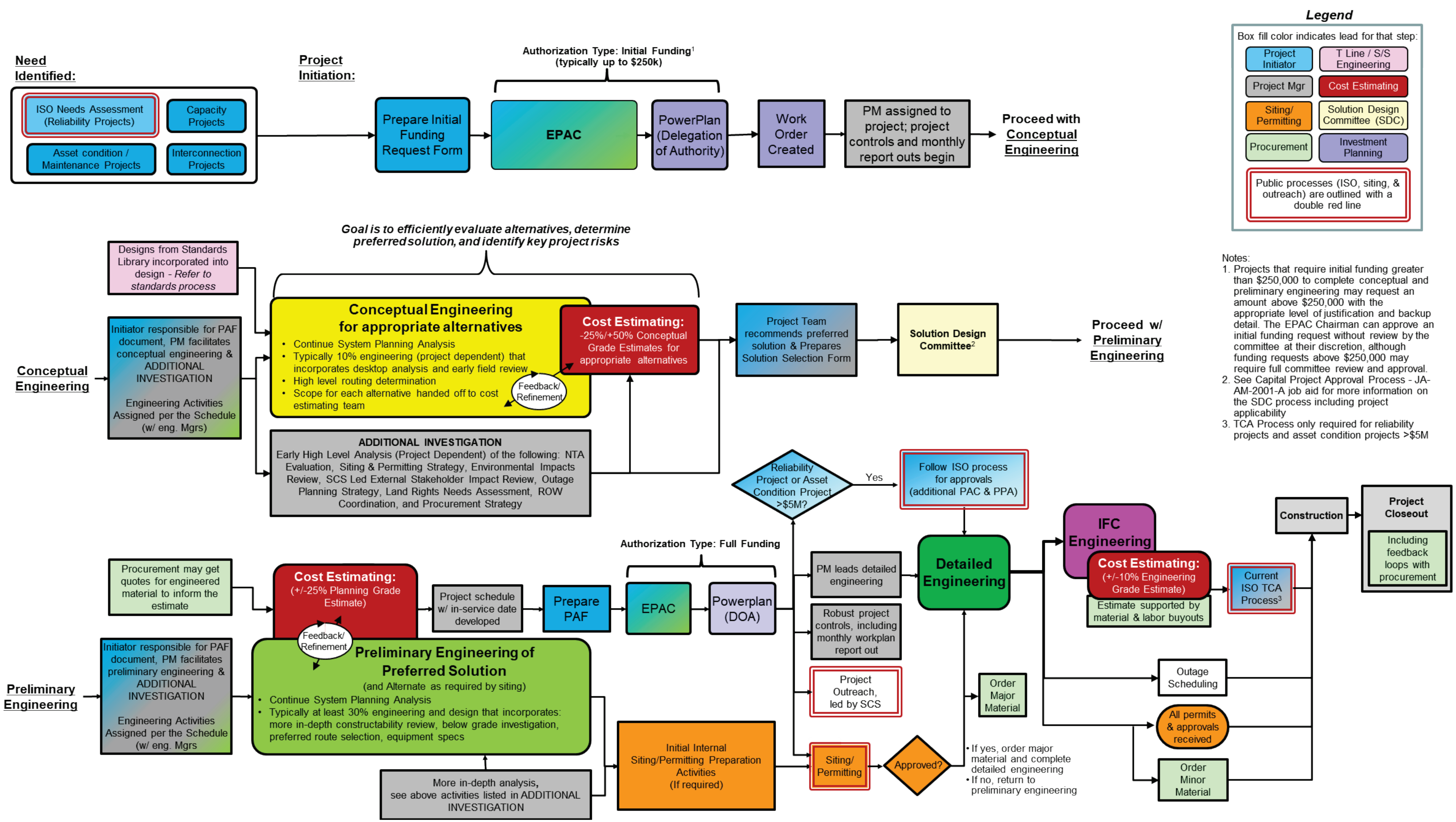



## Supplemental Authorization Process

(if required per APS guidelines)



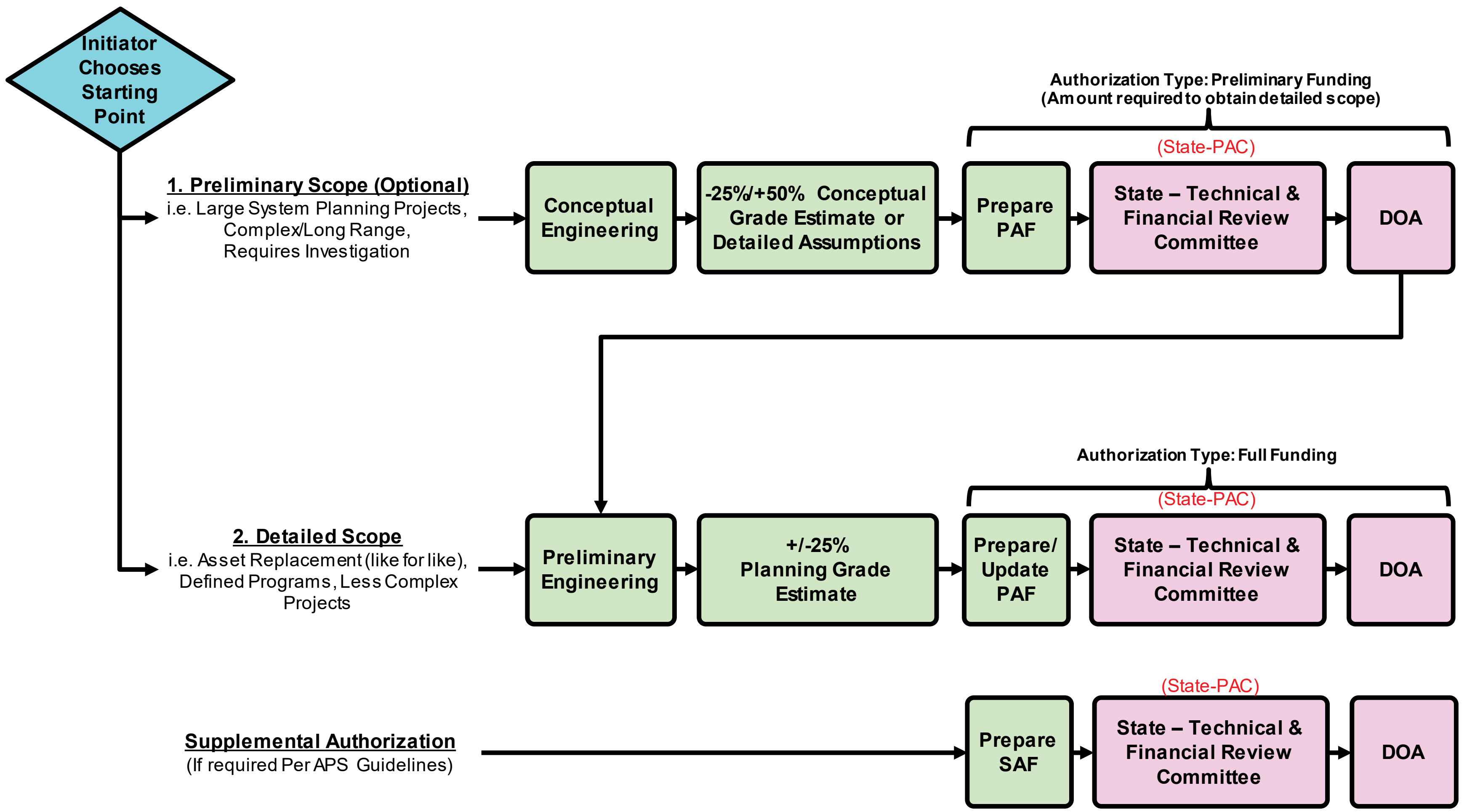
## Attachment E, Transmission and Substation Project Approval Process Detailed Flow Chart




Notes:

1. Projects that require initial funding greater than $250,000 to complete conceptual and preliminary engineering may request an amount above $250,000 with the appropriate level of justification and backup detail. The EPAC Chairman can approve an initial funding request without review by the committee at their discretion, although funding requests above $250,000 may require full committee review and approval.
2. See Capital Project Approval Process - JA-AM-2001-A job aid for more information on the SDC process including project applicability
3. TCA Process only required for reliability projects and asset condition projects >$5M

## Attachment F, Distribution Project Approval Process Flow Chart



## Attachment G, PAF Schedule Milestone Requirements

Use the appropriate list of milestones for the authorization type to populate the project milestone schedule within the IFR or PAF.

Inclusion of the appropriate milestones is required for IFR and PAF submittal.

These milestones support baselining of the project schedule. In the case of initial funding the initial project baseline schedule is defined within twenty business days of IFR approval. The IFR milestones are used as reference to support the initial baseline. In the cases of partial funding and full funding the included milestones are representative of the schedule baseline established ahead of submittal. Projects can re-baseline at each funding stage of a project.

| INITIAL FUNDING REQUEST FORM | PROEJCT AUTHORIZATION FORM<br>[PARTIAL AND FULL FUNDING REQUESTS] |
|---|---|
| *Project initiator leads this effort*<br><br><u>Required Items</u><br><br>➢ SDC Approval (for applicable projects)<br>➢ Conversion of Tx development costs, 183 to 107 (applicable to projects that require SSF approval and/or ISO preferred alternative selection)<br>➢ EPAC Partial Funding Approval (for applicable projects)<br>➢ EPAC Full Funding Approval<br>➢ Start of Construction<br>➢ Project In-Service Date (ISD)<br>➢ Project Need Date (for applicable projects)<br><br>In certain cases partial funding may not be necessary and the project can proceed directly from initial to full funding. Connect with Project Manager to identify the appropriate project stage. | *Project Manager leads this effort*<br><br><u>Required Items</u><br><br>➢ IFR Approval<br>➢ SDC Approval (for applicable projects)<br>➢ Conversion of Tx development costs, 183 to 107<br>➢ (applicable to projects that require SSF approval and/or ISO preferred alternative selection)<br>➢ EPAC Partial Funding Approval (for applicable projects)<br>➢ Preliminary Design Completion (or latest pre-full funding design phase)<br>➢ EPAC Full Funding Approval<br>➢ Siting Approval (for applicable projects)<br>➢ Start of Construction<br>➢ Project In-Service Date (ISD)<br>➢ Project Need Date (for applicable projects)<br>➢ ISO Related Milestones (for applicable projects)<br>• ISO Preferred Alternative Selected<br>• PAC Presentation<br>• TCA Submittal |

# Visual Comparison of Design Criteria

Comparison as-of March 2024

The following guide compares in a summarized fashion the differences between Eversource's New Hampshire electric system design criteria of both legacy guiding documents and today's Distribution System Planning Guide (DSPG 2020). For a detailed comparison of the planning criteria within ED-3002, SYSPLAN-010 and DSPG 2020, refer to the comparison table of design criteria.

The different planning criteria documents were in use as the primary document as follows:

| | |
|---|---|
| ED-3002 | January 10, 2003 to August 1, 2018 |
| SYSPLAN-010 | August 1, 2018 to September 22, 2020 |
| DSPG 2020 | September 22, 2020 to Present |

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## 1.0 – Base Case Loading

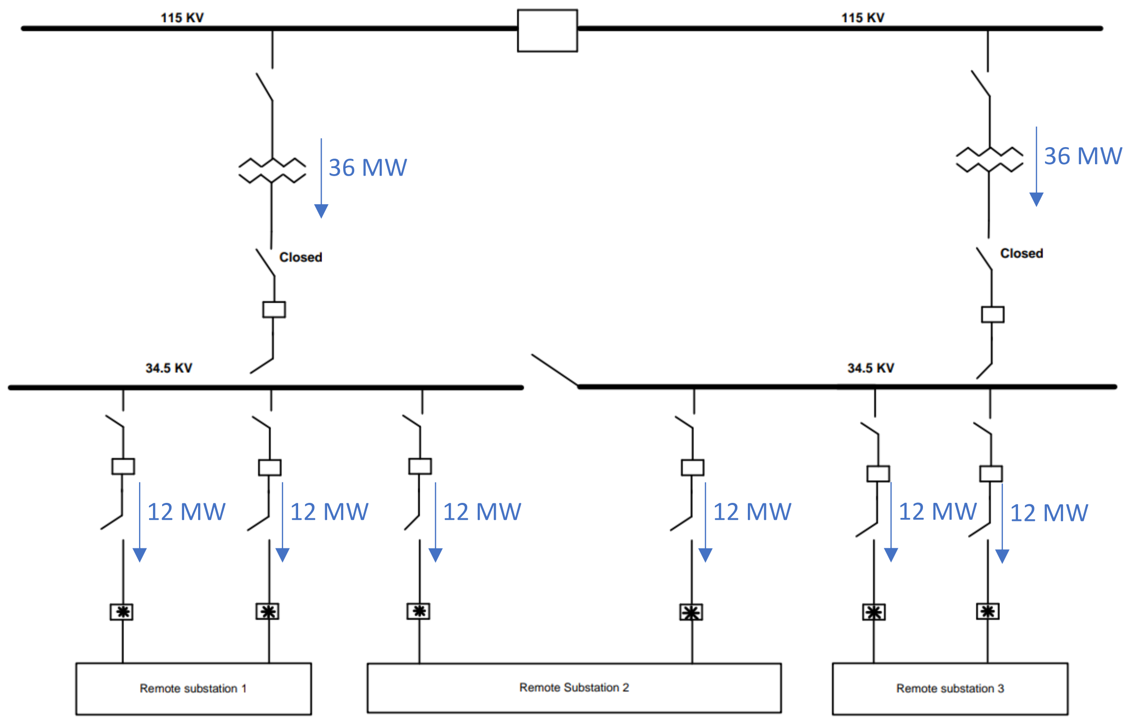


*Figure 1. Normal condition substation loading. Asterisk denotes a normally open line-tie.*

Transformer Ratings:

| Document | ED-3002 | SYSPLAN-010 | DSPG 2020 |
|---|---|---|---|
| **Top Nameplate** | 44.8 MVA | 44.8 MVA | 44.8 MVA |
| **Normal (Continuous)** | 50.0 MVA * | 44.0 MVA | 44.0 MVA |
| **Long-Term Emergency (4 or 12 hour rating)** | 50.0 MVA * | 51.0 MVA | 53.0 MVA |
| **Short-Term Emergency (30 minute rating)** | 67.2 MVA | 67.0 MVA | 61.0 MVA |

| Document | ED-3002 | SYSPLAN-010 | DSPG 2020 |
|---|---|---|---|
| **Design Criteria** | 97% to 127% of Nameplate Rating (85% of TFRAT*) | 75% of Nameplate Rating | 95% of Nameplate Rating |
| **Transformer Capacity** | 42.5 MVA | 33.6 MVA | 42.5 MVA |
| **Transformer Loading** | 36 MVA | 36 MVA | 36 MVA |
| **Design Compliance** | Meets Design Criteria | Design Violation | Meets Design Criteria |

* TFRAT = PSNH Transformer Rating = Singular rating was calculated above nameplate and is equivalent to both today's Normal and LTE ratings.

# 2.0 – Single Contingency Event, Transformer

## 2.1 – Initial Event (t=0+ event start)

Initial system loading before System Operator intervention. With loss of the transformer, the remaining transformer in service serves all load. For this example, assuming it is installed, transformer protection initiates load shed of a feeder (12 MW).

Feeder load shed is not an acceptable solution in newer design criteria.

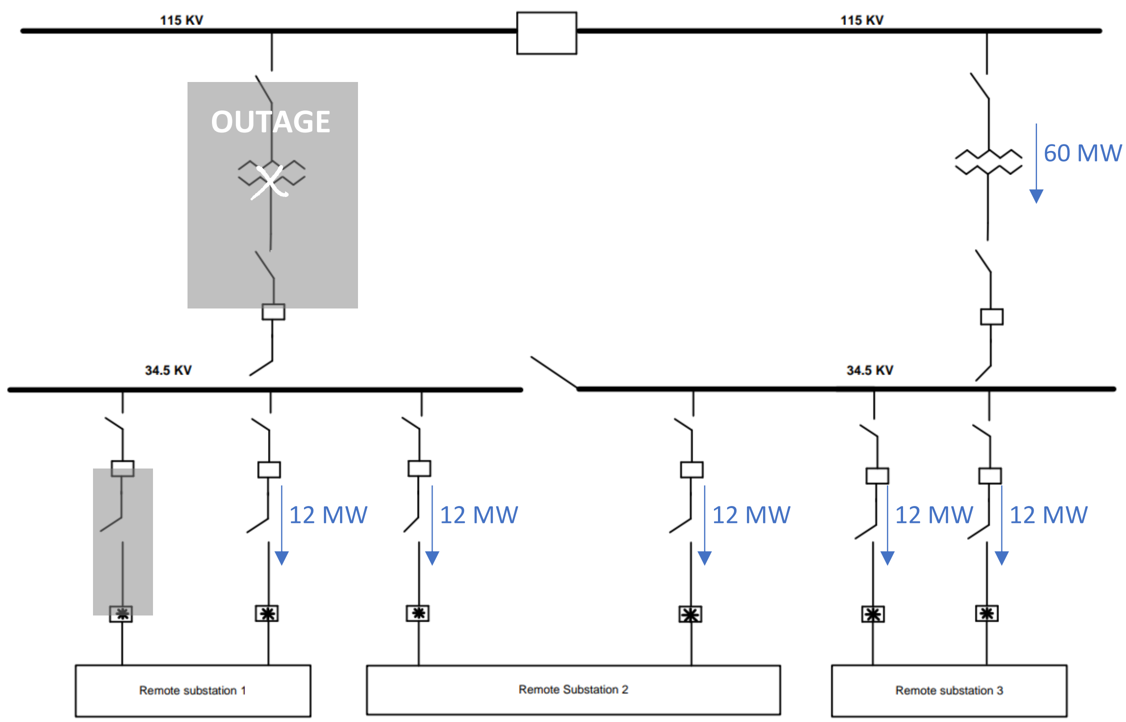


*Figure 2. Transformer N-1 Single Contingency with initial substation loading identified. One feeder is tripped as part of the station's transformer protection scheme. Asterisk denotes a normally open line-tie.*

| Document | ED-3002 | SYSPLAN-010 | DSPG 2020 |
|---|---|---|---|
| **Design Criteria: Transformer Rating** | 115% to 150% of Nameplate Rating | 100% STE | 100% STE |
| **Transformer Capacity** | 50 MVA | 67 MVA | 61 MVA |
| **Transformer Loading** | 60 MVA | With Load Shed: 60 MVA<br>Total: 72 MVA | With Load Shed: 60 MVA<br>Total: 72 MVA |
| **Design Compliance** | This stage of TX N-1 Contingency was not studied – Design Violation. | Feeder Load Shed is not an acceptable solution – Design Violation. | Feeder Load Shed is not an acceptable solution – Design Violation. |

## 2.2 – Contingency Restoration (t=30 minutes from event)

System Operators perform restoration of load or reduce loading on equipment with remote-controlled SCADA switching to within substation LTE ratings and line emergency ratings. Design criteria limits the restoration steps to three blocks. This example shows two load block transfers (24 MW, first and last feeders) to restore customer load and reduce equipment loading.

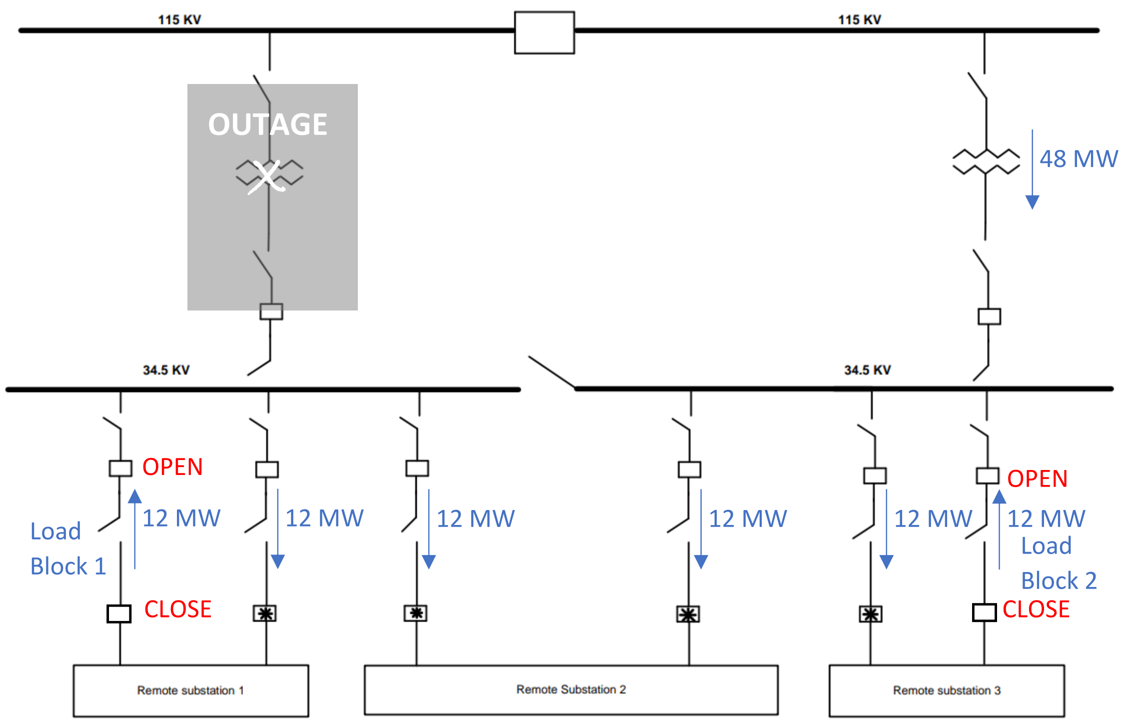


*Figure 3. Transformer N-1 Single Contingency showing two load block transfers. Asterisk denotes a normally open line-tie.*

| Document | ED-3002 | SYSPLAN-010 | DSPG 2020 |
|---|---|---|---|
| **Design Criteria: Transformer Rating** | 115% to 150% of Nameplate Rating | 100% LTE | 100% LTE |
| **Transformer Capacity** | 50 MVA | 51 MVA | 53 MVA |
| **Transformer Loading** | 48 MVA | 48 MVA | 48 MVA |
| **Design Criteria: Customer Outage** | < 30 MW | 0 MW | 0 MW |
| **Load Restored by other sources** | 24 MW | 24 MW | 24 MW |
| **Customer Outage** | 0 MW | 0 MW | 0 MW |
| **Design Compliance** | Meets Design Criteria | Meets Design Criteria | Meets Design Criteria |

## 2.3 – Post-Contingency (t=24 hours+ from event)

Reduce loading on equipment with additional switching (if available) to ensure load levels are within normal operating ratings within one load cycle (24-hours). An addition feeder (12 MW, second feeder) is offloaded to a remote source in addition to the first two feeders (24 MW, first and last feeders) that were moved as a result of initial event response.

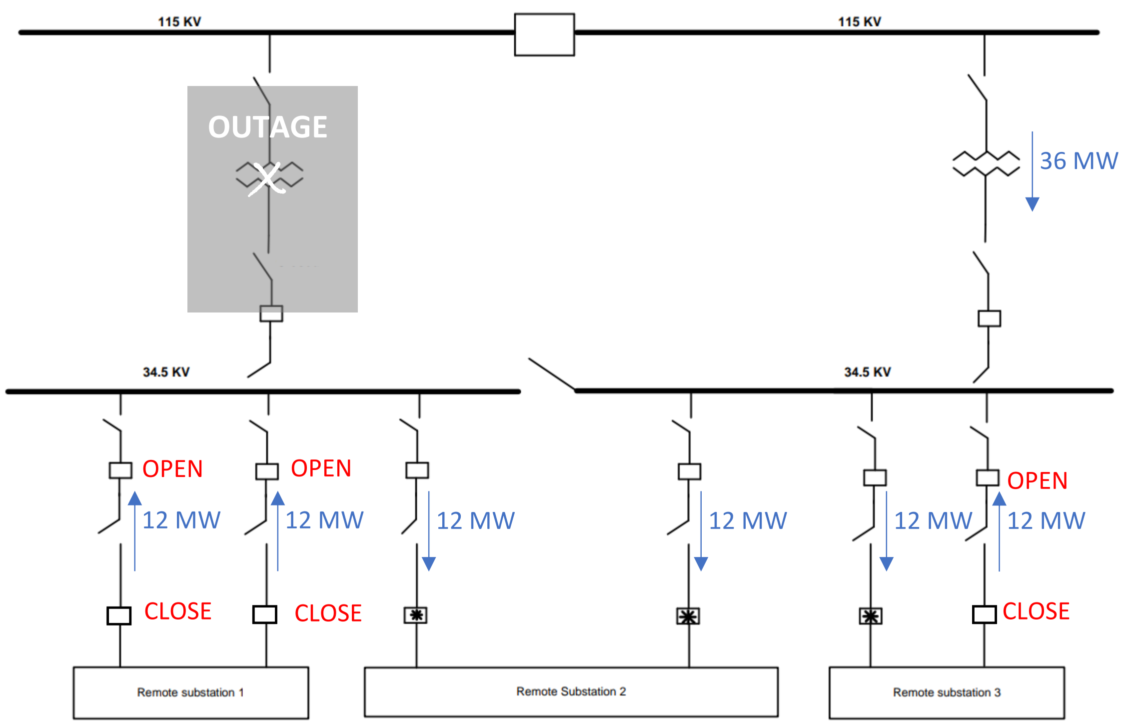


*Figure 4. Transformer N-1 Single Contingency showing additional switching performed to reduce loading within Nameplate and Normal ratings. Asterisk denotes a normally open line-tie.*

| Document | ED-3002 | SYSPLAN-010 | DSPG 2020 |
|---|---|---|---|
| **Design Criteria: Transformer Rating** | 115% to 150% of Nameplate Rating | 100% STE | 100% STE |
| **Transformer Capacity** | 50 MVA | 44.8 MVA | 44.8 MVA |
| **Transformer Loading** | 48 MVA | 36 MVA | 36 MVA |
| **Design Criteria: Customer Outage** | 0 MW | 0 MW | 0 MW |
| **Load Restored by other sources** | 24 MW | 36 MW | 36 MW |
| **Customer Outage** | 0 MW | 0 MW | 0 MW |
| **Design Compliance** | This stage of TX N-1 Contingency was not studied – Meets Design Criteria. | This stage of TX N-1 Contingency was not studied – Meets Design Criteria. | Meets Design Criteria |

# 3.0 – Single Contingency Event, Single Bus Section

## 3.1 – Solid Bus Substation Configuration

System Operators perform restoration of load or reduce loading on equipment with remote-controlled SCADA switching to within substation LTE ratings and line emergency ratings. Design criteria limits the restoration steps to three blocks. Three load blocks (36 MW) are transferred to remote sources, leaving three feeders in a sustained outage.

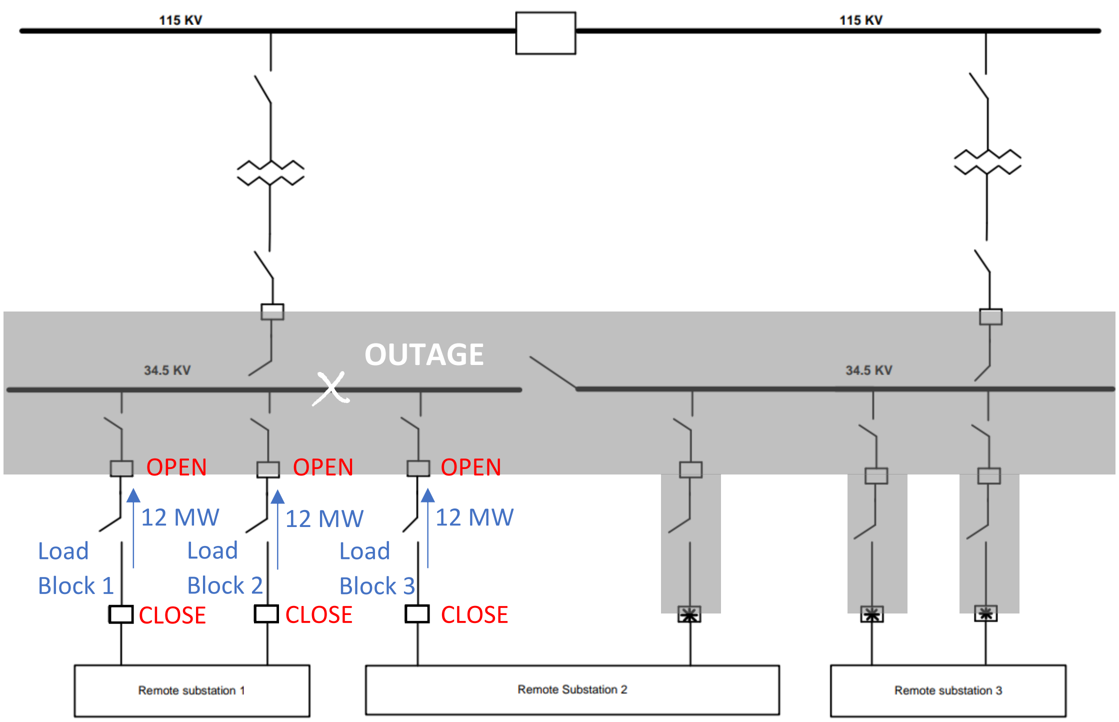


*Figure 5. Bus Section single contingency at a solid-bus substation with outage impacting all six feeders. Asterisk denotes a normally open line-tie.*

| Document | ED-3002 | SYSPLAN-010 | DSPG 2020 |
|---|---|---|---|
| **Design Criteria: Transformer Rating** | | | 100% LTE |
| **Transformer Capacity** | | | 53 MVA |
| **Transformer Loading** | | | 0 MVA |
| **Design Criteria: Customer Outage** | | | 0 MW |
| **Load Restored by other sources** | | | 36 MW |
| **Customer Outage** | | | 36 MW |
| **Design Compliance** | Bus N-1 Contingency was not studied. | Bus N-1 Contingency was not studied. | Design Violation |

## 3.2 – Single Bus Tie Breaker Configuration

System Operators perform restoration of load or reduce loading on equipment with remote-controlled SCADA switching to within substation LTE ratings and line emergency ratings. Design criteria limits the restoration steps to three blocks. Three load blocks (36 MW) are transferred to remote sources, restoring all impacted customer load.

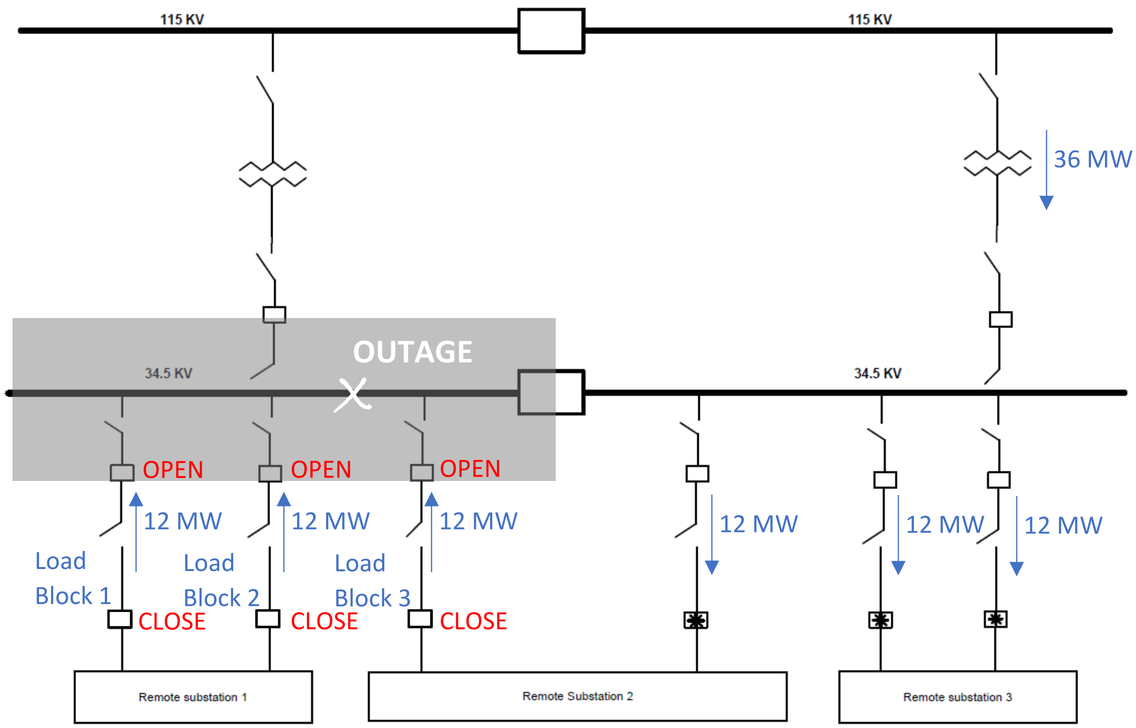


*Figure 6. Bus Section single contingency at a station with a bus tie breaker. Contingency event is limited to three of the six feeders. Asterisk denotes a normally open line-tie.*

| Document | ED-3002 | SYSPLAN-010 | DSPG 2020 |
|---|---|---|---|
| **Design Criteria: Transformer Rating** | | | 100% LTE |
| **Transformer Capacity** | | | 53 MVA |
| **Transformer Loading** | | | 36 MVA |
| **Design Criteria: Customer Outage** | | | 0 MW |
| **Load Restored by other sources** | | | 36 MW |
| **Customer Outage** | | | 0 MW |
| **Design Compliance** | Bus Section Contingency was not studied. | Bus Section Contingency was not studied. | Meets Design Criteria |

## 4.0 – Single Contingency Event, Bus Tie Breaker

System Operators perform restoration of load or reduce loading on equipment with remote-controlled SCADA switching to within substation LTE ratings and line emergency ratings. Design criteria limits the restoration steps to three blocks. Three load blocks (36 MW) are transferred to remote sources, leaving three feeders in a sustained outage.

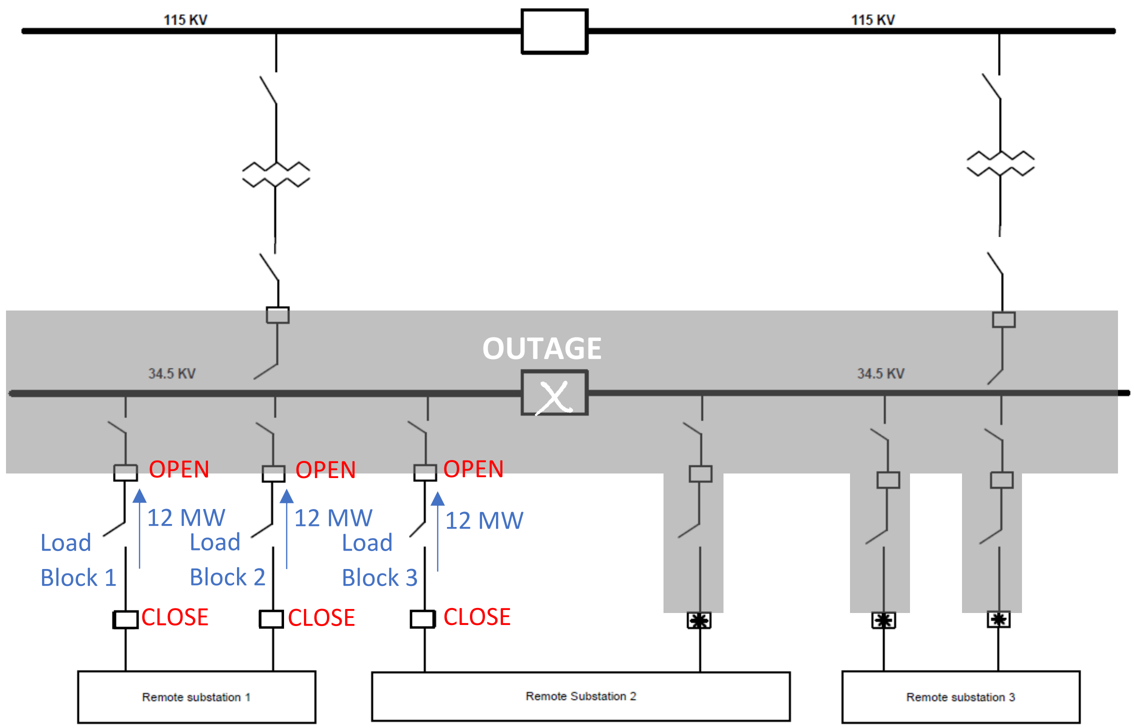


*Figure 7. Bus Tie Breaker single contingency at a solid-bus substation with outage impacting all six feeders. Asterisk denotes a normally open line-tie.*

| Document | ED-3002 | SYSPLAN-010 | DSPG 2020 |
|---|---|---|---|
| **Design Criteria: Transformer Rating** | | | 100% LTE |
| **Transformer Capacity** | | | 53 MVA |
| **Transformer Loading** | | | 0 MVA |
| **Design Criteria: Customer Outage** | | | 0 MW |
| **Load Restored by other sources** | | | 36 MW |
| **Customer Outage** | | | 36 MW |
| **Design Compliance** | Bus Tie Breaker Contingency was not studied. | Bus Tie Breaker Contingency was not studied. | Design Violation |

## 5.0 – Transmission Contingency Event

A single contingency event occurs on the transmission system. This could be a line fault, stuck breaker, or bus fault. In many cases this contingency event causes a study scenario that looks the same as one of the above distribution single contingencies. On occasion the location of the transmission equipment can cause a larger impact. Changing the original substation layout, this scenario with only three feeders presented has three load block transfers that restore all load.

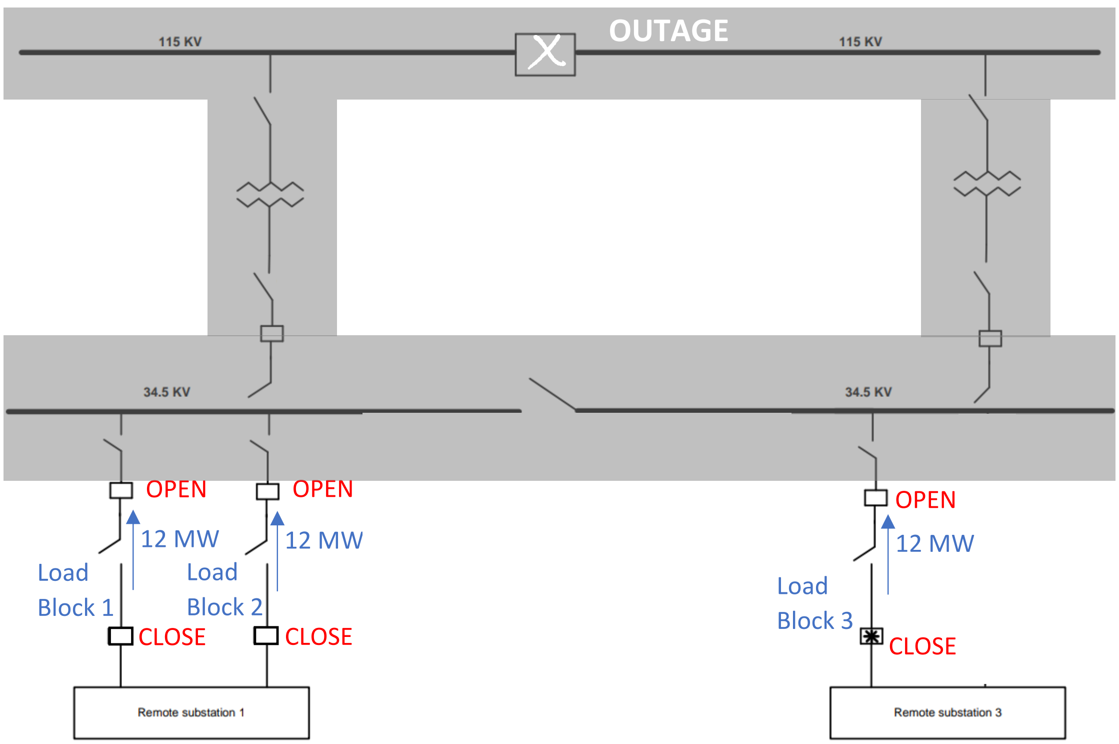


*Figure 8. Single contingency transmission outage impacting both sources at the substation. Asterisk denotes a normally open line-tie.*

| Document | ED-3002 | SYSPLAN-010 | DSPG 2020 |
|---|---|---|---|
| **Design Criteria: Transmission** | Outage < 30 MW | Outage = 0 MW | Transmission N-1 impacts no more than one Distribution TX |
| **Load Restored by other sources** | 36 MW | 36 MW | 36 MW |
| **Customer Outage** | 0 MW | 0 MW | 0 MW |
| **Transmission Outage** | N-1 | N-1 | N-1 |
| **Distribution Outage** | N-2 | N-2 | N-2 |
| **Design Compliance** | Meets Design Criteria | Meets Design Criteria | Design Violation |

| Document: | ED-3002 | SYSPLAN-010 | DSPG 2020 |
|---|---|---|---|
| Jurisdiction: | NH (D) | CT-MA-NH (T&D) | CT-MA-NH (D) |
| Primary Criteria Document: | 1/10/2003-8/1/2018 | 8/1/2018-9/22/2020 | 9/22/2020-Present |

| Bulk Substations (115kV and above) | | | |
|---|---|---|---|
| **Normal Operation (N-0, Base Case) - Distribution Design Criteria** | | | |
| | **PSNH ED-3002** | **SYSPLAN-010** | **Distribution System Planning Guide (DSPG 2020)** |
| Transformer Loading - Design *(Upgrade Identified)* | < 97% - 127% top nameplate rating (< 85% TFRAT) | < 75% top nameplate rating | CT-MA: < 75% top nameplate rating<br>NH: < 95% top nameplate rating |
| Transformer Loading - Operation | < 115% - 150% top nameplate rating (< 100% TFRAT) | < 100% top nameplate rating | < 100% top nameplate rating |
| **Contingency Operation (N-1, Single Event) - Distribution Design Criteria** | | | |
| | **PSNH ED-3002** | **SYSPLAN-010** | **Distribution System Planning Guide (DSPG 2020)** |
| Scenario(s) | Transformer<br>Feeder Breaker<br>Transmission Lines - Radial<br>Transmission Lines - Non-Radial<br>Dispatchable Peak Shaving Generation | Transformer<br>Transmission Line - Radial | Transformer<br>Bus Section<br>Bus Tie Breaker |
| Transformer Loading, Initial Event (t=0+ min) | < 115% - 150% top nameplate rating (< 100% TFRAT) | < 100% STE rating | < 100% STE rating |
| Transformer Loading, Contingency (t=30 min) | < 115% - 150% top nameplate rating (< 100% TFRAT) | < 100% LTE rating | < 100% LTE rating |
| Transformer Loading, Post-Contingent (t=24 hr) *(after LTE 12 or 4 hour duration or one 24-hour load cycle)* | < 115% - 150% top nameplate rating (< 100% TFRAT) | < 100% top nameplate rating | < 100% top nameplate rating |
| Load Block Transfer Limit | 3 | 3 | 3, with 4th in reserve |
| Remaining Isolated Load | < 30MW load out for up to 24 hrs | 0 MW (no loss of load) | 0 MW (no loss of load) |
| Transmission Supply | < 30MW load out for up to 24 hrs | 0 MW (no loss of load) | Single Transmisison N-1 shall not cause greater than a single Distribution N-1. |

| Non-Bulk Substations (below 115kV) | | | |
|---|---|---|---|
| **Normal Operation (N-0, Base Case) - Distribution Design Criteria** | | | |
| | **PSNH ED-3002** | **SYSPLAN-010** | **Distribution System Planning Guide (DSPG 2020)** |
| Transformer Loading - Design *(Upgrade Identified)* | < 85% TFRAT ( < 97% - 127% top nameplate rating) | < 100% LTE rating ( < 115% - 150% top nameplate rating) | < 100% top nameplate rating |
| Transformer Loading - Operation | < 100% TFRAT ( < 115% - 150% top nameplate rating) | < 100% LTE rating ( < 115% - 150% top nameplate rating) | < 100% top nameplate rating |
| **Contingency Operation (N-1, Single Event) - Distribution Design Criteria** | | | |
| | **PSNH ED-3002** | **SYSPLAN-010** | **Distribution System Planning Guide (DSPG 2020)** |
| Scenario(s) | Not defined. | Not defined. | Transformer |
| Transformer Loading, Initial Event (t=0+ min) | < 100% TFRAT ( < 115% - 150% top nameplate rating) | < 100% LTE rating ( < 115% - 150% top nameplate rating) | < 100% STE rating |
| Transformer Loading, Contingency (t=30 min) | < 100% TFRAT ( < 115% - 150% top nameplate rating) | < 100% LTE rating ( < 115% - 150% top nameplate rating) | < 100% LTE rating |
| Transformer Loading, Post-Contingent (t=24 hr) *(after LTE 12 or 4 hour duration or one 24-hour load cycle)* | < 100% TFRAT ( < 115% - 150% top nameplate rating) | < 100% LTE rating ( < 115% - 150% top nameplate rating) | < 100% top nameplate rating |
| Load Block Transfer Limit | Not defined. | Not defined. | Not defined. |
| Remaining Isolated Load | Not defined. | Not defined. | Not defined. |

| Distribution Lines | | | |
|---|---|---|---|
| **Normal Operation (N-0, Base Case) - Distribution Design Criteria** | | | |
| | **PSNH ED-3002** | **SYSPLAN-010** | **Distribution System Planning Guide (DSPG 2020)** |
| Line Loading, Overhead - Design *(Upgrade Identified)* | < 100% normal rating | < 100% normal rating | < 90% normal rating |
| Line Loading, Underground - Design *(Upgrade Identified)* | < 100% normal rating | < 100% normal rating | < 80% normal rating |
| Line Loading, Overhead - Operation | < 100% normal rating | < 100% normal rating | < 100% normal rating |
| Line Loading, Underground - Operation | < 100% normal rating | < 100% normal rating | < 100% normal rating |
| Voltage, Primary Line - Unregulated Load | 97.5% - 105% | n/a | n/a |
| Voltage, Primary Line - Regulated Load | 95% - 105% | n/a | n/a |
| Voltage, Customer Service | 95% - 105% | 95% - 105% | 95% - 105% |
| Voltage, Customer Service - Primary Voltage *Only for Customers Responsible for Voltage Regulation* | 90% - 110% | 90% - 110% | 90% - 110% |
| **Contingency Operation (N-1, Single Event) - Distribution Design Criteria** | | | |
| | **PSNH ED-3002** | **SYSPLAN-010** | **Distribution System Planning Guide (DSPG 2020)** |
| Line Loading, Overhead - Design *(Upgrade Identified)* | < 100% emergency rating | < 100% emergency rating | CT-MA: < 90% normal rating<br>NH: < 90% emergency rating |
| Line Loading, Underground - Design *(Upgrade Identified)* | < 100% emergency rating | < 100% normal rating | < 80% normal rating |
| Line Loading, Overhead - Operation | < 100% emergency rating | < 100% emergency rating | CT-MA: < 100% normal rating<br>NH: < 100% emergency rating |
| Line Loading, Underground - Operation | < 100% emergency rating | < 100% normal rating | < 100% normal rating |
| Voltage, Primary Line - Unregulated Load | 95% - 105% | n/a | n/a |
| Voltage, Primary Line - Regulated Load | 92% - 105% | n/a | n/a |
| Voltage, Customer Service | 92% - 105% | 95% - 105.8% | 92% - 105.8% |
| Voltage, Customer Service - Primary Voltage *Only for Customers Responsible for Voltage Regulation* | 90% - 110% | 90% - 110% | 90% - 110% |

# Administrative Procedure

# Substation & Transmission System Operations Review Committee

M5-OC-2001, Rev. 16

Approval Signature: Barry R. Bruun

| | | |
|---|---|---|
| | Barry R. Bruun | |
| Process Owner: | Director- Transmission Operations, CT & MA | Effective Date: 09/10/2021 |

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# 1. Purpose

The purpose of this administrative procedure is to establish and implement a Substation and Transmission System Operations Review Committee (S&TSORC), concerned with Substation and Transmission issues, such as:

- Substation and Transmission system reliability and availability
- Substation and Transmission system disturbances and trends in disturbances
- Industry Operating Experience/Events (OE)
- Transmission Availability Data System (TADS)
- Bulk Electric System (BES) Cyber Asset patch management for Medium Impact assets
- Associated tactical and strategic corrective actions designed to maximize transmission system reliability, efficiency and effectiveness

This procedure also discusses the responsibilities and activities of the following S&TSORC subcommittee and supporting committees:

- S&TSORC Disturbance Report Subcommittee (DRS)
- Substation Equipment Committee (SEC)
- Protection & Control and Test (PACT) Committee
- Transmission Operations Center Event Review Board (TOCERB)
- Transmission Line Equipment Committee (TLEC)
- BES Cyber Asset Patch Management Committee (BCAPMC)
- Operating Experience Subcommittee (OES)

# 2. Scope

This document applies to:

- Members and activities of, as well as subcommittees and supporting committees to, S&TSORC
- Asset Strategy and S&TSORC activities for OE

## 2.1. Eversource Transmission System vs. BPS and BES

Federal Energy Regulatory Commission (FERC) Order 693-A, “Mandatory Reliability Standards for the Bulk-Power System, section II.A.1” recognizes some ambiguity between the terms “Bulk-Power System” (BPS) and “Bulk Electric System” (BES) (reference Section 5.2 “Definitions” of this document). FERC Order 693-A tentatively resolves the conflict by advocating the North American Electric Reliability Corporation (NERC) Glossary, subject to future action by FERC.

Note that, at present, S&TSORC is concerned with the entire Eversource Transmission System, which can exceed the parameters of the current definitions for BES or BPS.

# 3. Roles and Responsibilities

Roles and responsibilities are identified in the Process Steps section. The role is listed along the left margin and is followed by numbered instructions.

S&TSORC consists of a S&TSORC Chair, a S&TSORC Secretary, and S&TSORC members. Director – Transmission Operations, CT & MA will serve as S&TSORC Chair. Members are representatives of various Eversource organizations associated with electrical transmission and interfaces, listed below or as selected by S&TSORC.

- Director, Transmission Operations, CT & MA
- Director System Operations, NH
- Director, Protection and Control Engineering
- Director, Substation Technical Engineering
- Director, Engineering, Transmission Lines
- Director, Substation Design
- Director(s), Field Engineering and Communication
- Director, Business and Quality Assurance, Transmission
- Director(s) Stations Operations - MA, CT and NH
- Manager(s) – Protection & Controls Engineering
- Manager(s) – Field Communications, CT, MA and NH
- Manager(s), Field Engineering, CT, MA and NHManager – Transmission Line Construction & Maintenance
- Manager – Transmission Line and Civil Engineering
- Manager – Asset Strategy & Performance
- Manager – Operations, CONVEX
- Manager – Bulk Power System Operations
- Manager - System Operations NH
- Manager(s) – Substation Operations – CT, MA and NH
- Manager – Construction & Maintenance, WMA
- Manager(s) – Substation Technical Engineering
- Manager, Compliance Standards and Support, P&C
- Manager, Reliability Compliance
- Manager, Technical Field Engineering
- Manager, UG Transmission
- Manager, Telecom Engineering

# 4. Process Steps

## 4.1. Conduct of S&TSORC

Disturbance activities in the following steps are coordinated with M7-EN-3011, "Transmission System Disturbance Analysis".

*S&TSORC Members*

4.1.1. Ensure issues affecting substation and transmission systems operations, reliability, continuity, integrity or quality of electric services to customers are addressed, to include, but not limited to, the following:

a. Review Significant Events such as substation and transmission system outages and disturbances, including corrective actions taken in response to these events.

- EXCEPTION - those disturbances reviewed and closed out per Attachment B, "S&TSORC Disturbance Report Subcommittee".

b. Proper operation of protection and control equipment.

c. Identify and monitor substation and transmission system performance issues, such as:

- Disturbances (notification received per ISO-NE OP 10, Electric System Control Center (ESCC) OP-0010, Connecticut Valley Electric Exchange (CONVEX) OI 0010, and NSTAR OP-10
- Underlying (root) causes categorized by the NERC TADS Automatic Outage Cause Code Types (reference Attachment A)
- Trends and symptoms of outages
- Relay misoperation and human error mitigation initiatives
- Protection System Degradation, as categorized and addressed per ISO-NE OP-24, Protection Outages, Settings and Coordination and Eversource ESOP-24, Protection System and Relay Work Control.

d. Coordinate investigations of causes of unplanned events affecting Nuclear Plant Interface Requirements (NPIRs) and develop corrective actions to minimize future risk of such events with nuclear generator operators.

e. Establish policies and procedures to correct system performance issues, maintain system integrity, and improve reliability.

f. Recommend engineering and design changes to improve reliability and performance.

g. Compliance with applicable revisions of NERC, Northeast Power Coordinating Council, Inc. (NPCC), and ISO-NE standards that address reviews of system outages and disturbances.

h. Under-Frequency Load Shedding (UFLS) and Under-Voltage Load Shedding (UVLS) events receive a thorough Engineering review to ensure transmission system operated as planned.

> **NOTE**
>
> Significant UFLS events may warrant the attention of the NPCC SS-38 working Group on Inter-Area Dynamic Analysis.

i. TADS and disturbances to TADS Elements (reference Section 4.2, "Transmission Availability Data System")

j. Review of BCAPMC activities, including:

- Assignment of evaluation of BES Cyber Asset patch
- Approval of mitigation plan for applicable BES Cyber Asset patches

*S&TSORC Chair*

4.1.2. Schedule monthly S&TSORC meetings.

a. Annually, ensure S&TSORC members are notified of S&TSORC meeting schedule.

*S&TSORC Secretary*

4.1.3. Within one week prior to regularly scheduled S&TSORC meeting, ensure the S&TSORC meeting agenda is prepared and distributed to S&TSORC members. Agenda to include, as a minimum when applicable:

- Review of minutes from previous S&TSORC meeting.
- Review of unresolved issues from previous S&TSORC meeting.
- Review and discussion of S&TSORC subcommittee activities and submittals (e.g., DRS, PACT, SEC)
- Summary of issues, events, resolutions, and recommended actions.
- Annual Eversource TADS Elements Disturbance Report (reference Section 4.2, "Transmission Availability Data System")

*S&TSORC Chair*
*S&TSORC Members*

4.1.4. Invite guests to the S&TSORC meeting, as needed to address investigations and resolutions of issues affecting guests' company or organization.

*S&TSORC Secretary*

4.1.5. Coordinate presenters with agenda items.

*S&TSORC Members*

4.1.6. Attend each S&TSORC meeting **or assign** personnel to attend in your place who can knowledgeably address S&TSORC issues affecting your organization.

*S&TSORC Chair, Secretary, and Members*

4.1.7. Refer to agenda and conduct/participate in S&TSORC meeting, as follows:

a. Ensure a quorum of at least two S&TSORC members, plus Chairman, is present at each S&TSORC meeting, subject to the following:

- S&TSORC business cannot be conducted without a quorum (minimum of two S&TSORC members plus the Chairman).
- Alternate personnel assigned to attend meeting in place of a S&TSORC Member do not count towards the two member quorum.
- If S&TSORC Chair is absent for a S&TSORC meeting, S&TSORC chair may appoint a S&TSORC member as an alternate, and alternate (in the role as S&TSORC Chair) does **not** count towards the two member quorum.

b. Review and discuss agenda items (and other concerns at the discretion of the S&TSORC chair), and identify actions to investigate and resolve issues.

c. Address disturbances and outages, as follows (reference M7-EN-3011, “Transmission System Disturbance Analysis”):

(1) Review disturbance and outage issues (except disturbances closed out per Attachment B “S&TSORC Disturbance Report Subcommittee”) and supporting documentation such as:

- Substation equipment malfunctions, e.g.:
  circuit breakers, capacitors, disconnect switches, protection & control equipment, etc.
- Transmission line equipment failures, e.g.: shield wires, poles, crossarms, etc.
- Storm related occurrences, e.g.: lightning, wind, ice, debris, etc.
- Current S&TSORC subcommittee submittals, such as
  - Summary reports
- Significant incident investigation reports prepared by construction and test contractors

(2) If disturbance investigations and corrective actions are not acceptable, identify shortcomings and return to DRS for resolution.

(3) If additional disturbance activity is required:

(a) Identify actions and action owners.

(b) Continue processing disturbance issue using M7-EN-3011, Transmission System Disturbance Analysis to include review and acceptance by DRS and/or at S&TSORC meeting.

d. Assign a S&TSORC status designator, as follows, to each S&TSORC issue:

| | |
|---|---|
| **O**, Open | • Items not reviewed by the assigned investigator nor signed off as resolved by S&TSORC.<br>• Items that require follow-up corrective action. These items remain open until recognized within another tracking system (i.e., an approved project number for an identified system modification). |
| **C**, Closed | Items with reviews and disposition completed by S&TSORC. |

- Assign personnel or subcommittees, as needed, to fulfill S&TSORC obligations and resolve issues. Subcommittee sponsors shall select the chair(s) and members. Subcommittee members may name a delegate in their absence. Current subcommittees include:
  - DRS (reference Attachment B)
  - SEC (reference Attachment C)
  - PACT Committee (reference Attachment D)
  - TOCERB (reference Attachment E)
  - TLEC (reference Attachment F)
  - BCAPMC (reference Attachment G)
  - OES (reference Attachment H)

*S&TSORC Secretary*

4.1.8. Record S&TSORC meeting activities in the minutes for each meeting.

4.1.9. Assign unique S&TSORC tracking number to each issue brought before S&TSORC, to facilitate tracking issue through resolution and follow-up.

**NOTE**

Currently, disturbances and OE are tracked in CATSWeb, which automatically assigns unique issue, action, and task tracking numbers.

4.1.10. Maintain Transmission Frequency (TFREQ) and Transmission Line Outage Duration Index (TLODI) Key Performance Indicator (KPI), on a monthly basis.

4.1.11. Within one week after a S&TSORC meeting, distribute meeting minutes to S&TSORC members, NH SORC Chair, and others as requested.

## 4.2. Transmission Availability Data System

Transmission availability data is critical in assessing transmission system performance. The NERC TADS User Group (TADSUG) expects Transmission Owners (TOs) to submit data on the transmission availability of TADS Elements (see section 5.2 Definitions) using forms prescribed in the NERC Transmission Availability Data System (TADS) Data Reporting Instructions This process was developed and is administered by the NERC TADSUG as described in the "Transmission Availability Data System Revised Final Report". (TADS documents and additional information are available at the "Transmission Availability Data System (TADS)" webpage http://www.nerc.com/pa/RAPA/tads/Pages/ default.aspx

TADS is limited to certain transmission elements with operating voltages of ≥ 200 kV. Currently at Eversource, only the 345 kV portions of the transmission system and the 230 kV terminal at Merrimack and MA East lines 282-602 (West Medway-Waltham) and 240-601 (West Medway-Framingham) are above this threshold.

*S&TSORC Secretary*

4.2.1. Reference the "TADS Data Reporting Instruction Manual" and perform the following:

- Maintain a list of disturbances to the Eversource Transmission System that meet the parameters for TADS submittal.
- Ensure that all disturbances of Eversource TADS Elements are submitted to the Reliability Compliance group within the schedule, and using the forms, prescribed in the "TADS Data Reporting Instruction Manual".

# 5. Administrative Information

## 5.1. Requirements

System outages and disturbances are required to be reviewed per the documents listed below:

- ISO-NE OP 20, Analysis and Reporting of Power System Incidents
- NERC CIP-007, Cyber Security – Systems Security Management
- NERC CIP-010 – Configuration Change Management, Vulnerability Assessments
- NERC EOP-004, Event Reporting
- NERC NUC-001, Nuclear Plant Interface Coordination
- NERC PRC-004, Protection System Misoperation Identification and Correction
- NERC PRC-012, Remedial Action Schemes
- NPCC C-45, Procedure for Analysis and Reporting of Protection System Misoperations

- NPCC Directory 4 – System Protection Criteria
- NPCC Directory 7 – Remedial Action Schemes
- NPCC Directory 12 – Automatic UFLS Program Requirements

BES Cyber Asset patch management process is required to be reviewed per the document listed below:

- NERC CIP-007, Cyber Security – Systems Security Management

## 5.2. Definitions

| Word or phrase | Definition |
|---|---|
| BCAPMC | BES Cyber Asset Patch Management Committee |
| BPS | Bulk Power System<br>“Generation and transmission facilities on which faults or disturbances can have a significant effect outside of the local area.” (per “Acronyms for Eversource Trans System”)<br><br>“The interconnected electrical systems within northeastern North America comprised of system elements on which faults or disturbances can have a significant adverse impact outside of the local area.” (per NPCC A-7 Glossary of Terms)<br><br>Bulk-Power System<br>“Facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and (B) electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.” (from Federal Power Act section 215, per FERC Order 693A) |
| CONVEX | Connecticut Valley Electric Exchange (CT, Western MA) |
| CT | Connecticut |
| DRS or S&TSORC-DRS | Disturbance Report Subcommittee (S&TSORC subcommittee) |
| ESCC | Electrical System Control Center (New Hampshire) |
| FERC | Federal Energy Regulatory Commission |
| ITOMS | International Transmission Operations & Maintenance Study - A consortium of international transmission companies that are interested in comparing performance and sharing leading practices and processes. |
| KPI | Key Performance Indicator |
| MA | Massachusetts |
| Near Miss (safety incident) | An unplanned event that could have created an undesired outcome including injury or property damage. |

| Word or phrase | Definition |
|---|---|
| NERC | North American Electric Reliability Corporation |
| NH | New Hampshire |
| NPCC | Northeast Power Coordinating Council, Inc. |
| OE | Operating/Operational Experience/Events |
| Outage | Removal of equipment from normal service. |
| P&C | Protection and Control |
| PACT or S&TSORC-PACT | Protection & Control and Test<br>(S&TSORC subcommittee) |
| SEC, or S&TSORC-SEC | Substation Equipment Committee<br>(S&TSORC subcommittee) |
| S&TSORC | Substation and Transmission System Operations Review Committee |
| Significant Event | A transmission system event which typically meets one or more of the following criteria:<br>• reportable to ISO-NE, NPCC, or DOE<br>• UFLS event<br>• Near Miss or higher safety incident<br>• involves inter-area coordination or impact<br>• involves failure of a Special Protection System (SPS) function<br>• total loss of transmission system equipment protection<br>• part of an adverse system trend |
| SMEs | Subject Matter Experts |
| SS-38 Working Group on Inter-Area Dynamic Analysis | Working group appointed by the NPCC Reliability Assessment Program, Task Force on System Studies (TFSS). |
| TADS | Transmission Availability Data System |
| TADSTF | Transmission Availability Data System Task Force |
| TFREQ | Transmission Frequency<br>KPI for the measure of disturbance frequency. |
| TLEC | Transmission Line Equipment Committee<br>(S&TSORC subcommittee) |
| TO | Transmission Owner |
| TOCERB | Transmission Operations Center Event Review Board |
| UFLS | Under-Frequency Load Shedding |
| UVLS | Under-Voltage Load Shedding |

## 5.3. References

FERC Order 693-A "Mandatory Reliability Standards for the Bulk-Power System"

NERC "Glossary of Terms Used in Reliability Standards", also known as the "NERC Glossary"

NERC Transmission Availability Data System (TADS) Data Reporting Instruction Manual

NERC Transmission Availability Data System Revised Final Report

NERC NUC-001-4 Nuclear Plant Interface Coordination

NPCC Document A-7 "NPCC Glossary of Terms"

ISO-NE OP 10 Emergency Incident and Disturbance Notifications

CONVEX OI 0010 Disturbance and Significant Incident Processing and Reporting

ESCC OP-0010 Power System Emergency Reporting

NSTAR OP-10 Emergency Incident and Disturbance Notifications

RF-PI-9001, CATSWeb NU Issue Management User Guide

# 6. Summary of Changes

**Revision 16**

Replaces M5-OC-2001, "Substation & Transmission System Operations Review Committee, Revision 15, Effective 08/22/2017

- Added additional Manager and Director Members. Replaced Attachment H, Operational Concerns Committee with new Operating Experience Subcommittee. Updated sponsors of committee/subcommittees. Updated regulatory requirements and various references. Removed TLODI references. Updated Definitions to remove those that are in the NERC glossary and TADS procedure

**Revision 15**

Replaces M5-OC-2001, "Substation & Transmission System Operations Review Committee, Revision 14, Effective 06/01/2017

- Added Attachment H, Operational Concerns Committee and reference to it in Section 4.1.7

**Revision 14**

Replaces M5-OC-2001, “Transmission System Operations Review Committee”, Revision 13, Effective 03/21/2016

- Updated 5.1, Requirements listing
- All instances of TSORC changed to S&TSORC
- Attachment A updated

**Revision 13**

Replaces M5-OC-2001, “Transmission System Operations Review Committee”, Revision 12, Effective 02/24/2015

- Replaced Northeast Utilities and NU with Eversource, where possible
- Revised Purpose
- Updated job titles
- Added Step 4.1.1.j.
- Updated Definitions and Requirements
- Added Attachment G, BES Cyber Asset Patch Management Committee, and associated references

**Revision 12**

Replaces M5-OC-2001, “Transmission System Operations Review Committee”, Revision 11, Effective 1/30/2014

- Added Note to Step 4.1.10
- Added Section 4.3 – TLODI Adjustments and Exclusions
- Changed all references to M1-PI-3002, “CATSWeb User Guideline for Transmission Disturbances/S&TSORC Actions” to RF-PI-9001, “CATSWeb NU Issue Management User Guide”
- Step 4.1.6 – reworded for clarity
- Added links
- Updated Requirements, Definitions and References

**Revision 11**

Replaces *“Transmission System Operations Review Committee”*, Revision 10, effective 5/20/2013

- Roles and Responsibilities – updated to reflect current practice of calling them out in the Process Steps
- Removed reference to Director-Transmission Asset Strategy from Roles and Responsibilities section and Attachment E
- Removed reference to Transmission Asset Strategy in Attachment E

**Revision 10**

Replaces *“Transmission System Operations Review Committee”,* Rev. 9, effective 07/24/12

- Updated procedure and attachments to include NSTAR members

- Removed Section 4.2 Operating Experience due to no longer an NATF member
- Changed TSAIDI to TLODI to improve transmission line reliability measurement
- Expanded step 4.1.8 to include "on a monthly basis"
- Updated Section 5.3 to cite references currently used in document

**Revision 9**

Replaces *"Transmission System Operations Review Committee",* Rev. 8, effective 11/22/10

- Updated Attachment A, NU Transmission Outage Internal Cause Code
- Updated Attachment E, Transmission Operations Center Event Review Board
- Changed all references to Transmission Owners & Operators Forum (TOOF) to North American Transmission Forum (NATF)
- Roles and Responsibilities – updated S&TSORC Member titles
- Corrected Definition of KPI

**Revision 8**

Replaces *"Transmission System Operations Review Committee"*, revision 7, effective 08/05/10

- Section 1 Purpose – Added Transmission Line Equipment Committee (TLEC) to the listing of subcommittees
- Section 3 Roles and Responsibilities - Added S&TSORC members
- Added TLEC to Definitions
- Added Attachment F

**Revision 7**

Replaces *"Transmission System Operations Review Committee"*, revision 6, effective 03/31/10

- Section 1 Purpose – Added Transmission Operations Center Event Review Board to the listing of subcommittees
- Section 4.1.7.e. – Added TOCERB
- Added TOCERB to Definitions
- Added Attachment E

**Revision 6** (change bars have been added in right margins)

Replaces *"Transmission System Operations Review Committee"* revision 5, effective 2/21/2008

- TADS – Added Section 4.3 and revised procedure accordingly to recognize activities related to the FERC Transmission Availability Data System.

- Section 1 Purpose and Att C S&TSORC DRS – clarified that DRS is a subcommittee to S&TSORC and does not have a management sponsor, as is typical for many NU committees such as the S&TSORC supporting committees, TSEC and TPACT, described in Attachments C and D.
- Added Section 4.1.1.d. “Coordinating investigations of causes of unplanned events affecting Nuclear Plant Interface Requirements (NPIRs) and developing corrective actions to minimize future risk of such events with nuclear generator operators.”
- Section 5.1 Requirements – added NERC EOP-004-1 Disturbance Reporting
- Deleted “M, Monitor” category from Section 4.1.7.d “Assign a S&TSORC status designator (following) to each S&TSORC issue:” as the designator is no longer used by S&TSORC.
- Deleted Attachment A “Disturbance Investigation Priorities” as a KPI is now used to track the close out of disturbance reports. Relabeled remaining attachments accordingly – A. B. C, and D from B, C, D, and E.

**Revision 5**

Replaces *“Transmission System Operations Review Committee”* revision 4, effective 12/17/2007

- Revised Attachment C “S&TSORC Disturbance Report Subcommittee” to recognize Manager/Supervisor-Distribution Protection & Controls Engineering responsibilities to address Distribution disturbances that affect NU Transmission System (to comply with NERC standards PRC-004, 009, 016 and 022 concerning Distribution corrective actions for disturbances affecting the Transmission system).
- Att. E TPACT, added member “Manager-Test and Technical Support” per Dan Anderson, current holder of that position.
- Added new section 2.1 “NU Transmission System” and discussion, and definitions for BES/BPS, to clarify the S&TSORC focus on the entire NU Transmission System regardless of limitations from definitions of BPS and BES.
- Moved Attachment F “Operating Experience” to section 4.0 “Process Steps” to align with approved document format.

**Revision 4**

Replaces *“Transmission System Operations Review Committee”* revision 3, effective 8/03/2007

- Revised Attachment F “Operating Experience” to provide additional instructions for NATF and OE activities (to address management expectations).
- Section 3 Roles and Responsibilities, S&TSORC Members: replaced “CL&P Distribution Representative” with “Manager – CL&P Maintenance” to align with current S&TSORC member roster.

**Revision 3**

Replaces *"Transmission System Operations Review Committee"* revision 2, effective 4/23/2007.

- Revised section 4.1 to recognize CATSWeb interface with disturbance report activities.
- Revised step 4.1.7 quorum requirements from 4 S&TSORC members to 2 S&TSORC members per direction of S&TSORC chair.
- Att. A "Disturbances Investigation Priorities", added note that source of this table is M8-MT-1001 "Transmission Maintenance Program".
- Att. B "NU Transmission Outage Internal Cause Coding", added words to code categories "E" and "HE-Ext" to clarify outage causes are limited to the NU transmission system.
- Added Operating Experience activity (Att. F and Sect. 3 Responsibilities).

**Revision 2**

Replaces *"Transmission System Operations Review Committee"* revision 1, effective 12/18/2006.

- Steps 4.1.1.c and 4.1.7.b, and Section 5.1 Requirements – recognized S&TSORC oversight of item 1 to 2006 NERC Readiness Audit Recommendations.
- Att. B "NU Transmission Internal Cause Code" - updated descriptions for cause code categories: Weather, Vegetation, Miscellaneous, Human Error.
- Added Attachment D Transmission Protection And Control & Test (TPACT) Committee, and recognized TPACT activities/input in body of procedure.
- Moved documents with requirements affecting this procedure from 5.3 References to 5.1 Requirements (no change bars shown).

**Revision 1**

Replaces *"Transmission System Operations Review Committee"* revision 0, effective 10/24/2006.

- Added details for Disturbance Report Subcommittee (DRS), including:
  - Attachment C "S&TSORC Disturbance Report Subcommittee"
  - S&TSORC review of DRS submittals
- Added details for Transmission Substation Equipment Committee (TSEC), including:
  - Attachment D "Transmission Substation Equipment Committee"
  - S&TSORC review of TSEC submittals
- Step 4.1.9: reduced time for distribution of S&TSORC meeting minutes from 2 weeks to 1 week to support DRS meeting schedule (monthly, about 2 weeks prior to S&TSORC meeting).
- Step 4.1.3, 3rd bullet: recognize subcommittee submittals (in lieu of minutes).
- Recognized use of Attachments A and B information in instructions.
- Recognized review of UVLS events like done for UFLS events.

**Revision 0**

- None – this document is the original issue

# Attachment A, NERC TADS Automatic Outage Cause Code Types

**Automatic Outage**

An outage that results from the automatic operation of a switching device, causing an element to change from an in-service state to a not in-service state. Single-pole tripping followed by successful AC single-pole (phase) reclosing is not an automatic outage.

**Weather, excluding lightning**

Automatic outages caused by weather such as snow, extreme temperature, rain, hail, fog, sleet/ice, wind (including galloping conductor), tornado, microburst, dust storm, and flying debris caused by wind.

**Lightning**

Automatic outages caused by lightning.

**Environmental**

Automatic outages caused by environmental conditions such as earth movement (including earthquake, subsidence, earth slide), flood, geomagnetic storm or avalanche.

**Contamination**

Automatic outages caused by contamination such as bird droppings, dust, corrosion, salt spray, industrial pollution, smog or ash.

**Foreign Interference**

Automatic outages caused by foreign interference from objects such as an aircraft, machinery, a vehicle, a train, a boat, a balloon, a kite, a bird (including streamers), an animal, flying debris not caused by wind, and when falling conductors from another line cause an outage.

Foreign interference is not due to an error by a utility employee or contractor. Categorize these as “Human Error”.

**Fire**

Automatic outages caused by fire or smoke.

**Vandalism, Terrorism or Malicious Acts**

Automatic outages caused by intentional activity such as shot conductors or insulators, removing bolts from structures, and bombs.

The above definition includes intentional malicious acts such as cyber-attacks. However, accidental acts initiated by any incorrect action traceable to employees and/or contractors for companies operating, maintaining, and/or providing assistance to the Transmission Owner should be cause coded as “Human Error”.

**Failed AC Substation Equipment**

Automatic outages caused by the failure of AC Substation, i.e., equipment "inside the substation fence" including transformers and circuit breakers, but not protection system equipment as is not part of the AC substation. Refer to the definition of "AC Substation".

**Failed AC/DC Terminal Equipment**

Automatic outages caused by the failure of AC/DC terminal equipment, i.e., equipment "inside the terminal fence" including power-line carrier (PLC) filters, AC filters, reactors and capacitors, transformers, DC valves, smoothing reactors, and DC filters, but not protection system equipment as it is not part of the DC terminal. Refer to the definition of "AC/DC Terminal".

**Failed Protection System Equipment**

Automatic outages caused by the failure of protection system equipment includes any relay and/or control misoperations, except those that are caused by incorrect relay or control settings that do not coordinate with other protective devices. Categorize these as "Human Error".

**Failed AC Circuit Equipment**

Automatic outages related to the failure of AC circuit equipment, i.e., overhead or underground equipment "outside the substation fence". Refer to the definition of "AC Circuit".

**Failed DC Circuit Equipment**

Automatic outages related to the failure of DC circuit equipment, i.e., overhead or underground equipment "outside the terminal fence". Refer to the definition of "DC circuit". However, include the failure of a connecting DC bus within an AC/DC back-to-back converter in this category.

**Vegetation**

Automatic outages (both momentary and sustained) caused by vegetation, with the exception of the following exclusions, which are contained in FAC-003-1:

1. Vegetation-related outages that result from vegetation falling into lines from outside the right-of-way that result from natural disasters shall not be considered reportable with the Vegetation cause code. Examples of disasters that could create non-reportable Vegetation cause code outages include, but are not limited to earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defied either by the Transmission owner or an applicable regulatory body, ice storms, floods, and
2. Vegetation-related outages due to human or animal activity shall not be considered reportable under the Vegetation cause code. Examples of human or animal activity that could cause a non-recordable Vegetation cause code outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation.

Outages that fall under the exclusions should be reported under another cause code and not the Vegetation cause code.

**Power System Condition**

Automatic outages caused by power system conditions such as instability, overload trip, out-of-step, abnormal voltage, abnormal frequency, or unique system configurations (e.g., an abnormal terminal configuration due to existing condition with one breaker already out-of-service).

## Human Error

Automatic outages caused by any incorrect action traceable to employees and/or contractors for companies operating, maintaining, and/or providing assistance to the Transmission Owner will be identified and reported in this category. In addition, any human failure or interpretation of standard industry practices and guidelines that cause an outage will be reported in this category.

## Unknown

Automatic outages caused by unknown causes should be reported in this category.

## Other

Automatic outages for which the cause is known, however, the cause is not included in the above list.

# Attachment B, S&TSORC Disturbance Report Subcommittee

## PURPOSE

The purpose of the S&TSORC Disturbance Report Subcommittee (S&TSORC-DRS, or DRS) is to promote S&TSORC meeting effectiveness by screening out those Disturbance Reports that do not require S&TSORC review or resolution.

## RESPONSIBILITY

S&TSORC has assigned the DRS responsibility for:

- Initial review of Disturbance Reports.
- Screening out, ensuring resolution, and closing out disturbance reports determined by DRS as not warranting S&TSORC involvement.
- Coordinating with Distribution to ensure misoperations affecting the Eversource Transmission System are reviewed, analyzed and resolved; and appropriate corrective actions identified and completed.

## ORGANIZATION

The S&TSORC-DRS sponsors are the Director – Substation Technical Engineering and Director Protection and Control Engineering who select DRS chairs and members. The DRS is composed of the following personnel, and as augmented by S&TSORC:

The following share chair responsibilities for DRS activities to include scheduling meetings and participants.

- Manager – Protection & Controls Compliance Standards and Support
- Manager – Field Engineering

Other DRS members:

- Manager – Field Communications
- Manager – Asset Management
- Manager – Substation Technical Engineering

## MEETING SCHEDULE AND FREQUENCY

Monthly meetings scheduled one to two weeks prior to scheduled S&TSORC meeting and post end of month under review.

## ACTIVITY

Perform an initial review of disturbance reports, and ensure the root cause of each disturbance is accurately and consistently identified per Attachment A "Eversource Transmission Outage Internal Cause Code".

Close-out those disturbance reports which meet any of the following criteria:

- Disturbance event resulted in correct operation of substation and transmission system/components, to include correct:  tripping times, reclosing operations, lockout operations, transfer trips, etc.
- Disturbance involving misoperation where **all** corrective actions have been identified and closure of disturbance event is assured via currently scheduled activity.

Prepare a DRS summary report containing the following:

- Disturbance reports closed out by DRS.
- Disturbance reports reviewed, but not closed out, by DRS.
- Trends, generic issues, and events considered by DRS having sufficient significance to warrant S&TSORC review.

## DELIVERABLES

Submit the DRS summary report and supporting information to S&TSORC to be included as attachments to minutes of the S&TSORC meeting where presented.

# Attachment C, Substation Equipment Committee

## PURPOSE

The Substation Equipment Committee (SEC) provides an overview of substation equipment performance, excluding equipment addressed by the Protection and Control & Test (PACT) Committee.

## RESPONSIBILITY

SEC has the responsibility for:

- Evaluating substation equipment issues
- Ensuring acceptable performance of substation equipment and components,
- Tracking and trending of equipment failures,
- Identification of opportunities for capital projects & programs,
- The sharing of critical information and lessons learned

## ORGANIZATION

SEC sponsor is the Director – Substation Technical Engineering, who selects a SEC chair and members consisting of CT, MA, and NH representatives from the following, as a minimum:

- Manager – Asset Management
- Manager – Substation Operations
- Manager – Field Engineering
- Manager – Substation Engineering and Design
- Manager – T&D Standards
- Manager – Substation Technical Engineering (Chair)

## MEETING SCHEDULE AND FREQUENCY

Monthly, and as requested by S&TSORC, the SEC sponsor, or SEC Chair.

## ACTIVITY

Provide the substation equipment implementation function for S&TSORC.

Provide a forum to:

- Review and discuss resolution of substation equipment issues
- Establish synergies in equipment, preventative maintenance, emergency spare inventory and other substation equipment issues across the Eversource system

Review service bulletins from suppliers of substation equipment for issues that may affect Eversource equipment

Identify and propose implementation of new substation technology/equipment based on best practices of industry.

## DELIVERABLES

Quarterly SEC reports (meeting minutes are acceptable) that summarize SEC activities, concerns, and recommendations to be submitted at the S&TSORC meetings.

# Attachment D, Protection and Control & Test Committee

## PURPOSE

The Protection and Control & Test (PACT) Committee provides an overview of all Protection and Control (P&C) issues associated with the Eversource system across all three regions, including related test issues.

## RESPONSIBILITY

PACT has the responsibility for:

- Oversight of Eversource P&C and testing regulatory compliance
- Evaluating P&C misoperations, equipment issues, and identifying equipment failure trends

## ORGANIZATION

PACT sponsors are Director – Protection and Control Engineering and Director(s) Field Engineering, who select PACT co-chairs and members. Members should include the following representatives from each region (CT, MA, NH):

- Manager – Operations (CONVEX, Mass Ave, ESCC)
- Manager – Protection & Controls Engineering
- Manager – Field Engineering
- Manager – Field Communications
- Manager – Asset Management (Chair)
- Manager – Substation Technical Engineering

## MEETING SCHEDULE AND FREQUENCY

Quarterly, and as requested by S&TSORC, the PACT sponsor, or the PACT Chair.

## ACTIVITY

Provide the P&C implementation function for S&TSORC

## DELIVERABLES

Quarterly PACT reports (meeting minutes are acceptable) that summarize PACT activities, concerns, and recommendations to be submitted at the S&TSORC meetings.

# Attachment E, Transmission Operations Center Event Review Board

## PURPOSE

The Transmission Operations Center Event Review Board (TOCERB) provides an internal forum to review transmission operations infrastructure events and oversee the disposition of follow-up actions.

## RESPONSIBILITY

The TOCERB shall:

i) ensure ongoing review of events
ii) ensure prompt and appropriate corrective actions are taken
iii) focus on maintaining continuous improvement in the reliability of transmission operations infrastructure

By institutionalizing the review and analysis process for significant transmission operations infrastructure events, Eversource will have an enhanced ability to:

- mitigate consequences of infrastructure events;
- enable Eversource leadership to consider and authorize corrective actions;
- share lessons learned among multiple departments;
- identify common causes and trends;
- ensure Eversource management has reviewed and identified internal changes necessary to ensure improvement in infrastructure performance;
- oversee internal assessments of Eversource's infrastructure failure events;
- ensure the development of Action Plans to correct the problem;
- ensure all key functional areas of Eversource that are affected by infrastructure failure are engaged and knowledgeable about events and issues with infrastructure failures.

## ORGANIZATION

Membership may consist of representatives, or designees, from Transmission Operations, NH Energy Delivery, eastern MA Operations, Environmental and Property Management, IT Infrastructure, and Transmission Maintenance and Work Management. Meetings are organized by the Director, Transmission Operations, CT and MA, who serves as chairman.

- **Chairman**
  - Schedule and conduct meetings.
- **Vice Chairman**
  - Act in the place of the Chairman at the Chairman's request.
- **Secretary**
  - Coordinate activities of the transmission Operations Infrastructure Event Review Board.
  - Create Agendas for the Chairman's review and approval.
  - Take meeting minutes and publish them following approval by the Chairman.
  - Prepare materials necessary to support the Board and Board meetings.
- **Members**
  - Attend all meetings or assign responsibility within the individual's functional area.
  - Review and discuss all significant transmission operations infrastructure events.
  - Collect and analyze all relevant data.
  - Provide oversight and guidance of internal assessment activity on infrastructure failures.

- Facilitate the development of corrective actions and prioritize for implementation.
- Follow through with action plans.

- **Transmission Operations:**
  - Establish and maintain a list of all infrastructure events and corrective actions.
  - Oversee, coordinate and track all CATSWeb items related to Infrastructure events.

- **Infrastructure Owner (Internal Technical Expert):**
  - Report significant transmission operations infrastructure events.
  - Investigate and prepare root cause analysis.
  - Prepare a report including the date and time of the incident, incident summary, root cause analysis, corrective actions and any other considerations and present the report to the TOCERB at their scheduled meeting.
  - Follow through with corrective actions.
  - Share lessons learned with other pertinent departments.

## MEETING SCHEDULE AND FREQUENCY

Meetings will be scheduled on an as needed basis depending on the frequency and severity of the Infrastructure Events. Meetings will take place in the Transmission Operations Center or at a place scheduled by the Chairman. A meeting will be scheduled within 30 days of an event requiring review.

## ACTIVITY

Review transmission operations infrastructure events and oversee the disposition of follow-up actions

## DELIVERABLES

Submit TOCERB status report and supporting information to S&TSORC at the S&TSORC meeting immediately following preparation of those documents. Corrective actions not completed at the time of the TOCERB review will be tracked in CATSWeb.

# Attachment F, Transmission Line Equipment Committee

## PURPOSE

The Transmission Line Equipment Committee (TLEC) provides an overview of line equipment performance.

## RESPONSIBILITY

TLEC has the responsibility for:

- Transmission line maintenance philosophy
- Evaluating all transmission line equipment issues
- Ensuring acceptable performance of transmission line equipment and components

## ORGANIZATION

TLEC sponsor is the Director – Transmission Engineering, who selects a TLEC chair and members consisting of CT, MA, and NH representatives from the following, as a minimum:

- Manager – Line Construction & Maintenance, Transmission (Chair)
- Field Supervisor – Transmission Line Construction & Maintenance
- Supervisor – Electric Field Operations (Transmission)
- Manager – Asset Strategy & Performance
- Manager – Transmission Line and Civil Engineering
- Senior/Lead Engineer

## MEETING SCHEDULE AND FREQUENCY

Quarterly, and as requested by S&TSORC, the TLEC sponsor, or TLEC Chair.

## ACTIVITY

Provide the line equipment implementation function for S&TSORC.

Provide a forum to:

- Review and discuss resolution of line equipment issues
- Assess and implement emerging technology and practices for use on the Eversource Transmission System

Provide current Maintenance activities and expenditures.

Provide status updates of active aerial and on-foot patrols.

## DELIVERABLES

Submit quarterly TLEC summary report that summarizes TLEC activities, concerns, and recommendations to S&TSORC at the S&TSORC meeting immediately following preparation of those documents.

# Attachment G, BES Cyber Asset Patch Management Committee

## PURPOSE

The BES Cyber Asset Patch Management Committee (BCAPMC) provides a patch management process for tracking, evaluating, and installing patches for applicable Medium Impact BES Cyber Assets.

## RESPONSIBILITY

BCAPMC has the responsibility for:

- Tracking BES Cyber Asset patches that involve cyber security fixes
- Assigning Subject Matter Experts (SMEs) to evaluate BES Cyber Asset patches that involve cyber security fixes
- Developing mitigation plans for S&TSORC approval to install BES Cyber Asset patches that involve cyber security fixes

## ORGANIZATION

BCAPMC sponsor is the Director-Transmission Operations, who selects a BCAPMC chair and members consisting of representatives from the following, as a minimum:

- Manager – Operational Compliance (Chair)
- Manager – Field Communications
- Manager – Protection and Controls Engineering
- Manager – System Control and Protections Engineering
- Supervisor – Transmission Protection & Controls (NH)

## MEETING SCHEDULE AND FREQUENCY

Monthly not to exceed 35 days, and as requested by S&TSORC.

## ACTIVITY

Identify and track source(s) for the release of cyber security patches for Medium Impact BES Cyber Systems.

Before monthly S&TSORC meeting:

- Prepare list of patches to be discussed
- Prepare preliminary assignment of SME to evaluate patch

Obtain S&TSORC approval for installation of applicable patches.

Obtain S&TSORC approval for mitigation plan to install applicable patches.

## DELIVERABLES

Submit monthly BCAPMC summary report to S&TSORC at the S&TSORC meeting immediately following preparation of those documents.

# Attachment H, Operating Experience Subcommittee (OES)

**PURPOSE**

The Operating Experience subcommittee (OES) provides an internal forum to review lessons learned from external reported events or incidents, currently obtained from the North American Transmission Forum (NATF) Human Performance Corrective Action Program Operating Experience (CAP-OE) Practice Group. Subjects reviewed can encompass a wide variety of issues including but not limited to substation or line equipment, maintenance, system operations, system protection, human performance, and compliance. The S&TSORC OES assists in determining if S&TSORC action is required to identify Eversource gaps, risks or threats and strengthen Eversource practices.

**RESPONSIBILITY**

The OE subcommittee shall:

- Ensure ongoing review of external events or incidents.
- Provide summary presentations of the events or incidents to support discussion at S&TSORC.
- Obtain recommendations of follow-up action, either assignments to S&TSORC subcommittee or individual.

**ORGANIZATION**

The OES sponsors are the Director – Substation Technical Engineering and Director Protection and Control Engineering who selects the OES chair and members. The OES is composed of Eversource personnel which participate in the following three NATF Participant groups and as augmented by S&TSORC:

- NATF Human Performance Corrective Action Program Operating Experience (CAP-OE) Practice Group, Substation Technical (Chair)
- NATF Equipment Performance and Maintenance Lines Equipment Practice Group
- NATF System Protection Practice Group

**MEETING SCHEDULE AND FREQUENCY**

Meetings to be scheduled monthly based on applicable NATF CAP-OE lessons learned available.

**ACTIVITY**

- Team Chair will provide members with monthly NATF OE reports
- The OES will filter reports for applicability to Eversource and recommend which reports get further review at S&TSORC.
- Team Chair will summarize the selected reports at each monthly S&TSORC meeting.
- S&TSORC members will decide if further action is needed and will delegate to the respective S&TSORC subcommittee, such as PACT, DR or TLECT. An individual may also be assigned.
- Per the current S&TSORC process, the assigned subcommittees will determine an Eversource extent of condition and action plan, which will be tracked until completion.
- On occasion, the S&TSORC members may have an Eversource Operating Experience to share with the NATF community. If so, this will be discussed during the OES section of the monthly S&TSORC agenda. The OES will support the development of the report and submittal to NATF, pending S&TSORC, senior leadership and legal review.

**DELIVERABLES**

Submit the OES summary report of supporting information to S&TSORC to be included as attachments to minutes of the S&TSORC meeting where presented.

# Supervisor's Briefing Sheet

Field Documentation

EVERSOURCE

**Issue Date:** 04-Oct-24

**Document Number**: **SBS-24-008**

**Revision:** 0

***Subject: Metal-Clad Switchgear Inspection and Maintenance***

**Effective Date:** 04-Oct-24

## Background

T&D Standards has been tasked with creating new work method standards for routine inspection and maintenance on equipment which corresponds to recent EMP Chapter updates. These work methods will supersede the current **EMP 6.0** Documents within the chapter which includes a routine inspection performed monthly, as well as major maintenance performed "as required".

**EMP 5.65** - Metal-Clad Switchgear was recently updated in 2023 and a newly written Work Method **WMS 51.07** has been created and will supersede **EMP 6.65** upon approval. **WMS 51.07** - *Metal-Clad Switchgear Inspection and Maintenance* provides details for the inspection and maintenance requirements for the metal-clad switchgear structure itself. Requirements for the components that reside within the structure are covered in separate documentation.

The highlights of the document include:

- Section 4 of the document details the inspection items for the monthly routine inspection performed while the switchgear is energized.
- Section 5 of the document details the items for major maintenance that are typically only performed when issues are found, and the switchgear needs to be removed from service for repairs.
- Section 6 added to cover annual inspection of lifting devices where applicable to meet OSHA requirements. This will also be included in an updated **EMP 5.65**.

## Expectations

Effective 2024, **WMS 51.07** shall be used for maintenance and inspections of metal-clad switchgear.

## References

**EMP 5.65 –** Metal-Clad Switchgear

**WMS 51.07 –** Metal-Clad Switchgear Inspection and Maintenance

## Contact Information

John Porazinski, Lead Engineer, john.porazinski@eversource.com
Aymen Lpizra, Manager, aymen.lpizra@eversource.com

## Revision History

| Revision Number | Date | Summary of Changes |
|---|---|---|
| 0 | 04-Oct-24 | Original document |

# Effort to harmonize the BASE model development approach between the DER Planning MA team, DSP MA team and the AFM team.

## Participants

**Team representative:** John Cerulli, Syed Ali - DER Planning MA
**Team representative:** Ling Yang - DSP MA
**Team representative:** Steffen Ziegler - AFM team
John Kreso
Andrew McPhee
Kendrick Lolange
Timith James
Jie Morgan
Souresh Mukherjee
Carlos Maldonado
Andrey Kulyna
Jean Amazan
Charles Thomas
Muhammad Khan
Mark Bentson

## Approvers

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## Scope

The effort to harmonize the BASE model development of Synergi Electric substation models is necessary to provide higher quality models and time savings to the DER Planning team and DSP MA team. The AFM team will modify and/or amend the existing recipe for BASE model development (referred to as “value stream” document). The expected start date of applying the new and modified recipe will go in effect from January 2024 on. The impact of the new and modified recipe will be evaluated in the meantime, by aspects of necessary effort, automation potential, database accesses and re-training.

## Transformer- and Transmission impedances:

1. Use transmission impedances from Aspen. This needs to be part of the model build effort.
2. Use transformer impedances from NX-9 (once verified with data owner). Verify transformer impedance from transformer nameplate/test report, compare with NX-9, this should be part of model build effort. (A common R/X calculator needs to be used by all modelers).
3. Use actual transformer voltages (rather than system nominal voltages), nameplate information and test report from NX-9.
4. Compare fault duty at substation bus, not on the feeders. Open the Synergi feeder breakers to eliminate the impact of DER on the substation bus fault current. (Aspen does not include DER. If you want to compare it to Aspen the modeler has to open the feeder breakers in Synergi).
5. Include the Aspen fault current in the notes to make the comparison easier.
6. Using the same fault current settings in Synergi for all departments is recommended. The fault current settings should be available to all System Planning departments.
7. Run fault analysis and compare with Aspen fault duties for feeders at the substation bus (within reasonable margin, e.g.: +- 15%).

## Large DER (>= 500 kW)

In general, there are two options to best integrate/allocate these loads:

Option 1:

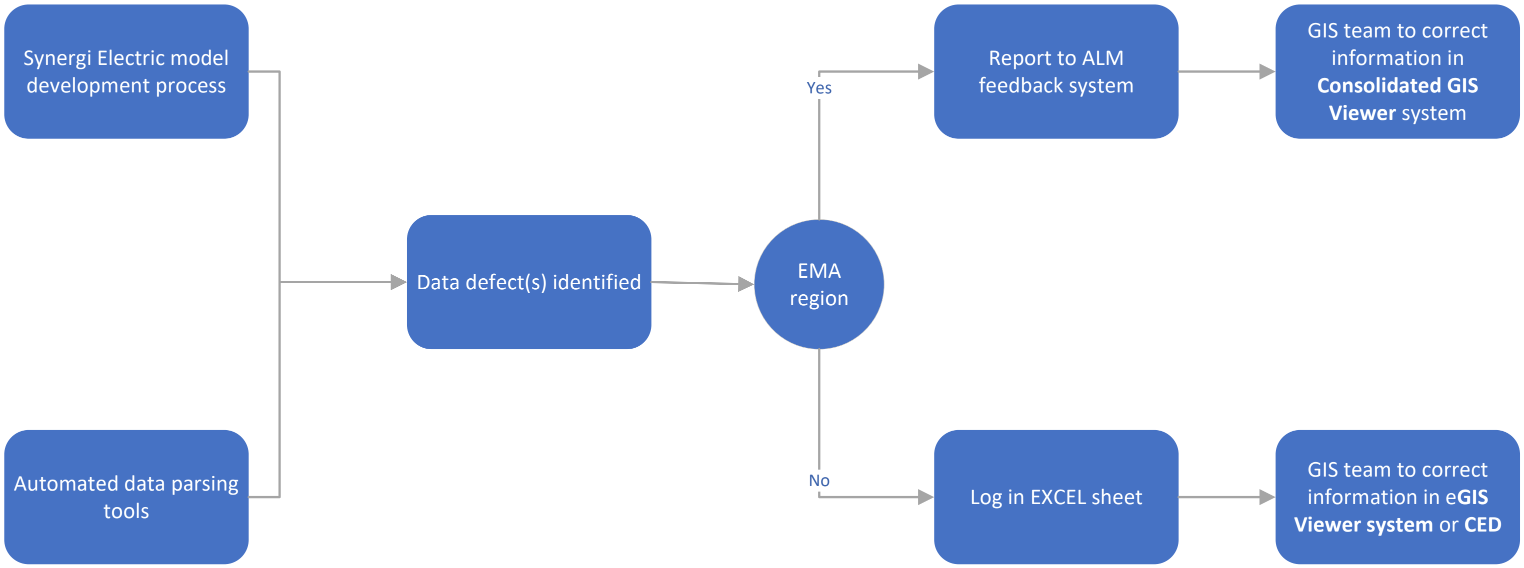
1. For large DER, 500 kW and above, it is recommended to run a simple effort monthly. It is necessary to combine CED and DERTS.
2. Get a list of DER from the CED, and then supplement the list with DER that are not in the CED but are in DERTS and where the feeder is listed in DERTS. This can be done in Excel. The expected effort is 4+ hours each month.

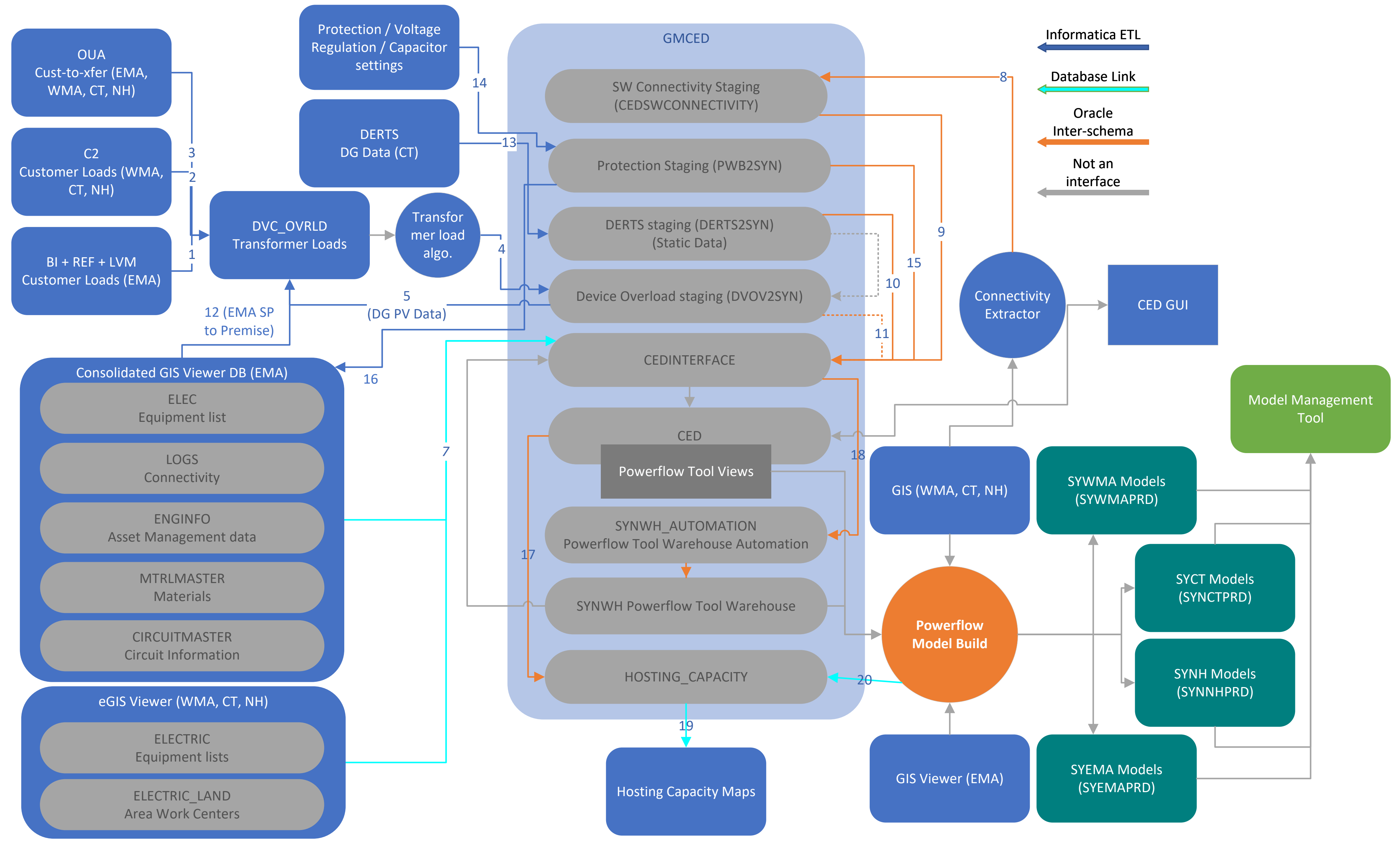
Option 2:

1. Take an Excel extract from the CED and map the circuit from the CED to an Excel extract from PowerClerk. In this way, the correct circuit numbers from the CED will be added to PowerClerk. The expected effort for that is 4+ hours. “Customer Care” needs to collaborate and update PowerClerk from the CED.

## Small DER (< 500 kW)

1. Attach all small DER (< 500 kW) as a lump (difference-reconciliated) to each associated feeder head.
2. The field “Circuit” is important for this calculation and circuit is the missing information. For individual DER, circuit is sometimes shown in the CED but not in DERTS, and the circuit in the CED is always better than the circuit in DERTS. It is recommended to do a reconciliation as noted above using Excel extracts. The source-of-truth is not always clear and has to be determined.


Synergi Electric model development process
Automated data parsing tools
Data defect(s) identified
EMA region
Yes
No
Report to ALM feedback system
GIS team to correct information in **Consolidated GIS Viewer** system
Log in EXCEL sheet
GIS team to correct information in e**GIS Viewer system** or **CED**


OUA
Cust-to-xfer (EMA, WMA, CT, NH)
C2
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BI + REF + LVM
Customer Loads (EMA)
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SYNWH Powerflow Tool Warehouse
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Informatica ETL
Database Link
Oracle
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Not an
interface
Model Management Tool
GIS (WMA, CT, NH)
SYWMA Models
(SYWMAPRD)
SYCT Models
(SYNCTPRD)
SYNH Models
(SYNNHPRD)
Powerflow Model Build
GIS Viewer (EMA)
SYEMA Models
(SYEMAPRD)

**Definitions for:**
**BASE MODEL**
**PLANNING MODEL**

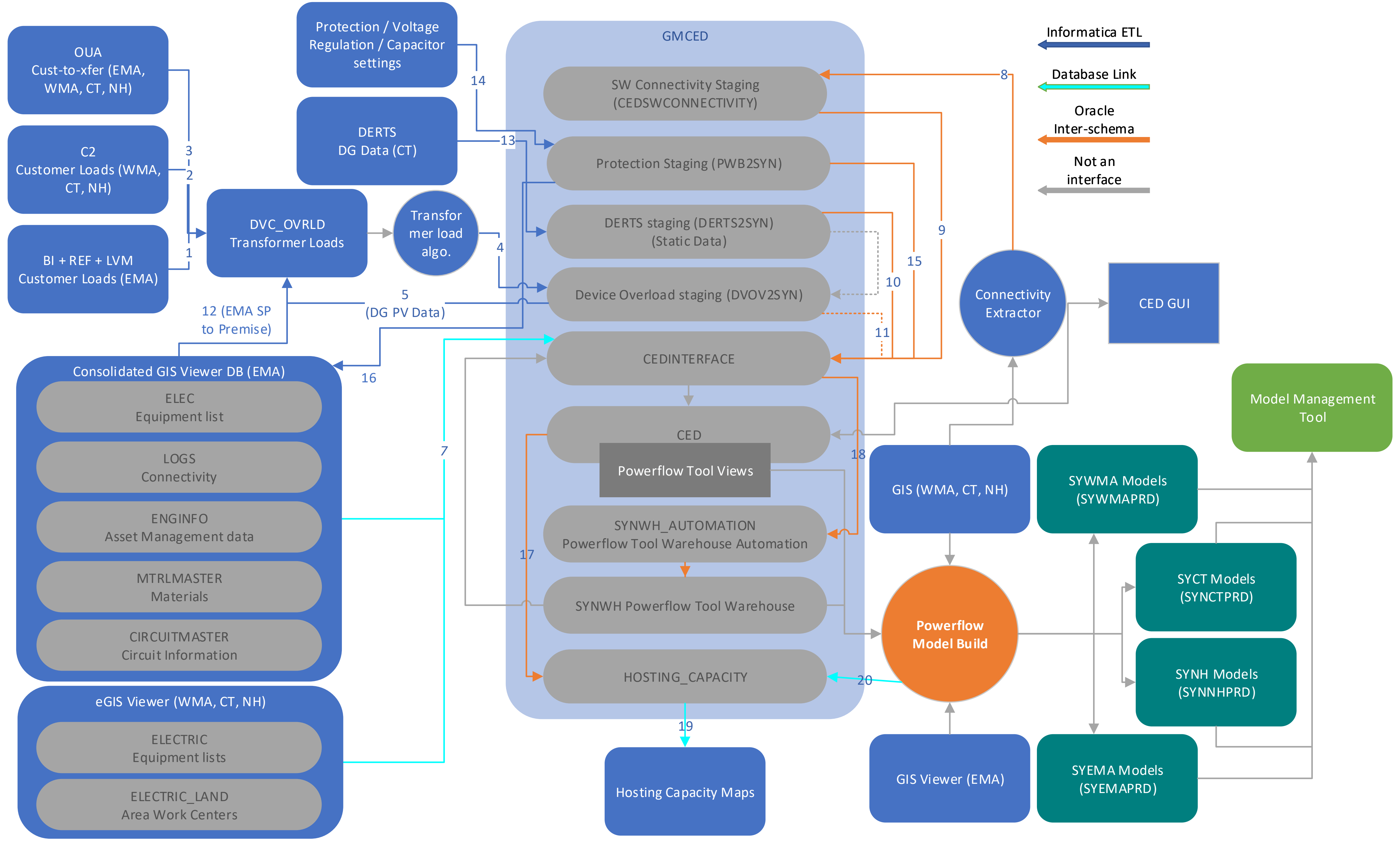
## Model Build Steps

| **#1 BASE** | | | | | | | |
|---|---|---|---|---|---|---|---|
| **#** | **STEP** | **KEY** | **SOURCE** | **VERIFICATION** | **DATA CURRENT STATE** | **COMMENT** | **ESTIMATED TIME** |
| 1 | Impedance verification Sub-station TRX | | ASPEN OneLiner | y | < 1 year | | 5.000% |
| 2 | Station Load Profile | Yearly *peak-day-X* for previous year | | n | previous year | | 10.000% |
| 3 | Irradiance Load Profile | Yearly *peak-day-X* for previous year | | y | previous year | | 10.000% |
| 4 | Station LTC setttings | | Methodology slide | y | previous year | | 5.000% |
| 5 | Capacitor and Regulator settings | | Methodology slide | y | previous year | | 10.000% |
| 6 | Connectivity check | Forge pull is referenced to source | GIS and MapViewerOnline | y | previous year | | 10.000% |
| 7 | Large Customer data | | GIS (1) and MVWeb | y | previous year | MV-Web is the last check to be made for L.C. Reach out to Distribution Engineering for unkown L.C. | 10.000% |
| 8 | DER >= 500 kW check | PowerBI (from CED) | CED (1) and PowerClerk (2) | y | current | | 10.000% |
| 9 | "Unknown" Conductor check | | OMS and EPOCH | y | current | Takes more time if DE is involved | 15.000% |
| 10 | Exceptions | Phase corrections, changes of TRX type, Synergi issues, missing information | | | previous year/current | Time spent heavily varies from station to station. | 5.000% |
| 11 | Meter Allocation | Forge pull is referenced to PI Data | PI Data | y | previous year | | 5.000% |
| 12 | Load Allocation check | Non-coincidental for *peak-day-X* | EXCEL from PI Data Links to Tag Access | y | previous year | Capacitors turned off before load allocation, then switched back on. | 2.500% |
| 13 | Run Load Flow Analysis | Compare results to Meter demand (should be within given tolerance) | | y | previous year | Capacitors can be turned on/off. DG can be turned on/off. | 2.500% |
| 14 | Check Base Model into Adept | | | | | | |
| | | | | | | | 100.000% |

| **#2 PLANNING** | | | | | | | |
|---|---|---|---|---|---|---|---|
| 1 | Clean and up-to-date BASE MODEL required | | | y | < 180 days | | 30.000% |
| 2 | Step Load changes and upgrades | Verified with GIS, OMS and Google Maps | EXCEL reference documents (EMA and WMA) | y | | | 10.000% |
| 3 | Reconductoring | Verified with GIS, OMS and Google Maps | EXCEL CIP sheet ("to" "from" info) | y | ? | Who manages CIP spread sheets? How frequently are these updated, are they comprehensive? | 10.000% |
| 4 | Equipment updates | Verified with GIS, OMS and Google Maps | EXCEL CIP sheet (location and conductor connection) | y | ? | | 10.000% |
| 5 | Peak Load Forecast (10-year) for each year | Given per substation, but pro-rated to feeder | Dan Ludwig? | | ? | Ideally we use the forecasting teams 10 year forecast in the future when this data becomes available. | 10.000% |
| 6 | Future DER (>= 500 kW). "In queue" | PowerBI from CED export to EXCEL. GIS, OMS and Google Maps used to verify. | CED (1) and PowerClerk (2) | y | | | 20.000% |
| 7 | Feeder or circuit reconfigurations | | Excel CIP sheet | y | y | | 10.000% |
| 8 | Check planning model into Adept | | | | | | |
| | | | | | | | 100.000% |

Volt-Var Optimization

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **#2 VVO** | | | | | | | |
| 1 | Clean and up-to-date BASE MODEL required | | | | | | 35.000% |
| 2 | Reconductoring | Verified with GIS, OMS and Google Maps | EXCEL CIP sheet ("to" "from" info) | | | | 15.000% |
| 3 | Equipment updates | Verified with GIS, OMS and Google Maps | EXCEL CIP sheet ("to" "from" info) | | | | 15.000% |
| 4 | Feeder or circuit reconfigurations | Verified with GIS, OMS and Google Maps | EXCEL CIP sheet ("to" "from" info) | | | | 15.000% |
| 5 | Future DER (>= 500 kW). "In queue" | PowerBI from CED export to EXCEL. GIS, OMS and Google Maps used to verify. | EXCEL CIP sheet ("to" "from" info) | | | | 20.000% |
| | | | | | | | 100.000% |


Informatica ETL
Database Link
Oracle Inter-schema
Not an interface
GMCED
SW Connectivity Staging (CEDSWCONNECTIVITY)
Protection Staging (PWB2SYN)
DERTS staging (DERTS2SYN) (Static Data)
Device Overload staging (DVOV2SYN)
CEDINTERFACE
CED
Powerflow Tool Views
SYNWH_AUTOMATION Powerflow Tool Warehouse Automation
SYNWH Powerflow Tool Warehouse
HOSTING_CAPACITY
Hosting Capacity Maps
Protection / Voltage Regulation / Capacitor settings
DERTS DG Data (CT)
OUA Cust-to-xfer (EMA, WMA, CT, NH)
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ELECTRIC Equipment lists
ELECTRIC_LAND Area Work Centers
Connectivity Extractor
CED GUI
Model Management Tool
GIS (WMA, CT, NH)
SYWMA Models (SYWMAPRD)
SYCT Models (SYNCTPRD)
SYNH Models (SYNNHPRD)
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Powerflow Model Build
GIS Viewer (EMA)

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# Massachusetts Grid Modernization Program Year 2022 Evaluation Report: Volt-VAR Optimization

## Massachusetts Electric Distribution Companies

**Submitted by:**

Guidehouse Inc.
77 South Bedford Street, Suite 400
Burlington, MA 01803
Telephone (781) 270-8300
Guidehouse.com

Reference No.: 219514
June 30, 2023

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# Executive Summary

## Introduction

As a part of their Grid Modernization Plans (GMPs), the Massachusetts Electric Distribution Companies (EDCs) are investing to enable Volt/VAR Optimization (VVO) on selected feeders across their distribution networks. VVO optimizes distribution voltage to reduce energy consumption and demand without the need for customer interaction or participation. The principle behind VVO is that power demand is reduced at voltages in the lower end of their allowable range for many end-use loads.

This evaluation focuses on the progress and effectiveness of each EDC's preauthorized VVO investments toward meeting the Department of Public Utilities (DPU) grid modernization objectives for Program Year (PY) 2022.

## Evaluation Process

The DPU requires a formal evaluation process, including an evaluation plan and evaluation studies, for the EDCs' preauthorized grid modernization plan investments. Guidehouse is completing the evaluation to establish a uniform statewide approach and to facilitate coordination and comparability. The evaluation is to measure and assess progress toward achieving the DPU's grid modernization objectives. The evaluation uses the DPU-established Infrastructure Metrics and Performance Metrics along with a set of Case Studies to understand if the GMP investments are meeting the DPU's objectives.

The original Evaluation Plan developed by Guidehouse[1] was submitted to the DPU by the EDCs in a petition for approval on May 1, 2019. Modifications to this original Evaluation Plan were required to enable evaluation of PY 2022. These modifications included an 1) extension of the evaluation window from the four year term spanning 2018 – 2021[2] (hereon referred to as Term 1) to incorporate the new four year term spanning 2022 – 2025 (hereon referred to as Term 2), and 2) revisions required to reflect the new Term 2 investment activity. Modifications to the original Evaluation Plan were submitted to the EDCs for approval on March 1, 2023. The modified Evaluation Plan has been used to develop the analysis and evaluation provided below in this document.

Table 1 illustrates the key Infrastructure Metrics and Performance Metrics relevant for the VVO evaluation by EDC.

[1] Guidehouse had previously filed as "Navigant Consulting" and did so during the initial evaluation plan filing.

[2] On May 10, 2018, the Massachusetts DPU issued its Order regarding the individual GMPs filed by the three Massachusetts EDCs. In the Order, the DPU preauthorized grid-facing investments over 3 years (2018-2020) for each EDC and adopted a 3-year (2018-2020) regulatory review construct for preauthorization of grid modernization investments. On May 12, 2020, the DPU issued an Order extending the 3-year grid modernization plan investment term to a 4-year term, which introduced a 2021 program year. In addition, on July 1, 2020, Eversource filed a request for an extension of the budget authorization associated with grid modernization investments. The 2018-2021 GMP term results provided for Eversource reflect these changes.

**Table 1. VVO Evaluation Metrics**

| Type | VVO Evaluation Metrics | ES | NG | UTL |
|---|---|---|---|---|
| IM-4 | Number of Devices or Other Technologies Deployed | ✓ | ✓ | ✓ |
| IM-5 | Cost for Deployment | ✓ | ✓ | ✓ |
| IM-6 | Deviation between Actual and Planned Deployment for the Plan Year | ✓ | ✓ | ✓ |
| IM-7 | Projected Deployment for the Remainder of the GMP Term | ✓ | ✓ | ✓ |
| PM-1 | VVO Baseline | ✓ | ✓ | |
| PM-2 | VVO Energy Savings | ✓ | ✓ | |
| PM-3 | VVO Peak Load Impact | ✓ | ✓ | |
| PM-4 | VVO Distribution Losses without Advanced Metering Functionality (AMF) (Baseline) | ✓ | ✓ | |
| PM-5 | VVO Power Factor | ✓ | ✓ | |
| PM-6 | VVO – GHG Emissions | ✓ | ✓ | |
| PM-7 | Voltage Complaints | ✓ | ✓ | |

IM = Infrastructure Metric, PM = Performance Metric, ES = Eversource, NG = National Grid, UTL = Unitil

* The EDCs are responsible for these metric calculations and the calculations are not addressed in this evaluation

*Source: Stamp Approved Performance Metrics, July 25, 2019*

## Data Management

Guidehouse worked with the EDCs to collect data to complete the VVO evaluation for the assessment of Infrastructure Metrics and Performance Metrics. A consistent methodology was used across Investment Areas and EDCs for evaluating and illustrating EDC progress toward the GMP metrics.

Table 2 summarizes data sources used throughout the VVO evaluation for PY 2022. Section 3.1.1 details each of the data sources.

**Table 2. VVO Data Sources**

| Data Source | Description |
|---|---|
| 2021 Grid Modernization Plan Term Report[3,4,5] | Planned device deployment and cost information from each EDC's appendix to the *2021 GMP Term Report* (filed April 1, 2022). Data was used as the reference to track progress against the GMP targets and are referred to as the GMP Plan in summary tables and figures throughout the report. |

[3] Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, Grid Modernization Plan Annual Report 2020. Submitted to Massachusetts DPU on April 1, 2021 as part of DPU 21-30.
[4] NSTAR Electric Company d/b/a Eversource Energy, Grid Modernization Plan Annual Report 2020. Submitted to Massachusetts DPU on April 1, 2021 as part of DPU 21-30. Note that Eversource Energy filed an updated Appendix 1 filing in December of 2021; however that update did not affect any of the data or results in the evaluation.
[5] Fitchburg Gas and Electric Light Company d/b/a Unitil, Grid Modernization Plan Annual Report 2020. Submitted to Massachusetts DPU on April 1, 2021 as part of DPU 21-30.

| Data Source | Description |
|---|---|
| 2022 Grid Modernization Plan Annual Report[6,7,8] | All PM-related data are from these 2022 GMP Annual Report Appendices. In addition, data collected as part of EDC Data Template (below) was compared to the data submitted by the EDCs to the DPU in the 2021 Grid Modernization Plan Term Reports and associated Appendix 1 filings. The evaluation team confirmed the consistency of the data from the various sources and reconciled any differences |
| EDC Device Deployment Data Template | Captures planned and actual device deployment and spend data. Actual device deployment and cumulative spend information were provided by work order ID and specified at the feeder- or substation-level as appropriate. Device deployment information and estimated spend for 2022 were provided as well. |
| VVO Supplemental Data Template | Includes additional information unique to the VVO Investment Area spanning inputs required for the Infrastructure Metrics and the Performance Metrics. Data covers actual versus planned VVO schedule, IT work schedule, customer demand response events, system events, distributed generation information, and voltage complaints. Information was requested at the feeder-level where possible. |
| Eversource's 2021 DPU-Filed Plan[9] | Eversource's GMP extension request was approved by the DPU on February 4, 2021. It includes budgets for PY 2021 deployment at the Investment Area level. This data source is included in the EDC Plan for Eversource planned spend at the Investment Area level. |
| 2022-2025 Grid Modernization Plan Track 1 Order[10] | The GMP Track 1 Order was filed by the DPU on October 7, 2022. It includes budgets for PY 2022-PY 2025 deployment at the Investment Area level. This data source is included in the EDC Plan for each EDC's planned spend at the Investment Area level. |
| EDC DOER Response Appendix[11] | Planned device deployment and cost information from each EDC's Appendix 1 filing was provided in response to DOER requests for information. Data was used as the reference to track progress against the GMP targets and are referred to as the GMP Plan in summary tables and figures throughout the report. |

*Source: Guidehouse analysis*

## Findings and Recommendations

Table 3 and Table 4 summarizes the Term 1 Infrastructure Metrics results for Eversource's VVO Investment Area through PY 2022.

[6] Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, Grid Modernization Annual Report for Calendar Year 2022. Submitted to Massachusetts DPU on April 24, 2023, as part of DPU 23-30.
[7] NSTAR Electric Company d/b/a Eversource Energy, Grid Modernization Annual Report for Calendar Year 2022. Submitted to Massachusetts DPU on April 24, 2023, as part of DPU 23-30.
[8] Fitchburg Gas and Electric Light Company d/b/a Unitil, 2022 Grid Modernization Plan Annual Report. Submitted to Massachusetts DPU on April 24, 2023, as part of DPU 23-30.
[9] Grid Modernization Program Extension and Funding Report. Submitted to Massachusetts DPU on July 1, 2020 as part of DPU 15-122.
[10] Massachusetts DPU 21-80/DPU 21-81/DPU 21-82 Order on Previously Deployed Technologies issued October 7, 2022.
[11] Plan data is sourced from EDC responses to the first set of information requests issued by the Department of Energy Resources (DOER). These responses were filed on October 4th, December 2nd, and October 5th, 2021, for Eversource, National Grid, and Unitil under DPU dockets 21-80, 21-81, and 21-82.

**Table 3. Term 1 VVO Infrastructure Metrics Summary**

| Infrastructure Metrics | | | Eversource |
|---|---|---|---|
| GMP Plan Total, PY 2018-2022 | | Devices | 1,142 |
| | | Spend, $M | $17.23 |
| IM-4 | Number of devices or other technologies deployed PY 2018-2022* | # Devices Deployed*** | 1,038 |
| | | % Devices Deployed | 91% |
| IM-5 | Cost for Deployment PY 2018-2022* | Total Spend, $M | $16.87 |
| | | % Spend | 98% |
| IM-6 | Deviation Between Actual and Planned Deployment for PY 2022 | % On Track (Devices) | 70% |
| | | % On Track (Spend) | 85% |
| IM-7 | Projected Deployment for the remainder of the GMP Term (i.e., Term 1)** | # Devices Remaining | 0 |
| | | Spend Remaining, $M | $0.00 |

*The metric names have been slightly changed here to clarify the time span used in analysis.

** This metric has been interpreted here (i.e., within the context of the 2022 Program Year Evaluation) as the units and spending that the EDC plans to complete their most recent 4-year Term 1 plans. Additional Grid Modernization units and dollars incurred in 2022 are attributed to Term 2, as appropriate, and all units and dollars spent during 2023 through 2025 will be considered as part of Term 2 GMPs.

***Note that "Deployed" here refers to commissioned devices. For full definitions of deployment stages, see Docket 20-46 Response to Information Request DPU-AR-4-11, September 3, 2020.

*Source: Guidehouse analysis of 2021 GMP Term Reports and 2022 EDC Data*

**Table 4. Term 1 Infrastructure Metrics for VVO Feeder Deployment Progress**

| IM | Parameter* | Eversource | National Grid | Unitil |
|---|---|---|---|---|
| IM-4 | # Feeders with VVO Enabled | 26 | 20 | 3 |
| | % Feeders with VVO Enabled | 81% | 100% | 100% |
| IM-6 | % On Track (Feeders with VVO Enabled) | 81% | 100% | 100% |
| IM-7 | # Feeders Remaining for VVO Enablement** | 0 | 0 | 0 |

* VVO Enabled denotes that the VVO system is commissioned and VVO is engaged. Feeders presented with VVO enabled may not be actively employing CVR.

** Does not include additional feeders that were not laid out in the original 3-Year Grid Modernization Plans.

*Source: Guidehouse analysis of 2021 GMP Term Report and 2022 EDC Data*

Table 5 and Table 6 summarizes the Term 2 Infrastructure Metrics results for each EDC's VVO Investment Area through PY 2022.

**Table 5. Term 2 VVO Infrastructure Metrics Summary**

| Infrastructure Metrics | | Eversource | National Grid** | Unitil |
|---|---|---|---|---|
| GMP Plan Total, PY 2022-2025 | # Devices Planned | 2,629 | 987 | 180 |
| | Spend, $M | $38.64 | $76.44 | $5.42 |
| EDC Data Total, PY 2022-2025 | # Devices Planned | 1711 | 1715 | 143 |
| | Spend, $M | $38.61 | $76.44 | $2.24 |

| Infrastructure Metrics | | | Eversource | National Grid** | Unitil |
|---|---|---|---|---|---|
| IM-4 | Number of devices or other technologies deployed thru PY 2022 | # Devices Deployed | 0 | 42 | 37 |
| | | % Devices Deployed | 0% | 4% | 21% |
| IM-5 | Cost for Deployment thru PY 2022 | Total Spend, $M | $0.04 | $7.61 | $0.28 |
| | | % Spend | 0% | 10% | 5% |
| IM-6 | Deviation Between Actual and Planned Deployment for PY 2022 | % On Track (Devices) | 0% | 25% | 119% |
| | | % On Track (Spend) | 0% | 69% | 105% |
| IM-7 | Projected Deployment for the Remainder of the Term | # Devices Remaining | 1711 | 1673 | 106 |
| | | Spend Remaining, $M | $38.58 | $68.83 | $1.96 |

*Note that “Deployed” here refers to commissioned devices. For full definitions of deployment stages, see Docket 20-46 Response to Information Request DPU-AR-4-11, September 3, 2020.

** To more closely align spend projections with DPU pre-authorized budgets, National Grid operations and maintenance (O&M) spend is included in actual and planned spend presented here. O&M spend is provided in aggregate for each investment area and is therefore excluded from device-specific summaries of spend.

*Source: Guidehouse analysis of 2021 DOER Responses and 2022 EDC Data*

**Table 6. Term 2 Infrastructure Metrics for VVO Feeder Deployment Progress**

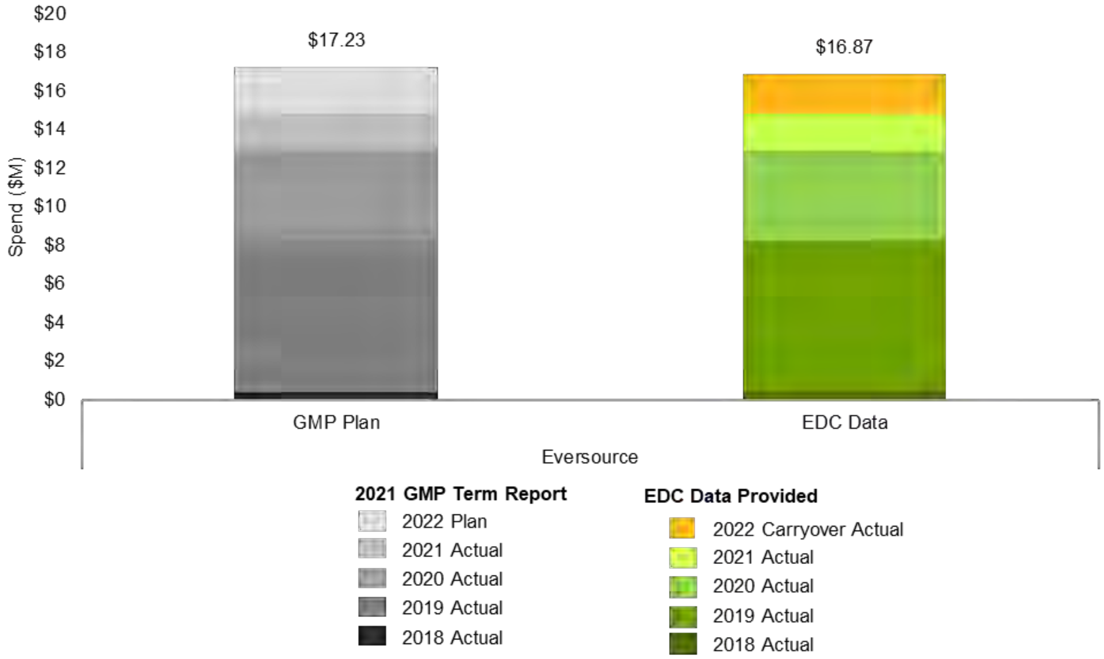
| IM | Parameter* | Eversource | National Grid | Unitil |
|---|---|---|---|---|
| IM-4 | # Feeders with VVO Enabled | 0 | 18 | 4 |
| | % Feeders with VVO Enabled | 0% | 35% | 50% |
| IM-6 | % On Track (Feeders with VVO Enabled) | 0% | 35% | 50% |
| IM-7 | # Feeders Remaining for VVO Enablement | 95 | 34 | 4 |

*VVO Enabled denotes that the VVO system is commissioned and VVO is engaged. Feeders presented with VVO enabled may not be actively employing CVR.

*Source: Guidehouse analysis of 2022 EDC Data*

Figure 1 compares the Term 1 GMP Plans and EDC Data totals and year-over-year spending for each EDC.

**Figure 1. VVO Term 1 Spend Comparison (2018-2022, $M)**

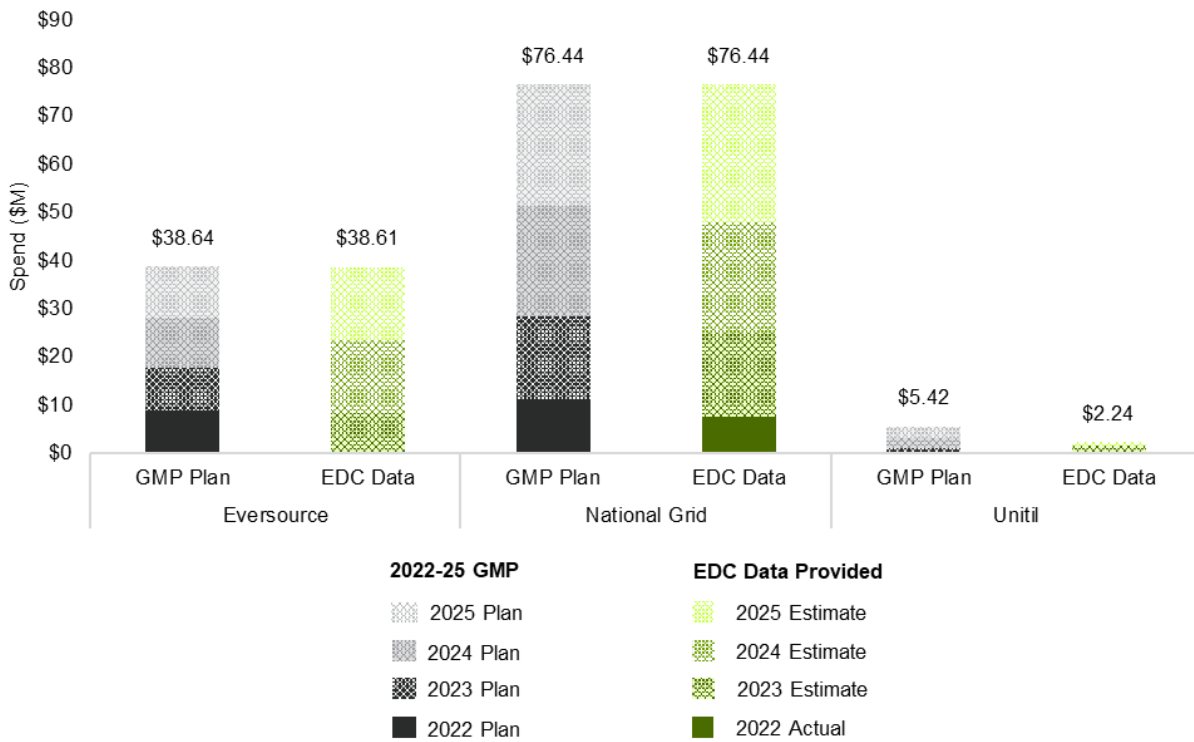



Note: Includes the Eversource planned spend on activity from 2021 that was transferred to 2022, set forth in Eversource's 2021 GMP Term Report, filed on April 1, 2022.

*Source: Guidehouse analysis of 2021 GMP Term Report, "GMP Extension and Funding Report," and 2022 EDC Data*

Figure 2 compares the Term 2 GMP Plans and EDC Data totals and year-over-year spending for each EDC.

**Figure 2. VVO Term 2 Spend Comparison (2022-2025, $M)**




Note: To more closely align spend projections with DPU pre-authorized budgets, National Grid operations and maintenance (O&M) spend is included in actual and planned spend presented here. O&M spend is provided in aggregate for each investment area and is therefore excluded from device-specific summaries of spend.

*Source: Guidehouse analysis of DPU Order (October 7, 2022) and 2022 EDC Data*

## Key Findings for VVO Infrastructure Metrics

Guidehouse's review of Eversource's VVO progress on Term 1 revealed that Eversource was approximately on-track with planned spend and deployment outlined in their *2021 GMP Term Report*. However, some spend and deployment remain in order to complete activities from Term 1. Key findings related to Eversource's progress include:

Device Deployment

- Eversource made headway on deploying 2021 investments in 2022, with Capacitor Banks and Grid Monitoring Line Sensors comprising the bulk of deployed devices. Eversource exceeded plans (25 devices) for Capacitor Banks, as refinements made during the planning and design process placed more priority on Capacitor Banks, less on Regulators, for VVO operation. At the close of 2022, Eversource was awaiting delivery of 3 ordered VVO Regulators from its vendor. Line Sensor and Micro-capacitor deployment also fell short of plans.

Total Spend

- Eversource made substantial progress on PY 2021 work that was planned for 2022. Total spend through the end of 2022 was approximately on track with plans for all device types, with total spend on VVO ($16.87M) being slightly below planned spend ($17.23M) laid out for Term 1.

VVO Enablement

- Eversource completed deployment of VVO at four of its six Term 1 plan substations (Agawam, Piper, Podick, and Silver) by the end of 2021, and conducted On/Off testing at these substations throughout 2022. Eversource stopped VVO On/Off testing on these four substations in May 2023, transitioning towards leaving VVO in its enabled state moving forward. Meanwhile, the Gunn and Oswald substations will be VVO enabled in 2023, with On/Off testing to begin shortly thereafter.

PY 2022's VVO Infrastructure Metrics findings show that the EDCs are at varying stages in VVO deployment for Term 2. Details pertaining to device deployment progress, total spend, and VVO enablement progress are shown below:

Device Deployment:

- Eversource did not meet VVO deployment goals for PY 2022. Eversource progress on VVO investments targeted for 2022 through 2025 was comprised of progressing engineering/design work for all VVO device types, as well as planning for future VVO deployments, while awaiting DPU decisions on continued VVO investment for 2022 through 2025. Given limited deployment on Term 2 investments in 2022, Eversource has adjusted plans for the remainder of Term 2, with the majority of deployment and spend activity projected to occur in 2024 and 2025. At the technology-level, planned deployment has declined for Regulators, Line Sensors, and Microcapacitors, and planned Capacitor Bank deployment has increased slightly. Capacitor Bank deployment has been revised upwards to reflect refinements made during the planning and design process.
- National Grid conducted less deployment than initially planned in PY 2022. A late-2022 DPU decision on preauthorizing 2022 through 2025 investment activity, resource constraints, and vendor lead times were all key contributors to this outcome. In response to lower-than-expected deployment in 2022, National Grid has accelerated its deployment timeline for 2023 through 2025. National Grid has also adjusted total deployment plans for numerous device types, increasing projected deployment for Capacitor Banks, Line Sensors, and LTC Controls, while reducing projected deployment for Regulators. National Grid cites that these revisions are primarily due to the VVO planning work that has been conducted since the 2022-2025 GMP was filed.
- Unitil deployment was below plans for 2022, with variation by technology. Unitil was on-track with deployment of VVO Capacitor Banks and Line Sensors in 2022, deploying 100% and 210% of planned units, respectively. However, deployment was under plans for Regulators and LTC Controls. Lower deployment than plans for these technologies may be attributed to Unitil's efforts to resolve LTC radio and control issues and cancelation of 4 deployments that were found to be unnecessary. Unitil has adjusted deployment plans for the remainder of Term 2 to conduct most deployment during 2023 and 2025. Additionally, Unitil has reduced its planned deployments of VVO Regulators and Capacitor Banks, as Unitil reassessed deployment plans and determined there were fewer Regulator and Capacitor Bank deployments needed than initially planned. Work in 2024 will be limited to material orders in preparation for construction work at the Beech Street substation.

Total Spend:

- Eversource spend on Term 2 investments amounted to $0.04M, short of the $8.70M that was initially planned for 2022. Given limited deployment and spend on Term 2 investments in 2022, as well as ongoing vendor delays in fulfilling material orders, Eversource has adjusted plans for the remainder of Term 2. In 2023, Eversource will be conducting additional design work, submitting material orders, and, when material orders are received, deploying VVO investments. Eversource has projected that most spend activity will occur in 2024 and 2025.
- National Grid spend on VVO was below plans for 2022. The majority of spend occurred on Capacitor Banks, while spend on Regulators and Line Sensors was well below plans. Lower-than-anticipated spend on Line Sensors can, in part, be attributed to National Grid's previous line sensor vendor discontinuing their selected model. For VVO Regulators, vendor delays in fulfilling material orders was a key contributor to lower spend than initially planned. In response to its 2022 experience with Line Sensors and Regulators, National Grid has begun to increase diversification of vendors that it sources materials from.
- Unitil spend on VVO was below initial plans. Unitil met 48% of its planned spend for Regulators. Spend and deployment of all other devices met or exceeded initial plans. Spend plans for the remainder of Term 2 have been revised downwards across all device types. Reduced spend on Regulators and Capacitor Banks can be attributed to a reduction in the units that Unitil plans to deploy, as well as lower than expected costs for deployment of Regulators. Reduced spend on LTC Controls and Line Sensors may be tied to process efficiencies implemented in 2022 that brought unit costs below plans. Most spend is planned for 2023 and 2025, with work in 2024 limited to material orders in preparation for construction work at the Beech Street substation.

VVO Enablement:

- For its Term 2 substations, Eversource is currently in the VVO Investment phase, and is conducting engineering / design work for the selected substations. Eversource anticipates completing deployment during 2024 and 2025. Once VVO investments are deployed, Eversource plans to conduct VVO On/Off testing, with testing start dates ranging from July 2024 through July 2025. Once VVO On/Off testing has begun, Eversource anticipates conducting this testing for 9 – 12 months to collect one summer, one winter, and one shoulder season of testing data.
- National Grid conducted VVO On/Off testing at its East Methuen and Maplewood Term 1 substations throughout 2022. Among its Term 2 substations, National Grid conducted On/Off testing at the East Bridgewater substation throughout 2022, as VVO deployment was completed at the substation in 2021. Additionally, National Grid completed VVO deployment at the Easton and West Salem substations and began VVO On/Off for these substations in winter 2022/23 and spring 2022, respectively. National Grid projects that it will complete VVO deployment and enable VVO at its remaining Term 2 substations in 2023.
- Unitil completed VVO deployment for its Term 1 substation (Townsend) in 2021, enabling VVO on December 1, 2021, and On/Off testing is expected to begin in spring 2023. Among its Term 2 substations, Unitil completed deploying VVO investments at the Summer Street substation and enabled VVO in December 2022, with VVO On/Off testing projected to begin at the substation in December 2023. Lunenburg and West Townsend are currently receiving VVO investments and Unitil plans to enable VVO at the substations in January and

November 2024, respectively. Unitil then plans to conduct On/Off testing at the substations beginning in December 2024. For its remaining substations, Unitil is currently conducting planning and engineering/design work for its Beech Street, Pleasant Street, and Princeton Road substations. These substations are expected to be enabled after the close of Term 2 in 2026 and 2027.

## Key Findings and Recommendations for VVO Performance Metrics

Table 7 includes the Performance Metrics results and key findings for the Spring 2022 – Winter 2022/23 M&V period. It can be difficult to compare the results from Performance Metrics analysis between Eversource and National Grid. For example, there are differences in the granularity of telemetry (e.g., 5-minute versus 15-minute), data quality at different times of the year (e.g., sustained pauses in VVO On/Off testing for one EDC, data outages during On/Off testing for another EDC). As such, certain portions of the M&V period, such as the Spring season, may be represented more for one EDC than the other. Additionally, there are numerous differences in DG penetration, customer types, and geographic areas served by Eversource and National Grid feeders that limit the ability to directly compare Eversource and National Grid VVO outcomes.

**Table 7. Performance Metrics Results for the Spring 2022 – Winter 2022/23 M&V Period**

| Performance Metrics | | Eversource | | National Grid | |
|---|---|---|---|---|---|
| Feeders Included in Evaluation | | 26 | | 34 | |
| PM-1 | Spring 2022 – Winter 2022/23 Baseline | 524,992 MWh | | 882,631 MWh | |
| PM-2 | Energy Savings – All Hours VVO On† | 2,128 ± 476 MWh | 0.41 ± 0.09% | 6,769 ± 1,162 MWh | 0.84 ± 0.15% |
| | Energy Savings – Actual VVO On Hours‡ | 879 ± 184 MWh | 0.41 ± 0.09% | 1,867 ± 302 MWh | 0.84 ± 0.15% |
| - | Voltage Reduction | 1.52 ± 0.01 V | 1.24 ± 0.01% | 0.08 ± <0.001 V | 0.62 ± 0.01% |
| - | CVRf^ | 0.60 | | 0.36 | |
| PM-3^^ | Peak Load Reduction | -369 ± 245 kW | -0.70 ± 0.46% | -2,189 ± 1,173 kW | -2.41 ± 1.28% |
| PM-4 | Reduction in Distribution Losses | 0.01% | | -1.95%¶ | |
| PM-5 | Change in Power Factor | <0.001 ± <0.001 | 0.06 ± 0.02% | -0.01 ± 0.002¶ | -0.96 ± 0.2%¶ |
| PM-6 | GHG Reductions ($CO_2$) All Hours VVO On† | 723 ± 162 tons $CO_2$ | | 2,301 ± 395 tons $CO_2$ | |
| | GHG Actual VVO-On Hours‡ | 299 ± 63 tons $CO_2$ | | 645 ± 103 tons $CO_2$ | |
| PM-7 | Voltage Complaints | 53 (13% decrease from 2015 – 2017 baseline period average) | | 136 (16% decrease from 2016 – 2017 baseline period average)§ | |

* National Grid feeders at the Easton substation did not begin testing until mid-January, 2023. All overall estimates are inclusive of Easton feeders and only incorporate impact estimates from this feeder during the Winter period. Additionally, even-numbered Maplewood feeders underwent a prolonged period over which VVO On/Off testing was paused, resulting in their removal from analysis that informed PM-1 through PM-6.
† Calculation assumes VVO was enabled for all hours between March 1, 2022 and February 28, 2023.
‡ Calculation uses actual number of VVO On hours spanning the analysis period. Actual VVO On Hours are the number of hours VVO was engaged between March 1, 2022 and February 28, 2023 for each feeder.
^The CVR factor provided for each EDC is the load-weighted average of CVR factors estimated for each feeder with a voltage response to VVO On/Off testing.[12]
^^Guidehouse evaluated the impact of VVO during peak load periods, defined by ISO-NE as 1:00 p.m. to 5:00 p.m. ET from June 1 to August 31 on non-holiday weekdays.
¶ Changes in power factor and distribution losses could not be estimated for substations going through VVO On/Off testing during Spring 2022 through Winter 2022/23 due to data quality issues. Results presented for these metrics are based off of VVO substations that completed VVO On/Off testing prior to this evaluation period. For this evaluation period, the only substation to conclude On/Off testing is Stoughton.
§ National Grid did not start tracking voltage complaints until 2016.
*Source: Guidehouse analysis*

[12] All of Eversource's Podick 18G feeders and Silver feeders 30A2, 30A4, and 30A6 are removed from aggregated CVRf results due to unreliable voltage and energy responses to VVO On/off testing. National Grid's West Salem feeders 29W2, 29W4, and 29W6, as well as East Bridgewater feeders 797W1, 797W23, 797W29, and 797W42 are also removed from aggregated CVRf results due to unreliable voltage and energy responses to VVO On/off testing.

Findings from the evaluation of Performance Metrics indicate that VVO allowed Eversource and National Grid to realize energy savings and voltage reductions during the Spring 2022 – Winter 2022/23 M&V period.[13] More specifically:

- During the Spring 2022 – Winter 2022/23 M&V period, Eversource's Agawam, Piper, Podick, and Silver substations realized 879 MWh (0.41%) energy savings and 1.52 V (1.24%) voltage reduction associated with VVO. The CVR Factor, which provides an estimate of energy savings possible with voltage reductions, was 0.60.[50] During the same M&V period, National Grid's East Methuen, East Bridgewater, Easton, Maplewood, Stoughton, and West Salem substations realized 1,867 MWh (0.84%) energy savings and 0.08 kV (0.62%) voltage reduction associated with VVO. National Grid's CVR factor was 0.36.[50]
- Eversource energy savings of 879 MWh yielded a 299 short ton reduction of $CO_2$ emissions. National Grid energy savings of 1,867 MWh yielded a 645 short ton reduction in $CO_2$ emissions.
- Eversource and National Grid VVO feeders experienced a minimal benefit associated with peak load, power factor, and distribution losses. Eversource VVO feeders experienced a statistically significant increase (0.70%) in peak load, a statistically significant decrease (0.06%) in power factor, and a minimal decrease in distribution losses when VVO was engaged. National Grid VVO feeders experienced a statistically significant increase in peak load (2.41%), a small increase (0.96%) in power factor, and a 1.95% increase in distribution losses when VVO was engaged.
- For Eversource, a total of 53 voltage complaints were received from customers connected to the Agawam, Piper, Podick, and Silver VVO feeders during the Spring 2022 – Winter 2022/23 M&V period. This is a 13% decrease relative to the average voltage complaints per year received between 2015 – 2017. For National Grid, a total of 136 voltage complaints were received from customers connected to the East Methuen, East Bridgewater, Easton, Maplewood, Stoughton, and West Salem VVO feeders during the period. This is a 16% decrease relative to the average voltage complaints per year received between 2016 – 2017. For both EDCs, there is not sufficient evidence to support changes in voltage complaints being attributed to VVO.

In 2023 and beyond, Guidehouse recommends that Eversource and National Grid:

- Ensure VVO On/Off testing is running according to plan, with limited pauses to the VVO On/Off testing schedule. Across the VVO feeders, one-quarter to one-half of data points were removed due to extended pauses in VVO On/Off testing. For some feeders, this resulted in the vast majority of provided data to be unusable for components of this evaluation (e.g., for estimation of distribution loss and power factor reductions). Sustained On/Off testing will increase the amount of usable data in the evaluation and improve the ability for Guidehouse to provide a comprehensive evaluation of VVO performance metrics.

[13] It can be difficult to compare the results from Performance Metrics analysis between Eversource and National Grid. For example, there are differences in the granularity of telemetry (e.g., 15-minute versus 1 hour), data quality at different times of the year (e.g., sustained pauses in VVO testing, repeated data). As such, data cleaning can cause certain portions of the M&V period to be represented more for one EDC than the other. Additionally, there are numerous differences in DG penetration, customer types, and geographic areas served by Eversource and National Grid feeders that limit the ability to directly compare Eversource and National Grid VVO outcomes.

- Confirm adjustments to VVO On/Off testing schedule for any VVO feeders prior to implementation. VVO On/Off testing is designed similarly to a Randomized Controlled Trial (RCT), and adjustments to the testing schedule could, potentially, hinder the effectiveness of the testing design and cause biases to evaluation results. Ensuring there is proper balance in the number of VVO on and off hours throughout the evaluation period will allow for Guidehouse to provide a comprehensive and accurate evaluation of VVO performance metrics.
- Continue to investigate how to improve outcomes across VVO feeders. Many feeders across the EDCs underwent no material change in voltage. Correspondingly, energy reduction estimates were small-to-insignificant. These observations may indicate flaws in the VVO control scheme for these feeders. In order to improve VVO performance, Guidehouse recommends that the EDCs continue their efforts to investigate root causes to shortcomings in the VVO control schemes and work with distribution engineers and the VVO vendors to respond accordingly. If needed, Guidehouse can conduct in-depth case studies at these substations further understand shortcomings in the VVO control scheme.

# 1. Introduction to Massachusetts Grid Modernization

This section provides a brief background to the Grid Modernization Evaluation process and an overview of the Volt/VAR Optimization (VVO) Investment Area and specific VVO evaluation objectives. These are provided for context when reviewing the subsequent sections that address the specific evaluation process and findings.

## 1.1 Massachusetts Grid Modernization Plan Background

The following subsections summarize the progression of Massachusetts Grid Modernization Plans (GMPs) filed by the three Massachusetts Electric Distribution Companies (EDCs): Eversource, National Grid, and Unitil.

### 1.1.1 Grid Modernization Term 1 (2018-2021)

On May 10, 2018, the Massachusetts DPU issued its Order[14] regarding the individual Grid Modernization Plans (GMPs) filed by the three Massachusetts EDCs.[15,16] In the Order, the DPU preauthorized grid-facing investments over 3 years (2018-2020) for each EDC and adopted a 3-year (2018-2020) regulatory review construct for preauthorization of grid modernization investments. On May 12, 2020, the DPU issued an Order[17] extending the 3-year grid modernization plan investment term to a 4-year term, which introduced a 2021 program year.

During the GMP term spanning 2018-2021 (hereon referred to as Term 1) the grid modernization investments were organized into six Investment Areas to facilitate understanding, consistency across EDCs, and analysis.

- Monitoring and Control (M&C)
- Advanced Distribution Automation (ADA)
- Volt/VAR Optimization (VVO)
- Advanced Distribution Management Systems/Advanced Load Flow (ADMS and ALF)
- Communications/IoT (Comms)
- Workforce Management (WFM)

A certain level of spending for each of these GMP Investment Areas was preauthorized by the DPU, with the expectation they would advance the achievement of DPU's grid modernization objectives:

[14] Massachusetts DPU 15-120/DPU 15-121/DPU 15-122 (Grid Modernization) Order issued May 10, 2018 (DPU Order).

[15] On August 19, 2015, National Grid, Unitil, and Eversource each filed a grid modernization plan with the DPU. The DPU docketed these plans as DPU 15-120, DPU 15-121, and DPU 15-122, respectively.

[16] On June16, 2016, Eversource and National Grid each filed updates to their respective grid modernization plans

[17] Massachusetts DPU 15-120; DPU 15-121; DPU 15-122 (Grid Modernization) Order (1) Extending Current Three-Year Grid Modernization Plan Investment Term; and (2) Establishing Revised Filing Date for Subsequent Grid Modernization Plans (issued May 12, 2020).

- Optimize system performance by attaining optimal levels of grid visibility command and control, and self-healing
- Optimize system demand by facilitating consumer price responsiveness
- Interconnect and integrate distributed energy resources (DER)

For Term 1, the Massachusetts DPU's preauthorized budget for grid modernization varied by Investment Area and EDC. Eversource originally had the largest preauthorized budget at $133 million, with ADA and M&C representing the largest share ($44 million and $41 million, respectively). National Grid's preauthorized budget was $82.2 million, with ADMS representing over 50% ($48.4 million). Unitil's preauthorized budget was $4.4 million and VVO makes up 50% ($2.2 million).

On July 1, 2020, Eversource filed a request for an extension of the budget authorization associated with grid modernization investments.[18] The budget extension, approved by the DPU on February 4, 2021,[19] included $14 million for ADA, $16 million for ADMS/ALF, $5 million for Communications, $15 million for M&C, and $5 million for VVO.[20] These values are included in the Eversource total budget by Investment Area in Table 8.

**Table 8. Term 1 (2018-2021) Preauthorized Budget, $M**

| Investment Areas | Eversource | National Grid | Unitil | Total |
|---|---|---|---|---|
| **ADA** | $58.00 | $13.40 | N/A | **$71.40** |
| **ADMS/ALF** | $33.00 | $48.40 | $0.70 | **$79.10** |
| **Comms** | $23.00 | $1.80 | $0.84 | **$25.60** |
| **M&C** | $56.00 | $8.00 | $0.35 | **$64.75** |
| **VVO** | $18.00 | $10.60 | $2.22 | **$30.80** |
| **WFM** | -- | -- | $0.30 | **$1.00** |
| **2018-2021 Total** | **$188.00** | **$82.20** | **$4.41** | **$272.65** |

*Source: DPU Order, May 10, 2018, and Eversource filing "GMP Extension and Funding Report," July 1, 2020*

### 1.1.2 Grid Modernization Term 2 (2022-2025)

On July 2, 2020, the Massachusetts DPU issued an Order[21] that triggered further investigation into modernization of the electric grid. In the order, the DPU required that the EDCs file a grid modernization plan on or before July 1, 2021. In accordance with this order, the Massachusetts EDCs filed grid modernization plans for a 4-year period spanning 2022-2025 (hereby referred to as Term 2).[22] In these plans, the EDCs outlined continued investment in the areas that received

[18] Grid Modernization Program Extension and Funding Report. Submitted to Massachusetts DPU on July 1, 2020 as part of DPU 15-122

[19] Massachusetts DPU 20-74 Order issued on February 4, 2021.

[20] The DPU allowed flexibility to these budgets to accommodate changing technologies and circumstances. For example, EDCs can shift funds across the different preauthorized investments if a reasonable explanation for these shifts is supplied.

[21] Massachusetts DPU 20-69: Investigation by the Department of Public Utilities on its own Motion into the Modernization of the Electric Grid – Phase Two (issued July 2, 2020).

[22] On July 1, 2021, Eversource, National Grid, and Unitil each filed a grid modernization plan with the DPU for the period spanning 2022-2025. The DPU docketed these plans as DPU 21-80, 21-81, and 21-82, respectively.

investment during Term 1 (referred to as Track 1 Investment Areas), and investment in new Investment Areas (Track 2 Investment Areas). The Track 2 grid modernization investments were organized into the following additional Investment Areas to facilitate understanding, consistency across EDCs, and analysis.

- Interconnection Automation
- Probabilistic Power Flow Modeling
- Distributed Energy Resource Mitigation (DER Mitigation)
- Distributed Energy Resource Management System (DERMS)
- Demonstration Projects

### 1.1.3 Investment Areas

Table 9 and Table 10 summarize the DPU pre-authorized GMP investments.

**Table 9. Overview of Term 2, Track 1 Investment Areas**

| Investment Areas | Description | Objective |
|---|---|---|
| **Monitoring and Control (M&C)** | Remote monitoring and control of devices in the substation for feeder monitoring or online devices for enhanced visibility outside the substation | Enhancing grid visibility and control capabilities, reliability increase |
| **Advanced Distribution Automation (ADA)** | National Grid-only investment for Term 2. ADA allows for isolation of outage events with automated restoration of unaffected circuit segments | Reduces the impact of outages |
| **Volt/VAR Optimization (VVO)** | Control of line and substation equipment to optimize voltage, reduce energy consumption, and increase hosting capacity | Optimization of distribution voltage to reduce energy consumption and demand |
| **Advanced Distribution Management Systems** | New capabilities in real-time system control with investments in developing accurate system models and enhancing Supervisory control and data acquisition (SCADA) and outage management systems to control devices for system optimization and provide support for distribution automation and VVO with high penetration of DER | Enables high penetration of DER by supporting the ability to control devices for system optimization, ADA, and VVO |
| **Communications/IoT** | Fiber middle mile and field area communications systems | Enables the full benefits of grid modernization devices to be realized |
| **Workforce Management (WFM)** | Unitil-only investment for Term 2 to improve workforce and asset utilization related to outage management and storm response | Improves the ability to identify damage after storms |

*Source: Grid Mod RFP – SOW (Final 8-8-18).pdf; Guidehouse*

**Table 10. Overview of Term 2, Track 2 Investment Areas**

| Investment Areas | Description | Objective |
|---|---|---|
| **Interconnection Automation** | Eversource plans to integrate, into a single software, both their existing Distributed Generation (DG) tools and customer interconnection portal. | Improve the DG interconnection process with reductions in time & resources for a growing number of applications |
| **Probabilistic Power Flow Modeling** | Eversource plans to use a simulation of locational load and generation based on variables such as customer behavior and energy market prices. | Leverage GMP term 1 ALF investments into an automated approach to system modelling. |
| **DER Mitigation** | Unitil plans to install ground-fault overvoltage protection as well as upgrade either voltage regulators or load tap changers for three substations with reverse power flow issues | Address reverse power flow issues caused by DER saturation at three specific substations. |
| **DERMS** | Software that forms the hub of DER management functions and integrates with other applications such as a Demand Response Management System ("DRMS") and ADMS, to create the DERMS Platform. | Cost-effectively optimize system performance and integrate DERS with more granularity |
| **Demonstration Projects** | Two demonstration projects proposed by National Grid to test new tools. Includes Active Resource Integration (ARI) and Local Export Power Control | Facilitates the interconnection of DG in certain areas of the EDC's distribution system that are approaching saturation |
| **Project Management and Third-Party Evaluation** | Investment into evaluation and project management. Evaluation includes third party evaluator budget, where the evaluator will conduct studies on appropriate topics related to the deployment of preauthorized investments. Project management includes portfolio management and reporting. | Assess and report on GMP deployment progress and performance of grid modernizing investments. |

*Source: Massachusetts DPU 21-80/DPU 21-81/DPU 21-82 Order on New Technologies and Advanced Metering Infrastructure Proposals issued November 30, 2022.*

The Massachusetts DPU preauthorized budget for Track 1 investments and Track 2 investments on October 7, 2022[23] and November 30, 2022, [24] respectively. The preauthorized budget for grid modernization varies by Investment Area and EDC. National Grid has the largest preauthorized track one budget at $300.8 million, with Communications and VVO representing the largest share ($103 million and $76 million, respectively). Eversource's preauthorized Track 1 budget is $176.6 million, with M&C representing about 50% ($76.3 million). Unitil's preauthorized track one budget is $9.1 million with VVO making up more than 50% ($5.4 million).

[23] Massachusetts DPU 21-80/DPU 21-81/DPU 21-82 Order on Previously Deployed Technologies issued October 7, 2022.

[24] Massachusetts DPU 21-80/DPU 21-81/DPU 21-82 Order on New Technologies and Advanced Metering Infrastructure Proposals issued November 30, 2022.

**Table 11. Term 2 (2022-2025) Preauthorized Budget, $M**

| Investment Areas | Eversource | National Grid | Unitil | Total |
|---|---|---|---|---|
| **ADA** | -- | $37.70 | -- | **$37.70** |
| **ADMS*** | $21.90 | $61.00 | $1.50 | **$84.40** |
| **Comms**** | $38.00 | $102.80 | $0.82 | **$141.62** |
| **M&C** | $76.30 | $4.10 | $1.10 | **$81.50** |
| **VVO** | $40.40 | $76.40 | $5.40 | **$122.20** |
| **WFM** | -- | -- | $0.25 | **$0.25** |
| **IT/OT** | -- | $18.80 | -- | **$18.80** |
| ***Track 1 Total*** | ***$176.60*** | ***$300.80*** | ***$9.07*** | ***$486.47*** |
| **Interconnection Automation** | $2.77 | -- | -- | **$2.77** |
| **Probabilistic Power Flow** | $2.07 | -- | -- | **$2.07** |
| **DER Mitigation** | -- | -- | $1.04 | |
| **DERMS** | $16.00 | $24.60 | $0.16 | **$41.80** |
| **Demonstration Projects** | -- | $6.40 | -- | **$6.40** |
| **Project Management and Third-Party Evaluation** | $8.00 | $4.40 | $0.30 | **$12.70** |
| ***Track 2 Total*** | ***$29.00*** | ***$35.40*** | ***$1.50*** | ***$65.90*** |
| **2022-2025 Total** | **$205.60***** | **$336.20** | **$10.57** | **$552.37** |

* Given as $1.50M minus DERMS cost from DPU Order, Oct. 7, 2022, and calculated from DPU Order, Nov. 30, 2022.

** Includes Communications Modernization for Eversource, with added budget taken from DPU Order, Nov. 30, 2022.

*** Budget includes $16.3 million in funds remaining from the supplemental budget approved in D.P.U. 20-74 for DMS, substation automation, and VVO investments that Eversource sought to expend in calendar year 2022.

*Source: DPU Order on Previously Deployed Technologies, October 7, 2022, and DPU Order on New Technologies, November 30, 2022 under docket 21-80, 21-81, and 21-82.*

### 1.1.4 Evaluation Goals and Objectives

The DPU requires a formal evaluation process (including an evaluation plan and evaluation studies) for the EDCs' preauthorized GMP investments. Guidehouse is completing the evaluation to enable a uniform statewide approach and to facilitate coordination and comparability. The evaluation measures the progress made toward the achievement of DPU's grid modernization objectives. It uses the DPU-established Infrastructure Metrics and Performance Metrics, as well as Case Studies that illustrate the performance of specific technology deployments, to help determine if the investments are meeting the DPU's GMP objectives.

As previously noted, the Massachusetts DPU order on Track 2 technologies was released on November 30, 2022. The EDCs waited for DPU ruling on these technologies prior to commencing with significant investment, and thus were not able to complete deployment of

Track 2 technologies within the remaining 2022 calendar year.[25] Guidehouse has, therefore, not included evaluation findings for Track 2 technologies in this PY 2022 evaluation report, but instead will report GMP Track 2 evaluation findings for PY 2023 through PY 2025 in future program year reports.

### 1.1.5 Metrics for Evaluation

The DPU-required evaluation involves Infrastructure Metrics and Performance Metrics for each Investment Area. In addition, selected case studies have been added for some Investment Areas (e.g., M&C) as part of the evaluation to help facilitate understanding of how the technology performs in specific instances (e.g., in remediating the effects of a line outage).

#### *1.1.5.1 Infrastructure Metrics*

The Infrastructure Metrics assess the deployment of the GMP investments. Table 12 summarizes the Infrastructure Metrics.

**Table 12. Infrastructure Metrics Overview**

| Metric | | Description | Applicable IAs | Metric Responsibility* |
|---|---|---|---|---|
| **IM-1** | **Grid Connected Distribution Generation Facilities** | Tracks the number and type of distributed generation facilities in service and connected to the distribution system | ADMS/ALF | EDC |
| **IM-2** | **System Automation Saturation** | Measures the quantity of customers served by fully or partially automated devices. | M&C, ADA | EDC |
| **IM-3** | **Number and Percent of Feeders with Installed Sensors** | Measures the total number of feeders with installed sensors which will provide information useful for proactive planning and intervention. | M&C | EDC |
| **IM-4** | **Number of Devices or Other Technologies Deployed** | Measures how the EDC is progressing with its GMP from an equipment or device standpoint. | All IAs | Evaluator |
| **IM-5** | **Cost for Deployment** | Measures the associated costs for the number of devices or technologies installed; designed to measure how the EDC is progressing under its GMP. | All IAs | Evaluator |
| **IM-6** | **Deviation Between Actual and Planned Deployment for the Plan Year** | Measures how the EDC is progressing relative to its GMP on a year-by-year basis. | All IAs | Evaluator |

[25] Within PY 2022, there was limited spend for Track 2 technologies for both Unitil and Eversource. Unitil reported approximately $20k collectively across DER mitigation, workforce management, and Program Management and EM&V, while Eversource reported approximately $6k for DERMS.

| Metric | | Description | Applicable IAs | Metric Responsibility* |
|---|---|---|---|---|
| **IM-7** | **Projected Deployment for the Remainder of the GMP Term** | Compares the revised projected deployment with the original target deployment as the EDC implements its GMP. | All IAs | Evaluator |

PM = Performance Metric, IA = Investment Area, ES = Eversource, NG = National Grid, UTL = Unitil

* Column indicates which EDC is responsible for calculating each metric, for statewide metrics, all EDCs are responsible

*Source: Guidehouse Review of DPU Order, May 10, 2018*[26]

### *1.1.5.2 Performance Metrics*

The Performance Metrics assess the performance of all the GMP investments. Table 13 summarizes the Performance Metrics used for the various Investment Areas. This report discusses Performance Metrics that pertain specifically to the M&C Investment Area.

**Table 13. Performance Metrics Overview**

| Metric | | Description | Applicable IAs | Metric Responsibility* |
|---|---|---|---|---|
| **PM-1** | **VVO Baseline** | Establishes a baseline impact factor for each VVO-enabled feeder which will be used to quantify the peak load, energy savings, and greenhouse gas (GHG) impact measures. | VVO | All |
| **PM-2** | **VVO Energy Savings** | Quantifies the energy savings achieved by VVO using the baseline established for the feeder against the annual feeder load with the intent of optimizing system performance. | VVO | All |
| **PM-3** | **VVO Peak Load Impact** | Quantifies the peak demand impact VVO/CVR has on the system with the intent of optimizing system demand. | VVO | All |
| **PM-4** | **VVO Distribution Losses without Advanced Metering Functionality (AMF) (Baseline)** | Presents the difference between feeder load measured at the substation via the SCADA system and the metered load measured through advanced metering infrastructure. | VVO | All |
| **PM-5** | **VVO Power Factor** | Quantifies the improvement that VVO/CVR is providing toward maintaining feeder power factors near unity. | VVO | All |

[26] Massachusetts DPU 15-120/DPU 15-121/DPU 15-122 (Grid Modernization) Order issued May 10, 2018 (DPU Order), pg. 198-201.

| Metric | | Description | Applicable IAs | Metric Responsibility* |
|---|---|---|---|---|
| **PM-6** | **VVO – GHG Emissions** | Quantifies the overall GHG impact VVO/CVR has on the system. | VVO | All |
| **PM-7** | **Voltage Complaints** | Quantifies the prevalence of voltage-related complaints before and after deployment of VVO investments to assess customer experience, voltage stability under VVO. | VVO | All |
| **PM-8** | **Increase in Substations with DMS Power Flow and Control Capabilities** | Examines the deployment and data cleanup associated with deployment of ADMS, primarily by counting and tracking the number of feeders and substations per year. | ADMS/ ALF | All |
| **PM-9** | **Control Functions Implemented by Feeder** | Examines the control functions of DMS power flow and control capabilities, focused on the control capabilities including VVO-CVR and FLISR. | ADMS/ ALF | All |
| **PM-10** | **Numbers of Customers that benefit from GMP funded Distribution Automation Devices** | Shows the progress of ADA investments by tracking the number of customers that have benefitted from the installation of ADA devices. | ADA | ES, NG |
| **PM-11** | **Grid Modernization investments' effect on outage durations** | Provides insight into how ADA and M&C investments can reduce outage durations (CKAIDI). Compares the experience of customers on GMP M&C-enabled feeders as compared to the previous 3-year average for the same feeder. | M&C, ADA | All |
| **PM-12** | **Grid Modernization investments' effect on outage frequency** | Provides insight into how ADA and M&C investments can reduce outage frequencies (CKAIFI). Compares the experience of customers on M&C-enabled feeders as compared to the prior 3-year average for the same feeder. | M&C, ADA | All |
| **PM-ES-1** | **Advanced Load Flow – Percent Milestone Completion** | Examines the fully developed ALF capability across Eversource's feeder population. | ADMS/ ALF | ES |
| **PM-ES-2** | **Protective Zone: Average Zone Size per Feeder** | Measures Eversource's progress in sectionalizing feeders into protective zones designed to limit outages to customers located within the zone. | ADA | ES |

| Metric | | Description | Applicable IAs | Metric Responsibility* |
|---|---|---|---|---|
| **PM-UTL1** | **Customer Minutes of Outage Saved per Feeder** | Tracks time savings from faster AMI outage notification than customer outage call, leading to faster outage response and reduced customer minutes of interruption. | M&C | UTL |
| **PM-NG-1** | **Main Line Customer Minutes of Interruption Saved** | Measures the impact of ADA investments on the customer minutes of interruption (CMI) for main line interruptions. Compares the CMI of GMP ADA-enabled feeders to the previous 3-year average for the same feeder. | ADA | NG |

PM = Performance Metric, IA = Investment Area, ES = Eversource, NG = National Grid, UTL = Unitil

* Column indicates which EDC is responsible for calculating each metric, for statewide metrics, all EDCs are responsible

*Source: Stamp Approved Performance Metrics, July 25, 2019.*[27]

[27] Massachusetts Department of Public Utilities, Grid Modernization Plan Performance Metrics. Submitted on July 25, 2019, as part of DPU 12-120,15-121, & 15-122

## 1.2 VVO Investment Area Overview

As a part of grid modernization, the Massachusetts EDCs are investing to enable VVO on selected feeders across their distribution networks. VVO optimizes distribution voltage to reduce energy consumption and demand without the need for customer interaction or participation. The principle behind VVO is that power demand is reduced at voltages in the lower end of their allowable range for many end-use loads.

VVO reduces feeder demand and energy consumption by flattening and lowering the voltage profile on the feeder while maintaining customer service voltage standards. In addition, VVO systems allow for more gradual and responsive control of reactive power control devices, such as capacitors, which can improve the overall system power factor and reduce system losses. VVO allows customers to realize lower consumption without experiencing a reduction in their level of service.

The VVO investment will first be used to condition feeders, install equipment, and commission software. Once the software commissioning is complete, and as feeders complete their conditioning and equipment installation, they will become VVO enabled.

Table 14 summarizes preauthorized budget for VVO for Eversource, National Grid, and Unitil.

**Table 14. GMP Preauthorized Budget for VVO**

| Period | Eversource | National Grid | Unitil | Total |
|---|---|---|---|---|
| **Term 1 (2018 – 2021)** | $13.00 | $10.60 | $2.22 | **$25.82** |
| **Term 2 (2022 – 2025)** | $40.40 | $76.40 | $5.40 | **$122.20** |

*Source: Term 1 preauthorized budgets were populated using DPU Order, May 10, 2018, and Eversource filing "GMP Extension and Funding Report," July 1, 2020. Term 2 preauthorized budgets were populated using DPU Order, October 7, 2022, and DPU Order, November 30, 2022 under docket 21-80, 21-81, and 21-82.*

The following subsection discusses EDC-specific approaches to VVO.

### 1.2.1 EDC Approach to VVO

The VVO investment process for each of the EDCs involves four core phases: VVO investment, VVO commissioning, VVO enablement, and VVO On/Off testing. Table 15 provides the four phases and a brief description of each phase, and Section 3 summarizes the status of each deployment phase by EDC.

**Table 15. VVO Deployment Phases**

| Phase | Description |
|---|---|
| **VVO Investment** | Deployment and installation of VVO devices, including but not limited to capacitor banks, load tap changer (LTC) controls, and voltage regulators. Load rebalancing may occur during this time. |
| **VVO Commissioning** | Process of preparing VVO investments installed on conditioned feeders to begin VVO control. |
| **VVO Enablement** | Date at which the VVO system is enabled and managing voltage and reactive power. |
| **VVO On/Off Testing Period** | Dates over which the VVO system is cycled between the on and off states using a predetermined cycling schedule. |

*Source: Guidehouse*

Table 16 defines the devices and technologies that each EDC has deployed as part of VVO investment. Sections 3 (Infrastructure Metrics) and 4 (Performance Metrics) below discuss specifics related to each EDCs' goals and objectives in the VVO Investment Area, while Section 2 below explains the evaluation process.

**Table 16. Description of Devices Deployed Under VVO Investment**

| Device | Description | Term |
|---|---|---|
| **Capacitor Bank Controls** | Reactive compensation devices, equipment combined with two-way communications infrastructure, and remote-control capability to regulate reactive power (VAR) flows throughout the distribution network. | 1 2 |
| **Inverter Demonstration*** | Advanced inverters, which will be deployed at an Eversource-owned solar site in Western Massachusetts to support in coordination with VVO operations and set points. | 2 |
| **Line Sensors** | Voltage sensors, which relay verified field measurements to allow VVO algorithm to regulate voltage and reactive power appropriately. | 1 2 |
| **Load Tap Changer (LTC) Controls** | Transformer load tap changers, which automatically adjust feeder voltage based on local measurement. First of the two devices required to regulate voltage on a distribution feeder. | 1 2 |
| **Voltage Regulators** | Optimized for VVO and equipped with communications equipment to enable remote-control and monitoring of voltage; required to regulate voltage on a distribution feeder. | 1 2 |
| **Micro-capacitors*** | Installed at strategic locations in order to support system load, provide remote visibility and control of the devices, and prepare the feeder for conversion to VVO in the future. While not commissioned into the VVO system, microcapacitors enable additional voltage and power factor control on feeders. | 1 2 |
| **Grid Monitoring Line Sensors*** | Deployed at strategic locations like large side taps, step down transformers, and larger distributed generation sites that do not have SCADA reclosers. Grid monitoring line sensors also allow Eversource to gather additional telemetry from VVO enabled feeders. | 1 |

* Microcapacitors and Grid Monitoring Line Sensors are VVO devices that are solely being deployed by Eversource. National Grid and Unitil have no plan to deploy these device types at this time.

*Source: Guidehouse*

### 1.2.2 VVO Evaluation Objectives

This evaluation focuses on the progress and effectiveness of the DPU preauthorized VVO investments for each EDC toward meeting the DPU's grid modernization objectives.[28] Table 17 illustrates the key Infrastructure Metrics and Performance Metrics relevant for the VVO evaluation.

**Table 17. VVO Evaluation Metrics**

| Metric Type | VVO Evaluation Metrics | ES | NG | UTL |
|---|---|---|---|---|
| IM | Number of devices or other technologies deployed | ✓ | ✓ | ✓ |
| IM | Cost for deployment | ✓ | ✓ | ✓ |
| IM | Deviation between actual and planned deployment for the plan year | ✓ | ✓ | ✓ |
| IM | Projected deployment for the remainder of the term | ✓ | ✓ | ✓ |
| PM | VVO Baseline | ✓ | ✓ | |
| PM | VVO Energy Savings | ✓ | ✓ | |
| PM | VVO Peak Load Impact | ✓ | ✓ | |
| PM | VVO Distribution Losses w/o AMF (Baseline) | ✓ | ✓ | |
| PM | VVO Power Factor | ✓ | ✓ | |
| PM | VVO GHG Emissions | ✓ | ✓ | |
| PM | Voltage Complaints | ✓ | ✓ | |

Note: Unitil will not be receiving an evaluation of VVO Performance Metrics until VVO On/Off testing has begun. Unitil anticipates conducting VVO On/Off testing beginning in April 2023.

*Source: Guidehouse Stage 3 Evaluation Plan submitted to EDCs on March 1, 2023*

The EDCs provided data supporting the Infrastructure Metrics to the evaluation team. Guidehouse presents results from analysis of Infrastructure Metrics data in Section 3. The Performance Metrics will be based on statistical analyses performed by the evaluation team using data provided by each EDC.

Table 18 summarizes the VVO evaluation objectives and associated research questions that will be addressed in the report. The scope of the VVO measurement and verification (M&V) includes tracking the VVO infrastructure deployment against the plan (Infrastructure Metrics) and measuring the energy, peak demand, greenhouse gas (GHG), and voltage complaint impacts of installing the VVO investments and operating VVO (Performance Metrics).

**Table 18. VVO M&V Objectives and Associated Research Questions**

| VVO M&V Objective | Associated Research Questions |
|---|---|
| **Infrastructure Deployment** | • What is the extent, type, and cost of VVO investments?<br>• How well does each EDC's deployment track the planned deployment? |

[28] DPU Order, May 10, 2018, p.106.

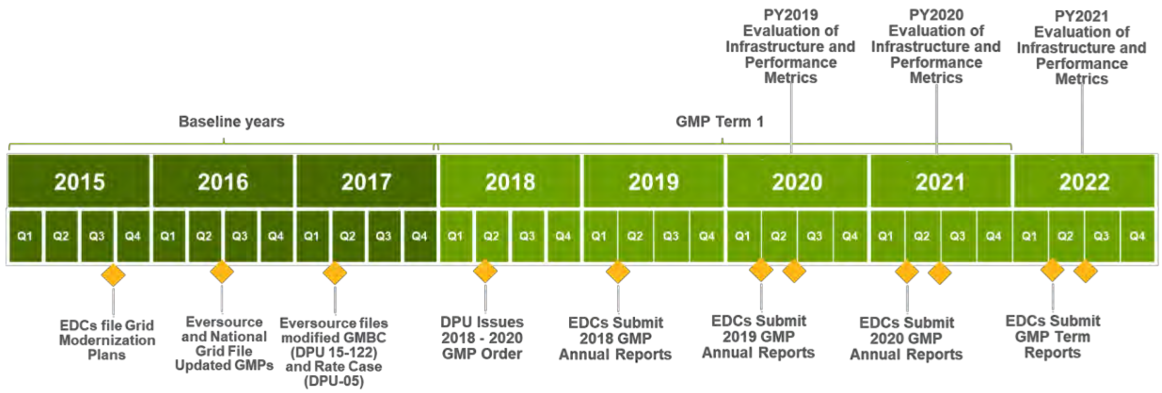
| VVO M&V Objective | Associated Research Questions |
|---|---|
| **Energy and Peak Savings by Feeder (Device Deployment)** | • How many energy savings were realized from device deployment on VVO enabled feeders?<br>• What is the impact on peak load from VVO investments operating on VVO enabled feeders?<br>• How much GHG emissions reduction has been enabled from device deployment on VVO enabled feeders? |
| **Energy and Peak Savings by Feeder (VVO-Operation)** | • How many energy savings were realized from VVO operating on VVO enabled feeders?<br>• What is the impact on peak load from VVO operating on VVO enabled feeders?<br>• What is the impact on loss reductions and feeder-level power factor associated from VVO operating on VVO enabled feeders?<br>• How much GHG emissions reduction was enabled from VVO operating on VVO enabled feeders? |
| **Voltage Complaints** | • What is the impact of VVO-related investments on the number of voltage complaints? |

*Source: Guidehouse Stage 3 Evaluation Plan submitted to EDCs on March 1, 2023*

# 2. VVO Evaluation Process

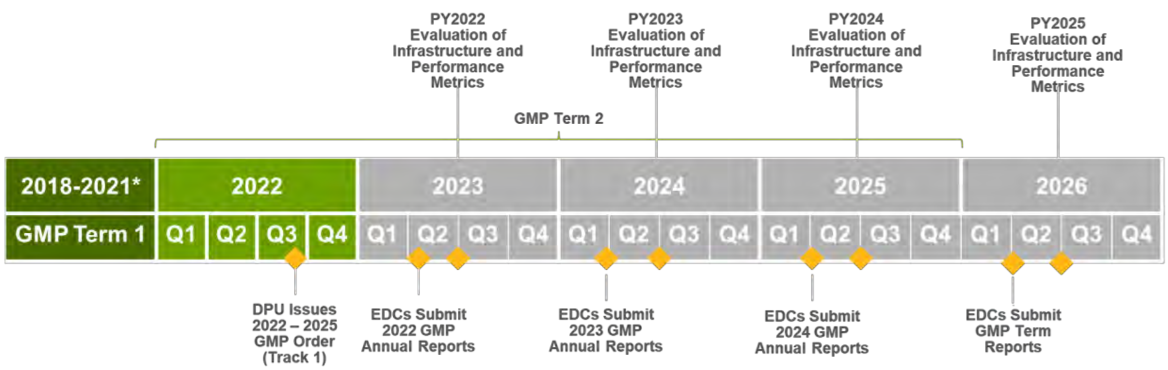
This section presents a high-level overview of the Guidehouse methodologies for the evaluation of Infrastructure Metrics and Performance Metrics. Figure 3 highlights the Term 1 filing background and timeline of the GMP Order and the evaluation process, and Figure 4 indicates the expected timeline for Term 2.

**Figure 3. Term 1 Evaluation Timeline**




*Source: Guidehouse review of the DPU orders and GMP process*

**Figure 4. Term 2 Evaluation Timeline**




*Source: Guidehouse review of the DPU orders and GMP process*

As a note, spend and deployment was conducted in PY 2022 to account for any spend and deployment from Term 1 (2018-2021 plan) as well as new spend to be included in Term 2 (2022 – 2025). Term 1 spend and deployment will be denoted separately within the analysis for Eversource, as Eversource provided data to support a comparison of Term 1 and Term 2 planned versus actual activity.

## 2.1 Infrastructure Metrics Analysis

Guidehouse annually assesses the progress of each of the EDCs toward deploying VVO on their feeders. Table 19 through Table 22 highlight the Infrastructure Metrics that were evaluated.

**Table 19. GMP Term 1 Infrastructure Metrics Overview – Eversource Only**

| Infrastructure Metrics | | | Calculation |
|---|---|---|---|
| IM-4 | **Number of devices or other technologies deployed thru. PY 2022** | # Devices Deployed | $\sum_{PY=2018}^{2021}(Devices\ Commissioned)_{PY} + Devices\ Commissioned_{CY2022(T1)}$ |
| | | % Devices Deployed | $\frac{\sum_{PY=2018}^{2021}(Devices\ Commissioned)_{PY} + Devices\ Commissioned_{CY2022(T1)}}{\sum_{PY=2018}^{2021}(Devices\ Commissioned)_{PY} + (Planned\ Devices)_{CY2022(T1)}}$ |
| IM-5 | **Cost through PY 2022** | Total Spend, $M | $\sum_{PY=2018}^{2021}(Actual\ Spend)_{PY} + Actual\ Spend_{CY2022(T1)}$ |
| | | % Spend | $\frac{\sum_{PY=2018}^{2021}(Actual\ Spend)_{PY} + Actual\ Spend_{CY2022(T1)}}{\sum_{PY=2018}^{2021}(Actual\ Spend)_{PY} + Planned\ Spend_{CY2022(T1)}}$ |
| IM-6 | **Deviation Between Actual and Planned Deployment for PY 2022** | % On Track (Devices) | $\frac{(Devices\ Commissioned)_{CY2022(T1)}}{(Planned\ Devices)_{CY2022(T1)}}$ |
| | | % On Track (Spend) | $\frac{(Actual\ Spend)_{CY2022(T1)}}{(Planned\ Spend)_{CY2022(T1)}}$ |
| IM-7 | **Projected Deployment for the remainder of the GMP Term (i.e., Term 1)*** | # Devices Remaining | $N/A^*$ |
| | | Spend Remaining , $M | $N/A^*$ |

Note**:** This table pertains to Infrastructure Metrics for Eversource only. Planned devices and spend are based on the 2021 GMP Term Report filing (filed on April 1, 2022 under DPU docket 21-80). All CY2022 spend and deployment data given above, to be calculated, includes only units/dollars dedicated to work intended for Term 1, and excludes any deployment and spend apportioned for Term 2.

* This metric has been interpreted here (i.e., within the context of the 2022 Program Year Evaluation) as the units and spending that the EDC plans to complete their most recent 4-year Term 1 plans. Additional Grid Modernization units and dollars incurred in 2022 are attributed to Term 2, as appropriate, and all units and dollars spent during 2023 through 2025 will be considered as part of Term 2 GMPs.

*Source: Guidehouse*

### Table 20. GMP Term 1 Infrastructure Metrics Overview by Feeder – Eversource Only

| Infrastructure Metrics* | | | Calculation |
|---|---|---|---|
| **IM-4** | **Number of Devices or Other Technologies Deployed through PY 2022** | # Feeders with VVO Enabled | $(VVO\ Enabled\ Feeders)_{CY2022(T1)}$ |
| | | % Feeders with VVO Enabled | $\frac{(VVO\ Enabled\ Feeders)_{CY2022(T1)}}{\sum_{PY=2018}^{2021}(\ Actual\ \ VVO\ Enabled\ Feeders)_{PY}+(VVO\ Enabled\ Feeders)_{CY2022(T1)}}$ |
| **IM-6** | **Deviation Between Actual and Planned Deployment for PY 2022** | % On Track (VVO Enabled Feeders) | $\frac{(VVO\ Enabled\ Feeders)_{CY2022(T1)}}{(Planned\ VVO\ Enabled\ Feeders)_{CY2022(T1)}}$ |
| **IM-7** | **Projected Deployment for the remainder of the GMP Term (i.e., Term 1)**** | # VVO Enabled Feeders Remaining | $N/A*$ |

Note: This table pertains to Infrastructure Metrics for Eversource. All CY2022 feeder status includes only feeders identified as receiving VVO within GMP Term 1 plans and excludes activity on any feeders planned for GMP Term 2.

* VVO Enabled denotes that the VVO system is commissioned and VVO is engaged. Feeders presented with VVO enabled may not be actively employing CVR.

** This metric has been interpreted here (i.e., within the context of the 2022 Program Year Evaluation) as the feeders that the EDC plans to complete their most recent 4-year Term 1 plans. Additional VVO feeders that were enabled 2022 are attributed to Term 2, as appropriate, and all VVO feeders that will be enabled during 2023 through 2025 will be considered as part of Term 2 GMPs.

*Source: Guidehouse*

### Table 21. GMP Term 2 Infrastructure Metrics Overview – All EDCs

| Infrastructure Metrics | | | Calculation |
|---|---|---|---|
| **IM-4** | **Number of devices or other technologies deployed thru. PY 2022** | # Devices Planned | $(Devices\ Commissioned)_{PY2022}$ |
| | | % Devices Deployed | $\frac{(Devices\ Comissioned)_{PY2022}}{(Devices\ Comissioned)_{PY2022}+\sum_{PY=2023}^{2025}(Planned\ Devices)_{PY}}$ |
| **IM-5** | **Cost through PY 2022** | Total Spend, $M | $(Actual\ Spend)_{PY2022}$ |
| | | % Spend | $\frac{(Actual\ Spend)_{PY2022}}{\sum_{PY=2022}^{2025}(Planned\ Spend)_{PY}}$ |
| **IM-6** | **Deviation Between Actual and Planned Deployment for PY 2022** | % On Track (Devices) | $\frac{(Devices\ Commissioned)_{PY2022}}{(Planned\ Devices)_{PY2022}}$ |
| | | % On Track (Spend) | $\frac{(Actual\ Spend)_{PY2022}}{(Planned\ Spend)_{PY2022}}$ |

| Infrastructure Metrics | | | Calculation |
|---|---|---|---|
| IM-7 | **Projected Deployment for the remainder of the GMP Term** | # Devices Remaining | $\sum_{PY=2022}^{2025}(Planned\ Devices)_{PY} - (Devices\ Comissioned)_{PY2022}$ |
| | | Spend Remaining, $M | $\sum_{PY=2022}^{2025}(Planned\ Spend)_{PY} - (Actual\ Spend)_{PY2022}$ |

Note: CY2022 spend and deployment data given above includes only units/dollars within Term 2 plans, and excludes any deployment and spend apportioned for Term 1 (carryover).

*Source: Guidehouse*

**Table 22. GMP Term 2 Infrastructure Metrics Overview by Feeder – All EDCs**

| Infrastructure Metrics* | | | Calculation |
|---|---|---|---|
| IM-4 | **Number of Devices or Other Technologies Deployed through PY 2022** | # Feeders with VVO Enabled | $(VVO\ Enabled\ Feeders)_{PY2022}$ |
| | | % Feeders with VVO Enabled | $\frac{(VVO\ Enabled\ Feeders)_{PY2022}}{(VVO\ Enabled\ Feeders)_{PY2022} + \sum_{PY=2023}^{2025}(\ Planned\ VVO\ Enabled\ Feeders)_{PY}}$ |
| IM-6 | **Deviation Between Actual and Planned Deployment for PY 2022** | % On Track (VVO Enabled Feeders) | $\frac{(VVO\ Enabled\ Feeders)_{PY2022}}{(Planned\ VVO\ Enabled\ Feeders)_{PY2022}}$ |
| IM-7 | **Projected Deployment for the remainder of the GMP Term*** | # VVO Enabled Feeders Remaining | $\sum_{PY=2022}^{2025}(Planned\ VVO\ Enabled\ Feeders)_{PY} - (VVO\ Enabled\ Feeders)_{PY2022}$ |

Note: CY2022 feeder data given above includes only feeders within Term 2 plans, and excludes any VVO feeders apportioned for Term 1 (carryover). These most recent plan totals were included in each EDC's VVO Supplemental data submissions, provided February 2022. These submissions listed the date in which each Term 1 and Term 2 feeder were slated to have full VVO capability.

* VVO Enabled denotes that the VVO system is commissioned and VVO is engaged. Feeders presented with VVO enabled may not be actively employing CVR.

*Source: Guidehouse*

Section 3.2 provides the results from the evaluation of Infrastructure Metrics. To evaluate Infrastructure Metrics, Guidehouse:

- Reviewed the data provided by the EDCs to confirm their progress through PY 2022 (see Section 3.1.2, "Data QA/QC Process")
- Interviewed representatives from each EDC to understand the status of the VVO investments, including:
    - Updates to their planned VVO investments
    - Reasons for deviation between actual and planned deployment and spend

## 2.2 Performance Metrics Analysis

Guidehouse evaluated Performance Metrics for two of the three EDCs, focusing on the utility and customer experience with VVO. Table 23 describes the Performance Metrics evaluated in PY 2022.

**Table 23. Performance Metrics Overview**

| PM | Performance Metrics | Description |
|---|---|---|
| **PM-1** | **VVO – Baseline** | Establishes a baseline impact factor for each VVO enabled feeder which will be used to quantify the peak load, energy savings, and GHG impact measures |
| **PM-2** | **VVO – Energy Savings** | Quantifies the energy savings achieved by VVO using the baseline established for the feeder against the annual feeder load with the intent of optimizing system performance |
| **PM-3** | **VVO – Peak Load Impact** | Quantifies the peak demand impact VVO/CVR has on the system with the intent of optimizing system demand |
| **PM-4** | **VVO – Distribution Losses without AMF (Baseline)** | Presents the difference between feeder load measured at the substation via the SCADA system and the metered load measured through advanced metering infrastructure |
| **PM-5** | **VVO – Power Factor** | Quantifies the improvement that VVO/CVR is providing toward maintaining feeder power factors near unity |
| **PM-6** | **VVO – GHG Emissions** | Quantifies the overall GHG impact VVO/CVR has on the system |
| **PM-7** | **Voltage Complaints** | Quantifies the prevalence of voltage-related complaints before and after deployment of VVO investments to assess customer experience, voltage stability under VVO |

*Source: Stamp Approved Performance Metrics, July 25, 2019.*

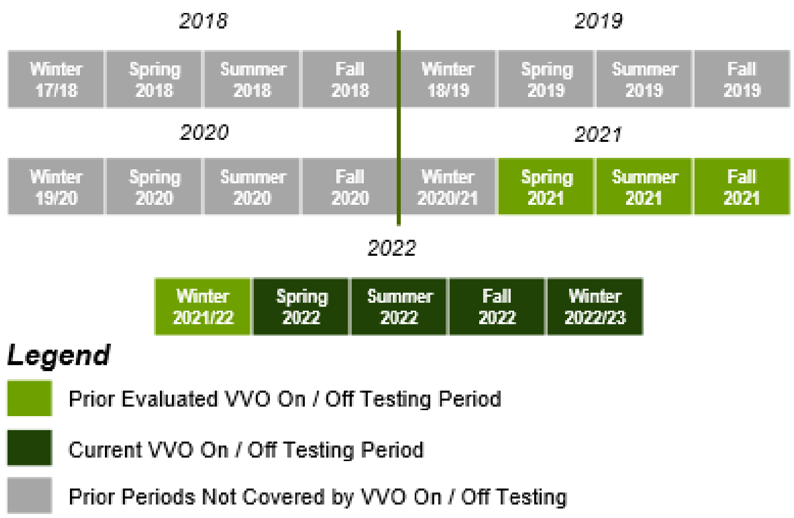
The metrics in Table 22 are based on a M&V process, which uses statistical analysis to quantify the impacts the VVO system has on the customers it serves. Quantifying VVO Performance Metrics requires interval measurements of feeder-level voltage and power demand while the voltage and reactive power controls are operated in both baseline (non-VVO) and VVO modes.

For changes associated with VVO being enabled to be quantified, Guidehouse and the EDCs have agreed to the plan for VVO On/Off testing to continue for at least 9 months, covering summer (June, July, and August), winter (December, January, and February), and one of the spring (March, April, and May) or fall (September, October, November) shoulder seasons.

### 2.2.1 Performance Metrics Timeline

Figure 5 highlights the key Performance Metrics analysis periods for Eversource. The Performance Metrics analysis provided for this report will be focused on results from VVO On/Off testing conducted during Spring 2022 – Winter 2022/23. Results from VVO On/Off testing conducted during Spring 2021 – Winter 2021/22 were provided in the Massachusetts Grid Modernization Program Year 2021 Evaluation Report for Volt-VAR Optimization.[29]

**Figure 5. Performance Metrics Timeline**




*Source: Guidehouse analysis*

[29] All Massachusetts Grid Modernization Program Year 2021 Evaluation Reports were filed on July 1, 2022 under DPU dockets 22-40, 22-41, and 22-42.

# 3. VVO Infrastructure Metrics

## 3.1 Data Management

Guidehouse worked with the EDCs to collect data to complete the evaluation for the assessment of VVO Infrastructure Metrics and Performance Metrics. The sections that follow highlight Guidehouse's data sources and data QA/QC processes used in the evaluation of Infrastructure Metrics.

### 3.1.1 Data Sources

Guidehouse used a consistent methodology (across Investment Areas and EDCs) for evaluating and illustrating EDC progress indicated by the GMP metrics. The subsections that follow summarize each of the data sources used to evaluate Infrastructure Metrics.

#### *3.1.1.1 Term 1 Planned Deployment and Spend for PY 2022*

To assess progress against planned carryover deployment and spend for Eversource, Guidehouse used the planned device deployment and cost information from each its *2021 GMP Term Report*[30,31,32], which were filed on April 1, 2022. These filings served as the sources for planning data in this report and are referred collectively as the *GMP Term 1 Plan* each EDC in summary tables and figures throughout this report.

Table 24 lists the sources for the planned and actual quantities reviewed, and it specifies the color/shade used to represent these quantities in graphics throughout the rest of the report.

**Table 24. GMP Term 1 Deployment Categories Used for the EDC Plan**

| Representative Color | Data | Description |
|---|---|---|
| | 2022 Plan | Projected 2022 Term 1 unit deployment and spend |
| | 2021 Actual | Actual 2021 unit deployment and spend |
| | 2020 Actual | Actual 2020 unit deployment and spend |
| | 2019 Actual | Actual reported unit deployment and spend in 2018 |
| | 2018 Actual | Actual reported unit deployment and spend in 2018 |

*Source: Plan and actual data is sourced from the EDCs' 2021 GMP Term Report Appendix 1 filed April 1, 2022.*

[30] Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, Grid Modernization Plan Annual Report 2020. Submitted to Massachusetts DPU on April 1, 2021 as part of DPU 21-30.
[31] NSTAR Electric Company d/b/a Eversource Energy, Grid Modernization Plan Annual Report 2020. Submitted to Massachusetts DPU on April 1, 2021 as part of DPU 21-30. Note that Eversource Energy filed an updated Appendix 1 filing in December of 2021; however that update did not affect any of the data or results in the evaluation.
[32] Fitchburg Gas and Electric Light Company d/b/a Unitil, Grid Modernization Plan Annual Report 2020. Submitted to Massachusetts DPU on April 1, 2021 as part of DPU 21-30.

Guidehouse used the Feeder Status tab of the 2022 GMP Annual Report Appendix 1[33,34,35] to obtain feeder characteristics including system voltage, total feeder count, customer count, feeder length, and annual peak load.

#### *3.1.1.2 Term 2 Planned Deployment and Spend for PY 2022*

Guidehouse used the planned device deployment and cost information from each EDCs' filed responses to the first set of information requests issued by the Department of Energy Resources (DOER).[36] These responses were filed on October 4th, October 5th, and December 2nd, 2021, for Eversource, Unitil, and National Grid respectively. These filings served as the sources for planning data in this report and are referred collectively as the *DOER Responses* for each EDC in summary tables and figures throughout this report. Table 25 lists the different sources for the planned and actual quantities reviewed, and it specifies the color/shade used to represent these quantities in graphics throughout the rest of the report.

**Table 25. GMP Term 2 Deployment Categories Used for the EDC Plan**

| Representative Color | Data | Description |
|---|---|---|
| | 2025 Plan | Projected 2025 unit deployment and spend |
| | 2024 Plan | Projected 2024 unit deployment and spend |
| | 2023 Plan | Projected 2023 unit deployment and spend |
| | 2022 Plan | Projected 2022 unit deployment and spend |

*Source: Plan data is sourced from EDC responses to the first set of information requests issued by the Department of Energy Resources, filed October 4, October 5, and December 2, 2021 under DPU dockets 21-80, 21-82, and 21-81 for Eversource, Unitil, and National Grid, respectively.*

#### *3.1.1.3 PY 2022 Actual Deployment and Spend, Planned Deployment and Spend for the Remainder of Term 2*

Guidehouse collected device deployment data and VVO schedule information at the feeder-level using standardized data collection templates. Guidehouse developed these templates for all EDCs: the All Device Deployment data and VVO Supplemental workbooks, respectively.

Guidehouse collected data using standardized data collection templates (e.g., All Device Deployment) for all EDCs in January through March 2023. The data collected provides an update of planned and actual deployment, in dollars, device units, substations, and feeders through the end of PY 2022. Data from these sources are referred to as EDC Data in summary tables and figures throughout the report.

33 Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, Grid Modernization Plan Annual Report 2022. Submitted to Massachusetts DPU on April 1, 2023 as part of DPU 22-41

34 NSTAR Electric Company d/b/a Eversource Energy, Grid Modernization Plan Annual Report 2022. Submitted to Massachusetts DPU on April 1, 2023 as part of DPU 22-40

35 Fitchburg Gas and Electric Light Company d/b/a Unitil, Grid Modernization Plan Annual Report 2022. Submitted to Massachusetts DPU on April 1, 2023 as part of DPU 22-42

36 Plan data is sourced from EDC responses to the first set of information requests issued by the Department of Energy Resources (DOER). These responses were filed on October 4th, December 2nd, and October 5th, 2021, for Eversource, National Grid, and Unitil under DPU dockets 21-80, 21-81, and 21-82.

The EDC device deployment data (collected in the All Device Deployment workbook) captured planned and actual device deployment and spend data. Actual device deployment and cumulative spend information were provided by work order ID and specified at the feeder- or substation-level, as appropriate. The evaluation team also collected the current implementation stage of the work order (commissioned, construction, or design), the commissioned date (if applicable), and all cumulative costs associated with the work order.

The VVO supplemental data collection template includes additional information unique to the VVO Investment Area. Table 26 summarizes the information requested. Data was provided in the data collection template or submitted in a separate file. Information was requested at the feeder-level where possible (except for IT work). The VVO schedule information and the IT work information are the only data within this template that are applicable to the Infrastructure Metrics. All additional information is applicable to the Performance Metrics.

**Table 26. VVO Supplemental Data**

| Information | Description |
|---|---|
| **Actual/Planned VVO Schedule** | Actual and updated planned VVO deployment start/end dates by feeder, including feeder conditioning, load rebalancing, phase balancing, VVO commissioning, VVO enabled, and On/Off testing. |
| **IT Work** | Actual and updated planned IT work progress start/end dates and cost information.[37] |
| **Customer Demand Response (DR) Events** | Demand response events (time-stamped log of any systemwide demand response (or similar), for example: ISO-NE DR, EDC direct load control programs, EDC behavioral demand response programs). |
| **System Events** | Operational changes, a time-stamped log of changes to substation and feeders away from normal operating state (temporary or permanent), and power outages. |
| **DG Log** | Log of distributed generation facilities connected to VVO feeders (e.g., type, size, installation date, feeder). |
| **Voltage Complaints** | Voltage-related complaints based on voltage perturbation (e.g., high voltage, low voltage, flicker), duration (e.g., multiple days, sporadic). |

*Source: Guidehouse Stage 3 Evaluation Plan submitted March 1, 2023*

Table 27 summarizes the file versions used for the evaluation, and the following subsections provide additional detail surrounding requested inputs in each workbook. The collected data was compared to the data submitted by the EDCs to the DPU in the 2021 Grid Modernization Plan Term Reports and associated Appendix 1 filings.[38,39,40] The evaluation team confirmed the consistency of the data from the various sources and reconciled any differences.

[37] IT work progress includes: planning, procurement, development, deployment, and go-live

[38] Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, Grid Modernization Plan Annual Report 2022. Submitted to Massachusetts DPU on April 1, 2021 as part of DPU 22-41

[39] NSTAR Electric Company d/b/a Eversource Energy, Grid Modernization Plan Annual Report 2021. Submitted to Massachusetts DPU on April 1, 2022 as part of DPU 22-40

[40] Fitchburg Gas and Electric Light Company d/b/a Unitil, Grid Modernization Plan Annual Report 2021. Submitted to Massachusetts DPU on April 1, 2022 as part of DPU 22-42

**Table 27. EDC Data Received for Analysis**

| Company | File Version Used for Analysis[41] | |
|---|---|---|
| | All Device Deployment | VVO Supplemental |
| Eversource | Received 3/20/2023 | Received 3/31/2023 |
| National Grid | Received 3/29/2023 | Received 3/20/2023 |
| Unitil | Received 3/30/2023 | Received 2/14/2023 |

*Source: Guidehouse*

Table 28 and Table 29 summarize the categories used for the revised planned and actual deployment and spend and specifies the color and pattern used in bar graphs to represent each in the remainder of the report.

[41] Some minor additional updates to specific work orders were addressed after these dates via email.

**Table 28. Term 1 EDC Device Deployment and Spending Data Legend – Eversource Only**

| Representative Color | Data | Description |
|---|---|---|
| **Device Deployment Data** | | |
| | 2022 Design/Engineering | Detailed design and engineering is in progress, but the device is not yet in construction (from All Device Deployment workbook) |
| | 2022 Construction | Field construction is in progress, but the device is not yet in-service (from All Device Deployment workbook) |
| | 2022 In-Service | Device is installed and “used and useful” but not yet commissioned to enable all Grid Modernization functionalities (from All Device Deployment workbook) |
| | 2022 Commissioned | Device is fully operational with all Grid Mod functionalities, and thus is considered “deployed” in PY 2022 (from All Device Deployment workbook) |
| | 2021 Actual | Actual 2021 deployment (units) (provided in 2022 Appendix 1 filings) |
| | 2020 Actual | Actual 2020 deployment (units) (provided in 2021 Appendix 1 filings) |
| | 2019 Actual | Actual 2019 deployment (units) (provided in 2020 Appendix 1 filings) |
| | 2018 Actual | Actual 2018 deployment (units) (provided in 2019 Appendix 1 filings) |
| **Spend Data** | | |
| | 2022 Actual | Actual 2022 spend (provided in All Device Deployment workbook) |
| | 2021 Actual | Actual 2021 spend ($) (provided in 2022 Appendix 1 filings) |
| | 2020 Actual | Actual 2020 spend ($) (provided in 2021 Appendix 1 filings) |
| | 2019 Actual | Actual 2019 spend ($) (provided in 2020 Appendix 1 filings) |
| | 2018 Actual | Actual 2018 spend ($) (provided in 2019 Appendix 1 filings) |

Note: This legend for deployment and spend data summaries are provided for Eversource only, as National Grid and Unitil tracked all spending and all deployment for all of 2022, independent of Term status (i.e., whether the work was carried over from PY 2021 of Term 1).

*Source: Guidehouse*

**Table 29. Term 2 EDC Device Deployment and Spending Data Legend**

| Representative Color | Data | Description |
|---|---|---|
| **Device Deployment Data (from All Device Deployment workbook)** | | |
| | 2025 Plan | Planned 2025 Deployment |
| | 2024 Plan | Planned 2024 Deployment |
| | 2023 Plan | Planned 2023 Deployment |
| | 2022 Commissioned | Device is fully operational with all Grid Mod functionalities, and thus is considered “deployed” in PY 2021 |
| | 2022 In-Service | Device is installed and “used and useful” but not yet commissioned to enable all Grid Modernization functionalities |
| | 2022 Construction | Field construction is in progress but the device is not yet in-service |
| | 2022 Design / Engineering | Detailed design and engineering is in progress but the device is not yet in construction |
| **Spend Data (from All Device Deployment workbook)** | | |
| | 2025 Estimate | Planned 2025 spend |
| | 2024 Estimate | Planned 2024 spend |
| | 2023 Estimate | Planned 2023 spend |
| | 2022 Actual | Actual 2022 spend |

*Source: Guidehouse*

### 3.1.2 Data QA/QC Process

Guidehouse reviewed all data provided for Infrastructure Metrics analysis upon receipt of requested data. To ensure accuracy, Guidehouse conducted a QA/QC of all device deployment data received. This review involved following up with the EDCs for explanations regarding the following:

- Potential errors in how the forms were filled out (e.g., feeder information provided in the wrong field)
- Missing or incomplete information
- Large variation in the unit cost of commissioned devices
- Variance between the aggregated totals by device/technology and work order-level data
- Variance between the actual unit costs and planned unit costs

## 3.2 Deployment Progress and Findings

Guidehouse presents findings from the Infrastructure Metrics analysis for the VVO Investment Area in the following subsections. Throughout this section, Guidehouse will reference Term 1 feeders and Term 2 feeders. Term 1 feeders are the feeders identified by each of the EDCs Grid Modernization Plans as receiving full VVO functionality in 2018 through 2021. Term 2 feeders are feeders that are currently planned to receive VVO investments in Term 2 spanning 2022 through 2025. The number of Term 1 plan feeders that received VVO for Eversource, National Grid, and Unitil total to 26, 20, and 0, respectively. As of the end of 2022, the number of Term 2 feeders planned for full VVO functionality for Eversource, National Grid, and Unitil total to 6, 52, and 11, respectively. The number of feeders slated to receive VVO functionality is expected to grow as Term 2 progresses, as the EDCs were continuing to assess which substations should be prioritized during this term at the end of 2022.

### 3.2.1 Statewide Comparison

This section discusses the current scope of VVO investments relative to the number of feeders and customers within the EDCs in Massachusetts and it summarizes the deployment progress and findings across all three EDCs.

#### *3.2.1.1 Anticipated Impact on Massachusetts*

VVO deployment is anticipated to impact 191 feeders serving 323,944 customers (11.7% of all EDC customers) throughout Massachusetts by the end of 2025. This includes 55 Term 1 feeders and 137 Term 2 feeders. Table 30 highlights the anticipated impact by EDC. VVO investments are expected to be complete by the end of 2025 at the following substations:

- **Eversource:** Agawam, Piper, Podick, Silver, Gunn, and Oswald (Term 1 feeders); Amherst, Breckwood, Cross Road, Cumberland, Doreen, Duxbury, Franconia, Industrial Park, Mashpee, Montague, Orchard, Wareham (Term 2 feeders)
- **National Grid:** East Methuen, Maplewood, and Stoughton (Term 1 feeders, VVO capability active in 2021); Billerica, Depot Street, East Bridgewater, East Dracut, Easton, Melrose, Parkview, Westboro, and West Salem (Term 2 feeders)
- **Unitil:** Townsend (Term 1 feeders); Beech Street, Lunenburg, Pleasant Street, Princeton Road, Summer Street, West Townsend,  (Term 2 feeders)

**Table 30. Number of Feeders and Customers Covered by VVO**

| VVO Impact | Eversource | | National Grid | | Unitil | | Total | |
|---|---|---|---|---|---|---|---|---|
| | Feeders | Customers | Feeders | Customers | Feeders | Customers | Feeders | Customers |
| Systemwide Total | 2,278 | 1,352,952 | 1,141 | 1,346,266 | 44 | 61,214 | **3,463** | **2,760,432** |
| **Term 1 Feeders** | | | | | | | | |
| Count | 32 | 55,491 | 20 | 53,204 | 3 | 2,109 | **55** | **110,804** |
| % System Total | 1.4% | 4.1% | 1.8% | 4.0% | 6.8% | 3.4% | **1.6%** | **4.0%** |
| **Term 2 Feeders** | | | | | | | | |
| Count | 95 | 127,403 | 34 | 74,920 | 8 | 10,367 | **137** | **212,690** |
| % System Total | 4.2% | 9.4% | 3.0% | 5.6% | 18.2% | 16.9% | **4.0%** | **7.7%** |
| **Term 1 and Term 2 Total** | | | | | | | | |
| **Count** | **126** | **183,344** | **54** | **128,124** | **11** | **12,476** | **191** | **323,944** |
| **% System Total** | **5.5%** | **13.6%** | **4.7%** | **9.5%** | **25.0%** | **20.4%** | **5.5%** | **11.7%** |

*Source: Guidehouse analysis of 2022 GMP Annual Report Appendix 1, filed April 24, 2023*

#### *3.2.1.2 Approach to VVO*

Each EDC has a unique approach to selecting feeders for VVO, deploying VVO devices, and implementing VVO control. Table 31 highlights the substations covered by VVO investment and the planned VVO On/Off testing period start date for each EDC. The following subsections include specifics related to each EDC's approach to VVO.

**Table 31. VVO Substations and VVO On/Off Testing Start by EDC**

| Company | Substations (Feeder Count) | VVO On/Off Testing Start |
|---|---|---|
| **Term 1 Feeders** | | |
| **Eversource** | Agawam (7) | Winter 2020/21 |
| | Piper (6) | Winter 2020/21 |
| | Podick (7) | Spring 2021 |
| | Silver (6) | Winter 2020/21 |
| | Gunn (4) | Spring 2022 |
| | Oswald (2) | Summer 2022 |
| **National Grid** | E. Methuen (6) | Spring 2021 |
| | Maplewood (8) | Winter 2021/22 |
| | Stoughton (6) | Winter 2020/21 |
| **Unitil** | Townsend (3) | Spring 2023 |
| **Term 2 Feeders** | | |
| **Eversource**[42] | Amherst (8) | Winter 2024/25 |
| | Breckwood (12) | Winter 2024/25 |
| | Cross Road (5) | Fall 2024 |
| | Cumberland (8) | Fall 2024 |
| | Doreen (10) | Fall 2024 |
| | Duxbury (4) | Spring 2025 |
| | Franconia (8) | Fall 2024 |
| | Industrial Park (10) | Fall 2025 |
| | Mashpee (4) | Winter 2024/25 |
| | Montague (8) | Winter 2024/25 |
| | Orchard (14) | Winter 2024/25 |
| | Wareham (4) | Winter 2024/25 |
| **National Grid** | E. Bridgewater (7) | Summer 2021 |
| | East Dracut (6) | Summer 2022 |
| | Easton (5) | Winter 2022/23 |
| | Melrose (5) | Winter 2022/23 |
| | Westboro (5) | Winter 2022/23 |
| | West Salem (6) | Summer 2022 |
| **Unitil** | Lunenburg (2) | Winter 2024/25 |
| | Summer St. (4) | Winter 2023/24 |
| | W. Townsend (2) | Winter 2024/25 |

*Source: Guidehouse analysis of 2022 EDC Data*

[42] The feeder count is the total number of feeders supplied by the substation. For various technical reasons that become apparent during the VVO equipment locational analyses, not all feeders will be enabled with VVO.

#### *3.2.1.3 VVO Timeline*

Table 32 summarizes the expected timelines for completion of each of the four VVO investment phases for each EDC. Further detail surrounding these timelines follows.

**Table 32. VVO Deployment Completion by Phase and EDC as of 12/31/2022**

| Deployment Phase | Number of Feeders* | | | | | |
|---|---|---|---|---|---|---|
| | Eversource | | National Grid | | Unitil | |
| | Complete | Remaining | Complete | Remaining | Complete | Remaining |
| **Term 1 Feeders** | | | | | | |
| **VVO Investment** | 32 | 0 | 20 | 0 | 3 | 0 |
| **VVO Commissioning** | 26 | 6 | 20 | 0 | 3 | 0 |
| **VVO Enabled**** | 26 | 6 | 20 | 0 | 3 | 0 |
| **VVO On/Off Testing** | 26 | 6 | 20 | 0 | 0 | 3 |
| **Term 2 Feeders** | | | | | | |
| **VVO Investment** | 0 | 95 | 18 | 34 | 4 | 4 |
| **VVO Commissioning** | 0 | 95 | 18 | 34 | 4 | 4 |
| **VVO Enabled**** | 0 | 95 | 18 | 34 | 4 | 4 |
| **VVO On/Off Testing** | 0 | 95 | 18 | 34 | 0 | 8 |

*The count of feeders remaining for each deployment phase is based on deployment plans received in early 2023. As a part of the VVO planning process, additional feeders may be identified by the EDCs for VVO deployment in subsequent years of Term 2 (2023 through 2025).

** VVO Enabled denotes that the VVO system is commissioned and VVO is engaged. Feeders presented with VVO enabled may not be actively employing CVR.

*Source: Guidehouse analysis of 2022 EDC Data*

Among Eversource's Term 1 feeders, VVO is enabled and VVO On/Off testing is ongoing at 26 feeders. Eversource began VVO On/Off testing at these feeders in winter 2020/21 for the Agawam, Piper, and Silver substations (19 feeders) and in spring 2021 for the Podick substation (7 feeders). For its Term 1 feeders yet to begin VVO On/Off testing, Eversource is finalizing commissioning of VVO investments and is expected to begin VVO On/Off testing at the Gunn and Oswald substations (6 feeders) in summer 2023 and winter 2023/24, respectively. Among its Term 2 feeders, Eversource is in the process of deploying VVO investments across all 95 currently identified feeders.

All 20 National Grid Term 1 plan feeders are VVO enabled. National Grid completed On/Off testing at the Stoughton substation (6 feeders) in winter 2021/22, and VVO On/Off testing is ongoing at the East Methuen and Maplewood substations (14 feeders). Of its Term 2 plan feeders, National Grid has completed VVO On/Off testing at the East Bridgewater substation (7 feeders) in winter 2022/23, and VVO On/Off testing is ongoing at the Easton and West Salem substations (11 feeders). National Grid is in the process of deploying VVO investments across the remainder of feeders in National Grid's current Term 2 plan (34 feeders).

Unitil has adjusted plans for its Summer Street, Lunenburg, and West Townsend substations (8 feeders) to have these substations receive VVO capability during Term 2, as Unitil was not able to complete VVO investments at these substations during Term 1. Unitil enabled VVO at the Townsend substation (3 feeders), the one substation remaining attributed to Term 1, in winter 2022/23. However, as is described in Section 3.2.4, Unitil was not able to conduct On/Off testing during 2022 due to ongoing vendor software troubleshooting. For the Term 2 feeders connected to the Summer Street, Lunenburg, and West Townsend substations (8 feeders), Unitil has completed VVO deployment at the Summer Street substation (4 feeders), with VVO currently enabled at this substation. VVO On/Off testing will not begin at the substation until winter 2023/24. Unitil is in the progress of deploying VVO investments across the remainder of feeders in Unitil's current Term 2 plan (4 feeders).

#### *3.2.1.4 Term 1 Infrastructure Metrics Results*

At the request of Eversource, Guidehouse provided analysis of Eversource's Term 1 spend and deployment. Table 33 summarizes the Infrastructure Metrics results for Eversource's M&C Investment Area through PY 2022. Subsequent sections explain each EDC's progress and plans in greater detail.

**Table 33. Term 1 2022 Infrastructure Metrics for VVO**

| Infrastructure Metrics | | | Eversource |
|---|---|---|---|
| GMP Plan Total, PY-2018-2022* | | # Devices Planned | 1,142 |
| | | Spend, $M | $17.23 |
| IM-4 | Number of devices or other technologies deployed thru PY 2018-2022* | # Devices Deployed*** | 1,038 |
| | | % Devices Deployed | 91% |
| IM-5 | Cost for Deployment thru PY 2018 – 2022* | Total Spend, $M | $16.87 |
| | | % Spend | 98% |
| IM-6 | Deviation Between Actual and Planned Deployment for PY 2022 | % On Track (Devices) | 70% |
| | | % On Track (Spend) | 85% |
| IM-7 | Projected Deployment for the remainder of the GMP Term (i.e., Term 1)* | # Devices Remaining | 0 |
| | | Spend Remaining, $M | $0.00 |

*The metric names have been slightly changed here to clarify the time span used in analysis.

** This metric has been interpreted here (i.e., within the context of the 2022 Program Year Evaluation) as the units and spending that the EDC plans to complete their most recent 4-year Term 1 plans. Additional Grid Modernization units and dollars incurred in 2022 are attributed to Term 2, as appropriate, and all units and dollars spent during 2023 through 2025 will be considered as part of Term 2 GMPs.

***Note that "Deployed" here refers to commissioned devices. For full definitions of deployment stages, see Docket 20-46 Response to Information Request DPU-AR-4-11, September 3, 2020.

*Source: Guidehouse analysis of 2021 GMP Term Report and 2022 EDC Data*

Table 34 summarizes the total number of Term 1 feeders that were VVO enabled by the end of Term 1. National Grid and Eversource have completed deployment of VVO at 4 substations (26 feeders) and 3 substations (20 feeders), respectively. Two Eversource substations (6 feeders) will receive VVO capability later in 2023. Unitil had completed VVO deployment at 1 substation (3 feeders) of the 3 substations (8 feeders) that were initially planned to receive VVO during Term 1. Unitil has shifted the feeders that remain for deployment to its deployment plans for Term 2. As such, Unitil deployment of Term 1 feeders is presented as 100% complete.

**Table 34. 2022 Infrastructure Metrics for VVO Feeder Deployment – Term 1 Plan Feeders**

| IM | Parameter* | Eversource | National Grid | Unitil |
|---|---|---|---|---|
| IM-4 | # Feeders with VVO Enabled | 26 | 20 | 3 |
| | % Feeders with VVO Enabled | 81% | 100% | 100% |
| IM-6 | % On Track (Feeders with VVO Enabled) | 81% | 100% | 100% |
| IM-7 | # Feeders Remaining for VVO Enablement | 0 | 0 | 0 |

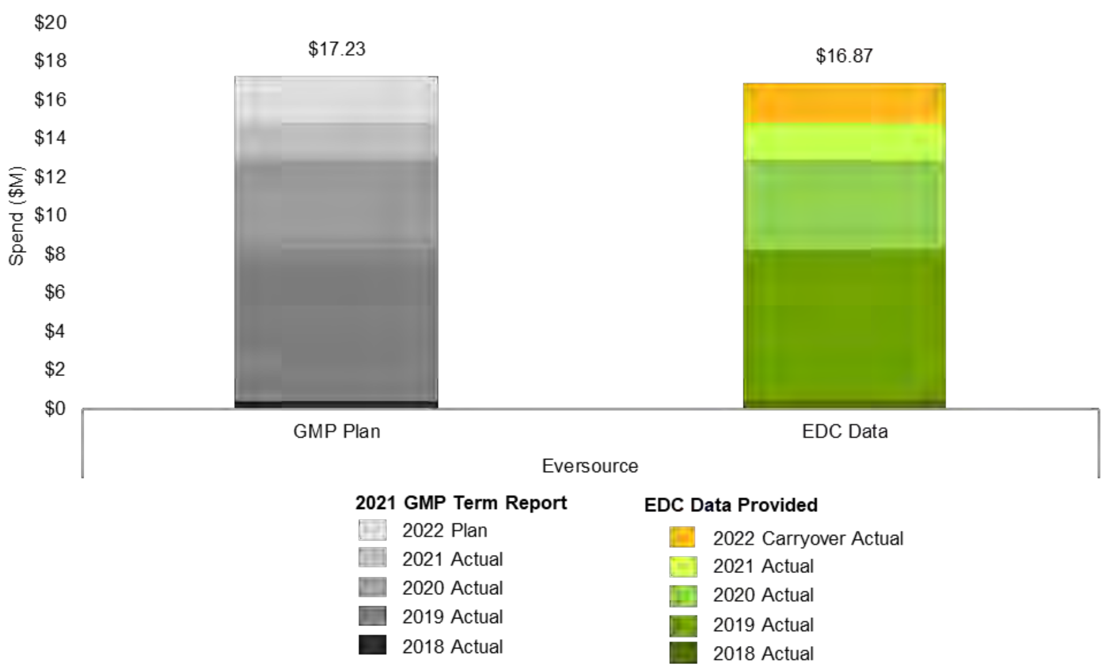
Note: This table considers Term 1 feeders for the three EDCs. Plan feeders for Term 1 may be found in Table 31.

* VVO Enabled denotes that the VVO system is commissioned and VVO is engaged. Feeders presented with VVO enabled may not be actively employing CVR.

*Source: Guidehouse analysis of 2021 GMP Term Report and 2022 EDC Data*

Figure 6 highlights planned versus actual spend on VVO for Eversource.

**Figure 6. Term 1 VVO Spend Comparison (2018–2022, $M)**




Note: Includes the Eversource planned spend on activity from 2021 that was transferred to 2022, set forth in Eversource's 2021 GMP Term Report, filed on April 1, 2022.

*Source: Guidehouse analysis of 2021 GMP Term Report, "GMP Extension and Funding Report," and 2021 EDC Data*

In addition to the capital costs Figure 6 shows, Eversource incurred approximately $27,948 in Term 1 operations and maintenance (O&M) costs toward the VVO Investment Area in PY 2022. Further details on the differences between planned and actual spend are provided in the Eversource results subsections.

### *3.2.1.5 Term 2 Infrastructure Metrics Results*

Table 35 and Table 36 summarize the Infrastructure Metrics results for each EDC's VVO Investment Area through PY 2022. Subsequent sections explain each EDC's progress and plans in greater detail.

**Table 35. Term 2 2022 Infrastructure Metrics for VVO**

| Infrastructure Metrics | | | Eversource | National Grid** | Unitil |
|---|---|---|---|---|---|
| GMP Plan Total, PY 2022-2025 | | # Devices Planned | 2,629 | 987 | 180 |
| | | Spend, $M | 38.64 | $76.44 | $5.42 |
| EDC Data Total, PY 2022-2025 | | # Devices Planned | 1,711 | 1,715 | 143 |
| | | Spend, $M | $38.61 | $76.44 | $2.24 |
| IM-4 | Number of devices or other technologies deployed thru. PY 2022 | # Devices Deployed* | 0 | 42 | 37 |
| | | % Devices Deployed | 0% | 4% | 21% |
| IM-5 | Cost for Deployment thru. PY 2022 | Total Spend, $M | $0.04 | $7.61 | $0.28 |
| | | % Spend | 0% | 10% | 5% |
| IM-6 | Deviation Between Actual and Planned Deployment for PY 2022 | % On Track (Devices) | 0% | 25% | 119% |
| | | % On Track (Spend) | 0% | 69% | 105% |
| IM-7 | Projected Deployment for the Remainder of the GMP Term | # Devices Remaining | 1,711 | 1,673 | 106 |
| | | Spend Remaining, $M | $38.58 | $68.83 | $1.96 |

*Note that "Deployed" here refers to commissioned devices. For full definitions of deployment stages, see Docket 20-46 Response to Information Request DPU-AR-4-11, September 3, 2020.

**To more closely align spend projections with DPU pre-authorized budgets, National Grid operations and maintenance (O&M) spend is included in actual and planned spend presented here. O&M spend is provided in aggregate for each investment area and is therefore excluded from device-specific summaries of spend.

*Source: Guidehouse analysis of 2021 DOER Responses and 2022 EDC Data*

**Table 36. 2022 Infrastructure Metrics for VVO Feeder Deployment – Term 2 Plan Feeders**

| IM | Parameter* | Eversource | National Grid | Unitil |
|---|---|---|---|---|
| IM-4 | # Feeders with VVO Enabled | 0 | 18 | 4 |
| | % Feeders with VVO Enabled | 0% | 35% | 50% |
| IM-6 | % On Track (Feeders with VVO Enabled) | 0% | 35% | 50% |
| IM-7 | # Feeders Remaining for VVO Enablement | 95 | 34 | 4 |

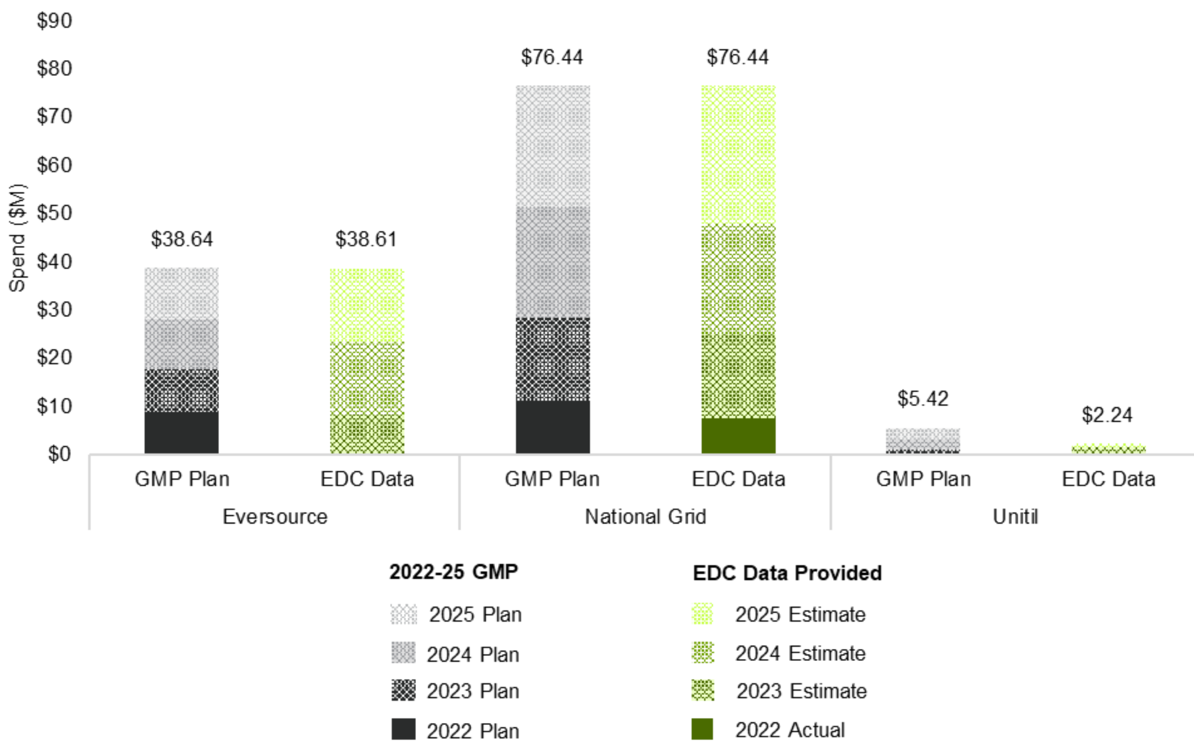
Note: This table considers Term 2 feeders for the three EDCs. Plan feeders for Term 2 may be found in Table 31.

* VVO Enabled denotes that the VVO system is commissioned and VVO is engaged. Feeders presented with VVO enabled may not be actively employing CVR.

*Source: Guidehouse analysis of 2022 EDC Data*

Figure 7 compares the GMP plans and EDC data totals and year-over-year spending for each EDC.

**Figure 7. Term 2 VVO Spend Comparison**




Note: To more closely align spend projections with DPU pre-authorized budgets, National Grid operations and maintenance (O&M) spend is included in actual and planned spend presented here. O&M spend is provided in aggregate for each investment area and is therefore excluded from device-specific summaries of spend.

*Source: Guidehouse analysis of 2021 DOER Responses and 2022 EDC Data*

PY 2022's VVO Infrastructure Metrics findings show that the EDCs are at varying stages in VVO deployment for Term 2. Details pertaining to device deployment progress, total spend, and VVO enablement progress are shown below:

Device Deployment:

- Eversource did not meet VVO deployment goals for PY 2022. Eversource progress on VVO investments targeted for 2022 through 2025 was comprised of progressing engineering/design work for all VVO device types, as well as planning for future VVO deployments, while awaiting DPU decisions on continued VVO investment for 2022 through 2025. Given limited deployment on Term 2 investments in 2022, Eversource has adjusted plans for the remainder of Term 2, with the majority of deployment and spend activity projected to occur in 2024 and 2025. At the technology-level, planned deployment has declined for Regulators, Line Sensors, and Microcapacitors, and planned Capacitor Bank deployment has increased slightly. Capacitor Bank deployment has been revised upwards to reflect refinements made during the planning and design process.

- National Grid conducted less deployment than initially planned in PY 2022. A late-2022 DPU decision on preauthorizing 2022 through 2025 investment activity, resource constraints, and vendor lead times were all key contributors to this outcome. In response to lower-than-expected deployment in 2022, National Grid has accelerated its deployment timeline for 2023 through 2025. National Grid has also adjusted total deployment plans for numerous device types, increasing projected deployment for Capacitor Banks, Line Sensors, and LTC Controls, while reducing projected deployment for Regulators. National Grid cites that these revisions are primarily due to the VVO planning work that has been conducted since the 2022-2025 GMP was filed.
- Unitil deployment was below plans for 2022, with variation by technology. Unitil was on-track with deployment of VVO Capacitor Banks and Line Sensors in 2022, deploying 100% and 210% of planned units, respectively. However, deployment was under plans for Regulators and LTC Controls. Lower deployment than plans for these technologies may be attributed to Unitil's efforts to resolve LTC radio and control issues and cancelation of 4 deployments that were found to be unnecessary. Unitil has adjusted deployment plans for the remainder of Term 2 to conduct most deployment during 2023 and 2025. Additionally, Unitil has reduced its planned deployments of VVO Regulators and Capacitor Banks, as Unitil reassessed deployment plans and determined there were fewer Regulator and Capacitor Bank deployments needed than initially planned. Work in 2024 will be limited to material orders in preparation for construction work at the Beech Street substation.

Total Spend:

- Eversource spend on Term 2 investments amounted to $0.04M, short of the $8.70M that was initially planned for 2022. Given limited deployment and spend on Term 2 investments in 2022, as well as ongoing vendor delays in fulfilling material orders, Eversource has adjusted plans for the remainder of Term 2. In 2023, Eversource will be conducting additional design work, submitting material orders, and, when material orders are received, deploying VVO investments. Eversource has projected that most spend activity will occur in 2024 and 2025.
- National Grid spend on VVO was below plans for 2022. The majority of spend occurred on Capacitor Banks, while spend on Regulators and Line Sensors was well below plans. Lower-than-anticipated spend on Line Sensors can, in part, be attributed to National Grid's previous line sensor vendor discontinuing their selected model. For VVO Regulators, vendor delays in fulfilling material orders was a key contributor to lower spend than initially planned. In response to its 2022 experience with Line Sensors and Regulators, National Grid has begun to increase diversification of vendors that it sources materials from.
- Unitil spend on VVO was below initial plans. Unitil met 48% of its planned spend for Regulators. Spend and deployment of all other devices met or exceeded initial plans. Spend plans for the remainder of Term 2 have been revised downwards across all device types. Reduced spend on Regulators and Capacitor Banks can be attributed to a reduction in the units that Unitil plans to deploy, as well as lower than expected costs for deployment of Regulators. Reduced spend on LTC Controls and Line Sensors may be tied to process efficiencies implemented in 2022 that brought unit costs below plans. Most spend is planned for 2023 and 2025, with work in 2024 limited to material orders in preparation for construction work at the Beech Street substation.

VVO Enablement:

- Eversource conducted VVO On/Off testing at four of six of its Term 1 substations (Agawam, Piper, Podick, and Silver) in 2022. Meanwhile, Eversource has shifted VVO deployment plans for its remaining Term 1 substations, shifting VVO enabled dates for the Gunn and Oswald substations by approximately 14 months and 19 months, respectively. The Gunn substation is now expected to be VVO enabled by June 2023, and Eversource plans to begin VVO On/Off testing by late June 2023. The Oswald substation is now expected to be VVO enabled by December 2023, and Eversource plans to begin VVO On/Off testing by late December 2023. Among its Term 2 feeders, Eversource is in the process of deploying VVO investments across all 95 currently identified feeders.
- National Grid conducted VVO On/Off testing at its East Methuen and Maplewood Term 1 substations throughout 2022. Among its Term 2 substations, National Grid conducted On/Off testing at the East Bridgewater substation throughout 2022, as VVO deployment was completed at the substation in 2021. Additionally, National Grid completed VVO deployment at the Easton and West Salem substations and began VVO On/Off for these substations in winter 2022/23 and spring 2022, respectively. National Grid projects that it will complete VVO deployment and enable VVO at its remaining Term 2 substations in 2023.
- Unitil completed VVO deployment for its Term 1 substation (Townsend) in 2021, enabling VVO on December 1, 2021, and On/Off testing is expected to begin in spring 2023. Among its Term 2 substations, Unitil completed deploying VVO investments at the Summer Street substation and enabled VVO in December 2022, with VVO On/Off testing projected to begin at the substation in December 2023. Lunenburg and West Townsend are currently receiving VVO investments and Unitil plans to enable VVO at the substations in January and November 2024, respectively. Unitil then plans to conduct On/Off testing at the substations beginning in December 2024. For its remaining substations, Unitil is currently conducting planning and engineering/design work for its Beech Street, Pleasant Street, and Princeton Road substations. These substations are expected to be enabled after the close of Term 2 in 2026 and 2027.

### 3.2.2 Eversource

This section discusses Eversource's VVO investment progress through PY 2022 in two subsections:

- Term 1 Progress: a comparison of progress Eversource made in 2022 against plans detailed in its *2021 GMP Term Report*. These results consider only the deployment and spending that were planned in 2021 to be carried over into 2022.
- Term 2 Progress: a comparison of progress Eversource made towards its 2022 plans outlined in its *2022-2025 GMP Plan.* These results do not consider deployment or spending that were planned in 2021 to be carried over into 2022.

#### *3.2.2.1 Overview of GMP Deployment Plan*

***Approach to VVO***
In Term 1, Eversource deployed full VVO functionality across four substations, amounting to 26 feeders. Eversource is also completing VVO investments at its two remaining Term 1 substations, amounting to 6 feeders. In deployment planning, all substations and feeders were selected based on whether they could be controlled from a single control room, cover a mix of

residential, commercial, and industrial customers, and cover a range of distributed generation capacities. Substation selections were based on engineering analysis and coordination with grid modernization teams.

Table 37 through Table 40 summarize the planned and actual deployment and spend for VVO for Term 1 and Term 2.

**Table 37. Term 1 Eversource Cumulative VVO Feeder Deployment Year-over-Year Comparison**

| Data | 2018 | 2019 | 2020 | 2021 | 2022 | 2018-2022 |
|---|---|---|---|---|---|---|
| EDC Actual Progress | 0 | 0 | 26 | 26 | 26 | 26 |
| EDC Plan | 26 | 26 | 26 | 26 | 32 | 32 |
| % EDC Actual Progress/EDC Plan | 0% | 0% | 100% | 100% | 81% | 81% |

Note: Due to rounding error, manual calculations of % EDC Actual Progress / EDC Plan will not precisely match calculated numbers provided in this table.

*Source: Guidehouse analysis of 2021 GMP Term Report and 2022 EDC Data*

**Table 38. Term 2 Eversource Cumulative VVO Feeder Deployment Year-over-Year Comparison**

| Data | 2022 | 2023 | 2024 | 2025 | 2022-2025 |
|---|---|---|---|---|---|
| EDC Actual Progress | 0 | N/A | N/A | N/A | N/A |
| EDC Plan | 95 | N/A | N/A | N/A | N/A |
| % EDC Actual Progress/EDC Plan | 0% | N/A | N/A | N/A | N/A |

Note: Due to rounding error, manual calculations of % EDC Actual Progress / EDC Plan will not precisely match calculated numbers provided in this table.

*Source: Guidehouse analysis of 2022 EDC Data*

**Table 39. Term 1 Eversource Cumulative VVO Investment Year-over-Year Comparison ($M)***

| Data | 2018 | 2019 | 2020 | 2021 | 2022 | 2018-2022 |
|---|---|---|---|---|---|---|
| EDC Actual Progress | $0.4 | $8.2 | $12.9 | $14.8 | $16.9 | $16.9 |
| EDC Plan | $13.0 | $13.0 | $17.4 | $18.9 | $17.2 | $17.2 |
| % EDC Actual Progress/EDC Plan | 3% | 63% | 74% | 78% | 98% | 98% |

Note: Due to a rounding error, manual calculations of % EDC Actual Progress / EDC Plan and % EDC Revised Plan / EDC Original Plan will not precisely match calculated numbers provided in this table.

*Source: Guidehouse analysis of 2021 GMP Term Report, 2022 EDC Data*

**Table 40. Term 2 Eversource Cumulative VVO Investment Year-over-Year Comparison ($M)***

| Data | 2022 | 2023 | 2024 | 2025 | 2022-2025 |
|---|---|---|---|---|---|
| EDC Actual Progress | $0.04 | N/A | N/A | N/A | N/A |
| EDC Plan | $38.6 | N/A | N/A | N/A | N/A |
| % EDC Actual Progress/EDC Plan | 0.1% | N/A | N/A | N/A | N/A |

Note: Due to a rounding error, manual calculations of % EDC Actual Progress / EDC Plan and % EDC Revised Plan / EDC Original Plan will not precisely match calculated numbers provided in this table.

*Source: Guidehouse analysis of 2021 DOER Responses and 2022 EDC Data*

Across its Term 1 substations, Eversource has completed VVO deployment and VVO On/Off testing across 26 feeders connected to the Agawam, Piper, Podick, and Silver substations. Additionally, Eversource is in the process of deploying VVO investments at the Gunn and Oswald substations. Eversource expects VVO deployment to be complete at these substations by June and December of 2023, respectively. Through the end of 2022, Eversource spent roughly $16.9M of its final estimated budget for Term 1 of $17.2M, approximately 98% of plans, on completing activity from 2021. Through the end of 2022, Eversource has spent less than 1% of its planned spend for Term 2, as much of 2022 activity was comprised of completing work from Term 1.

Table 41 highlights Eversource feeder characteristics as of the end of 2022. Feeder lengths and customer counts vary considerably across VVO feeders. Selected substations also present a mix of distributed generation capacity across feeders, with distributed generation capacity ranging from 0.0 MW to 14.3 MW. Table 41 contains additional information related to the VVO feeders. Appendix A contains additional information related to the VVO feeders.

**Table 41. 2022 Eversource VVO Feeder Characteristics**

| Substation | Feeder | Feeder Length (mi.) | Customer Count | Annual Peak Load (MVA) | Distributed Generation (MW) |
|---|---|---|---|---|---|
| **Term 1 Feeders** | | | | | |
| **Agawam (13.8 kV)** | **16C11** | 24 | 1,350 | 5.8 | 2.2 |
| | **16C12** | 6 | 80 | 4.4 | 2.0 |
| | **16C14** | 15 | 1,632 | 6.2 | 0.2 |
| | **16C15** | 11 | 1,270 | 4.1 | 0.1 |
| | **16C16** | 22 | 2,563 | 7.4 | 2.5 |

| Substation | Feeder | Feeder Length (mi.) | Customer Count | Annual Peak Load (MVA) | Distributed Generation (MW) |
|---|---|---|---|---|---|
| | **16C17** | 29 | 2,388 | 7.0 | 1.3 |
| | **16C18** | 21 | 3,054 | 6.3 | 0.8 |
| **Piper (13.8 kV)** | **21N4** | 33 | 2,299 | 6.8 | 1.7 |
| | **21N5** | 15 | 829 | 8.4 | 0.2 |
| | **21N6** | 15 | 787 | 4.3 | 0.5 |
| | **21N7** | 5 | 2 | 4.8 | 0.0 |
| | **21N8** | 9 | 557 | 6.8 | 0.1 |
| | **21N9** | 24 | 2,404 | 6.4 | 1.0 |
| **Podick (13.8 kV)** | **18G2** | 5 | 9 | 0.5 | 0.0 |
| | **18G3** | 37 | 2,141 | 4.0 | 2.2 |
| | **18G4** | 35 | 2,347 | 4.7 | 5.7 |
| | **18G5** | 40 | 1,778 | 5.8 | 5.9 |
| | **18G6** | 38 | 1,289 | 5.0 | 3.6 |
| | **18G7** | 64 | 2,226 | 4.5 | 11.6 |
| | **18G8** | 47 | 1,089 | 7.5 | 8.7 |
| **Silver (13.8 kV)** | **30A1** | 37 | 2,519 | 6.8 | 1.5 |
| | **30A2** | 12 | 2,286 | 8.8 | 0.4 |
| | **30A3** | 12 | 239 | 7.8 | 5.1 |
| | **30A4** | 11 | 801 | 4.6 | 0.3 |
| | **30A5** | 21 | 1,659 | 4.4 | 0.9 |
| | **30A6** | 20 | 1,007 | 5.5 | 2.3 |
| **Gunn (23 kV)** | **15A1** | 78 | 3,142 | 8.2 | 5.5 |
| | **15A2** | 22 | 2,143 | 8.3 | 4.1 |
| | **15A3** | 96 | 3,755 | 8.4 | 10.1 |
| | **15A5** | 31 | 3,427 | 6.5 | 2.1 |
| **Oswald (23 kV)** | **30B5** | 34 | 2,462 | 4.4 | 5.0 |
| | **30B7** | 84 | 1,957 | 7.7 | 14.3 |
| **Term 2 Feeders** | | | | | |
| **Amherst (13.8 kV)** | **17K1** | 12.25 | 1,046 | 2.58 | 6.76 |
| | **17K2** | 51.41 | 2,069 | 4.66 | 3.94 |
| | **17K3** | 3.59 | 396 | 0.88 | 0.18 |
| | **17K4** | 9.20 | 1,076 | 4.49 | 4.20 |
| | **17K5** | 28.56 | 1,628 | 7.25 | 1.09 |
| | **17K6** | 13.44 | 868 | 4.89 | 2.61 |
| | **17K7** | 11.46 | 874 | 1.27 | 0.33 |
| | **17K8** | 34.41 | 1,652 | 3.64 | 2.38 |
| **Breckwood (13.8 kV)** | **20A11** | 1.19 | 0 | 1.90 | 0.00 |
| | **20A12** | 9.52 | 841 | 2.30 | 0.22 |
| | **20A13** | 9.63 | 1,430 | 3.30 | 0.76 |
| | **20A14** | 22.19 | 1,949 | 6.00 | 2.25 |
| | **20A21** | 27.76 | 2,656 | 7.60 | 1.75 |
| | **20A22** | 17.03 | 2,166 | 5.60 | 1.02 |
| | **20A23** | 7.07 | 710 | 1.70 | 0.34 |
| | **20A31** | 15.10 | 1,590 | 4.30 | 0.31 |
| | **20A32** | 21.90 | 2,602 | 5.90 | 2.08 |
| | **20A33** | 22.05 | 2,872 | 9.70 | 1.72 |
| | **20A34** | 24.59 | 2,081 | 6.50 | 2.25 |

| Substation | Feeder | Feeder Length (mi.) | Customer Count | Annual Peak Load (MVA) | Distributed Generation (MW) |
|---|---|---|---|---|---|
| | **20A35** | 17.25 | 1,749 | 4.80 | 1.12 |
| **Cross Road (13.2 kV)** | **2-522-522** | 34.10 | 872 | 3.08 | 3.49 |
| | **2-523-523** | 116.25 | 3,112 | 8.47 | 6.13 |
| | **2-524-524** | 45.71 | 751 | 1.21 | 1.20 |
| | **2-525-525** | 3.55 | 3 | 4.96 | 6.00 |
| | **2-528-528** | 118.70 | 0 | 7.06 | 3.55 |
| **Cumberland (13.8 kV)** | **22B1** | 46.79 | 1,220 | 7.44 | 2.19 |
| | **22B2** | 13.87 | 1,411 | 3.73 | 0.75 |
| | **22B3** | 25.59 | 969 | 3.11 | 2.76 |
| | **22B4** | 26.31 | 1,319 | 4.15 | 5.24 |
| | **22B5** | 66.47 | 1,110 | 2.22 | 8.20 |
| | **22B6** | 1.65 | 0 | 1.27 | 0.00 |
| | **22B7** | 90.79 | 2,187 | 6.73 | 2.56 |
| | **22B8** | 18.00 | 2,247 | | 0.84 |
| **Doreen (23 kV)** | **19A1** | 27.89 | 1,900 | 2.50 | 1.60 |
| | **19A2** | 16.06 | 1,225 | 1.80 | 0.76 |
| | **19A3** | 8.64 | 99 | 1.80 | 2.41 |
| | **19A4** | 2.41 | 64 | 1.80 | 2.01 |
| | **19A5** | 22.99 | 999 | 4.50 | 1.72 |
| | **19A6** | 5.50 | 3 | 4.10 | 1.76 |
| | **19A7** | 25.53 | 3,390 | 4.60 | 0.82 |
| | **19A8** | 10.47 | 1,407 | 1.60 | 0.45 |
| **Duxbury (4.16 kV)** | **3-24A-34J1** | 14.05 | 662 | 14.04 | 0.38 |
| | **3-24A-34J2** | 1.08 | 61 | 3.16 | 0.01 |
| | **3-24A-35J1** | 7.56 | 250 | 5.13 | 0.07 |
| | **3-24A-35J2** | 0.08 | 0 | 0.00 | 0.00 |
| **Franconia (13.8 kV)** | **22H11** | 0.93 | 0 | 0.00 | 0.01 |
| | **22H12** | 13.29 | 837 | 3.50 | 1.11 |
| | **22H13** | 27.50 | 1,666 | 7.20 | 0.73 |
| | **22H14** | 32.70 | 3,691 | 9.70 | 0.97 |
| | **22H15** | 19.53 | 3,515 | 7.20 | 0.87 |
| | **22H16** | 19.37 | 3,498 | 7.00 | 1.05 |
| | **22H17** | 21.90 | 1,932 | 6.30 | 0.45 |
| | **22H18** | 4.61 | 1,534 | 6.50 | 0.07 |
| **Industrial Park (13.2 kV)** | **2-101-101** | 4.33 | 25 | 8.7 | 2.30 |
| | **2-102-102** | 34.68 | 1,757 | 11.5 | 11.72 |
| | **2-102-608** | 15.84 | 739 | 2.3 | 0.68 |
| | **2-103-103** | 8.87 | 19 | 6.5 | 5.52 |
| | **2-104-104** | 14.96 | 1,239 | 4.8 | 1.85 |
| | **2-105-105** | 21.53 | 2,557 | 8.0 | 1.76 |
| | **2-106-106** | 2.24 | 5 | 7.5 | 0.00 |
| | **2-106-160** | 15.34 | 1,251 | 1.4 | 0.91 |
| | **2-106-161** | 11.97 | 1,008 | 2.9 | 0.92 |
| | **2-107-107** | 30.66 | 531 | 6.6 | 13.59 |
| | **2-108-108** | 50.57 | 0 | 14.5 | 17.20 |
| | **2-151-151** | 1.24 | 6 | 1.9 | 2.64 |
| | **2-152-152** | 0.45 | 0 | 1.6 | 0.00 |

| Substation | Feeder | Feeder Length (mi.) | Customer Count | Annual Peak Load (MVA) | Distributed Generation (MW) |
|---|---|---|---|---|---|
| **Mashpee (22.8 kV)** | **4-71-455** | 94.17 | 3,408 | 7.26 | 4.20 |
| | **4-71-71** | 0.21 | 9 | 13.84 | 0.00 |
| | **4-77B-456** | 31.65 | 1,381 | 4.81 | 0.68 |
| | **4-77B-77B** | 7.56 | 294 | 12.15 | 0.01 |
| **Montague (13.8 kV)** | **21C1** | 58.52 | 1,475 | 7.19 | 6.68 |
| | **21C2** | 24.27 | 1,086 | 7.53 | 9.57 |
| | **21C3** | 0.44 | 0 | 0.00 | 0.00 |
| | **21C4** | 16.66 | 1,852 | 7.36 | 1.26 |
| | **21C5** | 41.76 | 1,387 | 2.79 | 0.61 |
| | **21C6** | 4.52 | 461 | 0.84 | 7.29 |
| | **21C7** | 69.68 | 1,730 | 3.42 | 1.50 |
| | **21C8** | 25.50 | 1,130 | 3.44 | 10.41 |
| **Orchard (13.8 kV)** | **27A10** | 10.41 | 1,301 | 2.60 | 3.96 |
| | **27A11** | 1.58 | 1 | 4.60 | 0.00 |
| | **27A12** | 1.56 | 6 | 4.60 | 7.62 |
| | **27A13** | 12.25 | 2,002 | 7.60 | 4.12 |
| | **27A14** | 0.60 | 0 | 1.10 | 0.00 |
| | **27A15** | 9.44 | 1 | 0.20 | 0.00 |
| | **27A16** | 0.66 | 0 | 1.10 | 0.00 |
| | **27A17** | 0.65 | 0 | 1.10 | 0.00 |
| | **27A4** | 12.72 | 1,337 | 3.90 | 0.82 |
| | **27A5** | 17.18 | 723 | 5.90 | 2.56 |
| | **27A6** | 18.32 | 2,969 | 7.10 | 4.74 |
| | **27A7** | 9.86 | 963 | 3.50 | 0.55 |
| **Wareham (22.8 kV)** | **3-85-85** | 76.51 | 2,469 | 15.78 | 6.45 |
| | **3-85-928** | 16.90 | 488 | 2.80 | 3.75 |
| | **3-85-957** | 11.43 | 278 | 0.99 | 0.26 |
| | **3-86-966** | 33.26 | 1,383 | 8.13 | 4.81 |

Note: Values presented in this table were published on April 24, 2023 and are reflective of data collected through the end of 2022.
*Source: 2022 GMP Annual Report, Appendix 1 filed April 24, 2023*

### *3.2.2.2 VVO Timeline*

Table 42 summarizes substation-specific progress in each of the four VVO investment phases.

**Table 42. Eversource Combined Plan Feeders Deployment Completion Dates**

| Substation | VVO Investment | VVO Commissioning[43] | VVO Enabled[44] | VVO On/Off Testing |
|---|---|---|---|---|
| **Term 1 Plan Substations** | | | | |

[43] VVO Commissioning is the time at which VVO devices are controlled by and have data visible to each EDC.

[44] VVO Enabled is the time at which the VVO system is commissioned and VVO is engaged. Feeders presented with VVO enabled may not be actively employing CVR.

| Substation | VVO Investment | VVO Commissioning[43] | VVO Enabled[44] | VVO On/Off Testing |
|---|---|---|---|---|
| **Agawam** | 1/14/2019 - 12/31/2019 (Complete) | 11/1/2019 - 12/31/2019 (Complete) | 12/2/2020 (Complete) | 12/2/2020 - May 2023 (Complete) |
| **Piper** | 1/14/2019 - 12/31/2019 (Complete) | 11/1/2019 - 12/31/2019 (Complete) | 12/2/2020 (Complete) | 12/2/2020 - May 2023 (Complete) |
| **Podick** | 3/29/2019 - 12/31/2019 (Complete) | 11/1/2019 - 12/31/2019 (Complete) | 12/2/2020 (Complete) | 3/4/2021 - May 2023 (Complete) |
| **Silver** | 1/14/2019 - 12/31/2019 (Complete) | 11/1/2019 - 12/31/2019 (Complete) | 12/2/2020 (Complete) | 12/2/2020 - May 2023 (Complete) |
| **Gunn** | 1/1/2021 - 6/1/2023 (In-Progress) | 9/1/2022 - 6/1/2023 (In-Progress) | 6/15/2023 (Planned) | 6/30/2023 - TBD (Planned) |
| **Oswald** | 1/1/2021 - 12/1/2023 (In-Progress) | 9/1/2022 - 12/1/2023 (In-Progress) | 12/15/2023 (Planned) | 12/31/2023 - TBD (Planned) |
| **Term 2 Plan Substations** | | | | |
| **Amherst** | TBD | TBD | TBD | 1/1/2025 – TBD (Planned) |
| **Breckwood** | TBD | TBD | TBD | 10/1/2024 – TBD (Planned) |
| **Cross Road** | TBD | TBD | TBD | 7/1/2024 – TBD (Planned) |
| **Cumberland** | TBD | TBD | TBD | 7/1/2024 – TBD (Planned) |
| **Doreen** | TBD | TBD | TBD | 7/1/2024 – TBD (Planned) |
| **Duxbury** | TBD | TBD | TBD | 4/1/2025 – TBD (Planned) |
| **Franconia** | TBD | TBD | TBD | 7/1/2024 – TBD (Planned) |
| **Industrial Park** | TBD | TBD | TBD | 7/1/2025 – TBD (Planned) |

| Substation | VVO Investment | VVO Commissioning[43] | VVO Enabled[44] | VVO On/Off Testing |
|---|---|---|---|---|
| **Mashpee** | TBD | TBD | TBD | 10/1/2024 – TBD (Planned) |
| **Montague** | TBD | TBD | TBD | 10/1/2024 – TBD (Planned) |
| **Orchard** | TBD | TBD | TBD | 10/1/2024 – TBD (Planned) |
| **Wareham** | TBD | TBD | TBD | 10/1/2024 – TBD (Planned) |

Note: Term 2 feeder schedules were provided in quarterly form (e.g., Q4 2024). As such, Guidehouse has assigned VVO On/Off testing start dates as the first day of the quarter in which VVO On/Off testing is anticipated to begin.

*Source: Guidehouse analysis of 2022 EDC Data*

Eversource conducted VVO On/Off testing at four of its Term 1 substations throughout 2022. In tandem, Eversource conducted deployment of VVO devices across the Gunn and Oswald substations. In 2022, Eversource found that the existing LTC controls at the Oswald substation were incompatible with VVO and needed replacement and commissioning before being fully deployed. Additionally, Eversource is working through troubleshooting communications equipment before the Gunn substation will have full VVO capability. Eversource expects to complete LTC deployment and resolve communications issues in 2023. VVO On/Off testing is then expected to begin at the Gunn and Oswald substations in June and December 2023, respectively.

For its Term 2 substations, Eversource is currently in the VVO Investment phase, and is conducting engineering / design work for the selected substations. Eversource anticipates completing deployment during 2024 and 2025. Once VVO investments are deployed, Eversource plans to conduct VVO On/Off testing, with testing start dates ranging from July 2024 through July 2025. Once VVO On/Off testing has begun, Eversource anticipates conducting this testing for 9 – 12 months to collect one summer, one winter, and one shoulder season of testing data.

Table 43 presents an additional VVO enablement progress by substation, including actual and planned VVO enabled dates and notes on the status of VVO deployment.

**Table 43. Eversource VVO Enabled Progress by Substation**

| Substation | January 2022 Planned/Actual VVO Enabled Date | January 2023 Planned/Actual VVO Enabled Date** | Current Status[45] |
|---|---|---|---|
| **Term 1 Feeders** | | | |
| Agawam | 12/2/2020 (actual) | 12/2/2020 (actual) | VVO On/Off testing complete |
| Piper | 12/2/2020 (actual) | 12/2/2020 (actual) | VVO On/Off testing complete |
| Podick | 3/4/2021 (actual) | 3/4/2021 (actual) | VVO On/Off testing complete |
| Silver | 12/2/2020 (actual) | 12/2/2020 (actual) | VVO On/Off testing complete |
| Gunn | 4/15/2022 (planned) | 6/15/2023 (planned) | VVO Commissioning in progress |
| Oswald | 5/15/2022 (planned) | 12/15/2023 (planned) | VVO Commissioning in progress |
| **Term 2 Feeders** | | | |
| Amherst | N/A* | 1/1/2025 (planned) | VVO Investment in progress |
| Breckwood | N/A* | 10/1/2024 (planned) | VVO Investment in progress |
| Cross Road | N/A* | 7/1/2024 (planned) | VVO Investment in progress |
| Cumberland | N/A* | 7/1/2024 (planned) | VVO Investment in progress |
| Doreen | N/A* | 7/1/2024 (planned) | VVO Investment in progress |
| Duxbury | N/A* | 4/1/2025 (planned) | VVO Investment in progress |
| Franconia | N/A* | 7/1/2024 (planned) | VVO Investment in progress |
| Industrial Park | N/A* | 7/1/2025 (planned) | VVO Investment in progress |
| Mashpee | N/A* | 10/1/2024 (planned) | VVO Investment in progress |
| Montague | N/A* | 10/1/2024 (planned) | VVO Investment in progress |
| Orchard | N/A* | 10/1/2024 (planned) | VVO Investment in progress |
| Wareham | N/A* | 10/1/2024 (planned) | VVO Investment in progress |

* Guidehouse did not previously report on VVO schedules for Term 2 feeders in its PY 2021 report, and so all information has been listed as not applicable.

** Term 2 feeder schedules were provided in quarterly form (e.g., Q4 2024). As such, Guidehouse has assigned VVO On/Off testing start dates as the first day of the quarter in which VVO On/Off testing is anticipated to begin.

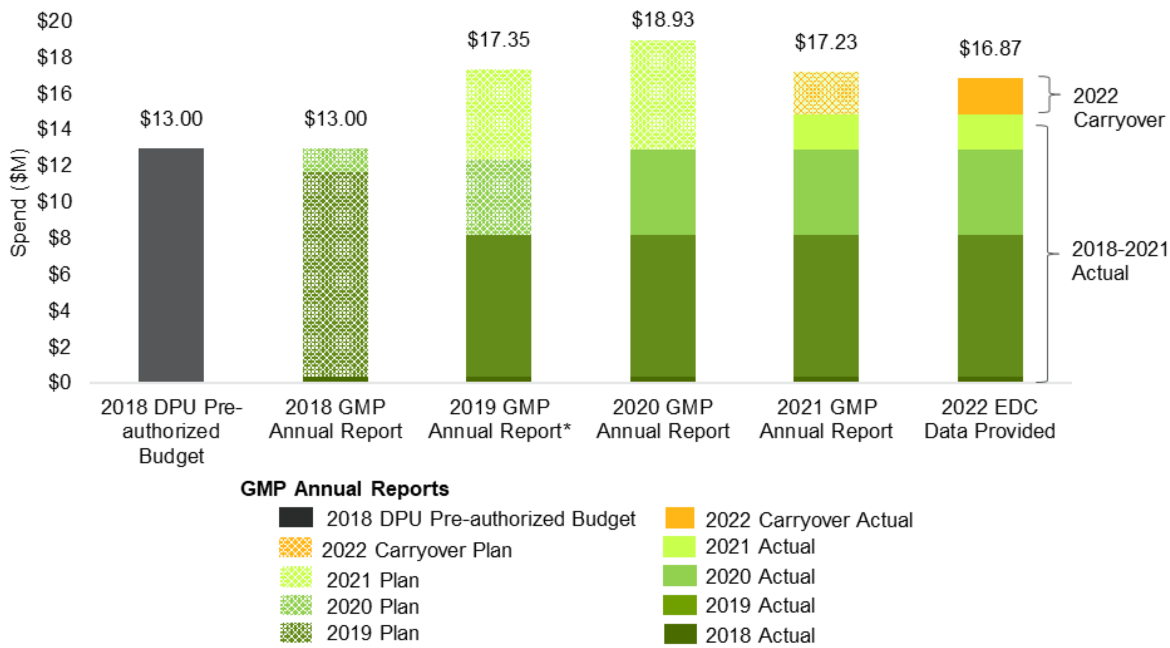
*Source: Guidehouse analysis of 2021 and 2022 EDC Data*

### *3.2.2.3 Term 1 VVO Deployment Plan Progression*

Figure 8 shows the progression of Eversource's VVO deployment plans from DPU-approval in 2018 through PY 2022.

[45] Status can be: planning, design, construction, device deployment complete, VVO commissioning in process, or VVO enabled. VVO Enabled denotes that the VVO system is commissioned and VVO is engaged. Feeders presented with VVO enabled may not be actively employing CVR.

**Figure 8. Term 1 Eversource VVO Planned vs. Actual Spend (2018–2022, $M)**




*Note that Eversource received pre-authorization from the Department for another $5 million in spending for its VVO investment area in late 2020.

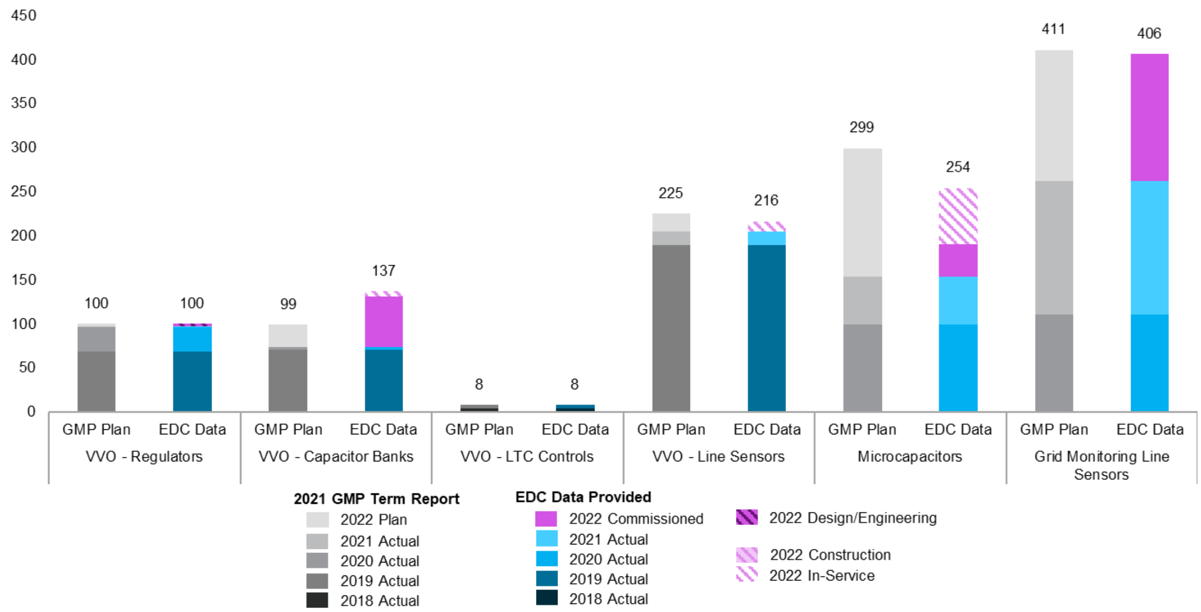
*Source: Guidehouse analysis of DPU Order (May 10, 2018), 2021 GMP Term Report, Eversource GMP Extension and Funding Report filed on July 1, 2020, Eversource extension filing, and 2022 EDC Data*

Eversource made progress towards meeting planned PY 2021 deployment and spend that was carried over to 2022. As of the end of 2022, total spend ($16.87M) was slightly below plans ($17.23M). This is largely attributed to vendor delays in fulfilling material orders.

### *3.2.2.4 Term 1 VVO Device Type Progress through PY 2022*

Figure 9 shows the progress and details of each device type for the 2018-2022 period.

**Figure 9. Term 1 Eversource Planned vs Actual Deployment (2018–2022, Unit Count)**




*Source: Guidehouse analysis of 2021 GMP Term Report and 2022 EDC Data*

The EDC Data presented in Figure 9 is also shown in tabular form in Table 44. to provide the specific deployment units in each category.

**Table 44. Term 1 Eversource VVO Deployment Progress**

| | VVO - Regulators | VVO - Capacitor Banks | VVO - LTC Controls | VVO - Line Sensors | Micro-capacitors | Grid Monitoring Line Sensors |
|---|---|---|---|---|---|---|
| **2018-2022 Total** | **97** | **131** | **8** | **205** | **0** | **191** |
| Engineering/Design during PY 2022* | 0 | 0 | 0 | 0 | 0 | 0 |
| Construction during PY 2022* | 0 | 6 | 0 | 11 | 0 | 63 |
| In-Service during PY 2022* | 0 | 57 | 0 | 0 | 0 | 37 |
| Commissioned in PY 2022 | 1 | 0 | 0 | 16 | 0 | 55 |
| Commissioned in PY 2021 | 27 | 3 | 0 | 0 | 0 | 99 |
| Commissioned in PY 2020 | 69 | 71 | 4 | 189 | 0 | 0 |
| Commissioned in PY 2019 | 0 | 0 | 4 | 0 | 0 | 0 |
| Commissioned in PY 2018 | **97** | **131** | **8** | **205** | **0** | **191** |

*Deployment of these devices began during PY 2022, but was not completed during the program year. All units and dollars spent to deploy remaining units during 2023 through 2025 will be considered as part of Term 2 GMPs.

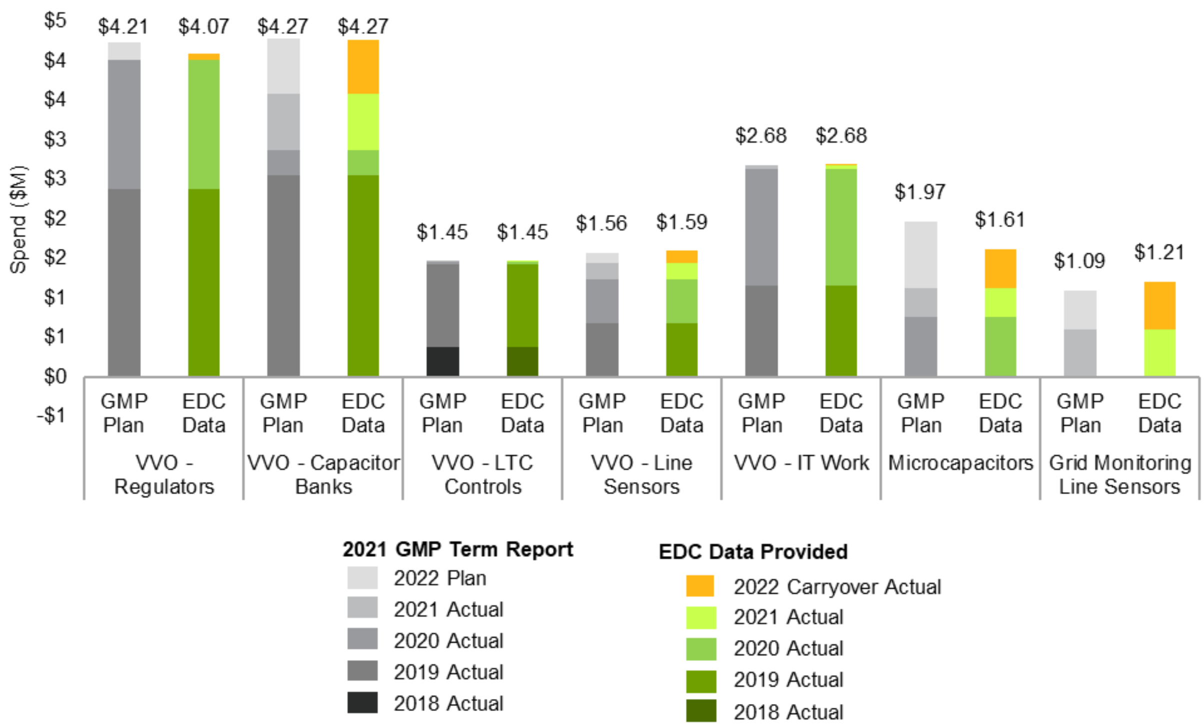
*Source: Guidehouse analysis of 2021 GMP Term Report and 2022 EDC Data*

Eversource made headway on deploying 2021 investments in 2022, with Capacitor Banks and Grid Monitoring Line Sensors comprising the bulk of deployed devices. Eversource exceeded plans (25 devices) for Capacitor Banks, deploying 57 devices, as refinements made during the planning and design process placed more priority on Capacitor Banks, less on Regulators, for VVO operation. Grid Monitoring Line Sensors deployed (141 devices) were approximately in-line with plans (148 devices).

Eversource had anticipated deploying three VVO Regulators during 2022, and ultimately was not able to meet this goal due to vendor delays on material orders. As of the end of 2022, Eversource was awaiting delivery of 3 ordered VVO Regulators from its vendor. Line Sensor and Micro-capacitor deployment also fell short of plans.

Figure 10 shows Eversource's corresponding planned versus actual spend over the 2018-2022 Term period, broken out by device type.

**Figure 10. Term 1 Eversource VVO Spend Plan vs. Actual (2018-2022, $M)**




*Source: Guidehouse analysis of 2021 GMP Term Report and 2022 EDC Data*

The EDC Data presented in Figure 10 is also shown in Table 45 to provide the specific dollar spend in each category.

**Table 45. Term 1 Eversource Total Spend Comparison (2018–2022, $M)**

| | VVO - Regulators | VVO - Capacitor Banks | VVO - LTC Controls | VVO - Line Sensors | VVO - IT Work | Microcapacitors | Grid Monitoring Line Sensors |
|---|---|---|---|---|---|---|---|
| **2018-2022 Total** | **$4.07** | **$4.27** | **$1.45** | **$1.59** | **$2.68** | **$1.61** | **$1.21** |
| PY 2022 Actual | $0.08 | $0.69 | $0.00 | $0.16 | $0.00 | $0.50 | $0.61 |
| PY 2021 Actual | -$0.02 | $0.71 | $0.00 | $0.20 | $0.05 | $0.36 | $0.59 |
| PY 2020 Actual | $1.63 | $0.31 | $0.03 | $0.56 | $1.47 | $0.75 | $0.00 |
| PY 2019 Actual | $2.38 | $2.55 | $1.04 | $0.68 | $1.16 | $0.00 | $0.00 |
| PY 2018 Actual | $0.00 | $0.00 | $0.38 | $0.00 | $0.00 | $0.00 | $0.00 |

*Source: Guidehouse analysis of 2021 GMP Term Report and 2022 EDC Data*

Eversource made substantial progress on PY 2021 work that was planned for 2022. Total spend through the end of 2022 was approximately on track with plans for all device types. The largest variance from plans identified was for microcapacitors ($0.36M below plan). While total spend through 2022 exceeded plans for Grid Monitoring Line Sensors, spend being on-track for Capacitor Banks and lower than plans for other device types led to total spend on VVO ($16.87M) being slightly below planned spend ($17.23M).

### *3.2.2.5 Term 1 Infrastructure Metrics Results and Key Findings*

Table 46 and Table 47 present the Infrastructure Metrics results through PY 2022 for each device type related to Eversource's VVO Investment Area.

**Table 46. Term 1 2022 Eversource Infrastructure Metrics for VVO Devices**

| Infrastructure Metrics | | | VVO - Regulators | VVO - Capacitor Banks | VVO - LTC Controls | VVO - Line Sensors | VVO - IT Work | Microcapacitors | Grid Monitoring Line Sensors |
|---|---|---|---|---|---|---|---|---|---|
| GMP Plan Total, 2018-2022 | | Devices | 100 | 99 | 8 | 225 | 0 | 299 | 411 |
| | | Spend, $M | $4.21 | $4.27 | $1.45 | $1.56 | $2.68 | $1.97 | $1.09 |
| IM-4 | Number of devices or other technologies deployed PY 2018-2022* | # Devices Deployed | 97 | 131 | 8 | 205 | 0 | 191 | 406 |
| | | % Devices Deployed | 97% | 132% | 100% | 91% | N/A | 64% | 99% |
| IM-5 | Cost for Deployment PY 2018-2022* | Total Spend, $M | $4.07 | $4.27 | $1.45 | $1.59 | $2.68 | $1.61 | $1.21 |
| | | % Spend | 97% | 100% | 100% | 102% | 100% | 82% | 110% |
| IM-6 | Deviation Between Actual and Planned Deployment for PY 2022 | % On Track (Devices) | 0% | 228% | N/A | 0% | N/A | 26% | 97% |
| | | % On Track (Spend) | 36% | 99% | N/A | 120% | N/A | 59% | 123% |

| Infrastructure Metrics | | | VVO - Regulators | VVO - Capacitor Banks | VVO - LTC Controls | VVO - Line Sensors | VVO - IT Work | Microcapacitors | Grid Monitoring Line Sensors |
|---|---|---|---|---|---|---|---|---|---|
| IM-7 | Projected Deployment for the remainder of the GMP Term (i.e., Term 1)** | # Devices Remaining | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Spend Remaining, $M | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |

*The metric names have been slightly changed here to clarify the time span used in analysis.

** This metric has been interpreted here (i.e., within the context of the 2022 Program Year Evaluation) as the units and spending that the EDC plans to complete their most recent 4-year Term 1 plans. Additional Grid Modernization units and dollars incurred in 2022 are attributed to Term 2, as appropriate, and all units and dollars spent during 2023 through 2025 will be considered as part of Term 2 GMPs.

*Source: Guidehouse analysis of 2021 GMP Term Report and 2022 EDC Data*

**Table 47. Term 1 2022 Eversource Infrastructure Metrics for VVO Feeders**

| IM | Metric | Parameter* | Number of Feeders |
|---|---|---|---|
| IM-4 | Number of Devices/Technologies Deployed thru. 2022 | # Feeders with VVO Enabled | 26 |
| | | % Feeders with VVO Enabled | 81% |
| IM-6 | Deviation Between Actual and Planned Deployment | % On Track (Feeders with VVO Enabled) | 81% |
| IM-7 | Projected Deployment for the Remainder of the GMP Term | # Feeders Remaining for VVO Enablement | 0 |

Note: This table considers Term 1 plan feeders for Eversource. Feeders that were projected to receive VVO capability during Term 1 may be found in Table 31.

* VVO Enabled denotes that the VVO system is commissioned and VVO is engaged. Feeders presented with VVO enabled may not be actively employing CVR.

*Source: Guidehouse analysis of 2021 DOER Responses and 2022 EDC Data*

Guidehouse's review of Eversource's VVO progress on Term 1 revealed that Eversource was approximately on-track with planned spend and deployment outlined in their *2021 GMP Term Report*. However, some spend and deployment remain in order to complete activities from Term 1. Key findings related to Eversource's progress include:

Device Deployment

- Eversource made headway on deploying 2021 investments in 2022, with Capacitor Banks and Grid Monitoring Line Sensors comprising the bulk of deployed devices. Eversource exceeded plans (25 devices) for Capacitor Banks, as refinements made during the planning and design process placed more priority on Capacitor Banks, less on Regulators, for VVO operation. At the close of 2022, Eversource was awaiting delivery of 3 ordered VVO Regulators from its vendor. Line Sensor and Micro-capacitor deployment also fell short of plans.

Total Spend

- Eversource made substantial progress on PY 2021 work that was planned for 2022. Total spend through the end of 2022 was approximately on track with plans for all device types, with total spend on VVO ($16.87M) being slightly below planned spend ($17.23M) laid out for Term 1.

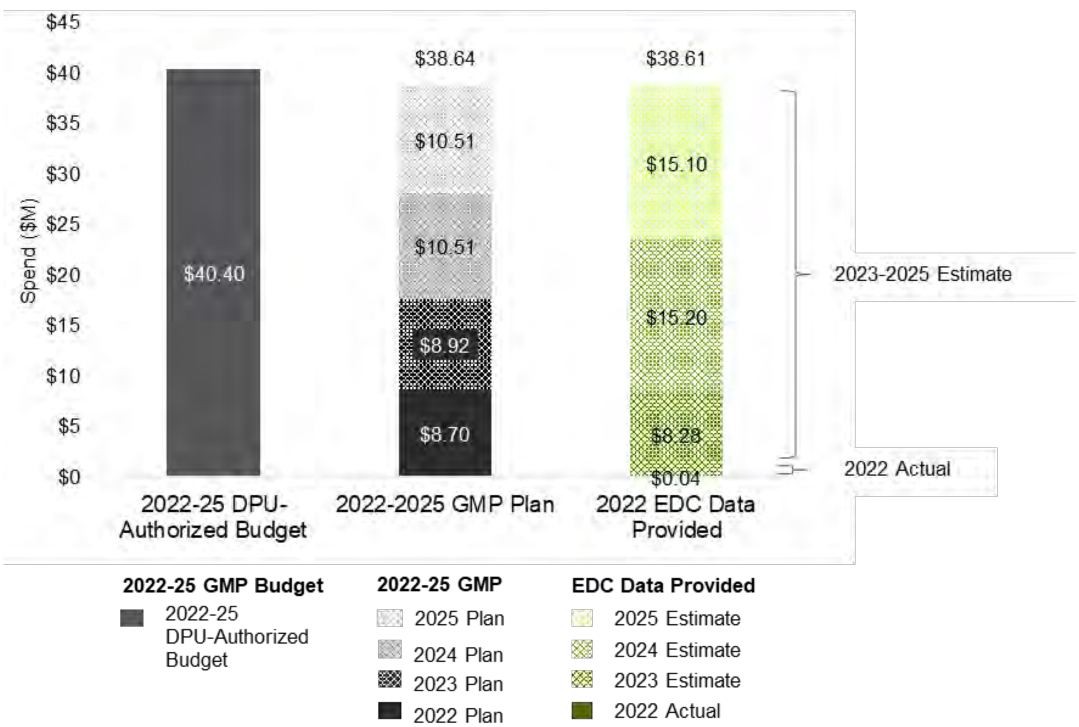
VVO Enablement

- Eversource completed deployment of VVO at four of its six Term 1 plan substations (Agawam, Piper, Podick, and Silver) by the end of 2021, and conducted On/Off testing at these substations throughout 2022. Eversource stopped VVO On/Off testing on these four substations in May 2023, transitioning towards leaving VVO in its enabled state moving forward. Meanwhile, the Gunn and Oswald substations will be VVO enabled in 2023, with On/Off testing to begin shortly thereafter.

#### *3.2.2.6 Term 2 VVO Deployment Plan Progression*

Figure 11 shows how Eversource's Term 2 VVO deployment spend has progressed since the Term 2 GMP was approved in late 2022.

**Figure 11. Term 2 Eversource VVO Planned vs. Actual Spend (2022–2025, $M)**



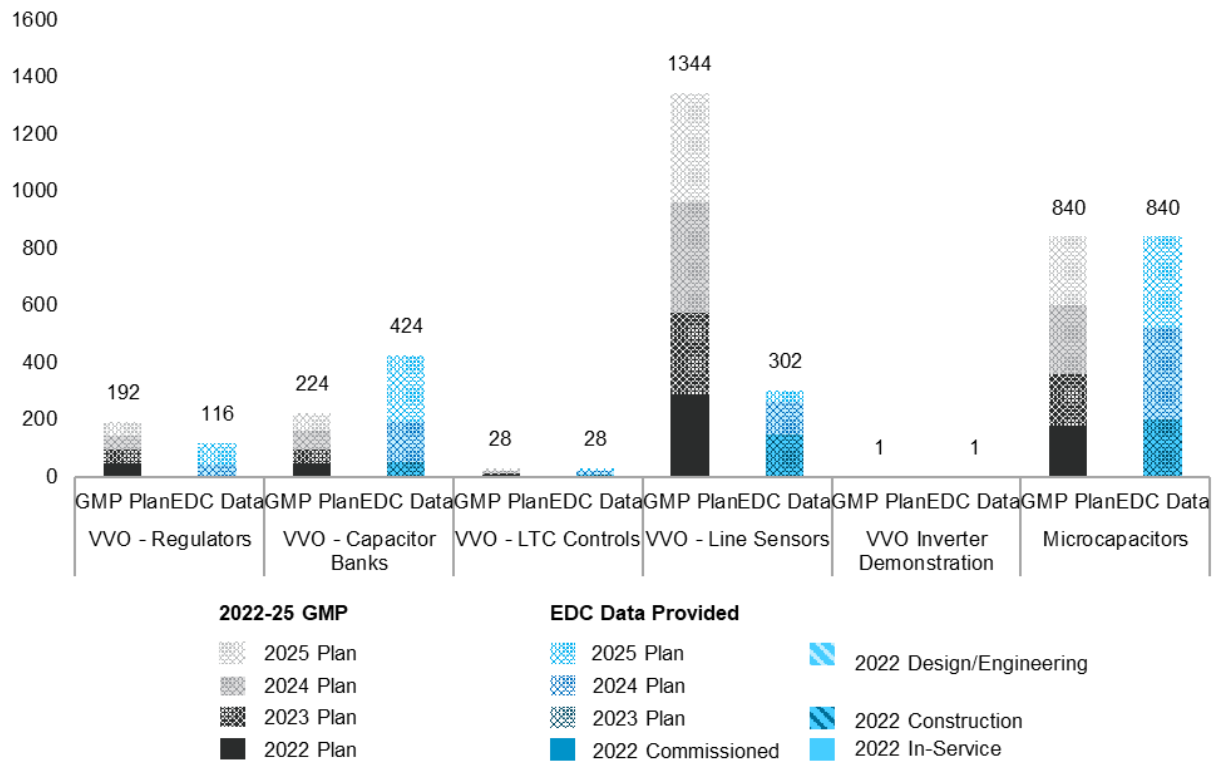

*Source: Guidehouse analysis of DPU Order on Previously Deployed Technologies (October 7, 2022), 2021 DOER Responses,* and *2022 EDC Data*

Eversource progress on VVO investments targeted for 2022 through 2025 was comprised of progressing engineering/design work for all VVO device types. Spend on Term 2 investments amounted to $0.04M, short of the $8.70M that was initially planned for 2022. Lower deployment and spend relative to plans can primarily be attributed to the timing of the DPU's rulings on Track 1 investments (Oct. 7, 2022) and Track 2 investments (Nov. 30, 2022). Engineering / design work conducted in 2022 enabled Eversource to begin submitting material orders once DPU decision was released. Given limited deployment and spend on Term 2 investments in 2022, as well as ongoing vendor delays in fulfilling material orders, Eversource has adjusted plans for the remainder of Term 2. In 2023, Eversource will be conducting additional design work, submitting material orders, and, when material orders are received, deploying VVO investments. To account for ongoing vendor delays, Eversource has projected that the majority of deployment and spend activity will occur in 2024 and 2025.

#### *3.2.2.7 Term 2 VVO Device Type Progress through PY 2022*

Figure 12 shows planned versus actual device deployment progress for PY 2022, as well as planned investment for PY 2023 through PY 2025.

**Figure 12. Term 2 Eversource Planned vs Actual Deployment (2022-2025, Unit Count)**




*Source: Guidehouse analysis of 2021 DOER Responses and 2022 EDC Data*

The EDC Data presented in Figure 12 is also shown in tabular form in Table 48 to provide the specific deployment units in each category.

**Table 48. Term 2 Eversource VVO Deployment Progress**

| | VVO - Regulators | VVO - Capacitor Banks | VVO - LTC Controls | VVO - Line Sensors | VVO - Inverter Demo | Micro-capacitors |
|---|---|---|---|---|---|---|
| **2022-2025 Planned Deployment** | **116** | **424** | **28** | **302** | **1** | **840** |
| PY 2025 Planned | 72 | 234 | 10 | 39 | 0 | 320 |

| | VVO - Regulators | VVO - Capacitor Banks | VVO - LTC Controls | VVO - Line Sensors | VVO - Inverter Demo | Micro-capacitors |
|---|---|---|---|---|---|---|
| PY 2024 Planned | 44 | 140 | 10 | 117 | 0 | 320 |
| PY 2023 Planned | 0 | 50 | 8 | 146 | 1 | 200 |
| Commissioned in PY 2022 | 0 | 0 | 0 | 0 | 0 | 0 |
| In-Service during PY 2022 | 0 | 0 | 0 | 0 | 0 | 0 |
| Construction during PY 2022 | 0 | 0 | 0 | 0 | 0 | 0 |
| Engineering/Design during PY 2022 | **116** | **424** | **28** | **302** | **1** | **840** |

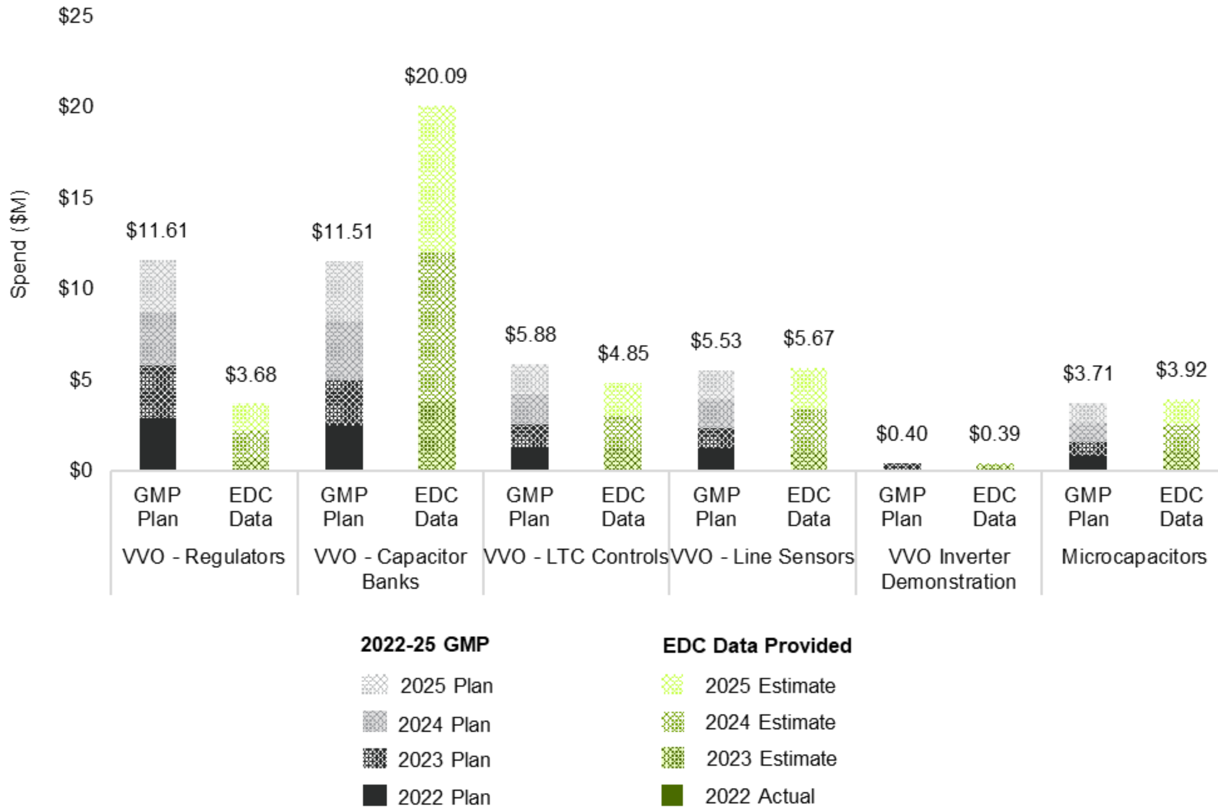
*Source: Guidehouse analysis of 2021 DOER Responses and 2022 EDC Data*

During PY 2022, Eversource was not able to deploy VVO investments targeted for Term 2. Work on Term 2 investments was focused on engineering/design, as well as identification of substations to receive VVO during Term 2. Engineering/design work conducted in 2022 enabled Eversource to begin submitting material orders once DPU decisions were released in late 2022.

Since Eversource filed its 2022-2025 GMP, planned deployment has declined for Regulators, Line Sensors, and Microcapacitors. Meanwhile, planned deployment for LTC controls has not changed, and Capacitor Bank planned deployment has increased slightly. Capacitor Bank deployment has been revised upwards to reflect refinements made during the planning and design process, which placed more priority on Capacitor Banks, less on Regulators, for VVO operation. Vendor delays continued through 2022, with average lead times for Regulators and Capacitor Banks at around 56 weeks. Eversource has adjusted plans to conduct the most deployment in 2024 and 2025 to account for ongoing vendor delays and ongoing design work.

Figure 13 shows Eversource's corresponding planned versus actual spend for PY 2022, as well as planned investment for PY 2023 through PY 2025, broken out by device type.

**Figure 13. Term 2 Eversource VVO Spend Plan vs. Actual (2022-2025, $M)**




*Source: Guidehouse analysis of 2021 DOER Responses and 2022 EDC Data*

The EDC Data presented in Figure 13 is also shown in Table 49 to provide the specific dollar spend in each category.

**Table 49. Term 2 Eversource Total Spend Comparison (2022-2025, $M)**

| | VVO - Regulators | VVO - Capacitor Banks | VVO - LTC Controls | VVO - Line Sensors | VVO - Inverter Demo | Micro-capacitors |
|---|---|---|---|---|---|---|
| **2022-2025 Total** | **$3.68** | **$20.09** | **$4.85** | **$5.67** | **$0.39** | **$3.92** |
| PY 2025 Estimate | $1.50 | $8.10 | $1.80 | $2.30 | $0.00 | $1.40 |
| PY 2024 Estimate | $1.50 | $8.10 | $1.80 | $2.30 | $0.10 | $1.40 |
| PY 2023 Estimate | $0.68 | $3.88 | $1.23 | $1.07 | $0.29 | $1.12 |
| PY 2022 Actual | $0.00 | $0.01 | $0.02 | $0.00 | $0.00 | $0.00 |

*Source: Guidehouse analysis of 2021 DOER Responses and 2022 EDC Data*

Eversource has reduced planned spend for Regulators while increasing planned spend for Capacitor Banks. This shift in planned spend is consistent with a shift in deployment plans for Regulators and Capacitor Banks. However, Eversource has not changed planned spend for Line Sensors, despite a marked reduction in planned deployment of Line Sensors. In response to vendor delays and design work being in progress for numerous device types, Eversource has reduced spend plans for 2023, increased spend plans for 2024 and 2025.

### *3.2.2.8 Term 2 Infrastructure Metrics Results and Key Findings*

Table 50 and Table 51 present the Infrastructure Metrics results through PY 2022 for each device type in Eversource's VVO Investment Area.

**Table 50. Term 2 2022 Eversource Infrastructure Metrics for VVO Devices**

| Infrastructure Metrics | | | VVO - Regulators | VVO - Capacitor Banks | VVO - LTC Controls | VVO - Line Sensors | VVO Inverter Demo | Micro-capacitors |
|---|---|---|---|---|---|---|---|---|
| GMP Plan Total, 2022-2025 | | # Devices Planned | 192 | 224 | 28 | 1344 | 1 | 840 |
| | | Spend, $M | $11.61 | $11.51 | $5.88 | $5.53 | $0.40 | $3.71 |
| EDC Data Total, 2022-2025 | | # Devices Planned | 116 | 424 | 28 | 302 | 1 | 840 |
| | | Spend, $M | $3.68 | $20.09 | $4.85 | $5.67 | $0.39 | $3.92 |
| IM-4 | Number of devices or other technologies deployed thru. PY 2022 | # Devices Deployed | 0 | 0 | 0 | 0 | 0 | 0 |
| | | % Devices Deployed | 0% | 0% | 0% | 0% | 0% | 0% |
| IM-5 | Cost for Deployment thru PY 2022 | Total Spend, $M | $0.00 | $0.01 | $0.02 | $0.00 | $0.00 | $0.00 |
| | | % Spend | 0% | 0% | 0% | 0% | 0% | 0% |

| Infrastructure Metrics | | | VVO - Regulators | VVO - Capacitor Banks | VVO - LTC Controls | VVO - Line Sensors | VVO Inverter Demo | Micro-capacitors |
|---|---|---|---|---|---|---|---|---|
| IM-6 | Deviation Between Actual and Planned Deployment for PY 2022 | % On Track (Devices) | 0% | 0% | 0% | 0% | N/A | 0% |
| | | % On Track (Spend) | 0% | 0% | 2% | 0% | N/A | N/A |
| IM-7 | Projected Deployment for the Remainder of the GMP Term* | # Devices Remaining | 116 | 424 | 28 | 302 | 1 | 840 |
| | | Spend Remaining, $M | $3.68 | $20.08 | $4.83 | $5.67 | $0.39 | $3.92 |

*The metric names have been slightly changed here to clarify the time span used in analysis.

*Source: Guidehouse analysis of 2021 DOER Responses and 2022 EDC Data*

**Table 51. Term 2 2022 Eversource Infrastructure Metrics for VVO Feeders**

| IM | Metric | Parameter* | Number of Feeders |
|---|---|---|---|
| IM-4 | Number of Devices/Technologies Deployed | # Feeders with VVO Enabled | 0 |
| | | % Feeders with VVO Enabled | 0% |
| IM-6 | Deviation Between Actual and Planned Deployment | % On Track (Feeders with VVO Enabled) | 0% |
| IM-7 | Projected Deployment for the Remainder of the GMP Term | # Feeders Remaining for VVO Enablement | 95 |

Note: This table considers Term 2 plan feeders for Eversource. Feeders currently projected to receive VVO capability during Term 2 may be found in Table 31.

* VVO Enabled denotes that the VVO system is commissioned and VVO is engaged. Feeders presented with VVO enabled may not be actively employing CVR.

*Source: Guidehouse analysis of 2021 DOER Responses and 2022 EDC Data*

Guidehouse's review of Eversource's VVO progress revealed that Eversource were below planned spend and deployment outlined in their 2022-2025 GMP. Key findings related to Eversource's progress include:

Device Deployment

- During PY 2022, Eversource was not able to deploy VVO investments targeted for Term 2. Lower deployment and spend relative to plans can primarily be attributed to the timing of the DPU's rulings on Track 1 investments (Oct. 7, 2022) and Track 2 investments (Nov. 30, 2022). Eversource progress on VVO investments targeted for 2022 through 2025 was comprised of progressing engineering/design work for all VVO device types, as well as planning for future VVO deployments. Engineering/design work conducted in 2022 enabled Eversource to begin submitting material orders once DPU decisions were released in late 2022.
- Given limited deployment and spend on Term 2 investments in 2022, as well as ongoing vendor delays in fulfilling material orders, Eversource has adjusted plans for the remainder of Term 2. In 2023, Eversource will be conducting additional design work, submitting material orders, and, when material orders are received, deploying VVO investments. To account for ongoing vendor delays, Eversource has projected that the majority of deployment and spend activity will occur in 2024 and 2025.

- In addition to an accelerated deployment timeline as compared to its 2022-2025 GMP, planned deployment has declined for Regulators, Line Sensors, and Microcapacitors. Meanwhile, Capacitor Bank deployment has been revised upwards to reflect refinements made during the planning and design process, which placed more priority on Capacitor Banks, less on Regulators, for VVO operation.

Total Spend

- Spend on Term 2 investments amounted to $0.04M, short of the $8.70M that was initially planned for 2022. Given limited deployment and spend on Term 2 investments in 2022, as well as ongoing vendor delays in fulfilling material orders, Eversource has adjusted plans for the remainder of Term 2. In 2023, Eversource will be conducting additional design work, submitting material orders, and, when material orders are received, deploying VVO investments. Eversource has projected that most spend activity will occur in 2024 and 2025.
- Consistent with shifts in planned deployment for Regulators and Capacitor Banks, Eversource has reduced planned spend for Regulators while increasing planned spend for Capacitor Banks.

VVO Enablement:

- For its Term 2 substations, Eversource is currently in the VVO Investment phase, and is conducting engineering / design work for the selected substations. Eversource anticipates completing deployment during 2024 and 2025. Once VVO investments are deployed, Eversource plans to conduct VVO On/Off testing, with testing start dates ranging from July 2024 through July 2025. Once VVO On/Off testing has begun, Eversource anticipates conducting this testing for 9 – 12 months to collect one summer, one winter, and one shoulder season of testing data.

### 3.2.3 National Grid

This section discusses National Grid's planned and actual VVO investment progress through PY 2022.

#### *3.2.3.1 Overview of GMP Deployment Plan*

During Term 1, National Grid completed deployment of VVO investments across the East Methuen, Stoughton, and Maplewood substations, amounting to 20 feeders. For Term 2, National Grid has currently identified 52 feeders for VVO investment. National Grid selected substations for VVO primarily based on whether they yielded the greatest customer savings. Other considerations in the selection process included the future or ongoing planned work scopes, resourcing availability, and a load flow and power quality analysis.

Table 52 and Table 53 summarize the planned and actual deployment and spending on VVO as of the end of 2022. In 2022, National Grid had identified 52 feeders to receive VVO functionality during Term 2. As of the end of 2022, National Grid has enabled VVO at 18 feeders, 35% of the feeders outlined in its Term 2 plans. To date, National Grid has spent roughly 10% of its Term 2 planned spend of $76.44M.

**Table 52. Term 2 National Grid Cumulative VVO Feeder Deployment Year-over-Year Comparison**

| Data | 2022 | 2023 | 2024 | 2025 | 2022-2025 |
|---|---|---|---|---|---|
| EDC Actual Progress | 18 | N/A | N/A | N/A | N/A |
| EDC Plan | 52 | N/A | N/A | N/A | N/A |
| % EDC Actual Progress/EDC Plan | 35% | N/A | N/A | N/A | N/A |

Note: Due to rounding error, manual calculations of % EDC Actual Progress / EDC Plan will not precisely match calculated numbers provided in this table.

*Source: Guidehouse analysis of 2022-2025 GMPs and 2022 EDC Data*

**Table 53. Term 2 National Grid Cumulative VVO Investment Year-over-Year Comparison ($M)***

| Data | 2022 | 2023 | 2024 | 2025 | 2022-2025 |
|---|---|---|---|---|---|
| EDC Actual Progress | $7.6 | N/A | N/A | N/A | N/A |
| EDC Plan | $76.4 | N/A | N/A | N/A | N/A |
| % EDC Actual Progress/EDC Plan | 10% | N/A | N/A | N/A | N/A |

Note: Due to rounding error, manual calculations of % EDC Actual Progress / EDC Plan will not precisely match calculated numbers provided in this table.

*Source: Guidehouse analysis of 2021 Responses to DOER IRs and 2022 EDC Data*

Table 54 highlights National Grid VVO feeder characteristics as of the end of 2022. Feeder lengths and customer counts vary considerably across VVO feeders. Selected substations also present a mix of distributed generation capacity across feeders, with distributed generation capacity ranging from 0.6 MW to 7.9 MW. Appendix A contains additional information related to the VVO feeders.

**Table 54. Term 1 2022 National Grid VVO Feeder Characteristics**

| Substation | Feeder | Feeder Length (mi.) | Customer Count | Annual Peak Load (MVA) | Distributed Generation (MW) |
|---|---|---|---|---|---|
| **Original 2018–2020 Plan Feeders** | | | | | |
| **East Methuen (13.2 kV)** | **74L1** | 39 | 3,088 | 12.1 | 5.9 |
| | **74L2** | 17 | 1,574 | 6.7 | 0.9 |
| | **74L3** | 20 | 3,355 | 8.2 | 2.0 |
| | **74L4** | 9 | 1,609 | 6.6 | 1.2 |
| | **74L5** | 55 | 3,162 | 10.7 | 1.3 |
| | **74L6** | 8 | 1,781 | 5.0 | 0.7 |
| **Stoughton (13.8 kV)** | **913W17** | 14 | 1,350 | 5.5 | 1.8 |
| | **913W18** | 12 | 1,504 | 4.6 | 0.7 |
| | **913W43** | 32 | 2,132 | 7.1 | 1.5 |
| | **913W47** | 16 | 1,796 | 5.8 | 0.6 |
| | **913W67** | 13 | 755 | 3.0 | 1.0 |
| | **913W69** | 32 | 3,603 | 9.9 | 1.7 |
| **Maplewood** | **16W1** | 17 | 3,683 | 9.6 | 1.4 |

| Substation | Feeder | Feeder Length (mi.) | Customer Count | Annual Peak Load (MVA) | Distributed Generation (MW) |
|---|---|---|---|---|---|
| (13.8 kV) | 16W2 | 11 | 4,674 | 8.6 | 1.1 |
| | 16W3 | 13 | 3,352 | 7.6 | 0.7 |
| | 16W4 | 8 | 1,131 | 9.2 | 0.9 |
| | 16W5 | 7 | 1,710 | 5.7 | 1.0 |
| | 16W6 | 24 | 5,627 | 14.3 | 2.0 |
| | 16W7 | 14 | 3,891 | 10.9 | 2.0 |
| | 16W8 | 16 | 3,427 | 9.6 | 1.9 |
| | | | | | |
| East Bridgewater (13.8 kV) | 797W1 | 36 | 2,821 | 10.4 | 1.4 |
| | 797W19 | 38 | 2,563 | 8.3 | 2.8 |
| | 797W20 | 31 | 1,717 | 9.7 | 0.6 |
| | 797W23 | 41 | 2,650 | 9.7 | 1.7 |
| | 797W24 | 54 | 2,583 | 9.7 | 1.5 |
| | 797W29 | 37 | 2,338 | 8.3 | 2.7 |
| | 797W42 | 21 | 1,239 | 4.5 | 1.9 |
| East Dracut (13.2 kV) | 75L1 | 17 | 3,041 | 7.6 | 1.0 |
| | 75L2 | 39 | 2,613 | 8.4 | 1.1 |
| | 75L3 | 50 | 2,328 | 9.7 | 2.3 |
| | 75L4 | 9 | 387 | 3.3 | 0.2 |
| | 75L5 | 19 | 3,556 | 7.7 | 1.1 |
| | 75L6 | 25 | 1,485 | 6.5 | 0.9 |
| Easton (13.8 kV) | 92W43 | 28 | 1,973 | 7.1 | 1.2 |
| | 92W44 | 26 | 1,779 | 9.0 | 1.3 |
| | 92W54 | 34 | 2,284 | 7.3 | 7.9 |
| | 92W78 | 38 | 1,993 | 7.9 | 0.9 |
| | 92W79 | 24 | 1,655 | 6.4 | 5.3 |
| Melrose (13.8 kV) | 25W1 | 19 | 1,575 | 6.1 | 2.3 |
| | 25W2 | 17 | 1,245 | 6.1 | 0.8 |
| | 25W3 | 9 | 729 | 8.3 | 0.8 |
| | 25W4 | 22 | 4,770 | 11.5 | 1.3 |
| | 25W5 | 20 | 3,832 | 11.4 | 1.4 |
| Westboro (13.8 kV) | 312W1 | 30 | 2,278 | 9.8 | 2.0 |
| | 312W2 | 9 | 177 | 6.0 | 3.0 |
| | 312W3 | 21 | 1,492 | 8.0 | 0.9 |
| | 312W4 | 54 | 2,625 | 9.0 | 5.5 |
| | 312W5 | 14 | 424 | 9.6 | 0.9 |
| West Salem (13.8 kV) | 29W1 | 23 | 3,788 | 10.7 | 2.4 |
| | 29W2 | 16 | 1,653 | 6.0 | 0.7 |
| | 29W3 | 15 | 4,286 | 10.3 | 1.4 |
| | 29W4 | 18 | 2,700 | 8.2 | 2.1 |
| | 29W5 | 12 | 2,915 | 10.5 | 1.3 |
| | 29W6 | 17 | 1,426 | 6.8 | 1.3 |

Note: Values presented in this table were published on April 24, 2023 and are reflective of data collected through the end of 2022.
*Source: 2022 GMP Annual Report, Appendix 1 filed April 24, 2023.*

### *3.2.3.2 VVO Timeline*

Table 55 and Table 56 summarize substation-specific progress in each of the four VVO investment phases. The evaluation of Infrastructure Metrics spans spending and deployment under the VVO investment and VVO commissioning stages.

**Table 55. National Grid Combined Plan Feeders Deployment Completion Dates**

| Substation | VVO Investment | VVO Commissioning | VVO Enabled Date | VVO On/Off Testing Period |
|---|---|---|---|---|
| **Term 1 Plan Substations** | | | | |
| **E. Methuen** | 2/1/2020 - 8/31/2020 (Complete) | 7/27/2020 - 1/22/2021 (Complete) | 2/8/2021 (Complete) | 3/1/2021 - 1/6/2023 (Complete) |
| **Maplewood** | 1/15/2020 - 8/31/2020 (Complete) | 9/1/2021 - 12/15/2021 (Complete) | 12/16/2021 (Complete) | 12/16/2021 - TBD (In-Progress) |
| **Stoughton** | 11/15/2019 - 3/31/2020 (Complete) | 5/1/2020 - 7/23/2020 (Complete) | 7/24/2020 (Complete) | 12/1/2020 - 9/15/2021 (Complete) |
| **Term 2 Plan Substations** | | | | |
| **Billerica** | 1/1/2022 - 7/1/2023 (in progress) | 1/1/2023 - 8/1/2023 (planned) | 9/1/2023 (in progress) | TBD (in progress) |
| **Depot Street** | 1/1/2022 - 7/1/2023 (in progress) | 1/1/2023 - 8/1/2023 (planned) | 9/1/2023 (in progress) | TBD (in progress) |
| **E. Bridgewater** | 5/15/2020 - 6/1/2021 (Complete) | 6/1/2021 - 7/29/2021 (Complete) | 7/29/2021 (Complete) | 7/30/2021 - 1/6/2023 (Complete) |
| **E. Dracut** | 1/1/2021 - 12/15/2022 (Complete) | 12/15/2022 - 3/1/2023 (Planned) | 3/1/2023 (Planned) | 3/1/2023 - 2/1/2024 (Planned) |
| **Easton** | 1/1/2021 - 6/13/2022 (Complete) | 6/13/2022 - 12/1/2022 (Complete) | 12/1/2022 (Complete) | 12/31/2022 - 12/31/2023 (In-Progress) |
| **Melrose** | 1/1/2021 – TBD (In-Progress) | 3/1/2023 - 4/1/2023 (Planned) | 5/1/2023 (Planned) | TBD (Planned) |
| **Parkview** | 1/1/2022 - 7/1/2023 (in progress) | 1/1/2023 - 8/1/2023 (planned) | 9/1/2023 (in progress) | TBD (in progress) |

| Substation | VVO Investment | VVO Commissioning | VVO Enabled Date | VVO On/Off Testing Period |
|---|---|---|---|---|
| **Westboro** | 1/1/2021 – 10/17/2022 (In-Progress) | 10/17/2022 - 3/31/2023 (In-Progress) | 3/31/2023 (Planned) | TBD (Planned) |
| **W. Salem** | 1/1/2021 - 5/1/2022 (Complete) | 5/1/2022 - 6/1/2022 (Complete) | 6/1/2022 (Complete) | 6/1/2022 - TBD (In-Progress) |

*Source: Guidehouse analysis of 2022 EDC Data*

**Table 56. 2022 National Grid VVO Enabled Progress by Substation**

| Substation | January 2022 Planned/Actual VVO Enabled Date | January 2023 Planned/Actual VVO Enabled Date | Current Status[46] |
|---|---|---|---|
| **Term 1 Plan Feeders** | | | |
| **E. Methuen** | 2/8/2021 (actual) | 2/8/2021 (actual) | VVO On/Off Testing complete |
| **Maplewood** | 12/16/2021 (actual) | 12/16/2021 (actual) | VVO On/Off testing in progress |
| **Stoughton** | 7/24/2020 (actual) | 7/24/2020 (actual) | VVO On/Off Testing complete |
| **Term 2 Plan Feeders** | | | |
| **Billerica** | N/A | 9/1/2023 (planned) | VVO Investment in-progress |
| **Depot Street** | N/A | 9/1/2023 (planned) | VVO Investment in-progress |
| **E. Bridgewater** | 7/29/2021 (actual) | 7/29/2021 (actual) | VVO On/Off Testing complete |
| **E. Dracut** | 6/1/2022 (planned) | 3/1/2023 (planned) | VVO Investment complete |
| **Easton** | 11/15/2022 (planned) | 12/1/2022 (actual) | VVO On/Off testing in progress |
| **Melrose** | 11/15/2022 (planned) | 5/1/2023 (planned) | VVO Investment in progress |
| **Parkview** | N/A | 9/1/2023 (planned) | VVO Investment in-progress |
| **Westboro** | 11/15/2022 (planned) | 3/31/2023 (planned) | Commissioning in progress |
| **W. Salem** | 6/1/2022 (planned) | 6/1/2022 (actual) | VVO On/Off testing in progress |

*Source: Guidehouse analysis of 2021 and 2022 EDC VVO supplemental data submissions*

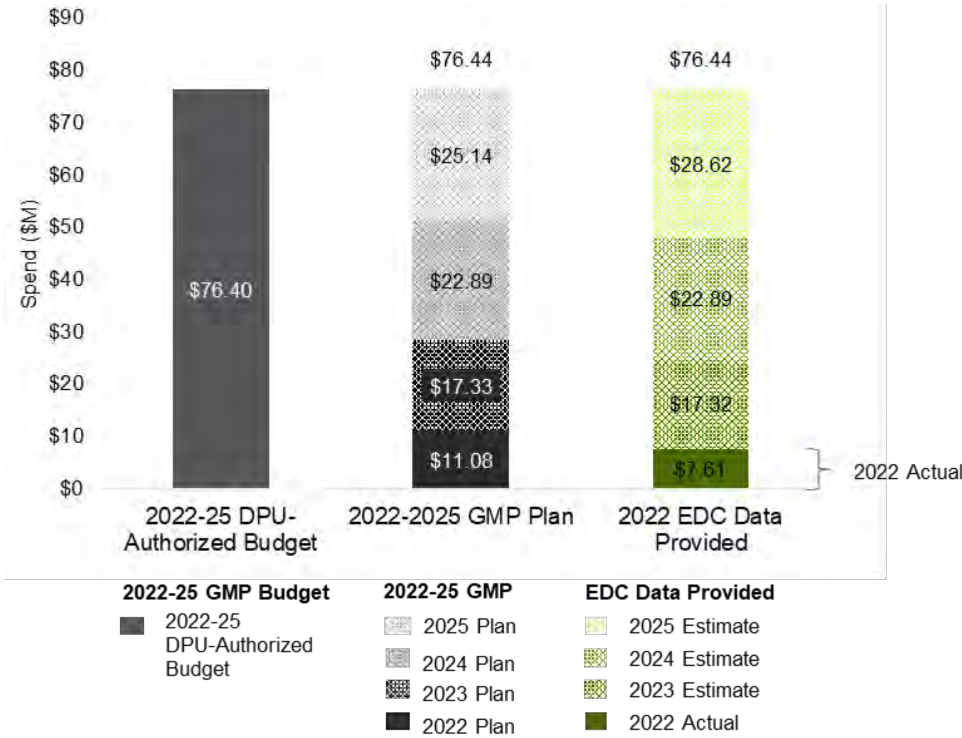
National Grid conducted VVO On/Off testing at its East Methuen and Maplewood Term 1 substations throughout 2022. Among its Term 2 substations, National Grid conducted On/Off testing at the East Bridgewater substation throughout 2022, as VVO deployment was completed at the substation in 2021. Additionally, National Grid completed VVO deployment at the Easton and West Salem substations and began VVO On/Off for these substations in winter 2022/23 and spring 2022, respectively. National Grid projects that it will complete VVO deployment and enable VVO at its remaining Term 2 substations in 2023.

### *3.2.3.3 Term 2 VVO Deployment Plan Progression*

Figure 14 shows how National Grid's Term 2 VVO deployment spend has progressed in 2022.

[46] Status can be: planning, design, construction, device deployment complete, VVO commissioning in process, or VVO enabled. VVO Enabled denotes that the VVO system is commissioned and VVO is engaged. Feeders presented with VVO enabled may not be actively employing CVR.

**Figure 14. Term 2 National Grid's VVO Planned and Actual Spend Progression, $M**




Note: To more closely align spend projections with DPU pre-authorized budgets, National Grid operations and maintenance (O&M) spend is included in actual and planned spend presented here. O&M spend is provided in aggregate for each investment area and is therefore excluded from device-specific summaries of spend.

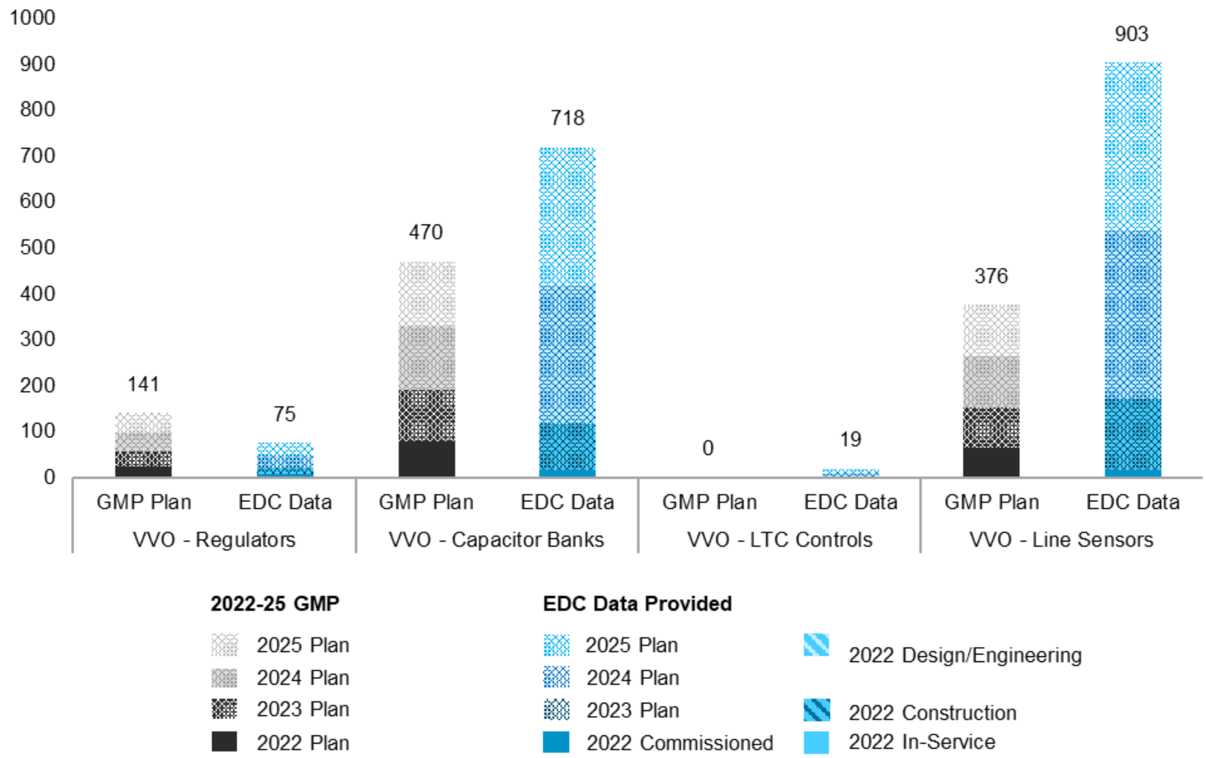
*Source: Guidehouse analysis of DPU Order (October 7, 2022), DOER Responses* and *2022 EDC Data*

National Grid spend and deployment were below plans for 2022, and progress was affected by a number of factors. National Grid's resourcing constraints led to shortfall of in-house planning and engineering resources to draw on, so National Grid needed to supplement in-house resources with incremental resources to maintain GMP progress. In addition, National Grid's previous line sensor vendor discontinued their model, requiring identification of a new vendor. In some cases, work that had previously passed the engineering/design phase required re-design. Lastly, procuring materials continues to be a difficult task for National Grid. Longer vendor lead times, present during PY 2021, continued into PY 2022, with Line Sensors and Regulators most affected by delays.

### *3.2.3.4 Term 2 VVO Investment Progress through PY 2022*

Figure 15 and Table 57 show planned versus actual device deployment progress for PY 2022, as well as planned investment for PY 2023 through PY 2025.

**Figure 15. Term 2 National Grid VVO Device Deployment (2022–2025)**




*Source: Guidehouse analysis of 2021 DOER Responses and 2022 EDC Data*

**Table 57. Term 2 National Grid VVO Planned and Actual Device Deployment (2022-2025)**

| | VVO - Regulators | VVO - Capacitor Banks | VVO - LTC Controls | VVO - Line Sensors |
|---|---|---|---|---|
| **2022-2025 Planned Deployment** | **75** | **718** | **19** | **903** |
| PY 2025 Planned | 27 | 300 | 8 | 365 |
| PY 2024 Planned | 27 | 300 | 8 | 365 |
| PY 2023 Planned | 12 | 102 | 3 | 156 |
| Commissioned in PY 2022 | 9 | 16 | 0 | 17 |
| In-Service during PY 2022 | 0 | 54 | 0 | 0 |
| Construction during PY 2022 | 3 | 57 | 0 | 26 |
| Engineering/Design during PY 2022 | 9 | 25 | 0 | 3 |

*Source: Guidehouse analysis of 2022 EDC Data*

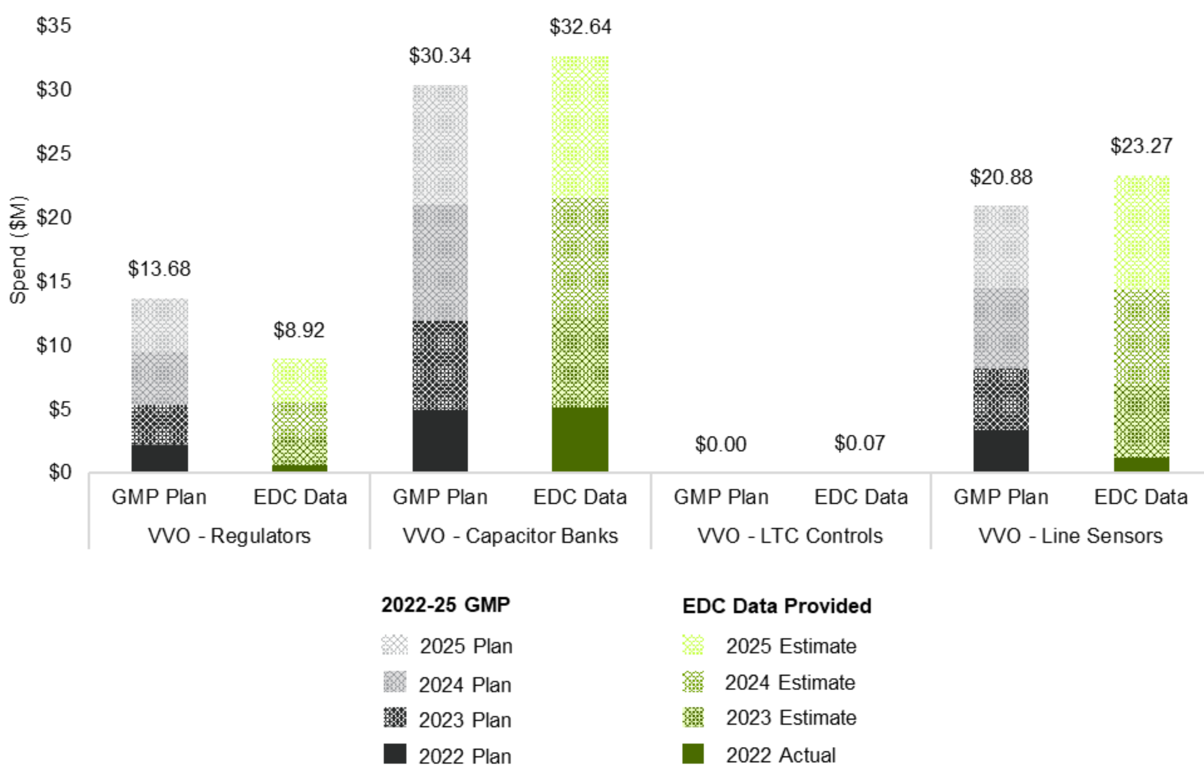
During PY 2022, National Grid deployed fewer devices than initially planned. National Grid deployed 20% of Capacitor Banks, 27% of Line Sensors, and 38% of Regulators that were initially planned for deployment during 2022. A late-2022 DPU decision, resource constraints, and vendor lead times were all key contributors to this outcome.

To account for a shortfall in deployment, National Grid has accelerated its deployment timeline for 2023 through 2025. Process improvements have increased rate of progress, which will enable National Grid to continue progressing with VVO deployment on this accelerated timeline. However, meeting deployment goals will require engineering/design and construction work on devices to be accelerated. National Grid will also need to coordinate schedules with vendors to ensure material orders can be fulfilled on its accelerated deployment schedule.

In addition to accelerating deployment plans for 2023 through 2025, National Grid has adjusted deployment plans for numerous device types. Similar to Eversource, National Grid has increased projected deployment for Capacitor Banks while reducing projected deployment for Regulators. In addition, National Grid has increased deployment plans for Line Sensors and LTC Controls. National Grid cites that these revisions are primarily due to the VVO planning work that has been conducted since the 2022-2025 GMP was filed.

Figure 16 shows National Grid's planned versus actual spend for PY 2022, as well as planned investment for PY 2023 through PY 2025.

**Figure 16. Term 2 National Grid VVO Plan vs. Actual (2022–2025, $M)**




Note: O&M spend is provided in aggregate for each investment area and is therefore excluded from device-specific summaries of spend.

*Source: Guidehouse analysis of 2021 DOER Responses and 2022 EDC Data*

The EDC Data presented in Figure 16 is also shown in Table 58 to provide the specific dollar spend in each category.

**Table 58. Term 2 National Grid Total Spend Comparison (2022–2025, $M)**

| | VVO - Regulators | VVO - Capacitor Banks | VVO - LTC Controls | VVO - Line Sensors |
|---|---|---|---|---|
| **2022-2025 Planned Spend** | **$8.92** | **$32.64** | **$0.07** | **$23.27** |
| PY 2025 Planned | $3.35 | $11.17 | $0.00 | $8.94 |
| PY 2024 Planned | $2.78 | $9.27 | $0.00 | $7.42 |
| PY 2023 Planned | $2.13 | $7.09 | $0.00 | $5.67 |
| PY 2022 Actual | $0.66 | $5.11 | $0.07 | $1.24 |

Note: O&M spend is provided in aggregate for each investment area and is therefore excluded from device-specific summaries of spend.

*Source: Guidehouse analysis of 2021 DOER Responses and 2022 EDC Data*

National Grid spend on VVO ($7.6M) was below plans for 2022 ($11.1M). The majority of spend occurred on Capacitor Banks ($5.1M), while spend on Regulators and Line Sensors was well below plans. Lower-than-anticipated spend on Line Sensors can, in part, be attributed to National Grid's previous line sensor vendor discontinuing their selected model. In response, National Grid identified a new vendor for its Line Sensors, but National Grid needed to restart some work that had previously passed the engineering/design phase. For VVO Regulators, National Grid cites that vendor delays in fulfilling material orders was a key contributor to lower spend than initially planned. In response to its 2022 experience with Line Sensors and Regulators, National Grid has begun to increase diversification of vendors that it sources materials from.

### *3.2.3.5 Term 2 Infrastructure Metrics Results and Key Findings*

Table 59 and Table 60 summarize the Term 2 Infrastructure Metrics results through PY 2022 for each investment type related to National Grid's VVO Investment Area.

**Table 59. Term 2 2022 National Grid Infrastructure Metrics Findings**

| Infrastructure Metrics | | | VVO - Regulators | VVO - Capacitor Banks | VVO - LTC Controls | VVO - Line Sensors |
|---|---|---|---|---|---|---|
| GMP Plan Total, 2022-2025 | | # Devices Planned | 141 | 470 | 0 | 376 |
| | | Spend, $M | $13.68 | $30.34 | $0.00 | $20.88 |
| EDC Data Total, 2022-2025 | | # Devices Planned | 75 | 718 | 19 | 903 |
| | | Spend, $M | $8.92 | $32.64 | $0.07 | $23.27 |
| IM-4 | Number of devices or other technologies deployed thru. PY 2022 | # Devices Deployed* | 9 | 16 | 0 | 17 |
| | | % Devices Deployed | 6% | 3% | N/A | 5% |
| IM-5 | Cost for Deployment thru PY 2022 | Total Spend, $M | $0.66 | $5.11 | $0.07 | $1.24 |
| | | % Spend | 5% | 17% | 0% | 6% |
| IM-6 | Deviation Between Actual and Planned | % On Track (Devices) | 38% | 20% | N/A | 27% |

| Infrastructure Metrics | | | VVO - Regulators | VVO - Capacitor Banks | VVO - LTC Controls | VVO - Line Sensors |
|---|---|---|---|---|---|---|
| | Deployment for PY 2022 | % On Track (Spend) | 30% | 104% | N/A | 36% |
| IM-7 | Projected Deployment for the Remainder of the GMP Term | # Devices Remaining | 66 | 702 | 19 | 886 |
| | | Spend Remaining, $M | $8.26 | $27.53 | $0.00 | $22.03 |

Note: The metric names have been slightly changed here to clarify the time span used in analysis. O&M spend is provided in aggregate for each investment area and is therefore excluded from device-specific summaries of spend.

*Note that "Deployed" here refers to commissioned devices. For full definitions of commissioned and in-service, see Docket 20-46 Response to Information Request DPU-AR-4-11, September 3, 2020.Source: Guidehouse analysis of 2021 DOER Responses and 2022 EDC Data

**Table 60. 2022 National Grid Infrastructure Metrics for VVO Feeders**

| IM | Metric | Parameter* | Number of Feeders |
|---|---|---|---|
| **Term 1 Plan Feeders** | | | |
| IM-4 | Number of Devices/Technologies Deployed | # Feeders with VVO Enabled | 20 |
| | | % Feeders with VVO Enabled | 100% |
| IM-6 | Deviation Between Actual and Planned Deployment | % On Track (Feeders with VVO Enabled) | 100% |
| IM-7 | Projected Deployment for the Remainder of the GMP Term | # Feeders Remaining for VVO Enablement | 0 |
| **Term 2 Plan Feeders** | | | |
| IM-4 | Number of Devices/Technologies Deployed | # Feeders with VVO Enabled | 18 |
| | | % Feeders with VVO Enabled | 35% |
| IM-6 | Deviation Between Actual and Planned Deployment | % On Track (Feeders with VVO Enabled) | 35% |
| IM-7 | Projected Deployment for the Remainder of the GMP Term | # Feeders Remaining for VVO Enablement | 34 |

* VVO Enabled denotes that the VVO system is commissioned and VVO is engaged. Feeders presented with VVO enabled may not be actively employing CVR.

*Source: Guidehouse analysis of EDC Data*

Guidehouse's review of National Grid's deployment and spend revealed that National Grid was below initial plans for 2022 outlined in National Grid's 2022-2025 GMP. Key findings related to National Grid's progress include:

Device Deployment

- During PY 2022, National Grid deployed fewer devices than initially planned. National Grid deployed 20% of Capacitor Banks, 27% of Line Sensors, and 38% of Regulators that were initially planned for deployment during 2022. A late-2022 DPU decision, resource constraints, analysis that fewer devices were needed, and vendor lead times were all key contributors to this outcome.
- National Grid has accelerated its deployment timeline for 2023 through 2025. Process improvements have increased rate of progress, which will enable National Grid to continue progressing with VVO deployment on this accelerated timeline. National Grid has adjusted

total deployment plans for numerous device types, increasing projected deployment for Capacitor Banks while reducing projected deployment for Regulators. In addition, National Grid has increased deployment plans for Line Sensors and LTC Controls. National Grid cites that these revisions are primarily due to the VVO planning work that has been conducted since the 2022-2025 GMP was filed.

Total Spend

- National Grid spend on VVO was below plans for 2022. The majority of spend occurred on Capacitor Banks, while spend on Regulators and Line Sensors was well below plans. Lower-than-anticipated spend on Line Sensors can, in part, be attributed to National Grid's previous line sensor vendor discontinuing their selected model. For VVO Regulators, vendor delays in fulfilling material orders was a key contributor to lower spend than initially planned. In response to its 2022 experience with Line Sensors and Regulators, National Grid has begun to increase diversification of vendors that it sources materials from.

VVO Enablement

- National Grid conducted VVO On/Off testing at its East Methuen and Maplewood Term 1 substations throughout 2022. Among its Term 2 substations, National Grid conducted On/Off testing at the East Bridgewater substation throughout 2022, as VVO deployment was completed at the substation in 2021. Additionally, National Grid completed VVO deployment at the Easton and West Salem substations and began VVO On/Off for these substations in winter 2022/23 and spring 2022, respectively. National Grid projects that it will complete VVO deployment and enable VVO at its remaining Term 2 substations in 2023.

### 3.2.4 Unitil

This section discusses Unitil's planned and actual VVO investment progress through PY 2022.

#### *3.2.4.1 Overview of GMP Deployment Plan*

***Approach to VVO***

Unitil's approach to VVO investment is unique. Unitil initially planned to enable VVO for the Townsend substation in 2019, the Lunenburg substation in 2020, and the Summer Street substation in 2021. This timeline was revised to allow Unitil to complete all grid modernization activities at a single substation before moving to another, as VVO is tied to the ADMS and M&C Investment Areas. For instance, deployment of VVO relies on the SCADA system being in place, tying the VVO deployment to the M&C Investment Area. The VVO project is also tied with the FAN deployment plan which will allow communication from the ADMS to the field devices. Given VVO progress was ultimately tied to the ADMS and M&C progress made during Term 1, Unitil ultimately revised plans to deploy VVO across 3 feeders during Term 1. Unitil met this plan, deploying VVO at the Townsend substation in 2021.

Table 61 and Table 62 summarize the planned deployment and spending on VVO from 2022 through 2025.

**Table 61. Term 2 Unitil Cumulative VVO Feeder Deployment Year-over-Year Comparison**

| Data | 2022 | 2023 | 2024 | 2025 | 2022-2025 |
|---|---|---|---|---|---|
| EDC Actual Progress | 4 | N/A | N/A | N/A | N/A |
| EDC Plan | 8 | N/A | N/A | N/A | N/A |
| % EDC Actual Progress/EDC Plan | 50% | N/A | N/A | N/A | N/A |

Note: Due to rounding error, manual calculations of % EDC Actual Progress / EDC Plan will not precisely match calculated numbers provided in this table.

*Source: Guidehouse analysis of 2022-2025 GMPs and 2022 EDC Data*

**Table 62. Unitil VVO Investment Year-over-Year Comparison ($M)***

| Data | 2022 | 2023 | 2024 | 2025 | 2022-2025 |
|---|---|---|---|---|---|
| EDC Actual Progress | $0.3 | N/A | N/A | N/A | N/A |
| EDC Plan | $5.4 | N/A | N/A | N/A | N/A |
| % EDC Actual Progress/EDC Plan | 5% | N/A | N/A | N/A | N/A |

Note: Due to rounding error, manual calculations of % EDC Actual Progress / EDC Plan will not precisely match calculated numbers provided in this table.

*Source: Guidehouse analysis of 2021 Responses to DOER IRs and 2022 EDC Data*

For Term 2, Unitil plans to deploy VVO across the Summer Street, Lunenburg, and West Townsend substations, amounting to 8 feeders. By the end of 2022, Unitil completed deployment of VVO at the Summer Street substation and its associated 4 feeders. Spend on VVO deployment has amounted to approximately $0.3M, or about 5% of planned spend for Term 2.

Table 63 highlights Unitil feeder characteristics for Term 1 and Term 2 plan feeders. Feeder lengths and customer counts vary considerably. Selected substations also present a mix of distributed generation capacity. Appendix A contains additional information related to the VVO feeders.

**Table 63. 2022 Unitil VVO Feeder Characteristics**

| Substation | Feeder | Feeder Length (mi.) | Customer Count | Annual Peak Load (MVA) | Distributed Generation (MW) |
|---|---|---|---|---|---|
| **Term 1 Feeders** | | | | | |
| **Townsend (13.8 kV)** | **15W15** | 1 | 1 | 3.9 | 0.0 |
| | **15W16** | 42 | 1,535 | 5.2 | 1.8 |
| | **15W17** | 11 | 574 | 1.5 | 0.5 |
| **Term 2 Feeders** | | | | | |
| **Lunenburg (13.8 kV)** | **30W30** | 46 | 1,428 | 5.5 | 1.8 |
| | **30W31** | 46 | 1,695 | 4.4 | 4.1 |
| **Summer Street (13.8 kV)** | **40W38** | 1 | 67 | 0.1 | 0.0 |
| | **40W39** | 8 | 369 | 5.1 | 1.1 |
| | **40W40** | 18 | 1,578 | 7.5 | 1.7 |

| Substation | Feeder | Feeder Length (mi.) | Customer Count | Annual Peak Load (MVA) | Distributed Generation (MW) |
|---|---|---|---|---|---|
| | **40W42** | 13 | 1,920 | 3.6 | 0.7 |
| **West Townsend (13.8 kV)** | **39W18** | 51 | 1,974 | 0.0 | 3.2 |
| | **39W19** | 62 | 1,336 | 3.0 | 0.0 |

Note: Values presented in this table were published on April 24, 2023 and are reflective of data collected through the end of 2022.
*Source: 2022 GMP Annual Report, Appendix 1 filed April 24, 2023*

### *3.2.4.2 VVO Timeline*

Table 64 and Table 65 summarize substation-specific progress in each of the four VVO investment phases, including anticipated and actual VVO enabled dates and notes on the current status of VVO deployment. The evaluation of Infrastructure Metrics spans spending and deployment under the VVO investment and VVO commissioning phases.

**Table 64. Unitil VVO Deployment Completion Dates by Phase and Substation**

| Phase | VVO Investment | VVO Commissioning[47] | VVO Enabled Date[48] | VVO On/Off Testing Period |
|---|---|---|---|---|
| **Term 1 Plan Substations** | | | | |
| **Townsend** | 1/1/2019 – 6/1/2021 (Complete:) | 6/1/2021 - 12/1/2021 (Complete) | 12/1/2021 (Complete) | 4/1/2023 - 3/1/2024 (Planned) |
| **Term 2 Plan Substations** | | | | |
| **Beech St.** | 1/1/2024 - 9/1/2026 (Planned:) | 9/1/2026 - 10/1/2026 (Planned:) | 11/1/2026 (Planned) | 12/1/2026 - 9/1/2027 (Planned) |
| **Lunenburg** | 1/1/2019 - 9/1/2023 (In Progress:) | 10/1/2023 - 12/1/2023 (Planned) | 1/1/2024 (Planned) | 12/1/2024 - 9/1/2025 (Planned) |
| **Pleasant St.** | 1/1/2025 - 9/1/2027 (Planned:) | 9/1/2027 - 10/1/2027 (Planned:) | 11/1/2027 (Planned) | 12/1/2027 - 9/1/2028 (Planned) |
| **Princeton Road** | 1/1/2025 - 9/1/2027 (Planned:) | 9/1/2027 - 10/1/2027 (Planned:) | 11/1/2027 (Planned) | 12/1/2027 - 9/1/2028 (Planned) |
| **Summer St.** | 1/1/2020 - 12/1/2022 (Complete:) | 5/1/2022 - 12/13/2022 (Complete) | 12/13/2022 (Complete) | 12/1/2023 - 9/1/2024 (Planned) |
| **W. Townsend** | 12/1/2020 - 11/1/2023 (In Progress:) | 10/1/2023 - 12/1/2023 (Planned) | 1/1/2024 (Planned) | 12/1/2024 - 9/1/2025 (Planned) |

*Source: Guidehouse analysis of 2022 EDC Data*

[47] VVO Commissioning is the time at which VVO devices are controlled by and have data visible to each EDC.

[48] VVO Enabled denotes that the VVO system is commissioned and VVO is engaged. Feeders presented with VVO enabled may not be actively employing CVR.

**Table 65. Unitil VVO Enabled Progress by Substation**

| Substation | January 2022 Actual/Planned VVO Enabled Date | January 2023 Actual/Planned VVO Enabled Date | Current Status[49] |
|---|---|---|---|
| **Term 1 Plan Feeders** | | | |
| Townsend | 12/1/2021 (actual) | 12/1/2021 (actual) | VVO Enabled |
| **Term 2 Plan Feeders** | | | |
| Beech St. | 11/1/2026 (planned) | 11/1/2026 (planned) | VVO Investment |
| Lunenburg | 11/1/2023 (planned) | 1/1/2024 (planned) | VVO Investment |
| Pleasant St. | 11/1/2027 (planned) | 11/1/2027 (planned) | VVO Investment |
| Princeton Road | 11/1/2027 (planned) | 11/1/2027 (planned) | VVO Investment |
| Summer St. | 11/1/2022 (planned) | 12/13/2022 (actual) | VVO Enabled |
| W. Townsend | 11/1/2024 (planned) | 11/1/2024 (planned) | VVO Investment |

*Source: Guidehouse analysis of 2021 and 2022 EDC VVO supplemental data submissions*

For its Term 1 substation (Townsend) Unitil completed VVO deployment in 2021, enabling VVO on December 1, 2021, and had expected to begin On/Off testing at the Townsend substation in April 2022. However, testing was delayed for the Townsend substation, as Unitil worked with Hitachi to improve the results from the algorithm as the quantity of Regulators and Capacitor Banks increased on a given feeder. The issue has been resolved, and VVO On/Off testing is expected to begin in spring 2023 at the Townsend substation. For Unitil's future planned deployments, Unitil has factored in the additional time needed for internal unit testing prior to formal On/Off testing.

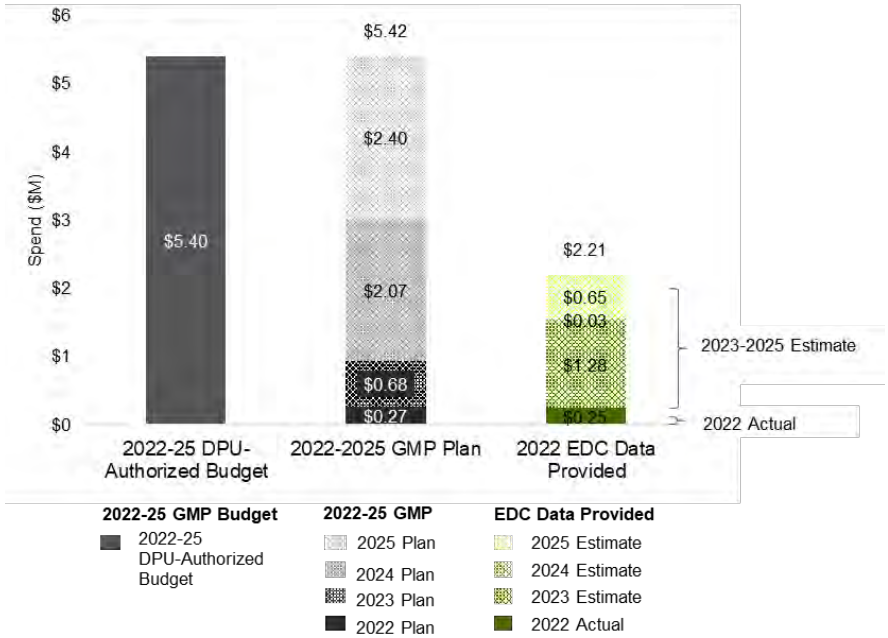
Among its Term 2 substations, Unitil completed deploying VVO investments at the Summer Street substation and enabled VVO after commissioning was completed in December 2022. VVO On/Off testing is projected to begin at the substation in December 2023. Lunenburg and West Townsend are currently receiving VVO investments and Unitil plans to enable VVO at the substations in January and November 2024, respectively. Unitil then plans to conduct On/Off testing at the substations beginning in December 2024. For its remaining substations, Unitil is currently conducting planning and engineering/design work for its Beech Street, Pleasant Street, and Princeton Road substations. These substations are expected to be enabled after the close of Term 2 in 2026 and 2027.

#### *3.2.4.3 Term 2 VVO Deployment Plan Progression*

Figure 17 shows the progression of Unitil's M&C Term 2 deployment plans from DPU pre-authorization in PY 2022 through PY 2025.

[49] Status can be: planning, design, construction, device deployment complete, VVO commissioning in process, or VVO enabled. VVO Enabled denotes that the VVO system is commissioned and VVO is engaged. Feeders presented with VVO enabled may not be actively employing CVR.

**Figure 17. Term 2 Unitil VVO Planned and Actual Spend Progression, $M**




*Source: Guidehouse analysis of DPU Order (October 7, 2022), 2021 DOER Responses* and *2022 EDC Data*

Deployment and spend for 2022 investments were approximately on-track with initial plans, with Unitil spending roughly $0.25M on VVO deployment as compared to its plan of $0.27M. Accomplishments in 2022 included resolution of LTC radio and control issues, as well as process efficiencies that brought unit costs below plans.

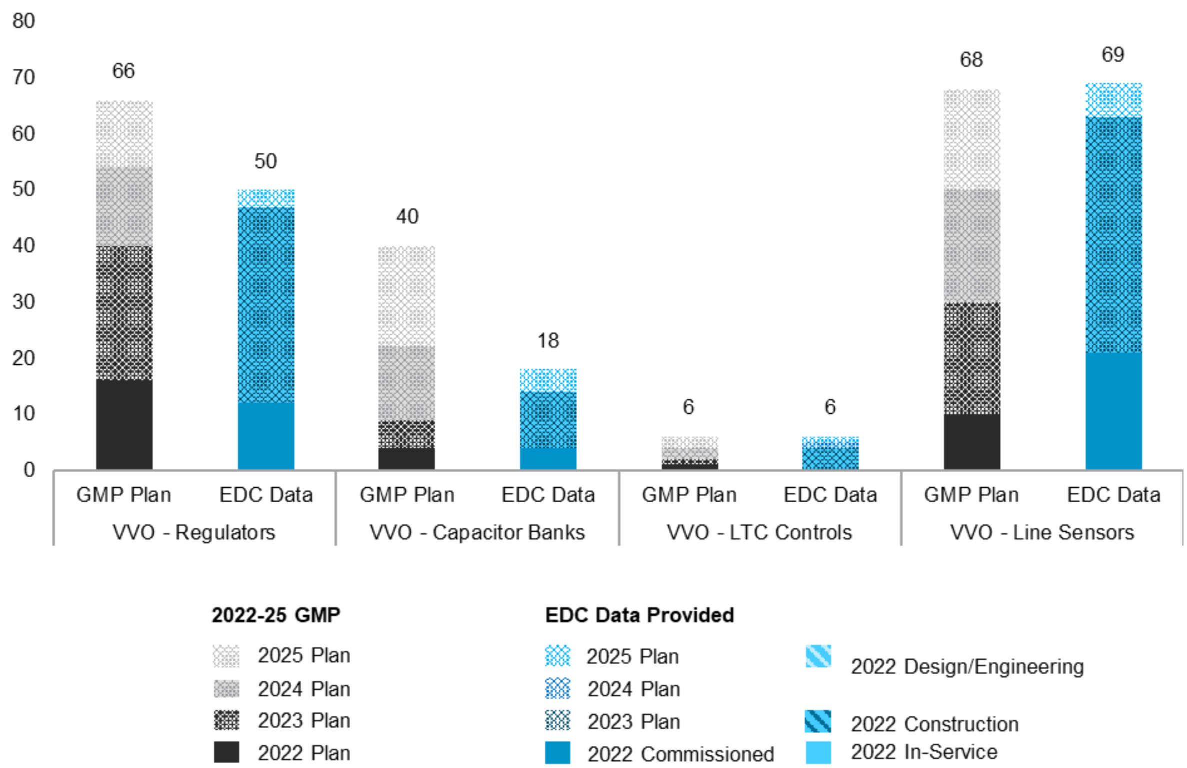
Unitil has reduced plans from what was filed in its 2022-2025 GMP, with spend plans for Term 2 revised downwards from $5.40M to $2.21M. Unitil projects spending most dollars in 2023 and 2025, with a small number of dollars planned for 2024. Most work in 2024 will be limited to engineering / design while Unitil awaits material shipments for orders submitted in 2023. Deployment and spend are projected to be below the DPU pre-authorized budget by the end of 2025.

Not reflected in spend data are challenges that Unitil faced with its VVO scheme. Although initially planned for VVO On/Off testing, testing was delayed for the Townsend substation, as Unitil worked with Hitachi to improve the results from the algorithm as the quantity of Regulators and Capacitor Banks increased on a given feeder. VVO On/Off testing is expected to begin in spring 2023 at the Townsend substation. Lessons learned included awareness of level of testing prior to putting VVO for feeders and substations into service. For Unitil's future planned deployments, Unitil has factored in the additional time needed for internal unit testing prior to formal On/Off testing.

### *3.2.4.4 Term 2 VVO Investment Progress through PY 2022*

Figure 18 shows Unitil's planned versus actual device deployment progress for PY 2022, as well as planned investment for PY 2023 through PY 2025.

**Figure 18. Term 2 Unitil VVO Device Deployment Comparison (2022–2025)**




*Source: Guidehouse analysis of 2021 DOER Responses and 2022 EDC Data*

The EDC Data presented in Figure 18 is also shown in tabular form in Table 66, to provide the specific deployment units in each category.

**Table 66. Term 2 Unitil VVO Deployment Progress**

| | VVO - Regulators | VVO - Capacitor Banks | VVO - LTC Controls | VVO - Line Sensors |
|---|---|---|---|---|
| **2022-2025 Planned Deployment** | **50** | **18** | **6** | **69** |
| PY 2025 Planned | 3 | 4 | 1 | 6 |
| PY 2024 Planned | 0 | 0 | 1 | 0 |
| PY 2023 Planned | 35 | 10 | 4 | 42 |
| Commissioned in PY 2022 | 12 | 4 | 0 | 21 |
| In-Service during PY 2022 | 0 | 0 | 0 | 9 |
| Construction during PY 2022 | 31 | 9 | 3 | 36 |
| Engineering/Design during PY 2022 | 0 | 0 | 1 | 0 |

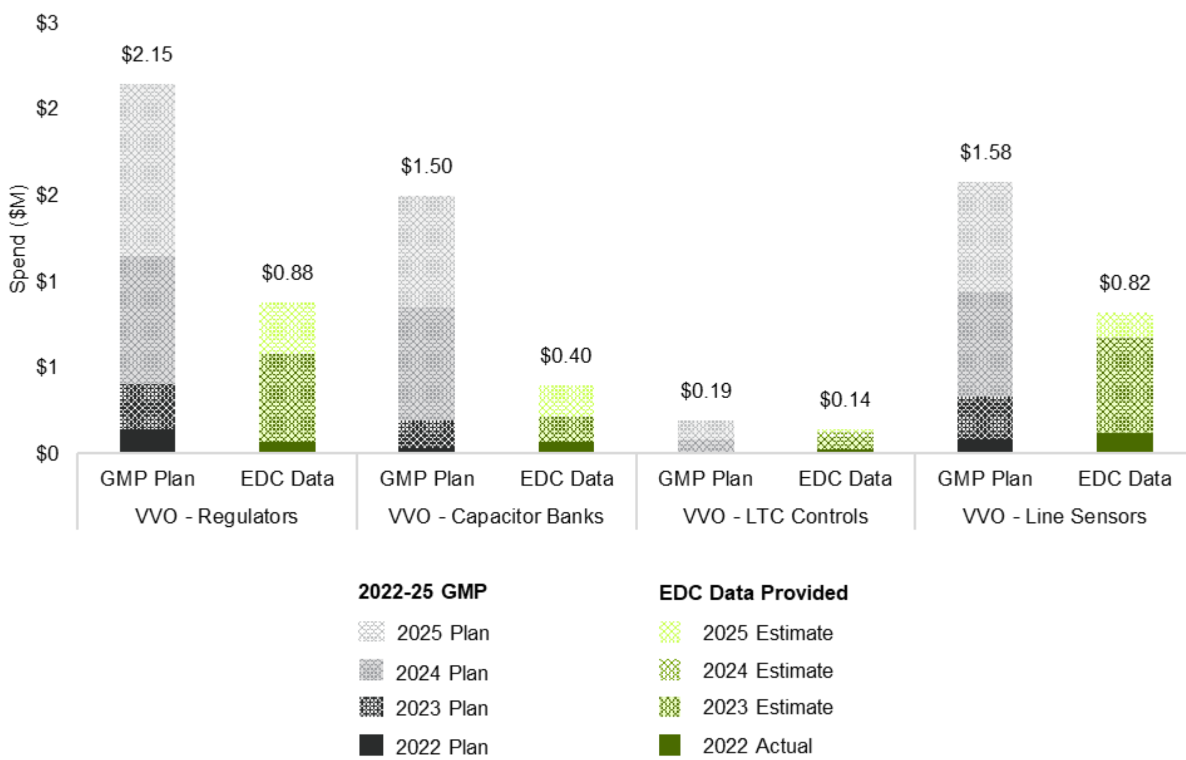
*Source: Guidehouse analysis of 2021 DOER Responses and 2022 EDC Data*

Unitil device deployment was slightly below initial plans for 2022 outlined in Unitil's 2022-2025 GMP. Work conducted in 2022 included deployment of VVO devices at the Summer Street and Lunenburg substations, construction work for the Princeton Road substation, and design/engineering work for the Canton Street substation. Unitil was on-track with deployment of VVO Capacitor Banks and Line Sensors in 2022, deploying 100% and 210% of planned units, respectively. However, deployment was under plans for Regulators and LTC Controls. Lower deployment than plans for LTC Controls may be attributed to Unitil's efforts to resolve LTC radio and control issues. Lower deployment than plans for Regulators can be attributed to cancelation of 4 deployments that were found to be unnecessary.

While deployment was initially projected to be evenly spread over Term 2, Unitil has adjusted deployment plans to conduct most deployment during 2023 and 2025. Additionally, Unitil has reduced its planned spend and deployment of VVO Regulators and Capacitor Banks, as Unitil reassessed deployment plans and determined there were fewer Regulator and Capacitor Bank deployments needed than initially planned. Work in 2024 will be limited to material orders in preparation for construction work at the Beech Street substation.

Figure 19 shows Unitil's planned versus actual spend for PY 2022, as well as planned investment for PY 2023 through PY 2025.

**Figure 19. Term 2 Unitil VVO Plan vs. Actual (2022-2025, $M)**




*Source: Guidehouse analysis of 2021 DOER Responses and 2022 EDC Data*

The EDC Data presented in Figure 19 is also shown in Table 67 to provide the specific dollar spend in each category.

**Table 67. Unitil Total Spend Comparison (2022–2025, $M)**

| | VVO – Regulators | VVO – Capacitor Banks | VVO – LTC Controls | VVO – Line Sensors |
|---|---|---|---|---|
| **2022-2025 Planned Spend** | **$0.88** | **$0.40** | **$0.14** | **$0.82** |
| PY 2025 Planned | $0.30 | $0.18 | $0.02 | $0.15 |
| PY 2024 Planned | $0.00 | $0.00 | $0.03 | $0.00 |
| PY 2023 Planned | $0.51 | $0.15 | $0.07 | $0.55 |
| PY 2022 Actual | $0.07 | $0.07 | $0.03 | $0.12 |

*Source: Guidehouse analysis of 2021 DOER Responses and 2022 EDC Data*

Unitil spend on VVO ($0.25M) was below initial plans ($0.27M), with variation in spend at the device level. Unitil met 48% of its planned spend for Regulators, which Unitil states was due to a reduction in work required to deploy Regulators. Spend and deployment of all other devices met or exceeded initial plans: Unitil met 100% of planned spend for Line Sensors and exceeded planned spend for Capacitor Banks (198%) and LTC Controls (289%).

In 2022, Unitil’s costs incurred per Regulator and Line Sensor were lower than initially projected. Initial projections, estimated using the deployment experience from the prior GMP term, indicated a larger level of effort for deployment and larger overhead costs. Unitil credits internal process improvements for lower costs (e.g., revised control work process reducing commissioning costs for capacitor banks). Costs incurred for LTC Controls, at 289% of planned costs in 2022, may be attributed to Unitil’s troubleshooting of radio and control issues, which have now been resolved.

Spend plans for the remainder of Term 2 have been revised downwards across all device types. Reduced spend on Regulators and Capacitor Banks can be attributed to a reduction in the units that Unitil plans to deploy, as well as lower than expected costs for deployment of Regulators. Reduced spend on LTC Controls and Line Sensors may be tied to process efficiencies implemented in 2022 that brought unit costs below plans. Most spend is planned for 2023 and 2025, with work in 2024 limited to material orders in preparation for construction work at the Beech Street substation.

### *3.2.4.5 Term 2 Infrastructure Metrics Results and Key Findings*

Table 68 and Table 69 summarize the Term 2 Infrastructure Metrics results through PY 2022 for each investment type related to Unitil’s VVO Investment Area.

**Table 68. Term 2 Unitil Infrastructure Metrics Findings**

| Infrastructure Metrics | | | VVO - Regulators | VVO - Capacitor Banks | VVO - LTC Controls | VVO - Line Sensors |
|---|---|---|---|---|---|---|
| GMP Plan Total, 2022-2025 | | # Devices Planned | 66 | 40 | 6 | 68 |
| | | Spend, $M | $2.15 | $1.50 | $0.19 | $1.58 |
| EDC Data Total, 2022-2025 | | # Devices Planned | 50 | 18 | 6 | 69 |
| | | Spend, $M | $0.88 | $0.40 | $0.14 | $0.82 |
| IM-4 | Number of devices or other technologies deployed thru. PY 2022 | # Devices Deployed | 12 | 4 | 0 | 21 |
| | | % Devices Deployed | 18% | 10% | 0% | 31% |
| IM-5 | Cost for Deployment thru PY 2022 | Total Spend, $M | $0.07 | $0.07 | $0.03 | $0.12 |
| | | % Spend | 3% | 5% | 13% | 8% |
| IM-6 | Deviation Between Actual and Planned Deployment for PY 2022 | % On Track (Devices) | 75% | 100% | 0% | 210% |
| | | % On Track (Spend) | 48% | 198% | 289% | 139% |
| IM-7 | Projected Deployment for the Remainder of the GMP Term | # Devices Remaining | 38 | 14 | 6 | 48 |
| | | Spend Remaining, $M | $0.81 | $0.33 | $0.12 | $0.70 |

Note: The metric names have been slightly changed here to clarify the time span used in analysis.

*Source: Guidehouse analysis of 2021 DOER Responses and 2022 EDC Data*

**Table 69. 2022 Unitil Infrastructure Metrics for VVO Feeders**

| IM | Metric | Parameter* | Number of Feeders |
|---|---|---|---|
| **Term 1 Plan Feeders** | | | |
| IM-4 | Number of Devices/Technologies Deployed | # Feeders with VVO Enabled | 3 |
| | | % Feeders with VVO Enabled | 100% |
| IM-6 | Deviation Between Actual and Planned Deployment | % On Track (Feeders with VVO Enabled) | 100% |
| IM-7 | Projected Deployment for the Remainder of the GMP Term | # Feeders Remaining for VVO Enablement | 0 |
| **Term 2 Plan Feeders** | | | |
| IM-4 | Number of Devices/Technologies Deployed | # Feeders with VVO Enabled | 4 |
| | | % Feeders with VVO Enabled | 50% |
| IM-6 | Deviation Between Actual and Planned Deployment | % On Track (Feeders with VVO Enabled) | 50% |
| IM-7 | Projected Deployment for the Remainder of the GMP Term | # Feeders Remaining for VVO Enablement | 4 |

* VVO Enabled denotes that the VVO system is commissioned and VVO is engaged. Feeders presented with VVO enabled may not be actively employing CVR.

*Source: Guidehouse analysis of 2021 DOER Responses and 2022 EDC Data*

Guidehouse's review of Unitil's deployment and spend revealed that Unitil was below initial plans for 2022 outlined in Unitil's 2022-2025 GMP, as several deployment plans were on hold until the late 2022 DPU approval of 2022-2025 GMPs. Key findings related to Unitil's progress include:

Device Deployment

- Unitil deployment was slightly below plans for 2022, with variation by device type. Unitil was on-track with deployment of VVO Capacitor Banks and Line Sensors in 2022, deploying 100% and 210% of planned units, respectively. However, deployment was under plans for Regulators and LTC Controls. Lower deployment than plans for LTC Controls may be attributed to Unitil's efforts to resolve LTC radio and control issues. Lower deployment than plans for Regulators can be attributed to cancelation of 4 deployments that were found to be unnecessary.
- While deployment was initially projected to be evenly spread over Term 2 in its 2022-2025 GMP filing, Unitil has adjusted deployment plans to conduct most deployment during 2023 and 2025. Additionally, Unitil has reduced its planned deployments of VVO Regulators and Capacitor Banks, as Unitil reassessed deployment plans and determined there were fewer Regulator and Capacitor Bank deployments needed than initially planned. Work in 2024 will be limited to material orders in preparation for construction work at the Beech Street substation.

Total Spend

- Unitil spend on VVO ($0.25M) was below initial plans ($0.27M), with variation in spend at the device level. Unitil met 48% of its planned spend for Regulators. Spend and deployment of all other devices met or exceeded initial plans: Unitil met 100% of planned spend for Line Sensors, and exceeded planned spend for Capacitor Banks (198%) and LTC Controls (289%). Initial plans, informed by the deployment experience from Term 1, overestimated the level of effort and overhead costs for Regulators and Line Sensors, reducing unit costs for these devices. Costs overruns on LTC Controls, at 289% of planned costs in 2022, may be attributed to Unitil's troubleshooting of radio and control issues, which have now been resolved.

- Spend plans for the remainder of Term 2 have been revised downwards across all device types. Reduced spend on Regulators and Capacitor Banks can be attributed to a reduction in the units that Unitil plans to deploy, as well as lower than expected costs for deployment of Regulators. Reduced spend on LTC Controls and Line Sensors may be tied to process efficiencies implemented in 2022 that brought unit costs below plans. Most spend is planned for 2023 and 2025, with work in 2024 limited to material orders in preparation for construction work at the Beech Street substation.

VVO Enablement

- For its Term 1 substation (Townsend) Unitil completed VVO deployment in 2021, enabling VVO on December 1, 2021, and On/Off testing is expected to begin in spring 2023. Among its Term 2 substations, Unitil completed deploying VVO investments at the Summer Street substation and enabled VVO in December 2022, with VVO On/Off testing projected to begin at the substation in December 2023. Lunenburg and West Townsend are currently receiving VVO investments and Unitil plans to enable VVO at the substations in January and November 2024, respectively. Unitil then plans to conduct On/Off testing at the substations beginning in December 2024. For its remaining substations, Unitil is currently conducting planning and engineering/design work for its Beech Street, Pleasant Street, and Princeton Road substations. These substations are expected to be enabled after the close of Term 2 in 2026 and 2027.

# 4. VVO Performance Metrics

## 4.1 Data Management

Guidehouse worked with the EDCs to collect data to complete the evaluation for the assessment of VVO Infrastructure Metrics and Performance Metrics. The sections that follow highlight Guidehouse's data sources and data QA/QC processes used in the evaluation of Performance Metrics.

### 4.1.1 Data Sources

Guidehouse used numerous datasets to evaluate Performance Metrics. The subsections that follow summarize the data sources used to evaluate Performance Metrics.

#### *4.1.1.1 VVO Supplemental Data Template*

The VVO supplemental data collection template includes additional information unique to the VVO Investment Area. Table 70 summarizes the information requested and included in the analysis. The EDCs provided data to the team in the data collection template or submitted it in a separate file. Guidehouse requested information at the feeder level where possible.

**Table 70. VVO Supplemental Data**

| Information | Description |
|---|---|
| Actual/Planned VVO Schedule | Actual and updated planned VVO deployment start/end dates by feeder, including feeder conditioning, load rebalancing, phase balancing, VVO commissioning, VVO enabled, and On/Off testing. |
| Customer DR Events | DR events (time-stamped log of any systemwide DR (or similar), for example: ISO-NE DR, EDC direct load control programs, EDC behavioral DR programs). |
| Voltage Complaints | Voltage-related complaints based on voltage perturbation (e.g., high voltage, low voltage, flicker) and duration (e.g., multiple days, sporadic). |

*Source: Guidehouse Stage 3 Evaluation Plan submitted to EDCs on March 1, 2023*

#### *4.1.1.2 Additional VVO Data Required for Performance Metrics Evaluation*

Table 71 summarizes the additional data inputs required for Performance Metrics analysis. Except for the weather data, the team obtained all fields from the EDCs.

**Table 71. Additional Data Required for Evaluation Performance Metrics**

| Data Type | Description |
|---|---|
| EDC system information | • Feeder characteristics (e.g., rated primary voltage, rated capacity, feeder length, number of customers [residential, commercial, industrial, etc.]), load factor (ratio of average load to peak load), ZIP code or town, number of capacitors, number of regulators |
| Time series data (hourly) | • Feeder head end data (voltage, real power, current, apparent power or reactive power, power factor)<br>• VVO status flags (e.g., VVO On/Off) |
| VVO system information | • Time-stamped log of VVO state changes between on and off states and any other VVO modes |
| Weather data | • Hourly temperature data from selected weather stations and collected by the National Oceanic and Atmospheric Administration (NOAA) |

*Source: Guidehouse Stage 3 Evaluation Plan submitted to EDCs on March 1, 2023*

### 4.1.2 Data QA/QC Process

Guidehouse reviewed all data provided for Performance Metrics analysis upon receipt of requested data. The QA/QC of Performance Metrics data included checks to confirm each of the required data inputs could be incorporated within the Performance Metrics analysis. Examples of the QA/QC include the following criteria:

- Time series data cover each feeder receiving VVO investments and include variables needed to facilitate analysis of Performance Metrics, including voltage, real power, and reactive or apparent power
- Time series data are complete in time and extent of devices and do not include erroneous data (e.g., interpolated values and outliers)
- Voltage complaints data have been received for each feeder receiving VVO investments and are at an adequate level of detail for analysis

After Performance Metrics data are received at the end of every season, Guidehouse provides status update memos that summarize the QA/QC to the EDCs, confirming receipt of the datasets and indicating quality. Any additional follow-up based on standing questions is required to confirm all EDC-provided data can be applied to Performance Metrics analysis.

## 4.2 VVO Performance Metrics Analysis and Findings

Guidehouse presents findings from the Performance Metrics analysis for the VVO Investment Area in the following subsections.

### 4.2.1 Statewide Comparison

This section summarizes the Performance Metrics analysis results and key findings for Eversource and National Grid. Results and key findings are provided for the Spring 2022 – Winter 2022/23 M&V period. It can be difficult to compare the results from Performance Metrics analysis between Eversource and National Grid. For example, there are differences in data quality at different times of the year (e.g., sustained pauses in VVO On/Off testing for one EDC, data outages during On/Off testing for another EDC). As such, certain portions of the M&V period, such as the Spring season, may be represented more for one EDC than the other. Additionally, there are numerous differences in DG penetration, customer types, and geographic areas served by Eversource and National Grid feeders that limit the ability to directly compare Eversource and National Grid VVO outcomes.

#### *4.2.1.1 Performance Metrics Analysis Results*

Table 72 includes the Performance Metrics results for Spring 2022 – Winter 2022/23 for Eversource and National Grid. The following EDC-specific subsections provide further detail.

**Table 72. Performance Metrics Results for the Spring 2022 – Winter 2022/23 M&V Period**

| Performance Metrics | | Eversource | | National Grid* | |
|---|---|---|---|---|---|
| Feeders Included in Evaluation | | 26 | | 34 | |
| PM-1 | Spring 2022 – Winter 2022/23 Baseline | 524,992 MWh | | 882,631 MWh | |
| PM-2 | Energy Savings – All Hours VVO On† | 2,128 ± 476 MWh | 0.41 ± 0.09% | 6,769 ± 1,162 MWh | 0.84 ± 0.15% |
| | Energy Savings – Actual VVO On Hours‡ | 879 ± 184 MWh | 0.41 ± 0.09% | 1,867 ± 302 MWh | 0.84 ± 0.15% |
| - | Voltage Reduction | 1.52 ± 0.01 V | 1.24 ± 0.01% | 0.08 ± <0.001 kV | 0.62 ± 0.01% |
| - | CVRf^ | 0.60 | | 0.36 | |
| PM-3^^ | Peak Demand Reduction | -369 ± 245 kW | -0.70 ± 0.46% | -2,189 ± 1,173 kW | -2.41 ± 1.28% |
| PM-4 | Reduction in Distribution Losses | 0.01% | | -1.95%¶ | |
| PM-5 | Change in Power Factor | <0.001 ± <0.001 | 0.06 ± 0.02% | -0.01 ± 0.002¶ | -0.96 ± 0.2%¶ |
| PM-6 | GHG Reductions ($CO_2$) All Hours VVO On† | 723 ± 162 tons $CO_2$ | | 2,301 ± 395 tons $CO_2$ | |
| | GHG Actual VVO-On Hours‡ | 299 ± 63 tons $CO_2$ | | 645 ± 103 tons $CO_2$ | |
| PM-7 | Voltage Complaints | 53 (13% decrease from 2015 – 2017 baseline period average) | | 136 (16% decrease from 2016 – 2017 baseline period average)§ | |

* National Grid feeders at the Easton substation did not begin testing until mid-January, 2023. Unless otherwise noted, all overall estimates are inclusive of Easton feeders and only incorporate impact estimates from this substation during the Winter period. National Grid feeders at the West Salem substation did not begin testing until early June, 2022. Unless otherwise noted, all overall estimates are inclusive of West Salem feeders and only incorporate impact estimates from this substation during the Summer 2022 – Winter 2023 period. Additionally, even-numbered Maplewood feeders underwent a prolonged period over which VVO on/off testing was paused, resulting in their removal from analysis that informed PM-1 through PM-6. Lastly, although the Stoughton substation ended VVO testing prior to this current evaluation, impact estimates for several performance metrics were calculated for Stoughton and, unless otherwise noted, these estimates are included in the aggregate estimates provided in this report.
† Calculation assumes VVO was enabled for all hours between March 1, 2022 and February 28, 2023.
‡ Calculation uses actual number of VVO On hours spanning the analysis period. Actual VVO On Hours are the number of hours VVO was engaged between March 1, 2022 and February 28, 2023 for each feeder.

^The CVR factor provided for each EDC is the load-weighted average of CVR factors estimated for each feeder with a voltage response to VVO On/Off testing.[50]
^^Guidehouse evaluated the impact of VVO during peak demand periods, defined by ISO-NE as 1:00 p.m. to 5:00 p.m. ET from June 1 to August 31 on non-holiday weekdays. Aggregate peak demand reduction is calculated only for feeders with statistically significant reductions in voltage.
¶ Changes in power factor and distribution losses could not be estimated for any substations going through VVO On/Off testing during Spring 2022 through Winter 2022/23 due to data quality issues. Results presented for these metrics are based off of VVO substations that completed VVO On/Off testing prior to this evaluation period. For this evaluation period, the only substation to conclude On/Off testing is Stoughton.
§ National Grid did not start tracking voltage complaints until 2016.
*Source: Guidehouse analysis*

### *4.2.1.2 Key Findings and Recommendations*

Findings from the evaluation of Performance Metrics indicate that VVO allowed Eversource and National Grid to realize energy savings and voltage reductions during the Spring 2022 – Winter 2022/23 M&V period.[51] More specifically:

- During the Spring 2022 – Winter 2022/23 M&V period, Eversource's Agawam, Piper, Podick, and Silver substations realized 879 MWh (0.41%) energy savings and 1.52 V (1.24%) voltage reduction associated with VVO. The CVR Factor, which provides an estimate of energy savings possible with voltage reductions, was 0.60.[50] During the same M&V period, National Grid's East Methuen, East Bridgewater, Easton, Maplewood, Stoughton, and West Salem substations realized 1,867 MWh (0.84%) energy savings and 0.08 kV (0.62%) voltage reduction associated with VVO. National Grid's CVR factor was 0.36.[50]
- Eversource energy savings of 879 MWh yielded a 299 short ton reduction of $CO_2$ emissions. National Grid energy savings of 1,867 MWh yielded a 645 short ton reduction in $CO_2$ emissions.
- Eversource and National Grid VVO feeders experienced a minimal benefit associated with peak demand, power factor, and distribution losses. Eversource VVO feeders experienced a statistically significant increase (0.70%) in peak demand, a statistically significant decrease (0.06%) in power factor, and a minimal decrease in distribution losses when VVO was engaged. National Grid VVO feeders experienced a statistically significant increase in peak demand (2.41%), a small increase (0.96%) in power factor, and a 1.95% increase in distribution losses when VVO was engaged.
- For Eversource, a total of 53 voltage complaints were received from customers connected to the Agawam, Piper, Podick, and Silver VVO feeders during the Spring 2022 – Winter

[50] Both Eversource and National Grid aggregated CVRf calculations only include estimates from feeders that experienced a minimum change in voltage of ±0.25% Certain feeders with changes in voltage greater than ±0.25% were also excluded from aggregated CVRf calculations due to highly unstable voltage and energy responses to VVO On / Off testing. Feeders excluded from this calculation are all of Eversource's Podick 18G feeders and Silver feeders 30A2, 30A4, and 30A6, All of National Grid's West Salem 29W feeders, and East Bridgewater feeders 797W1, 797W23, 797W23, and 797W42 are also removed from aggregated CVRf results due to unreliable voltage and energy responses to VVO On / Off testing.

[51] It can be difficult to compare the results from Performance Metrics analysis between Eversource and National Grid. For example, there are differences in the granularity of telemetry (e.g., 15-minute versus 1 hour), data quality at different times of the year (e.g., sustained pauses in VVO On / Off testing, repeated data). As such, data cleaning can cause certain portions of the M&V period to be represented more for one EDC than the other. Additionally, there are numerous differences in DG penetration, customer types, and geographic areas served by Eversource and National Grid feeders that limit the ability to directly compare Eversource and National Grid VVO outcomes.

2022/23 M&V period. This is a 13% decrease relative to the average voltage complaints per year received between 2015 – 2017. For National Grid, a total of 136 voltage complaints were received from customers connected to the East Methuen, East Bridgewater, Easton, Maplewood, Stoughton, and West Salem VVO feeders during the period. This is a 16% decrease relative to the average voltage complaints per year received between 2016 – 2017. For both EDCs, there is not sufficient evidence to support changes in voltage complaints being attributed to VVO.

In 2023 and beyond, Guidehouse recommends that Eversource and National Grid:

- Ensure VVO On/Off testing is running according to plan, with limited pauses to the VVO On/Off testing schedule. Across the VVO feeders, one-quarter to one-half of data points were removed due to extended pauses in VVO On/Off testing. For some feeders, this resulted in the vast majority of provided data to be unusable for components of this evaluation (e.g., for estimation of distribution loss and power factor reductions). Sustained On/Off testing will increase the amount of usable data in the evaluation and improve the ability for Guidehouse to provide a comprehensive evaluation of VVO performance metrics.
- Confirm adjustments to VVO On/Off testing schedule for any VVO feeders prior to implementation. VVO On/Off testing is designed similarly to a Randomized Controlled Trial (RCT), and adjustments to the testing schedule could, potentially, hinder the effectiveness of the testing design and cause biases to affect the results. Ensuring there is proper balance in the number of VVO on and off hours throughout the evaluation period will allow for Guidehouse to provide a comprehensive and accurate evaluation of VVO performance metrics.
- Continue to investigate how to improve outcomes across VVO feeders. Many feeders across the EDCs underwent no material change in voltage. Correspondingly, energy reduction estimates were small-to-insignificant. These observations may indicate flaws in the VVO control scheme for these feeders. In order to improve VVO performance, Guidehouse recommends that the EDCs continue to investigate root causes to shortcomings in the VVO control scheme and work with distribution engineers and the VVO vendor to respond accordingly. If needed, Guidehouse can conduct in-depth case studies at these substations to further understand shortcomings in the VVO control scheme.

### 4.2.2 Eversource

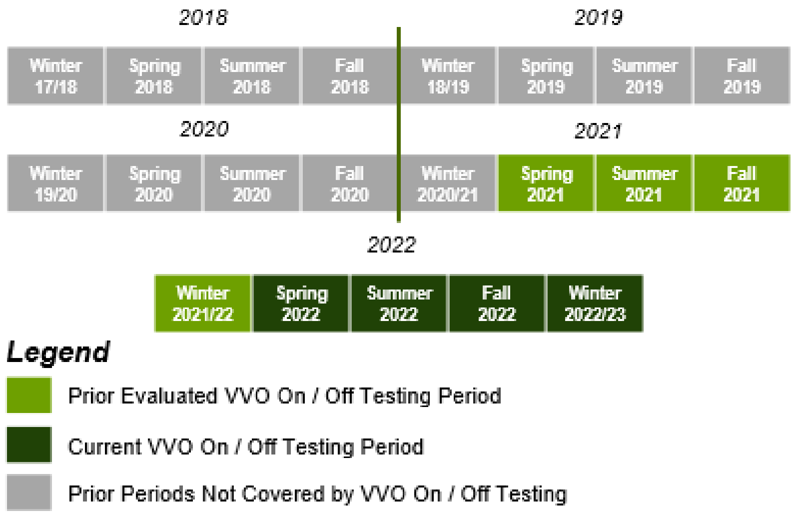
This section discusses Eversource's VVO Performance Metrics results following the Spring 2022 – Winter 2022/23 VVO M&V period.

#### *4.2.2.1 Performance Metrics Analysis Timeline*

Figure 20 highlights the key Performance Metrics analysis periods for Eversource. The Performance Metrics analysis provided for this report will be focused on results from VVO On/Off testing conducted during Spring 2022 – Winter 2022/23. Results from VVO On/Off testing conducted during Spring 2021 – Winter 2021/22 were provided in the Massachusetts Grid Modernization Program Year 2021 Evaluation Report for Volt-VAR Optimization.[52]

[52] All Massachusetts Grid Modernization Program Year 2021 Evaluation Reports were filed on July 1, 2022 under DPU dockets 22-40, 22-41, and 22-42.

**Figure 20. Eversource Performance Metrics Analysis Timeline**




*Source: Guidehouse analysis*

### *4.2.2.2 Evaluation Methodology*

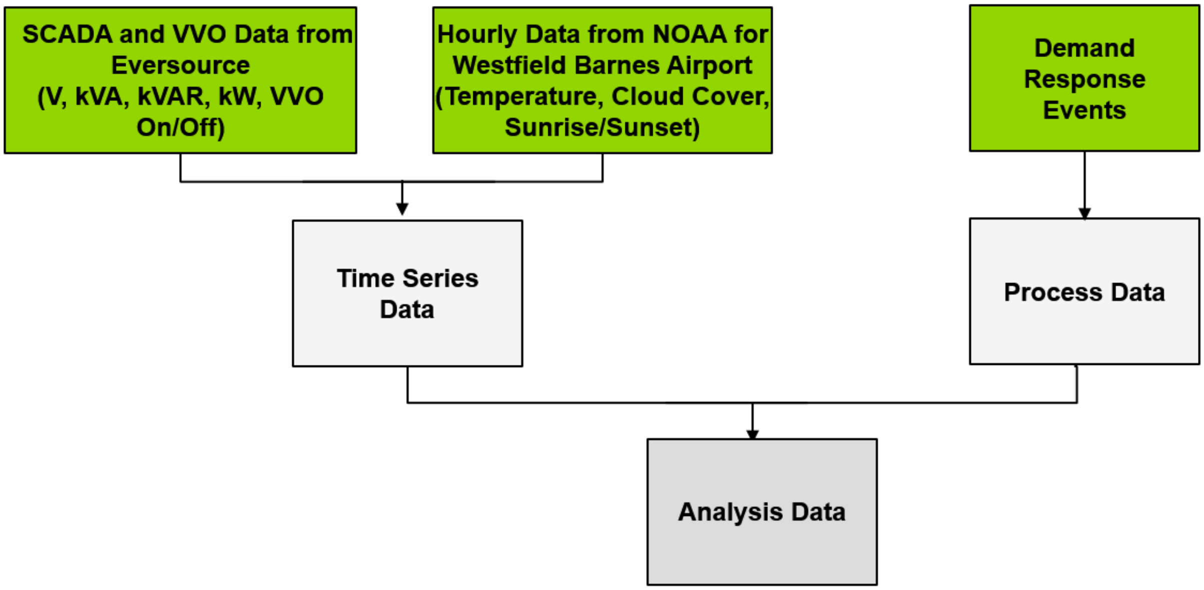
Guidehouse worked with Eversource to collect data necessary to complete the evaluation of VVO Performance Metrics. The sections that follow highlight the analysis data construction, analysis data cleaning, and the analysis approach.

#### *Analysis Data Construction*

To assess Performance Metrics, Guidehouse constructed an analysis dataset. This dataset was used in regression modeling to assess changes in multiple outcome variables, such as energy and peak demand. Figure 21 summarizes the data integration process used to construct the analysis dataset for the Eversource Performance Metrics analysis.[53]

[53] Guidehouse receives different data types and structures from the EDCs for estimating impacts across the performance metrics. These differences were minimized as much as possible, but any differences that remain may affect the comparability of performance metrics results across the EDCs.

**Figure 21. Eversource Analysis Data Construction Flowchart**




*Source: Guidehouse*

Guidehouse constructed time series and process data to arrive at a final analysis dataset for Eversource's Performance Metrics analysis. To construct time series data, the evaluation team first integrated SCADA interval data from Eversource that contained 15-minute measurements of voltage, real power, apparent power, and reactive power. Time-stamped logs of VVO state changes between VVO On (engaged) and Off (disengaged) states were also contained within the SCADA data provided by Eversource. To complete the construction of time series data, hourly dry bulb temperature and hourly cloud cover data from NOAA for Westfield Barnes Municipal Airport were then joined to SCADA interval data.[54]

To construct the process data, Guidehouse collected a log of demand response events during the evaluation period. The team joined resulting process data to time series data to construct a final analysis dataset.

### *Analysis Data Cleaning*

After constructing the analysis dataset, the team conducted data cleaning steps to remove interval data that may bias the estimates of VVO impacts. Table 73 summarizes data observations made by the evaluation team and the resulting data cleaning steps that were executed.

[54] Westfield Barnes Municipal Airport was selected due to it having a quality controlled local climatological dataset and due to its being near the Eversource substations. Documentation on the NOAA dataset used in this analysis can be found here: https://data.noaa.gov/dataset/dataset/quality-controlled-local-climatological-data-qclcd-publication

**Table 73. Data Cleaning Conducted for Eversource Analysis**

| Data Observation | Data Cleaning Step |
|---|---|
| Guidehouse identified a handful of periods of repeated, interpolated, and outlier values in the interval data received, as well as periods missing VVO-status data. | Guidehouse removed observations where anomalous data readings were flagged. |
| Guidehouse identified numerous periods where VVO events were longer than planned. | To reduce the risk of VVO estimates being biased by imbalance in the sample of VVO On/Off statuses (e.g., overrepresentation of VVO On during winter), Guidehouse removed all VVO events within the Spring – Fall seasons longer than 72 hours. Eversource switched to weekly VVO On/Off testing in mid-November; after the switch, Guidehouse removed all VVO events longer than ten days (240 hours). |

*Source: Guidehouse*

Table 74 indicates the number of 15-minute intervals contained in the analysis dataset for the Agawam, Piper, Podick, and Silver substations. Much of the data removed during data cleaning was due to extended periods over which VVO was engaged or disengaged. Detailed data attrition information is included in Appendix B.10.

**Table 74. Count of VVO On, VVO Off, and Removed Quarter-Hours for Eversource**

| Substation | Feeder | VVO On Quarter Hours | VVO Off Quarter Hours | Quarter Hours Removed by Data Cleaning | Spring 2022 – Winter 2022/23 Total |
|---|---|---|---|---|---|
| **Agawam** | 16C11 | 9,965 | 10,215 | 14,860 | 35,040 |
| | 16C12 | 13,071 | 14,444 | 7,525 | 35,040 |
| | 16C14 | 13,126 | 13,313 | 8,601 | 35,040 |
| | 16C15 | 13,084 | 13,212 | 8,744 | 35,040 |
| | 16C16 | 13,138 | 13,316 | 8,586 | 35,040 |
| | 16C17 | 13,244 | 13,353 | 8,443 | 35,040 |
| | 16C18 | 13,383 | 13,391 | 8,266 | 35,040 |
| **Piper** | 21N4 | 15,839 | 15,489 | 3,712 | 35,040 |
| | 21N5 | 12,385 | 11,223 | 11,432 | 35,040 |
| | 21N6 | 16,104 | 15,797 | 3,139 | 35,040 |
| | 21N7 | 15,552 | 14,482 | 5,006 | 35,040 |
| | 21N8 | 16,125 | 15,836 | 3,079 | 35,040 |
| | 21N9 | 7,570 | 7,399 | 20,071 | 35,040 |
| **Podick** | 18G2 | 10,046 | 8,776 | 16,218 | 35,040 |
| | 18G3 | 12,395 | 10,957 | 11,688 | 35,040 |
| | 18G4 | 13,074 | 11,614 | 10,352 | 35,040 |
| | 18G5 | 12,679 | 11,252 | 11,109 | 35,040 |
| | 18G6 | 8,431 | 7,379 | 19,230 | 35,040 |
| | 18G7 | 12,410 | 10,600 | 12,030 | 35,040 |
| | 18G8 | 11,239 | 10,272 | 13,529 | 35,040 |
| **Silver** | 30A1 | 6,594 | 7,646 | 20,800 | 35,040 |
| | 30A2 | 11,662 | 12,545 | 10,833 | 35,040 |
| | 30A3 | 5,002 | 5,900 | 24,138 | 35,040 |
| | 30A4 | 11,275 | 12,877 | 10,888 | 35,040 |
| | 30A5 | 8,651 | 9,562 | 16,827 | 35,040 |
| | 30A6 | 10,280 | 11,568 | 13,192 | 35,040 |

*Source: Guidehouse analysis*

### *Analysis Approach*

After the analysis data was constructed and cleaned, Guidehouse conducted regression modeling to assess the impacts of VVO on measured feeder-level energy and voltage. Equation 5-2 and Equation 5-3 in the Appendix summarizes the regression model used to estimate energy and voltage as a function of VVO.

To inform the regression model construction for estimation of energy and voltage, Guidehouse inspected the data to control for exogenous patterns. Table 75 summarizes observations made during this inspection and the implemented data analysis steps.

**Table 75. Data Analysis Summary for Eversource**

| Data Observation | Data Analysis Step |
|---|---|
| Load and voltage data exhibit similar curvature from day-to-day, with load and voltage profiles for any two adjacent days being largely similar | A 24-hour lag of load (for energy models) and voltage (for voltage models) was included as a predictor of load (for energy models) and voltage (for voltage models) |
| Numerous feeders had a large nominal capacity of connected solar facilities. | Cloud cover and daylight hour data from NOAA were integrated and included in regression analysis to control for hourly generation observed under an array of solar conditions. |
| Large differences in energy and voltage were observed between most months in the analysis period | Monthly fixed effects were incorporated into regression modeling to capture energy and voltage differences observed across each week. |
| Numerous feeders were identified with non-residential customers making up a large portion of load, with drops in measured load during holidays and non-business hours. | Day type (i.e., weekday or weekend day) and hour of day fixed effects were incorporated into regression models to capture typical load shapes by day type and control for large drops in demand observed during non-business hours. |
| Numerous demand response events were called during the Spring 2022 – Winter 2022/23 M&V test period. | Intervals that occurred during demand response events were flagged and controlled for in the regression analysis to control for changes in energy and voltage associated with demand response events. |

*Source: Guidehouse*

#### *4.2.2.3 Performance Metrics Results*

This section summarizes the Performance Metrics results for Eversource. Each of the subsections separately summarizes the evaluation results for each performance metric.

***PM-1: Baseline***

As detailed in the Stage 3 Plan submitted to the EDCs on March 1, 2023, Guidehouse provides a baseline using data collected when VVO was disabled during the evaluation period, which spans Spring 2022 – Winter 2022/23. Table 76 shows the energy baseline calculated using VVO Off data collected during Spring 2022 – Winter 2022/23 from the Agawam, Piper, Podick, and Silver substations.

**Table 76. Eversource VVO Energy Baseline**

| Metric | Baseline Total Energy Use |
|---|---|
| Baseline Energy | 524,992 MWh |

*Source: Guidehouse analysis*

To estimate total baseline energy use, Guidehouse used regression models to first estimate energy savings that occurred for each feeder during Spring 2022 – Winter 2022/23. This resulted in an estimate of how energy use changed as a function of VVO. From there, Guidehouse fitted the model to a case in which VVO was off for the entirety of Spring 2022 – Winter 2022/23 for each VVO feeder, holding all other observable conditions constant (e.g., allowing weather to remain as it actually was when VVO was engaged). Guidehouse then summed this calculated energy usage across all hours and feeders to calculate a baseline total energy use for the Spring 2022 – Winter 2022/23 evaluation period. Baseline energy use is provided by VVO feeder in Appendix B.11.

***PM-2: Energy Savings***

Table 77. Eversource VVO Net Energy Reduction during Actual VVO On Hours provides Eversource's estimated energy savings for Spring 2022 – Winter 2022/23, as well as for each season. The ± figure indicates 90% confidence bounds associated with the energy savings estimates.

**Table 77. Eversource VVO Net Energy Reduction during Actual VVO On Hours**

| Season | Net Energy Reduction | |
|---|---|---|
| | MWh† | %‡ |
| Spring^ | -282 ± 81 MWh | -0.58 ± 0.17% |
| Summer | 1,257 ± 151 MWh | 2.07 ± 0.25% |
| Fall | -391 ± 93 MWh | -0.74 ± 0.17% |
| Winter^^ | 582 ± 111 MWh | 1.06 ± 0.26% |
| Spring 2022 – Winter 2022/23 Total | 879 ± 184 MWh | 0.41 ± 0.09% |

† Total energy savings provided for each period is the sum of each feeder's energy savings within that period. Due to model noise, a manual sum of savings across periods may not equal the amount provided in the Total row.

‡ Percentage energy savings provided for each period is the load-weighted average of percentage savings estimated for each feeder.

^ Silver feeders 30A1, 30A3, and 30A5 are excluded from Spring estimate due to insufficient data.

^^Podick feeder 18G8 is excluded from Winter estimate due to insufficient data.

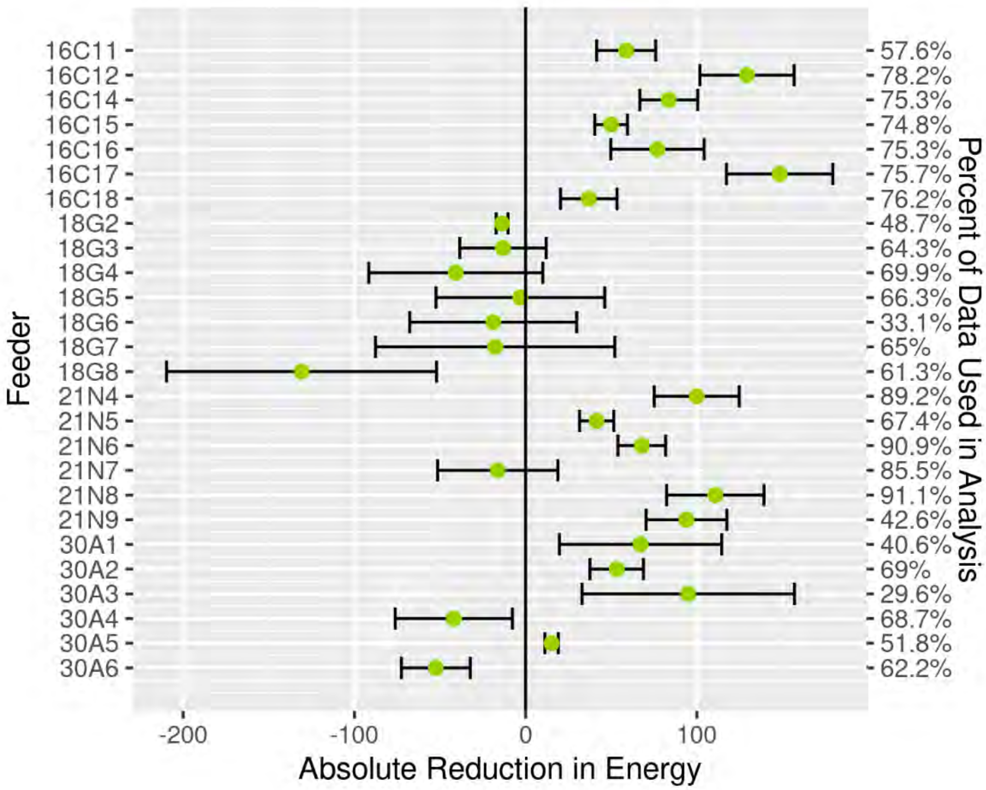
*Source: Guidehouse analysis*

Regression estimates indicate a statistically significant reduction in energy use associated with VVO, with 879 MWh (0.41%) in energy savings realized during the Spring 2022 – Winter 2022/23 M&V period.[55] Regression estimates indicate that there were statistically significant reductions in energy use for the Summer and Winter seasons, but statistically significant increases in energy use for the Spring and Fall seasons. The Summer season saw the largest reduction in energy, with an estimated value of 1,257 MWh, and the Fall season saw the largest increase in energy, with an estimated value of 391 MWh.

Figure 22 indicates the net energy reductions for each Eversource feeder in absolute terms (MWh), with green points indicating each feeder's MWh savings. The associated 90% confidence intervals are provided by the whiskers overlaid on each feeder's MWh savings estimate. Where the confidence interval crosses the zero line, results may be interpreted as statistically insignificant. Of the 26 feeders included in the Spring 2022 – Winter 2022/23 M&V period, 16 experienced statistically significant reductions in energy. Of these 16 feeders, feeders 16C17 and 16C12 realized the greatest energy savings.

[55] Calculation uses actual number of VVO On hours spanning the analysis period. Actual VVO On Hours are the number of hours VVO was engaged in the clean analysis data between March 1, 2022 and February 28, 2023.

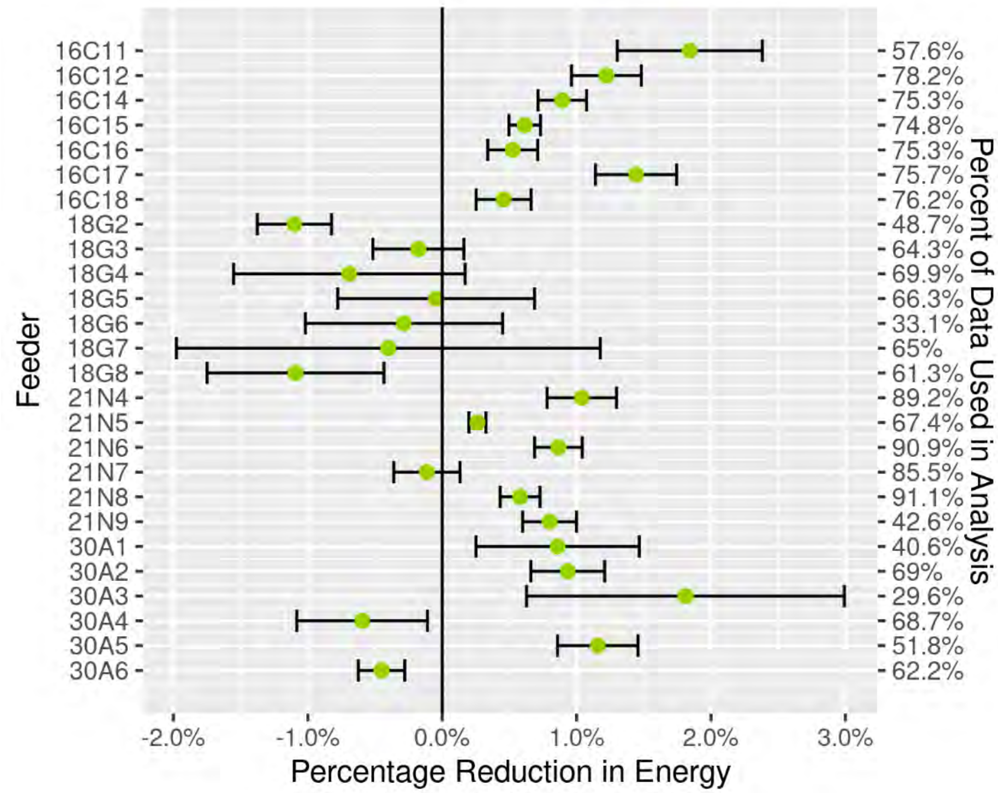
**Figure 22. Net Energy Reduction (MWh) for Eversource VVO Feeders**




*Source: Guidehouse analysis*

Figure 23 indicates the net energy reductions for each Eversource feeder in percentage terms, with green points indicating each feeder's percentage MWh savings. The whiskers overlaid on each feeder's percentage MWh savings estimate provide the associated 90% confidence levels. Where the confidence interval crosses the zero line, results may be interpreted as statistically insignificant.

**Figure 23. Net Energy Reduction (%) for Eversource VVO Feeders**




*Source: Guidehouse analysis*

To further understand VVO impacts, Guidehouse estimated changes in voltage associated with VVO. Table 78 provides the evaluated voltage reductions for Eversource, with 90% confidence bounds associated with voltage reductions estimates indicated by the ± figure. Regression estimates indicate a statistically significant reduction in voltage associated with VVO, with a 1.52 V (1.24%) voltage reduction realized during the Spring 2022 – Winter 2022/23 M&V period.

**Table 78. Eversource VVO Average Hourly Voltage Reduction***

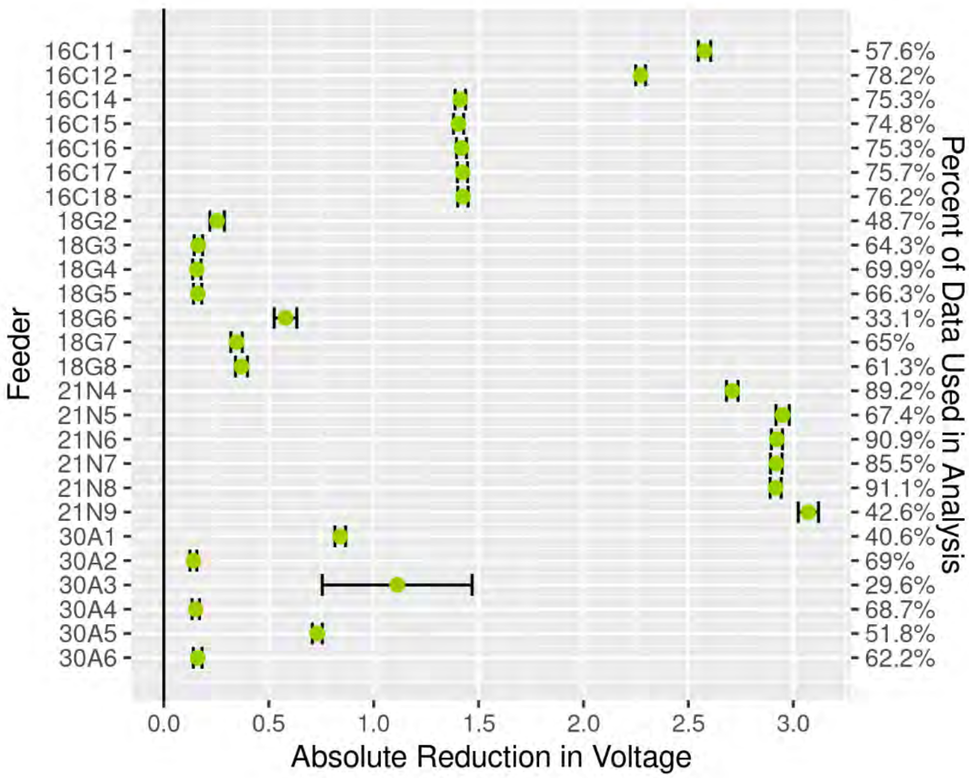
| Average Hourly Reduction (V) | Average Hourly Reduction (%) |
|---|---|
| 1.52 ± 0.01 Volts | 1.24 ± 0.01% |

* Absolute and percentage voltage reductions provided for each period is the load-weighted average of absolute and percentage voltage reductions estimated for each feeder.
*Source: Guidehouse analysis*

Figure 24 indicates the average hourly voltage reductions for each Eversource feeder, with green points indicating each feeder's voltage reduction. The whiskers overlaid on each feeder's voltage reduction estimate provide the associated 90% confidence intervals. Where the confidence interval crosses the zero line, results may be interpreted as statistically insignificant.

All 26 feeders experienced statistically significant reductions in voltage when VVO was engaged.

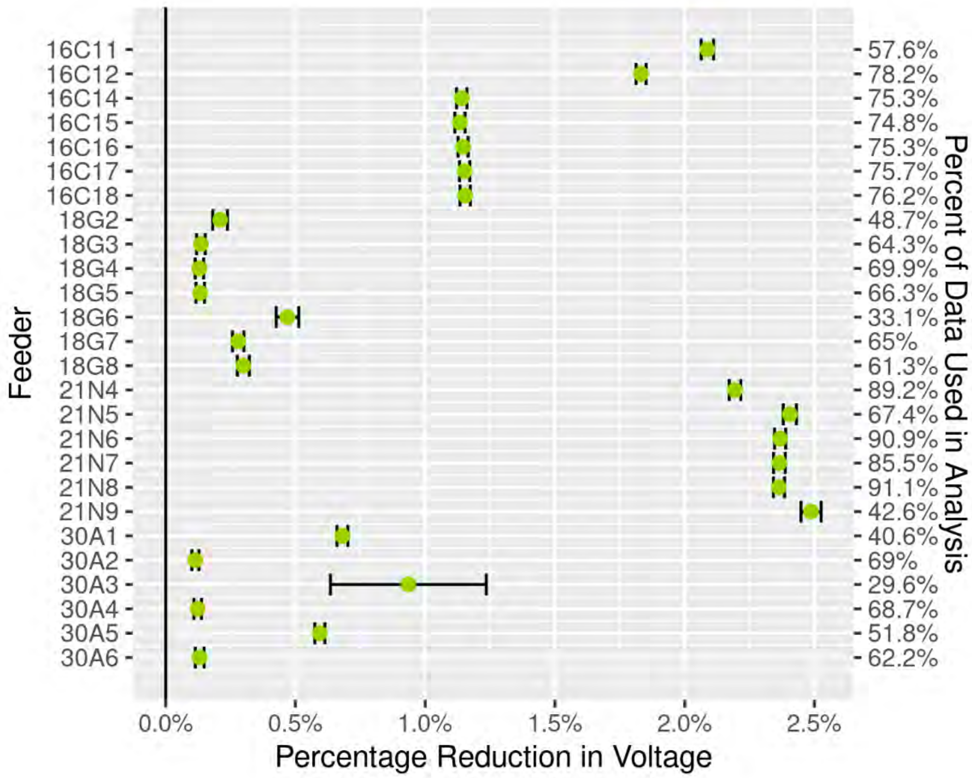
**Figure 24. Average Hourly Voltage Reduction (V) for Eversource VVO Feeders**




*Source: Guidehouse analysis*

Figure 25Figure 25 indicates the net voltage reductions for each Eversource feeder in percentage terms, with green points indicating each feeder's percentage voltage reduction. The whiskers overlaid on each feeder's percentage voltage reduction estimate provide the associated 90% confidence intervals. Where the confidence interval crosses the zero line, results may be interpreted as statistically insignificant.

**Figure 25. Average Hourly Voltage Reduction (%) for Eversource VVO Feeders**




*Source: Guidehouse analysis*

While all feeders underwent a statistically significant reduction in voltage, Podick 18G and even-numbered feeders at Silver 30A experienced a very minimal reduction in voltage, suggesting VVO was not operating as expected on these feeders. Energy reduction estimates are largely in-line with this finding, with most Podick feeders experiencing a statistically insignificant change in energy when VVO was engaged. In contrast, Piper 21N and Agawam 16C feeders experienced the largest reductions in voltage. Correspondingly, estimated energy savings for these feeders were statistically significant, with savings for most between 0.5% and 2.0%.

Following an estimation of percentage energy savings and percentage voltage reductions attributed to VVO, Guidehouse calculated the associated CVR factors for each feeder. The CVR factor, which is the ratio of percentage energy savings to percentage voltage reductions, can provide an estimate of the percentage energy savings possible with each percent voltage reduction. Equation 5-1 in the Appendix highlights how the CVR factor is calculated using an estimated percentage change in energy and in voltage. Table 79 provides the CVR factor for Eversource, and Figure 26 provides the CVR factors for the Spring 2022 – Winter 2022/23 M&V period for each feeder. Based on evaluation findings, the CVR factor for the Spring 2022 – Winter 2022/23 time period was 0.60.

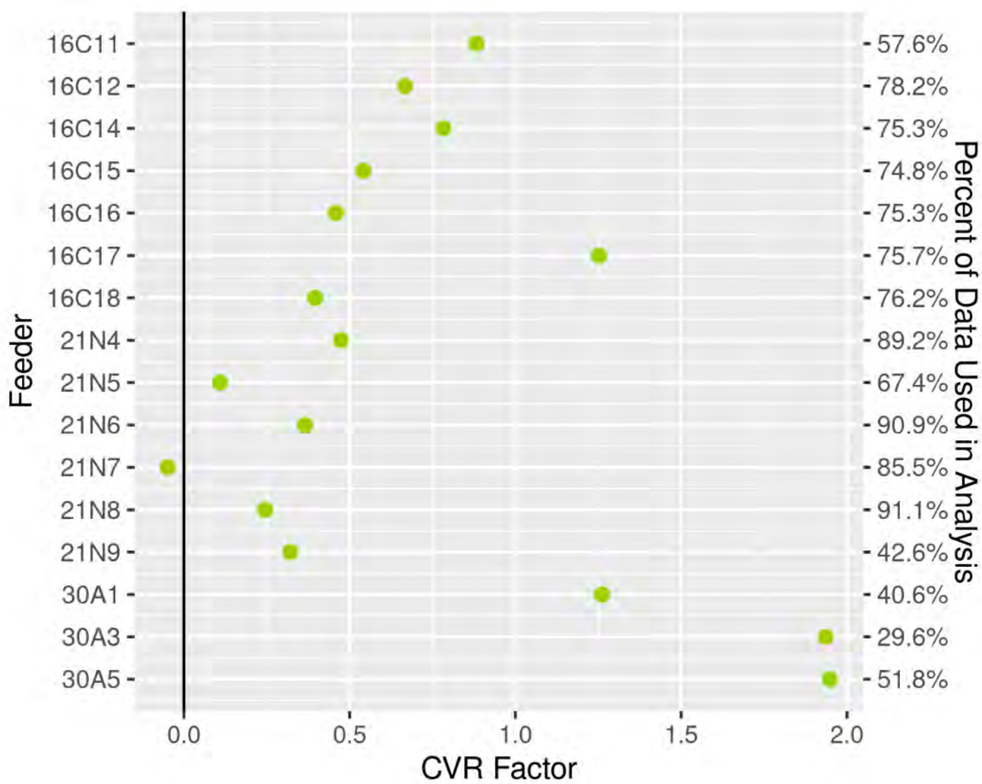
**Table 79. Eversource VVO CVR Factor**

| CVR Factor† |
|---|
| 0.60 |

† The CVR factor provided is the load-weighted average of CVR factors estimated for each feeder. All Podick feeders and Silver feeders 30A2, 30A4, and 30A6 experienced extremely small changes in voltage and have been excluded from overall CVRf calculations due to the outsize effect they have on overall estimates.

*Source: Guidehouse analysis*

**Figure 26. Eversource VVO CVR Factors***




* All Podick feeders and Silver feeders 30A2, 30A4, and 30A6 experienced extremely small changes in voltage and have been excluded from overall CVRf calculations due to the outsize effect they have on overall estimates.

*Source: Guidehouse analysis*

***PM-3: Peak Demand Impact***

Guidehouse evaluated the impact of VVO during peak demand periods, defined by ISO-NE as 1:00 p.m. to 5:00 p.m. ET from June 1 to August 31 on non-holiday weekdays. Table 80 details the evaluated peak demand impact across all feeders in absolute and percentage terms.

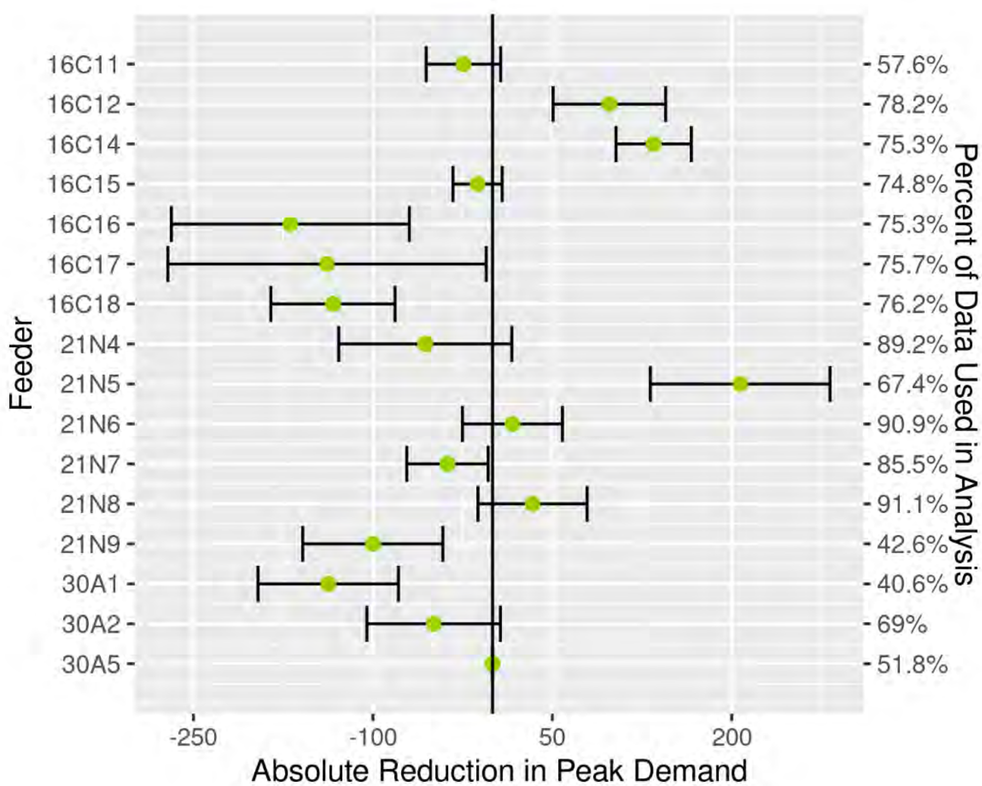
**Table 80. Eversource VVO Average Reduction in Peak Demand**

| Peak Demand Reduction (kW) † | Peak Demand Reduction (%)† |
|---|---|
| -369 ± 245 kW | -0.70 ± 0.46% |

† The percentage peak demand reduction presented in this table is the load-weighted average of percentage peak demand reductions estimated for each feeder. All Podick feeders and Silver feeders 30A3, 30A4, and 30A6 were removed from Peak Demand reduction calculations because they have unreliable standard error estimates.
*Source: Guidehouse analysis*

Figure 27 indicates the demand reductions measured in kW realized during the peak demand period, defined by ISO-NE as 1:00 p.m. to 5:00 p.m. ET from June 1 to August 31 on non-holiday weekdays. The whiskers overlaid on each feeder's absolute demand reduction estimate provide the associated 90% confidence intervals. Where the confidence interval crosses the zero line, results may be interpreted as statistically insignificant. Of the VVO feeders, only feeders 16C12, 16C14, and 21N5 experienced a statistically significant reduction in peak demand. All remaining feeders had an estimated statistically insignificant change in peak demand (7 feeders) or an estimated increase in peak demand (6 feeders).

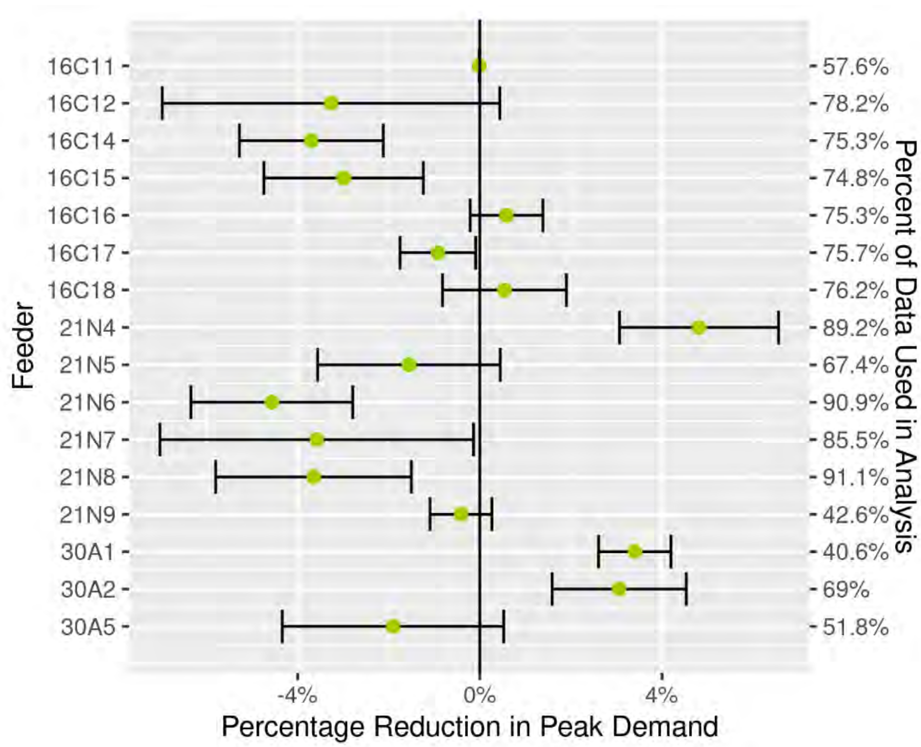
**Figure 27. Eversource Reduction in Peak Demand (kW)**




*Source: Guidehouse analysis* Where the confidence interval crosses the zero line, results may be interpreted as statistically insignificant.

Figure 28 indicates the percentage load reductions realized during the peak demand period, defined by ISO-NE as 1:00 p.m. to 5:00 p.m. ET from June 1 to August 31 on non-holiday weekdays. The whiskers overlaid on each feeder's percentage demand reduction estimate provide the associated 90% confidence intervals. Where the confidence interval crosses the zero line, results may be interpreted as statistically insignificant.

**Figure 28. Eversource Reduction in Peak Demand (%)**




*Source: Guidehouse analysis*

Eversource and National Grid saw increases in peak demand between 1:00 p.m. and 5:00 p.m. on non-holiday summer weekdays. This was a finding in both the previous and current evaluations (i.e., PY 2021 and PY 2022). This may be attributable to a number of factors that were present during those hours:

- There is variation in customer types and their relative load contributions depending on the time of day. If feeder load was more heavily comprised of end-uses with constant power load during peak hours as currently defined, a reduction in voltage can be met by a corresponding increase in amperage, which could appear as an increase in MW load at the feeder head-end. For instance, if feeder load was more heavily comprised of commercial or industrial load during those hours, industrial equipment could have actually become more inefficient with a drop in voltage, which could appear as an increase in MW load at the feeder head-end.
- Distribution generation, which has considerable generation during early- to mid-afternoon hours during the summer, may have caused unintended interactions with the VVO scheme.

The period of 1:00 p.m. to 5:00 p.m. for non-holiday summer weekdays was based on ISO-NE's peak demand definition, which was identified in the Stage 3 Evaluation Plan and has been used since the PY 2021 evaluation report. This was intended to be consistent with energy efficiency evaluations. Guidehouse has reviewed other time frames (e.g., 6:00 p.m. to 10:00 p.m.) that better represent the average feeder peaks for those feeders with VVO enabled. However, to be consistent with the Stage 3 Evaluation Plan and prior evaluation reports, this evaluation included the results for the 1:00 p.m. to 5:00 p.m. timeframe. Guidehouse will further explore alternative definitions for peak periods to determine the proper definition moving forward.

***PM-4: Distribution Losses***

Guidehouse evaluated reduction in distribution losses as a function of VVO during the Spring 2022 – Winter 2022/23 M&V period. Per the Stage 3 Evaluation Plan submitted March 1, 2023, Guidehouse estimated changes in power factor where kW was greater than 75% of annual peak demand.[56] There were several feeders with very little data where kW was greater than 75% of annual peak demand for kVA. These feeders were ultimately removed from the power factor models, as they had fewer than 100 hours of data available for use in regression modeling. Given power factor is an input for the distribution losses equation, these feeders were ultimately removed from the distribution losses calculation. The methodology for calculating the percent reduction in distribution losses is shown in Appendix 5.3B.8.

Table 81 and Figure 29 indicates the estimated percentage change in distribution losses for each Eversource feeder with sufficient data quality.

**Table 81. Eversource VVO Distribution Losses**

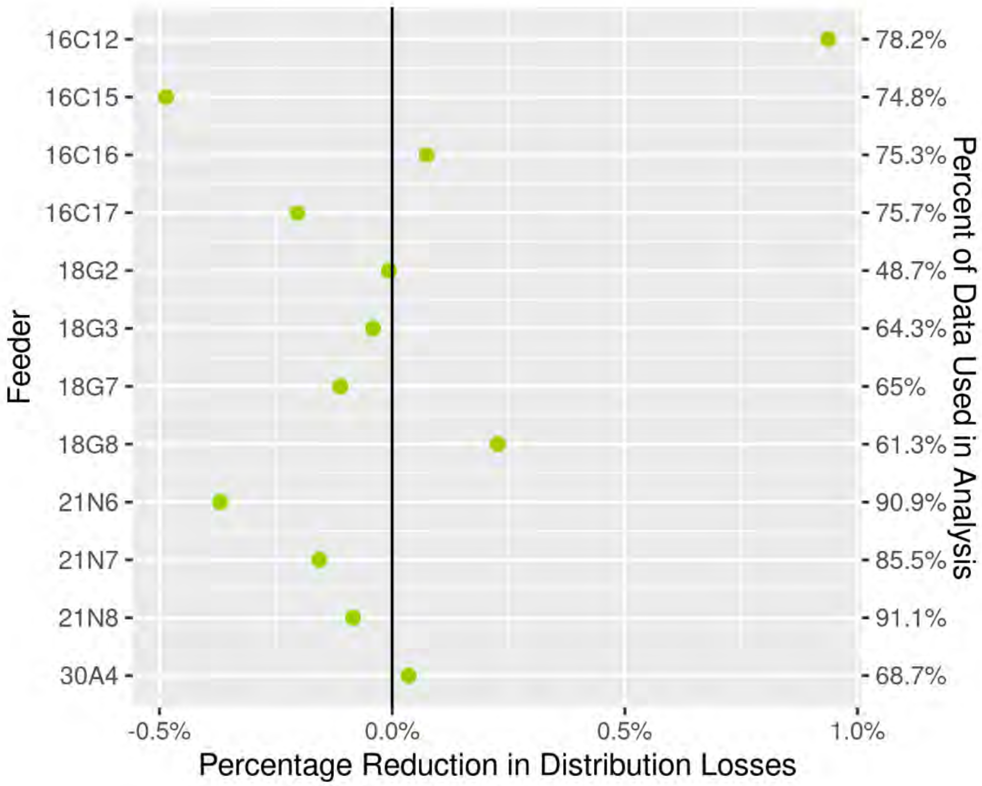
| Reduction in Distribution Losses (%)† |
|---|
| 0.01% |

† The change in distribution losses presented in this table is the load-weighted average of change in distribution losses estimated for each feeder

*Source: Guidehouse analysis*

[56] This assumes sufficient data being available for use in the analysis for each VVO feeder. For some seasons, including winter, there will be a relatively small number of hours that meet the 75% threshold. Data limitations will limit Guidehouse's ability to conduct analysis for specific feeders or seasons in this case.

**Figure 29. Eversource Reduction in Distribution Losses**




*Source: Guidehouse analysis*

***PM-5: Power Factor***

Guidehouse evaluated the impact on power factor associated with VVO during the Spring 2022 – Winter 2022/23 M&V period. Changes in power factor were analyzed during periods where power was greater than 75% of feeder-specific annual demand. Table 82 details the evaluated change in power factor for each Eversource feeder where clean data existed in sufficient quantity.[57]

**Table 82. Eversource VVO Average Hourly Power Factor Change**

| Change in Power Factor† | Change in Power Factor (%)† |
|---|---|
| <0.001 ± <0.001 | 0.06 ± 0.02% |

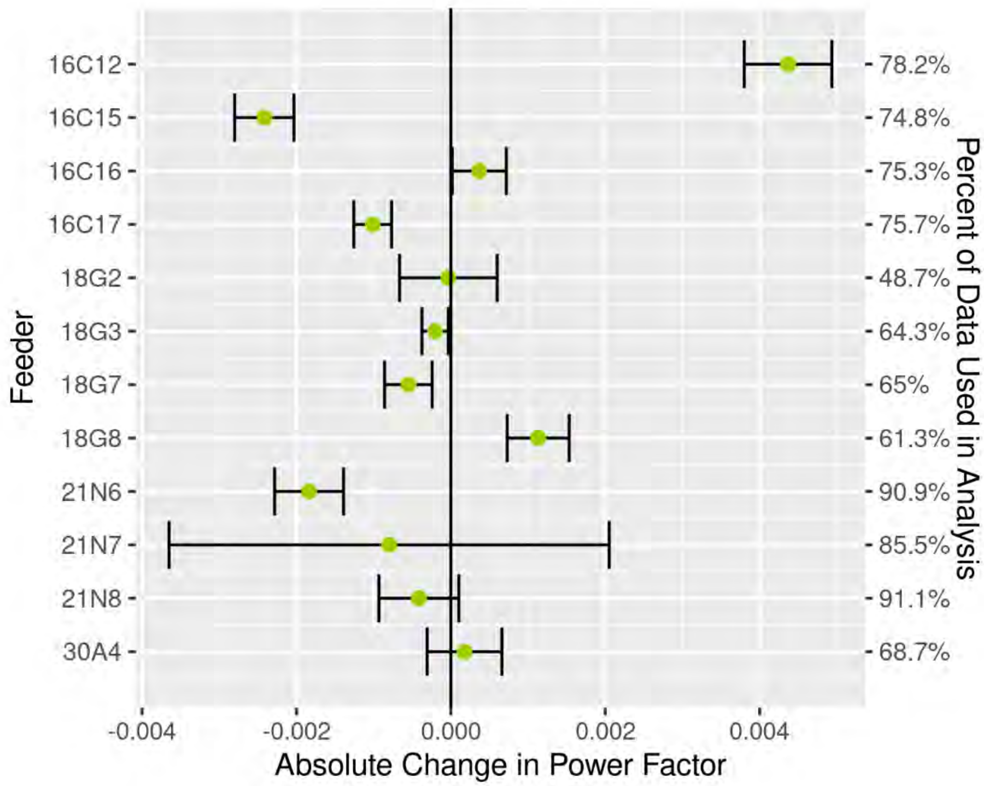
† Power factor changes presented in this table are the load-weighted averages of power factor changes estimated for each feeder
*Source: Guidehouse analysis*

Figure 30 indicates the change in power factor for each Eversource feeder in absolute terms, with green points indicating each feeder's absolute power factor change. The whiskers overlaid

[57] There were some feeders with very little data where kW was greater than 75% of annual peak load for kVA. These feeders were ultimately removed from the power factor models, as they had fewer than 100 hours available for use in regression modeling.

on each feeder's absolute power factor change estimate provide the associated 90% confidence intervals. Where the confidence interval crosses the zero line, results may be interpreted as statistically insignificant.

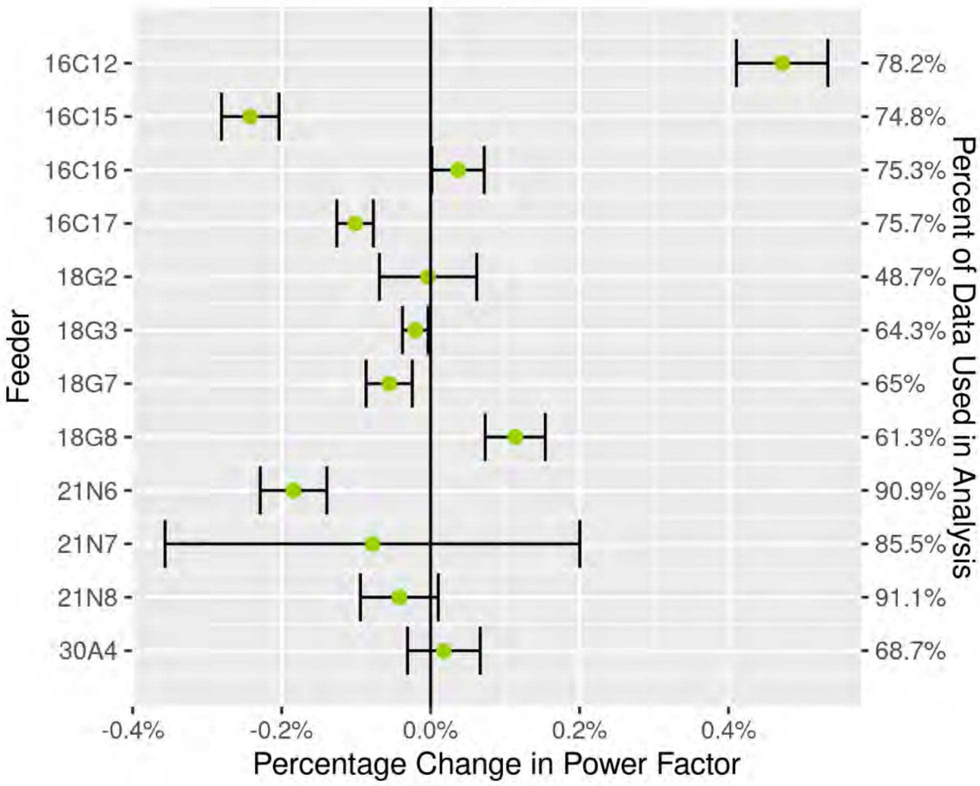
**Figure 30. Eversource Absolute Change in Power Factor**




*Source: Guidehouse analysis*

Figure 31 indicates the change in power factor for each Eversource feeder in percentage terms, with green points indicating each feeder's percentage power factor change. The whiskers overlaid on each feeder's percentage power factor change estimate provide the associated 90% confidence intervals. Where the confidence interval crosses the zero line, results may be interpreted as statistically insignificant. Most feeders underwent a statistically significant change in power factor, although the changes in power factors were relatively small.

**Figure 31. Eversource Percentage Change in Power Factor**




*Source: Guidehouse analysis*

***PM-6: GHG Reduction***

After evaluating energy savings attributed to VVO, Guidehouse calculated the resulting emissions reductions. For 2022, emissions reductions were determined by to be 0.34 metric tons of emissions per MWh. This was calculated drawing the 2019 value from DPU 18-110 – DPU 18-119, Massachusetts Joint Statewide Electric and Gas Three Year Energy Efficiency Plan for 2019 – 2021, the 2025 value from DPU 21-120 – DPU 21-129, Massachusetts Joint Statewide Electric and Gas Three-Year Energy Efficiency Plan for 2022-2024, and then interpolating the 2022 value from these two sources.[58]

Table 83 provides emissions reductions associated with VVO, with 90% confidence bounds indicated by the ± figure.

[58] 2019 Emissions factors can be found on page 201 of Massachusetts Joint Statewide Electric and Gas Three Year Energy Efficiency Plans for 2019 – 2021 https://ma-eeac.org/wp-content/uploads/Exh.-1-Final-Plan-10-31-18-With-Appendices-no-bulk.pdf. 2025 emissions factors can be found on page 326 of Massachusetts Joint Statewide Electric and Gas Three Year Energy Efficiency Plans for 2022 – 2024 https://ma-eeac.org/wp-content/uploads/Exhibit-1-Three-Year-Plan-2022-2024-11-1-21-w-App-1.pdf

**Table 83. Eversource VVO Emissions Reductions**

| Metric | $CO_2$ |
|---|---|
| Spring 2022 – Winter 2022/23 Emissions Reduction | 299 ± 63 tons |

*Source: Guidehouse analysis*

***PM-7: Voltage Complaints***

Guidehouse received voltage complaint logs from Eversource to facilitate Performance Metrics analysis. Guidehouse tabulated voltage complaints received by VVO feeder between 2015 and 2022. Discussion below highlights key observations for voltage complaints and compares the count of voltage complaints received during 2022 to the average number of voltage complaints from the 2015–2017 baseline period.

Table 84 summarizes voltage complaints for the Agawam substation. Relative to the average number of voltage complaints per year received prior to when VVO investments were deployed on these feeders (2015 – 2027), 2022 saw no change in voltage complaints relative to baseline at the Agawam substation.

**Table 84. Count of Voltage Complaints for Agawam Substation**

| Number of Voltage Complaints | 16C11 | 16C12 | 16C14 | 16C15 | 16C16 | 16C17 | 16C18 | Total |
|---|---|---|---|---|---|---|---|---|
| Customers* | 1,350 | 80 | 1,632 | 1,270 | 2,563 | 2,388 | 3,054 | 12,337 |
| 2015 | 0 | 0 | 2 | 2 | 4 | 2 | 0 | 10 |
| 2016 | 0 | 0 | 2 | 0 | 7 | 3 | 2 | 14 |
| 2017 | 1 | 0 | 2 | 3 | 7 | 3 | 5 | 21 |
| **Baseline†** | **1** | **0** | **2** | **3** | **6** | **3** | **3** | **15** |
| 2018 | 0 | 0 | 2 | 0 | 3 | 8 | 1 | **14** |
| 2019 | 4 | 0 | 1 | 0 | 5 | 5 | 4 | **19** |
| 2020 | 5 | 3 | 0 | 3 | 6 | 4 | 2 | **23** |
| 2021 | 1 | 0 | 1 | 2 | 7 | 2 | 2 | **15** |
| **2022** | **2** | **1** | **4** | **0** | **1** | **4** | **3** | **15** |

* Count of customers served by each feeder was extracted from the 2022 D.P.U 23-30 Report, Appendix B.
† The baseline number of voltage complaints is calculated as the average number of voltage complaints between 2015 and 2017, rounded up to the nearest whole number

*Source: Guidehouse analysis*

Table 85 summarizes the count of voltage complaints for the Piper substation. Looking at 2015–2017 baseline period, there were 21 voltage complaints received, amounting to 7 voltage complaints per year. Relative to the baseline period, there were 1 fewer voltage complaints reported at the Piper substation in 2022.

**Table 85. Count of Voltage Complaints for Piper Substation**

| Number of Voltage Complaints | 21N4 | 21N5 | 21N6 | 21N7 | 21N8 | 21N9 | Total |
|---|---|---|---|---|---|---|---|
| Customers* | 2,299 | 829 | 787 | 2 | 557 | 2,404 | 6,878 |
| 2015 | 1 | 1 | 2 | 0 | 0 | 2 | **6** |
| 2016 | 2 | 1 | 0 | 0 | 0 | 3 | **6** |
| 2017 | 4 | 2 | 1 | 0 | 0 | 2 | **9** |
| **Baseline†** | **3** | **2** | **1** | **0** | **0** | **3** | **7** |
| 2018 | 1 | 0 | 0 | 0 | 0 | 3 | **4** |
| 2019 | 2 | 1 | 0 | 0 | 3 | 5 | **11** |
| 2020 | 6 | 3 | 1 | 0 | 0 | 1 | **11** |
| **2022** | **2** | **1** | **0** | **0** | **0** | **3** | **6** |

* Count of customers served by each feeder was extracted from the 2022 D.P.U 23-30 Report, Appendix B.
† The baseline number of voltage complaints is calculated as the average number of voltage complaints between 2015 and 2017, rounded up to the nearest whole number

*Source: Guidehouse analysis*

Table 86 summarizes the count of voltage complaints for the Podick substation. Looking at 2015–2017 baseline period, there were 69 voltage complaints received, amounting to 23 voltage complaints per year. Based on voltage complaints data received, a total of 19 voltage complaints were reported along the Podick feeders during 2022, four fewer complaints than observed during the baseline period.

**Table 86. Count of Voltage Complaints for Podick Substation**

| Number of Voltage Complaints | 18G2 | 18G3 | 18G4 | 18G5 | 18G6 | 18G7 | 18G8 | Total |
|---|---|---|---|---|---|---|---|---|
| Customers* | 9 | 2,141 | 2,347 | 1,778 | 1,289 | 2,226 | 1,089 | 10,879 |
| 2015 | 0 | 3 | 1 | 2 | 1 | 3 | 3 | **13** |
| 2016 | 1 | 1 | 4 | 1 | 2 | 11 | 13 | **33** |
| 2017 | 0 | 0 | 5 | 4 | 3 | 6 | 5 | **23** |
| **Baseline†** | **1** | **1** | **4** | **3** | **2** | **7** | **7** | **23** |
| 2018 | 0 | 1 | 4 | 6 | 3 | 8 | 14 | **36** |
| 2019 | 0 | 6 | 5 | 8 | 1 | 4 | 3 | **27** |
| 2020 | 0 | 1 | 4 | 11 | 9 | 8 | 6 | **39** |
| 2021 | 0 | 3 | 6 | 7 | 3 | 7 | 5 | **31** |
| **2022** | **0** | **0** | **2** | **8** | **1** | **3** | **5** | **19** |

* Count of customers served by each feeder was extracted from the 2022 D.P.U 23-30 Report, Appendix B.
† The baseline number of voltage complaints is calculated as the average number of voltage complaints between 2015 and 2017, rounded up to the nearest whole number

*Source: Guidehouse analysis*

Table 87 summarizes the count of voltage complaints for the Silver substation. Looking at 2015–2017 baseline period, there were 45 voltage complaints received, amounting to 16 voltage complaints per year. Based on voltage complaints data received, a total of 13 voltage complaints were reported along the Silver feeders in 2022, three fewer complaints than were observed during the baseline period.

**Table 87. Count of Voltage Complaints for Silver Substation**

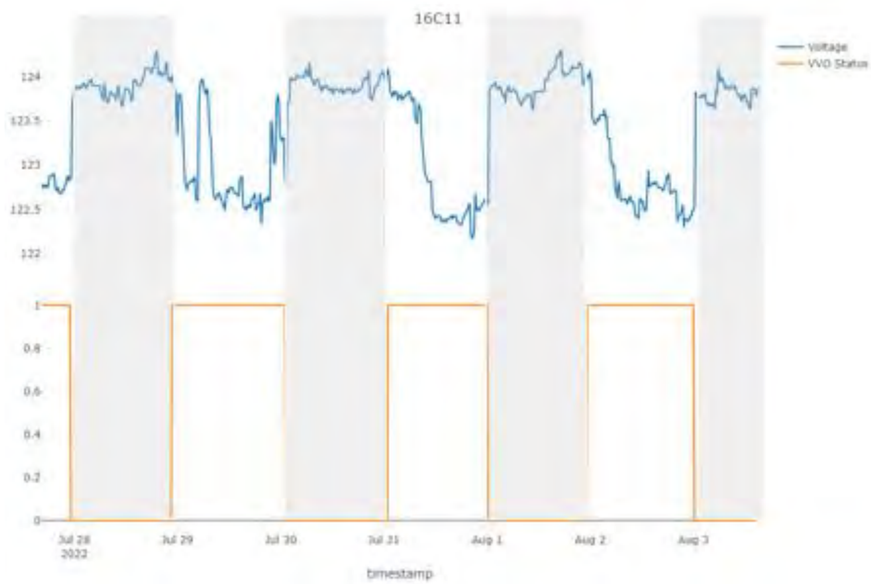
| Number of Voltage Complaints | 30A1 | 30A2 | 30A3 | 30A4 | 30A5 | 30A6 | Total |
|---|---|---|---|---|---|---|---|
| Customers* | 2,519 | 2,286 | 239 | 801 | 1,659 | 1,007 | 8,511 |
| 2015 | 2 | 1 | 0 | 1 | 1 | 2 | **7** |
| 2016 | 4 | 5 | 1 | 1 | 2 | 5 | **18** |
| 2017 | 3 | 8 | 2 | 1 | 3 | 3 | **20** |
| **Baseline†** | **3** | **5** | **1** | **1** | **2** | **4** | **16** |
| 2018 | 4 | 2 | 0 | 2 | 0 | 2 | **10** |
| 2019 | 6 | 5 | 1 | 0 | 2 | 3 | **17** |
| 2020 | 5 | 1 | 2 | 4 | 1 | 4 | **17** |
| 2021 | 8 | 3 | 0 | 0 | 1 | 5 | **17** |
| **2022** | **7** | **1** | **2** | **1** | **1** | **1** | **13** |

* Count of customers served by each feeder was extracted from the 2022 D.P.U 23-30 Report, Appendix B.
† The baseline number of voltage complaints is calculated as the average number of voltage complaints between 2015 and 2017, rounded up to the nearest whole number
‡ Only includes the first quarter of voltage complaints for 2023.
^ The count of voltage complaints in Spring 2022 – Winter 2022/23 contains some of the 2022 voltage complaints and all 2023 voltage complaints presented.
*Source: Guidehouse analysis*

#### *4.2.2.4 Additional Investigation of Podick and Even-Numbered Silver Feeders*

When feeders are undergoing VVO On/Off testing, Guidehouse usually expects to see head-end voltage levels cycling with VVO On/Off status, with voltage levels remaining somewhat higher when VVO is disengaged (e.g., around 124 Volts) and remaining somewhat lower when VVO is engaged (e.g., around 120 Volts). An example of the expected voltage response to VVO is shown in Figure 32 below highlights voltage (in blue) and VVO On/Off status (in orange, where VVO status equal to one corresponds with VVO being engaged) observed for the Agawam 16C substation from July 28, 2022 through August 3, 2022.

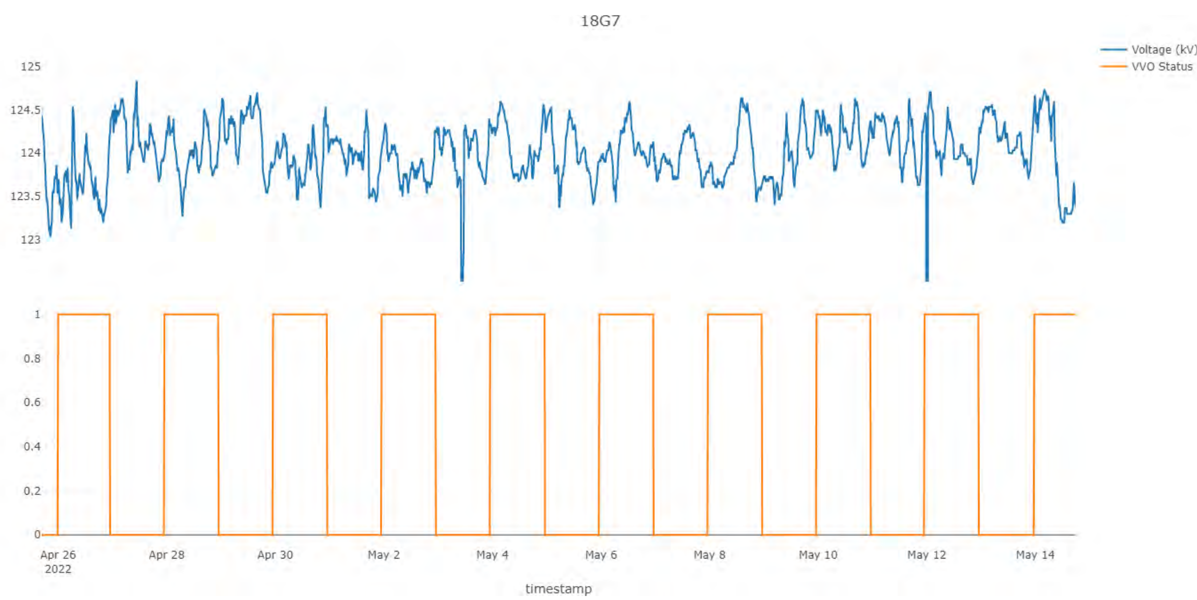
**Figure 32. VVO On/Off Testing at Feeder 16C11**




*Source: Guidehouse analysis*

During the process of data QA/QC, Guidehouse discovered that feeders at the Podick and Silver substations did not respond similarly to VVO signals. One such case is presented in Figure 33 for the feeder 18G7, where voltage (in blue) and VVO On/Off status (in orange, where VVO status equal to one corresponds with VVO being engaged) are plotted together for the period spanning April 26, 2022 through May 14, 2022.

**Figure 33. VVO On/Off Testing at Feeder 18G7**




*Source: Guidehouse analysis*

Figure 33 illustrates that voltage did not respond as expected during VVO On/Off testing throughout the period spanning April 26, 2022 through May 14, 2022. This was a pattern that was observed throughout much of the Spring 2022 – Winter 2022/23 evaluation period. These patterns were detected regression models and resulted in a minimal estimated impact associated with VVO across numerous feeders (e.g., all Podick 18G feeders and all even-numbered Silver 30A feeders), as VVO was marked as engaged but was not yielding clear voltage benefits. Guidehouse recommends that Eversource continue to investigate what may be driving these voltage patterns and what, if any, changes to the VVO control scheme needs to occur to ensure that VVO is correctly regulating voltage when VVO is engaged.

#### *4.2.2.5 Key Findings and Recommendations*

Guidehouse's VVO evaluation findings indicate that VVO allowed Eversource to realize some benefits during the Spring 2022 – Winter 2022/23 M&V period. More specifically:

- Eversource VVO feeders realized 0.41% energy savings and 1.24% voltage reductions when VVO was engaged. Podick feeders realized the least voltage benefits, with almost no change in voltage when VVO was engaged, which may indicate VVO malfunctions occurred. Additionally, Piper 21N4 realized the greatest energy savings, with 2.5% energy savings when VVO was engaged. Lastly, Podick 18G2, 18G8 as well as Silver 30A4 and 30A6 realized the least energy benefits, with a 0.75% increase in energy associated with VVO.
- Eversource VVO feeders experienced a statistically significant increase (0.70%) in peak demand when VVO was engaged. Additionally, Eversource VVO feeders experienced a statistically significant change (0.06%) in power factor when VVO was engaged, which resulted in a minimal decrease in distribution losses (0.01%).

In 2023 and beyond, Guidehouse recommends that Eversource:

- Ensure VVO On/Off testing is running according to plan, with limited pauses to the VVO On/Off testing schedule. Across the VVO feeders, one-quarter to one-half of data points were removed due to extended pauses in VVO On/Off testing. For some feeders, this resulted in the vast majority of provided data to be unusable for components of this evaluation (e.g., for estimation of distribution loss and power factor reductions). Sustained On/Off testing will increase the amount of usable data in the evaluation and improve the ability for Guidehouse to provide a comprehensive evaluation of VVO performance metrics.
- Confirm adjustments to VVO On/Off testing schedule for any VVO feeders prior to implementation. VVO On/Off testing is designed similarly to a Randomized Controlled Trial (RCT), and adjustments to the testing schedule could, potentially, hinder the effectiveness of the testing design and cause biases to evaluation results. Ensuring there is proper balance in the number of VVO on and off hours throughout the evaluation period will allow for Guidehouse to provide a comprehensive and accurate evaluation of VVO performance metrics.
- Continue to investigate how to improve outcomes across VVO feeders. Many feeders underwent no material change in voltage. Correspondingly, energy reduction estimates were small-to-insignificant. These observations may indicate flaws in the VVO control scheme for these feeders. In order to improve VVO performance, Guidehouse recommends that the EDCs continue their efforts to investigate root causes to shortcomings in the VVO control schemes and work with distribution engineers and the

VVO vendors to respond accordingly. If needed, Guidehouse can conduct in-depth case studies at these substations further understand shortcomings in the VVO control scheme.

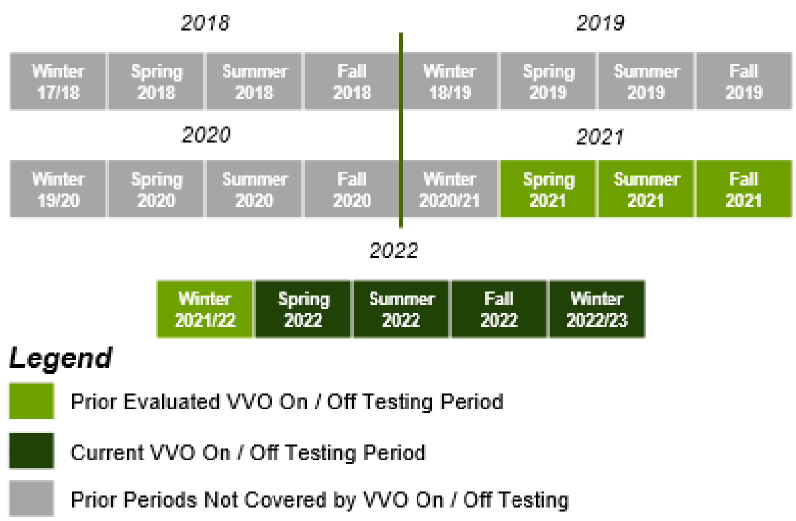
### 4.2.3 National Grid

This section discusses National Grid's VVO Performance Metrics results following the Spring 2022 – Winter 2022/23 VVO M&V period.

#### *4.2.3.1 Performance Metrics Analysis Timeline*

Figure 34 highlights the key Performance Metrics analysis periods for National Grid. The Performance Metrics analysis provided for this report will be focused on results from VVO On/Off testing conducted during Spring 2022 – Winter 2022/23.

**Figure 34. National Grid Performance Metrics Analysis Timeline**




*Source: Guidehouse analysis*

#### *4.2.3.2 Evaluation Methodology*

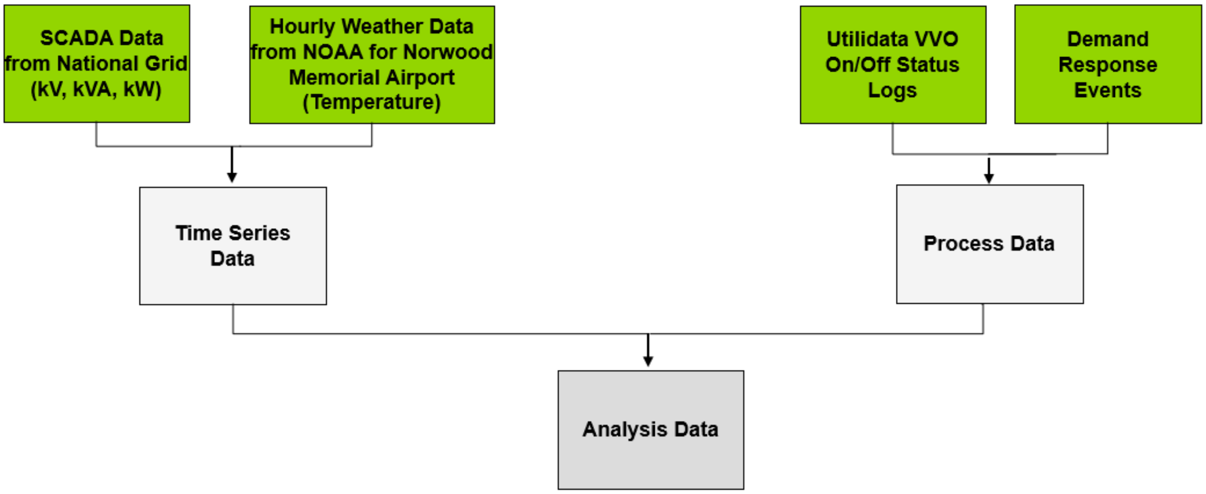
Guidehouse worked with National Grid to collect data necessary to complete the evaluation of VVO Performance Metrics. The sections that follow highlight the analysis data construction, analysis data cleaning, and the analysis approach.

***Analysis Data Construction***

To assess Performance Metrics, Guidehouse constructed an analysis dataset. This dataset was used in regression modeling to assess changes in multiple outcome variables, such as energy and peak demand. Figure 35 summarizes the data integration process used to construct the analysis dataset for the National Grid Performance Metrics analysis.[59]

[59] Guidehouse receives different data types and structures from the EDCs for estimating impacts across the performance metrics. These differences were minimized as much as possible, but any differences that remain may affect the comparability of performance metrics results across the EDCs.

**Figure 35. National Grid Analysis Data Construction Flowchart**




*Source: Guidehouse*

Guidehouse constructed time series and process data to arrive at a final analysis dataset for National Grid Performance Metrics analysis. To construct time series data, the evaluation team first integrated SCADA interval data from National Grid that contained hourly measurements of voltage, real power, and apparent power. The team then integrated hourly dry bulb temperature and hourly cloud cover data from NOAA for Norwood Memorial Airport to arrive at a final time series dataset.[60]

To construct the process data, Guidehouse integrated other VVO system information. Other system information included time-stamped logs of VVO state changes between VVO On (engaged) and Off (disengaged) states from Utilidata, and demand response events during the evaluation period. The time series and process data were then joined to construct a final analysis dataset.

***Analysis Data Cleaning***

After constructing the analysis dataset, the team conducted data cleaning steps to remove interval data that may bias the estimates of VVO impacts. Table 88 summarizes data observations made by the evaluation team and the resulting data cleaning steps that were executed.

[60] Norwood Memorial Airport was selected due to it having a quality controlled local climatological dataset and due to its being in close proximity to the National Grid substations evaluated this year. Documentation on the NOAA dataset used in this analysis can be found here: https://data.noaa.gov/dataset/dataset/quality-controlled-local-climatological-data-qclcd-publication

**Table 88. Data Cleaning Conducted for National Grid Analysis**

| Data Observation | Data Cleaning Step |
|---|---|
| Guidehouse identified a handful of periods of repeated, interpolated, and outlier values in kV, kW, and kVA data, as well as periods missing VVO-status data. | Guidehouse removed hours where anomalous data readings were flagged. |
| Guidehouse identified numerous VVO events that were longer than planned. | To reduce the risk of VVO estimates being biased by imbalance in the sample of VVO On/Off statuses (e.g., overrepresentation of VVO On during winter), Guidehouse removed all VVO events that were three or more days in length (72 hours+). |
| Even-numbered Maplewood feeders experienced almost no VVO On/Off testing during the evaluation period. | Limited VVO On and Off data streams resulted in the removal of all even-numbered Maplewood feeders from the evaluation of performance metrics. |
| Due to extensive pauses to VVO On/Off testing, as well as several data outages, there was insufficient data to measure power factor and distribution loss impacts attributed to VVO. | Guidehouse was not able to provide estimates of changes in power factor or distribution losses for any of the substations that underwent VVO On/Off testing during the evaluation period. The power factor and distribution losses results are based on feeders that completed VVO On/Off testing prior to the current evaluation period (i.e., Stoughton). |

*Source: Guidehouse*

Table 89Table 89 indicates the number of hours contained in the analysis dataset for the East Methuen, East Bridgewater, Easton, Maplewood, Stoughton, and West Salem substations. Much of the data removed during data cleaning was due to extended periods over which VVO was engaged or disengaged. Detailed data attrition information is included in Appendix B.10.

**Table 89. Count of VVO On, VVO Off, and Removed Hours for National Grid***

| Substation | Feeder | VVO On Hours | VVO Off Hours | Hours Removed by Data Cleaning | Spring 2022 – Winter 2022/23 Total |
|---|---|---|---|---|---|
| **Easton†** | 92W43 | 255 | 235 | 662 | 1,152 |
| | 92W44 | 255 | 235 | 662 | 1,152 |
| | 92W54 | 255 | 235 | 662 | 1,152 |
| | 92W78 | 255 | 235 | 662 | 1,152 |
| | 92W79 | 255 | 235 | 662 | 1,152 |
| **East Bridgewater** | 797W1 | 1,278 | 1,310 | 6,172 | 8,760 |
| | 797W19 | 1,323 | 1,351 | 6,086 | 8,760 |
| | 797W20 | 1,323 | 1,351 | 6,086 | 8,760 |
| | 797W23 | 1,278 | 1,310 | 6,172 | 8,760 |
| | 797W24 | 1,323 | 1,351 | 6,086 | 8,760 |
| | 797W29 | 1,278 | 1,310 | 6,172 | 8,760 |
| | 797W42 | 1,278 | 1,310 | 6,172 | 8,760 |
| **East Methuen** | 74L1 | 2,362 | 1,692 | 4,706 | 8,760 |
| | 74L2 | 2,008 | 1,908 | 4,844 | 8,760 |
| | 74L3 | 2,362 | 1,692 | 4,706 | 8,760 |
| | 74l4 | 2,008 | 1,908 | 4,844 | 8,760 |
| | 74L5 | 2,362 | 1,692 | 4,706 | 8,760 |
| | 74L6 | 2,008 | 1,908 | 4,844 | 8,760 |
| **Maplewood** | 16W1 | 1,175 | 1,137 | 6,448 | 8,760 |
| | 16W2 | 152 | 355 | 8,253 | 8,760 |
| | 16W3 | 1,175 | 1,137 | 6,448 | 8,760 |
| | 16W4 | 152 | 355 | 8,253 | 8,760 |
| | 16W5 | 1,175 | 1,137 | 6,448 | 8,760 |
| | 16W6 | 152 | 355 | 8,253 | 8,760 |
| | 16W7 | 1,127 | 1,092 | 6,541 | 8,760 |
| | 16W8 | 152 | 355 | 8,253 | 8,760 |
| **West Salem‡** | 29W1 | 1,109 | 1,249 | 4,209 | 6,567 |
| | 29W2 | 1,258 | 1,378 | 3,931 | 6,567 |
| | 29W3 | 1,174 | 1,275 | 4,118 | 6,567 |
| | 29W4 | 1,223 | 1,339 | 4,005 | 6,567 |
| | 29W5 | 1,133 | 1,150 | 4,284 | 6,567 |
| | 29W6 | 752 | 833 | 4,982 | 6,567 |

* Stoughton completed VVO On/Off testing prior to the evaluation period and was not subject to regression analysis to estimate performance metrics.
† Easton began VVO On/Off testing in Winter 2022/23, limiting the total number of possible hours able to be used in the analysis.

‡ West Salem began VVO On/Off testing in Summer 2022, limiting the total number of possible hours able to be used in the analysis.
*Source: Guidehouse*

### *Analysis Approach*

After the analysis data was constructed and cleaned, Guidehouse conducted regression modeling to assess the impacts of VVO on measured feeder-level energy and voltage. Equation 5-2 and Equation 5-3 in the Appendix summarizes the regression model used to estimate energy and voltage as a function of VVO.

To inform the regression model specification for estimation of energy and voltage as a function of VVO, Guidehouse conducted further inspection of the data to control for exogenous patterns. Table 90 summarizes observations made during this inspection and the resulting data analysis steps that were implemented.

**Table 90. Data Analysis Summary for National Grid**

| Data Observation | Data Analysis Step |
|---|---|
| Load and voltage data exhibit similar curvature from day-to-day, with load and voltage profiles for any two adjacent days being largely similar | A 24-hour lag of load (for energy models) and voltage (for voltage models) was included as a predictor of load (for energy models) and voltage (for voltage models) |
| Numerous feeders had a large nominal capacity of connected solar facilities. | Cloud cover and daylight hour data from NOAA were integrated and included in regression analysis to control for hourly generation observed under an array of solar conditions. |
| Large differences in energy and voltage were observed between most months in the analysis period | Monthly fixed effects were incorporated into regression modeling to capture energy and voltage differences observed across each month. |
| Numerous feeders were identified with non-residential customers making up a large portion of load, with drops in measured load during holidays and non-business hours. | Day type (i.e., weekday or weekend day) and hour of day fixed effects were incorporated into regression models to capture typical load shapes by day type and control for large drops in demand observed during non-business hours. |
| Numerous demand response events were called during the Spring 2022 – Winter 2022/23 M&V test period. | Intervals that occurred during demand response events were flagged in the regression analysis to control for changes in energy and voltage associated with demand response events. |

*Source: Guidehouse*

### *4.2.3.3 Performance Metrics Results*

This section summarizes the Performance Metrics results for National Grid. Each of the subsections separately summarize the evaluation results for each performance metric.

### *PM-1: Baseline*

As detailed in the Stage 3 Plan filed December 1, 2020, Guidehouse provides a baseline using data collected when VVO was disabled during the evaluation period, which spans Spring 2022 – Winter 2022/23. Table 91 provides the energy baseline calculated using VVO Off data collected during Spring 2022 – Winter 2022/23.

**Table 91. National Grid VVO Energy Baseline**

| Metric | Baseline Total Energy Use |
|---|---|
| Baseline Energy | 882,631 MWh |

*Source: Guidehouse analysis*

To calculate total baseline energy use, Guidehouse used regression models to first estimate energy savings that occurred for each feeder during Spring 2022 – Winter 2022/23. This resulted in an estimate of how energy use changed as a function of VVO. From there, Guidehouse fitted the model to a case in which VVO was off for the entirety of Spring 2022 – Winter 2022/23 for each VVO feeder, holding all other observable conditions constant (e.g., allowing weather to remain as it actually was when VVO was engaged). Guidehouse then summed this calculated energy usage across all hours and feeders to calculate a baseline total energy use for the Spring 2022 – Winter 2022/23 evaluation period. Baseline energy use is provided by VVO feeder in Appendix 5.3B.11.

***PM-2: Energy Savings***

Table 92 provides the evaluated energy savings for National Grid for the spring season, summer season, fall season, winter season, and Spring 2022 – Winter 2022/23 overall. The ± figure indicate 90% confidence bounds associated with energy savings estimates.

**Table 92. National Grid VVO Net Energy Reduction During Actual VVO On Hours**

| Season | Net Energy Reduction | |
|---|---|---|
| | MWh † | % ‡ |
| Spring^ | 169 ± 127 MWh | 0.37 ± 0.32% |
| Summer^^ | 317 ± 92 MWh | 1.44 ± 0.44% |
| Fall^^ | 569 ± 76 MWh | 3.33 ± 0.56% |
| Winter | 533 ± 263 MWh | 0.91 ± 0.30% |
| Spring 2022 – Winter 2022/23 Total† | 1,867 ± 302 MWh | 0.84 ± 0.15% |

† Total energy savings provided for each period is the sum of each feeder's energy savings within that period. Due to model noise, a manual sum of savings across periods may not equal the amount provided in the Total row.

‡ Percentage energy savings provided for each period is the load-weighted average of percentage savings estimated for each feeder.

^Easton and West Salem feeders are excluded from Spring estimate due to not having begun on/off testing.

^^In addition to being excluded from Spring estimate, Easton feeders are also excluded from the Summer and Fall estimates due to not having begun on/off testing.

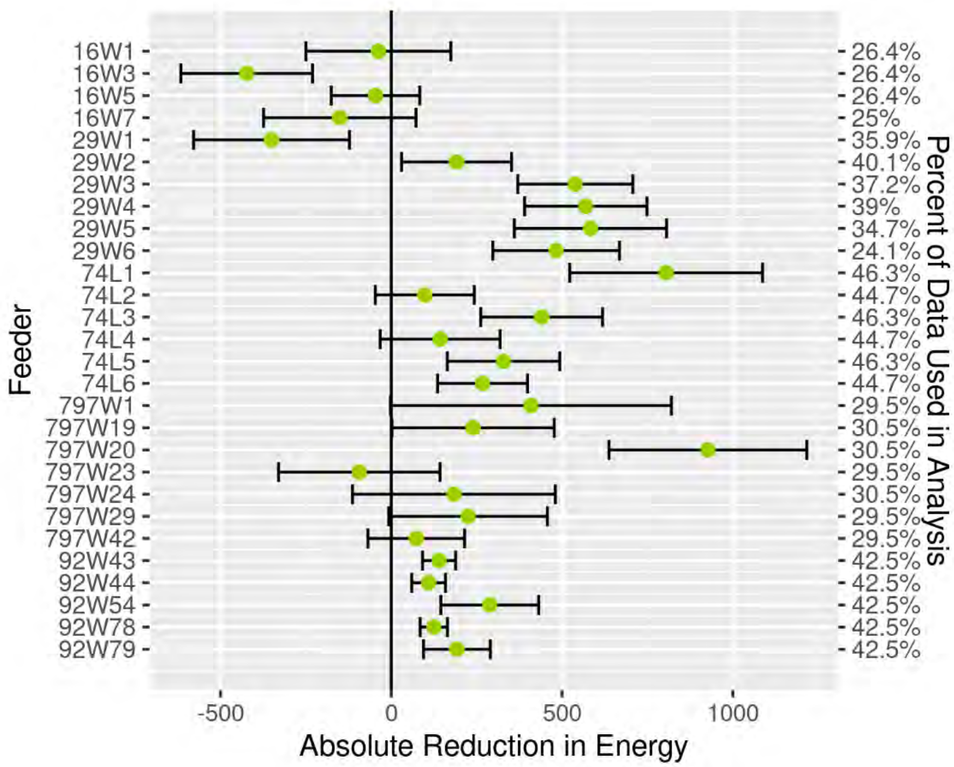
*Source: Guidehouse analysis*

Regression estimates indicate a statistically significant change in energy use associated with VVO, with 1,867 MWh (0.84%) energy savings realized during the Spring 2022 – Winter 2022/23 M&V period.[61] Regression estimates indicate that there were statistically significant reductions in energy use during all meteorological seasons. The Fall season saw the largest reduction in energy, with a value of 569 MWh, and the Spring saw the smallest reduction in energy, with a value of 169 MWh.

[61] Calculation uses actual number of VVO On hours spanning the analysis period. Actual VVO On Hours are the number of hours VVO was engaged in the clean analysis data between March 1, 2022 and February 28, 2023.

Figure 36 indicates the net energy reductions for each National Grid feeder in absolute terms (MWh), with green points indicating each feeder's MWh savings. The whiskers overlaid on each feeder's MWh savings estimate provide the associated 90% confidence intervals. Where the confidence interval crosses the zero line, results may be interpreted as statistically insignificant. During the Spring 2022 – Winter 2022/23 M&V period, 15 feeders experienced statistically significant reductions in energy. Although included in the aggregate energy impact estimate, Stoughton's individual feeder results are not presented here, as average hourly impacts estimates are unchanged from last year's evaluation.

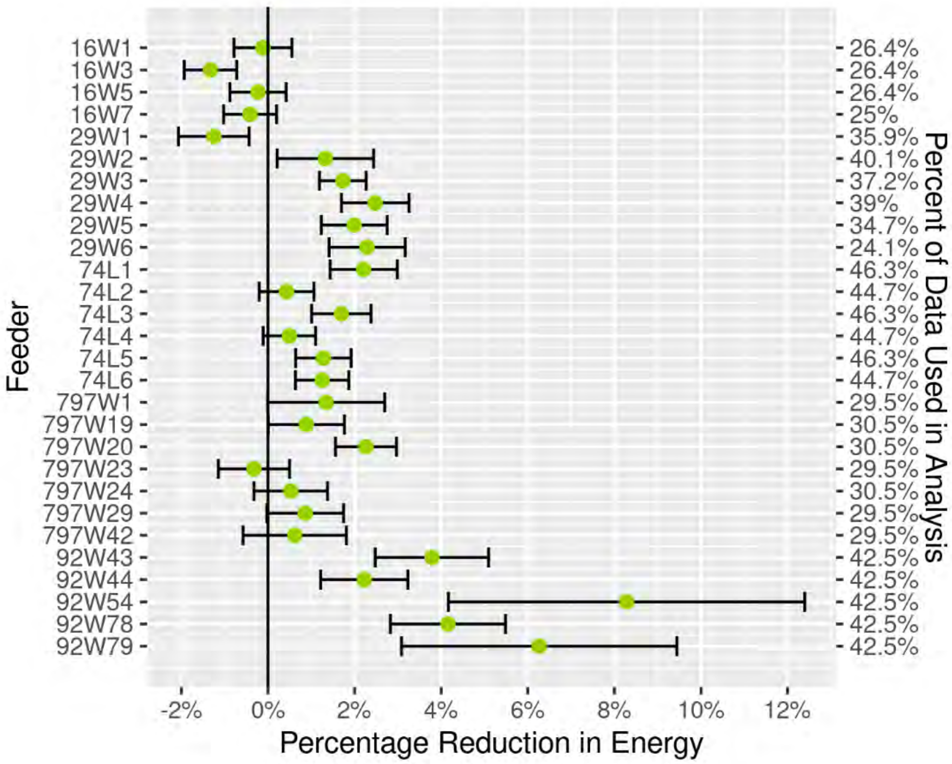
**Figure 36. Net Energy Reduction (MWh) for National Grid VVO Feeders***




* Maplewood feeders 16W2, 16W4, 16W6, and 16W8 are removed from the analysis data, as only 5 weeks of On/Off testing took place during the evaluation period. Additionally, Easton feeders only contain estimates from Winter 2023 testing and West Salem feeders only contain estimates from the Summer 2022 – Winter 2023 seasons.
*Source: Guidehouse analysis*

Figure 37 indicates the net energy reductions for each National Grid feeder in percentage terms, with green points indicating each feeder's percentage MWh savings. The whiskers overlaid on each feeder's percentage MWh savings estimate provide the associated 90% confidence intervals. Where the confidence interval crosses the zero line, results may be interpreted as statistically insignificant.

**Figure 37. Net Energy Reduction (%) for National Grid VVO Feeders***




* Maplewood feeders 16W2, 16W4, 16W6, and 16W8 are removed from the analysis data, as only 5 weeks of On/Off testing took place during the evaluation period. Additionally, Easton feeders only contain estimates from Winter 2023 testing and West Salem feeders only contain estimates from the Summer 2022 – Winter 2023 seasons.
*Source: Guidehouse analysis*

To further understand impacts, Guidehouse estimated changes in voltage associated with VVO, Table 93 provides the evaluated voltage reductions for National Grid, with 90% confidence bounds associated with voltage reductions estimates indicated by the ± figure. Regression estimates indicate a statistically significant reduction in voltage associated with VVO, with a 0.08 kV (0.62%) voltage reduction realized during the Spring 2022 – Winter 2022/23 M&V period.

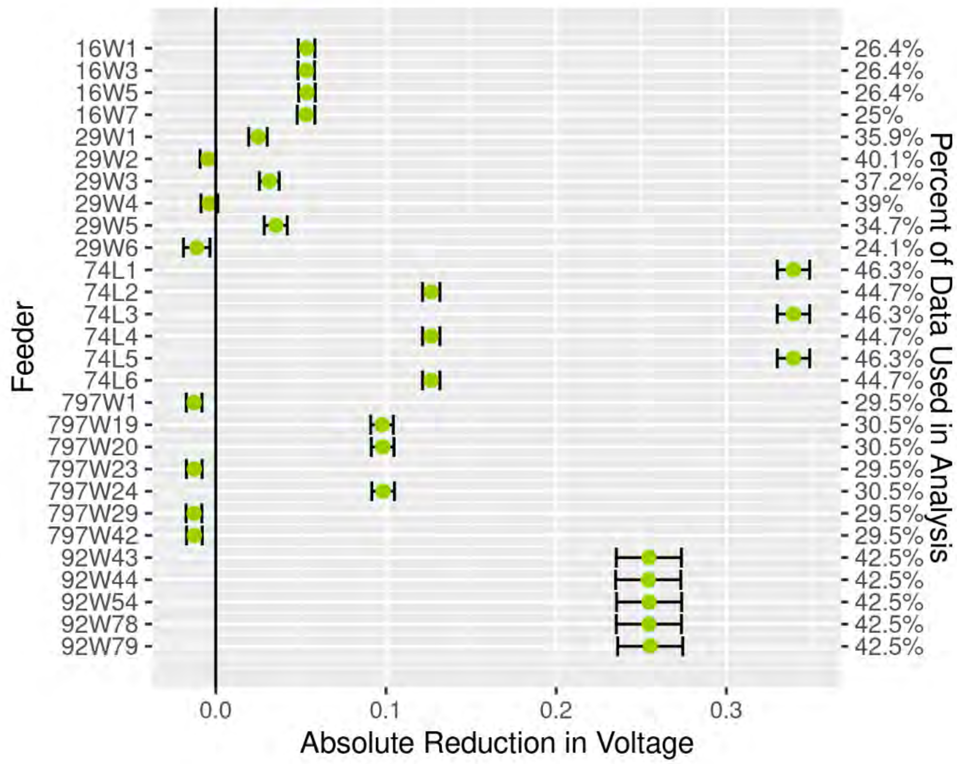
**Table 93. National Grid VVO Average Hourly Voltage Reduction***

| Average Hourly Reduction (kV) | Average Hourly Reduction (%) |
|---|---|
| 0.08 ± <0.001 kV | 0.62 ± 0.01% |

* Absolute and percentage voltage reductions provided for each period is the load-weighted average of absolute and percentage voltage reductions estimated for each feeder.
*Source: Guidehouse analysis*

Figure 38 indicates the average hourly voltage reductions for each National Grid feeder, with green points indicating each feeder's voltage reduction. The whiskers overlaid on each feeder's voltage reduction estimate provide the associated 90% confidence intervals, and the dashed line denotes the weighted average voltage reduction. Where the confidence interval crosses the zero line, results may be interpreted as statistically insignificant. The majority of feeders experienced a significantly significant average hourly voltage reduction when VVO was engaged.

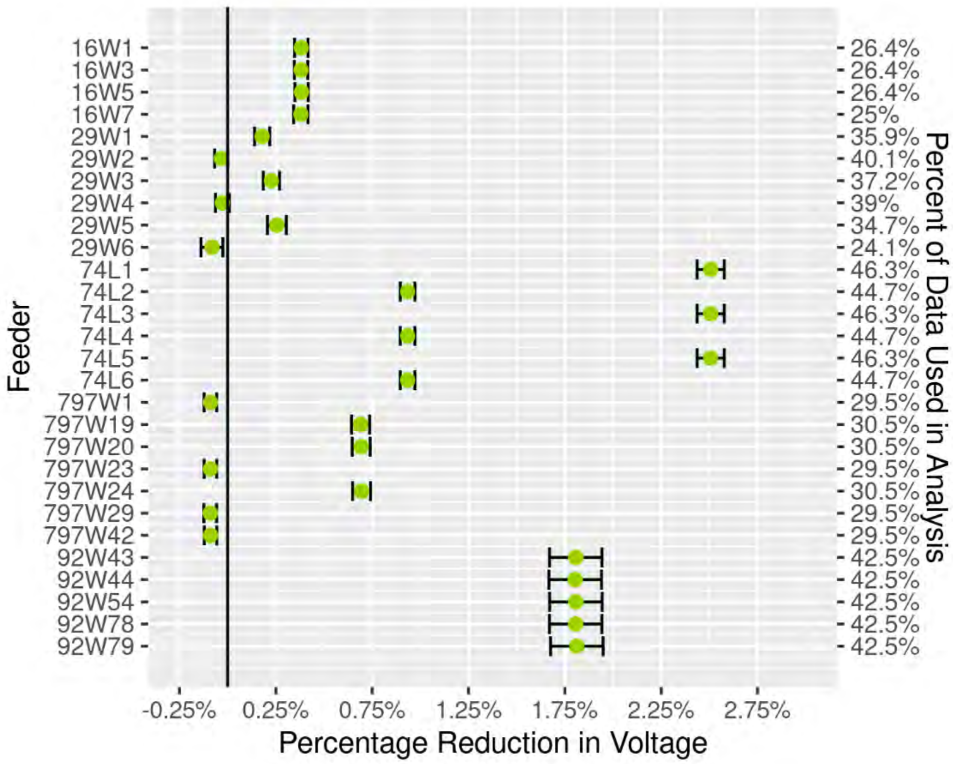
**Figure 38. Average Hourly Voltage Reduction (kV) for National Grid VVO Feeders***




* Maplewood feeders 16W2, 16W4, 16W6, and 16W8 are removed from the analysis data, as only 5 weeks of On/Off testing took place during the evaluation period. Additionally, Easton feeders only contain estimates from Winter 2023 testing and West Salem feeders only contain estimates from the Summer 2022 – Winter 2023 seasons.
*Source: Guidehouse analysis*

Figure 39 indicates the net voltage reductions for each National Grid feeder in percentage terms, with green points indicating each feeder's percentage voltage reduction. The whiskers overlaid on each feeder's percentage voltage reduction estimate provide the 90% confidence intervals. Where the confidence interval crosses the zero line, results may be interpreted as statistically insignificant. Similar to absolute voltage impacts, the majority of feeders experienced a statistically significant increase in voltage when VVO was enabled.

**Figure 39. Average Hourly Voltage Reduction (%) for National Grid VVO Feeders***




* Maplewood feeders 16W2, 16W4, 16W6, and 16W8 are removed from the analysis data, as only 5 weeks of On/Off testing took place during the evaluation period. Additionally, Easton feeders only contain estimates from Winter 2023 testing and West Salem feeders only contain estimates from the Summer 2022 – Winter 2023 seasons.
*Source: Guidehouse analysis*

Following an estimation of percentage energy savings and percentage voltage reductions attributed to VVO, Guidehouse calculated the associated CVR factors for each feeder. The CVR factor, which is the ratio of percentage energy savings to percentage voltage reductions, can provide an estimate of the percentage energy savings possible with each percent voltage reduction. Equation 5-1 in the Appendix highlights how the CVR factor is calculated using an estimated percentage change in energy and in voltage. Table 94 provides the CVR factor for National Grid.

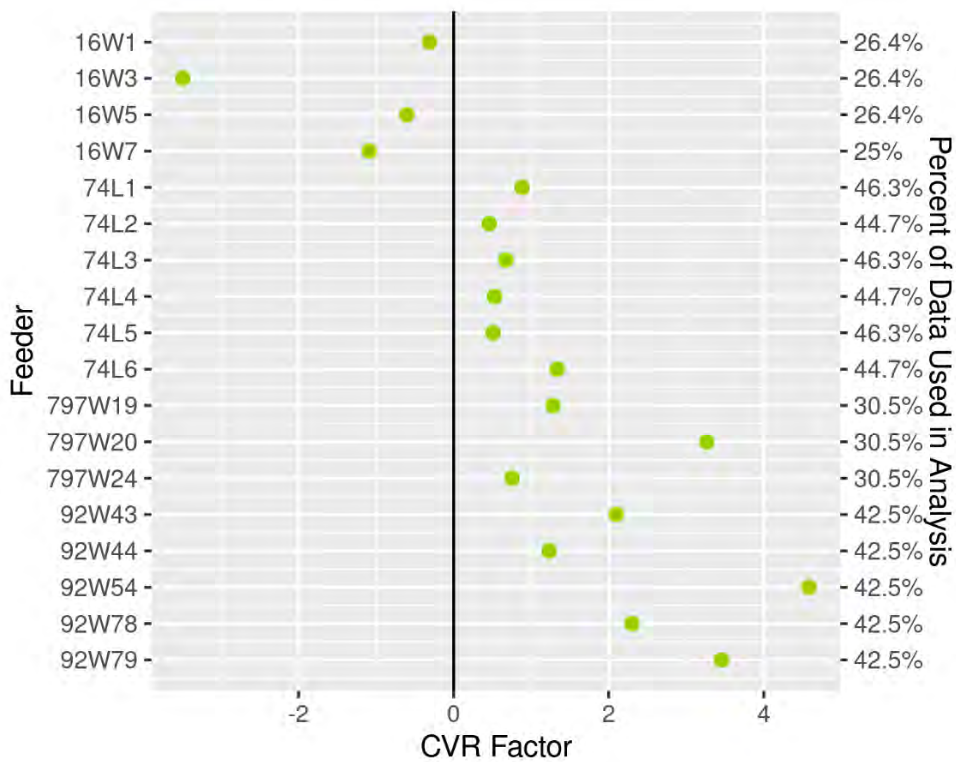
**Table 94. National Grid VVO CVR Factor***

| CVR Factor |
|---|
| 0.36 |

* Maplewood feeders 16W2, 16W4, 16W6, and 16W8 are excluded from the entire analysis due to poor VVO signal data quality. The CVR factor presented in this table is the load-weighted average of CVR factors for all analysis feeders that experienced a minimum change in voltage of ±0.25% Certain feeders with changes in voltage greater than ±0.25% were also excluded from aggregated CVRf calculations due to highly unstable voltage and energy responses to VVO On / Off testing. Feeders excluded from this calculation are all West Salem 29W feeders and East Bridgewater feeders 797W1, 797W23, 797W23, and 797W42.
*Source: Guidehouse analysis*

From prior experience evaluating VVO, Guidehouse expects a CVR factor in the neighborhood of 0.80 from a year of VVO M&V testing. Based on evaluation findings, the CVR factor for the Spring 2022 – Winter 2022/23 time period was 0.36. Figure 40 provides the CVR factors for the Spring 2022 – Winter 2022/23 M&V period for each feeder. Although included in the aggregate CVRf estimate, Stoughton's individual feeder results are not presented here, as CVRf estimates are unchanged from last year's evaluation.

**Figure 40. National Grid VVO CVR Factors***




* Maplewood feeders 16W2, 16W4, 16W6, and 16W8 are excluded from the entire analysis due to poor VVO signal data quality. The CVR factor presented in this table is the load-weighted average of CVR factors for all analysis feeders that experienced a minimum change in voltage of ±0.25% Certain feeders with changes in voltage greater than ±0.25% were also excluded from aggregated CVRf calculations due to highly unstable voltage and energy responses to VVO On / Off testing. Feeders excluded from this calculation are all West Salem 29W feeders and East Bridgewater feeders 797W1, 797W23, 797W23, and 797W42.

*Source: Guidehouse analysis*

### *PM-3: Peak Demand Impact*

Guidehouse evaluated the impact of VVO during peak demand, defined by ISO-NE as 1:00 p.m. to 5:00 p.m. ET from June 1 to August 31 on non-holiday weekdays. Not all analysis feeders are included in peak demand impact tables and figures (see footnote below Table 95) Table 95 details the evaluated peak demand impact across all feeders in absolute and percentage terms. Although included in the aggregate peak demand impact, Stoughton's individual feeder results are not presented here, as average hourly impacts estimates are unchanged from last year's evaluation.

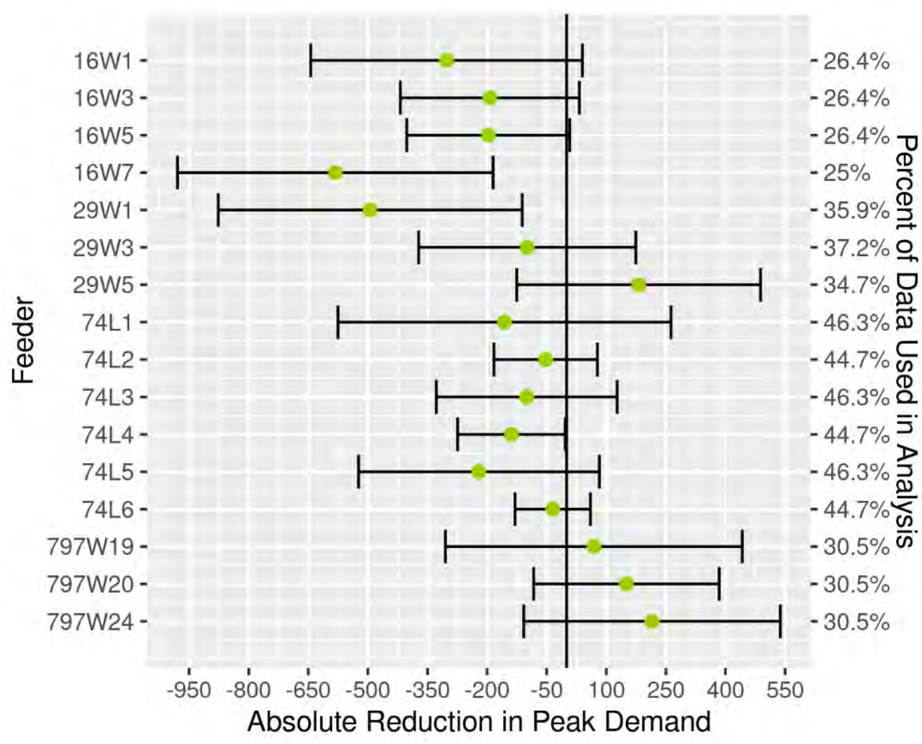
**Table 95. National Grid Average Reduction in Peak Demand**

| Peak Load Reduction (kW)† | Peak Load Reduction (%)† |
|---|---|
| -2,189 ± 1,173 kW | -2.41 ± 1.28% |

† The percentage peak load reduction presented in this table is the load-weighted average of percentage peak load reductions estimated for each feeder. Feeders with statistically insignificant estimates, or those unreliable standard error estimates associated with VVO, are excluded from the estimate of peak demand reductions. These include Maplewood 16W2, 16W4, 16W6, and 16W8, West Salem 29W2, 29W4, 29W6, and East Bridgewater 797W1, 797W23, 797W29, and 797W42.
*Source: Guidehouse analysis*

Figure 41 indicates the load reductions measured in kW realized during the peak load period, defined by ISO-NE as 1:00 p.m. to 5:00 p.m. ET from June 1 to August 31 on non-holiday weekdays. The whiskers overlaid on each feeder's absolute load reduction estimate provide the associated 90% confidence intervals. Where the confidence interval crosses the zero line, results may be interpreted as statistically insignificant. None of the feeders included in the analysis experienced a statistically significant reduction in peak load.

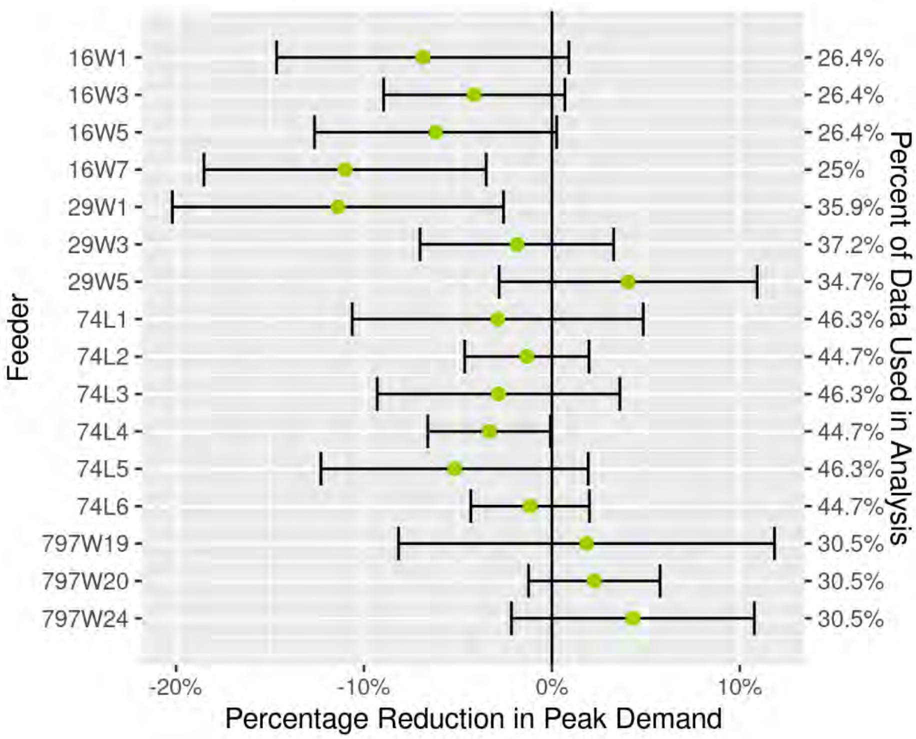
**Figure 41. National Grid Reduction in Peak Load (kW)***




* Feeders with statistically insignificant estimates, or those unreliable standard error estimates associated with VVO, are excluded from the estimate of peak demand reductions. These include Maplewood 16W2, 16W4, 16W6, and 16W8, West Salem 29W2, 29W4, 29W6, and East Bridgewater 797W1, 797W23, 797W29, and 797W42.
*Source: Guidehouse analysis*

Figure 42 indicates the percentage load reductions realized during the peak load period, defined by ISO-NE as 1:00 p.m. to 5:00 p.m. ET from June 1 to August 31 on non-holiday weekdays. The whiskers overlaid on each feeder's percent load reduction estimate provide the associated 90% confidence intervals. Where the confidence interval crosses the zero line, results may be interpreted as statistically insignificant.

**Figure 42. National Grid Reduction in Peak Demand (%)***




* Feeders with statistically insignificant estimates, or those unreliable standard error estimates associated with VVO, are excluded from the estimate of peak demand reductions. These include Maplewood 16W2, 16W4, 16W6, and 16W8, West Salem 29W2, 29W4, 29W6, and East Bridgewater 797W1, 797W23, 797W29, and 797W42.
*Source: Guidehouse analysis*

Eversource and National Grid saw increases in peak demand between 1:00 p.m. and 5:00 p.m. on non-holiday summer weekdays. This was a finding in both the previous and current evaluations (i.e., PY 2021 and PY 2022). This may be attributable to a number of factors that were present during those hours:

- There is variation in customer types and their relative load contributions depending on the time of day. If feeder load was more heavily comprised of end-uses with constant power load during peak hours as currently defined, a reduction in voltage can be met by a corresponding increase in amperage, which could appear as an increase in MW load at the feeder head-end. For instance, if feeder load was more heavily comprised of commercial or industrial load during those hours, industrial equipment could have actually become more inefficient with a drop in voltage, which could appear as an increase in MW load at the feeder head-end.

- Distribution generation, which has considerable generation during early- to mid-afternoon hours during the summer, may have caused unintended interactions with the VVO scheme.

The period of 1:00 p.m. to 5:00 p.m. for non-holiday summer weekdays was based on ISO-NE's peak demand definition, which was identified in the Stage 3 Evaluation Plan and has been used since the PY 2021 evaluation report. This was intended to be consistent with energy efficiency evaluations. Guidehouse has reviewed other time frames (e.g., 6:00 p.m. to 10:00 p.m.) that better represent the average feeder peaks for those feeders with VVO enabled. However, to be consistent with the Stage 3 Evaluation Plan and prior evaluation reports, this evaluation included the results for the 1:00 p.m. to 5:00 p.m. timeframe. Guidehouse will further explore alternative definitions for peak periods to determine the proper definition moving forward.

***PM-4: Distribution Losses***

Guidehouse evaluated reduction in distribution losses as a function of VVO during the Spring 2022 – Winter 2022/23 M&V period. There were some feeders with very little data where kW was greater than 75% of annual peak load for kVA. Given that power factor is an input for the distribution losses equation, these feeders were ultimately removed from the distribution losses calculation, as they had fewer than 100 hours available for use in the regression modeling. The methodology for calculating the percent reduction in distribution losses is shown in Appendix 5.3B.9. Table 96 details the evaluated percentage reduction in distribution losses for each National Grid feeder with sufficient data quality.

Changes in distribution losses could not be estimated for feeders going through VVO On/Off testing during the Spring 2022 – Winter 2022/23 M&V period due to data outages and prolonged pauses to On/Off testing during periods of greater demand. Therefore, the results in Table 96 and Figure 43 only include VVO feeders that completed On/Off testing prior to the Spring 2022 – Winter 2022/23 M&V period (i.e., Stoughton) and informed by last year's estimates.

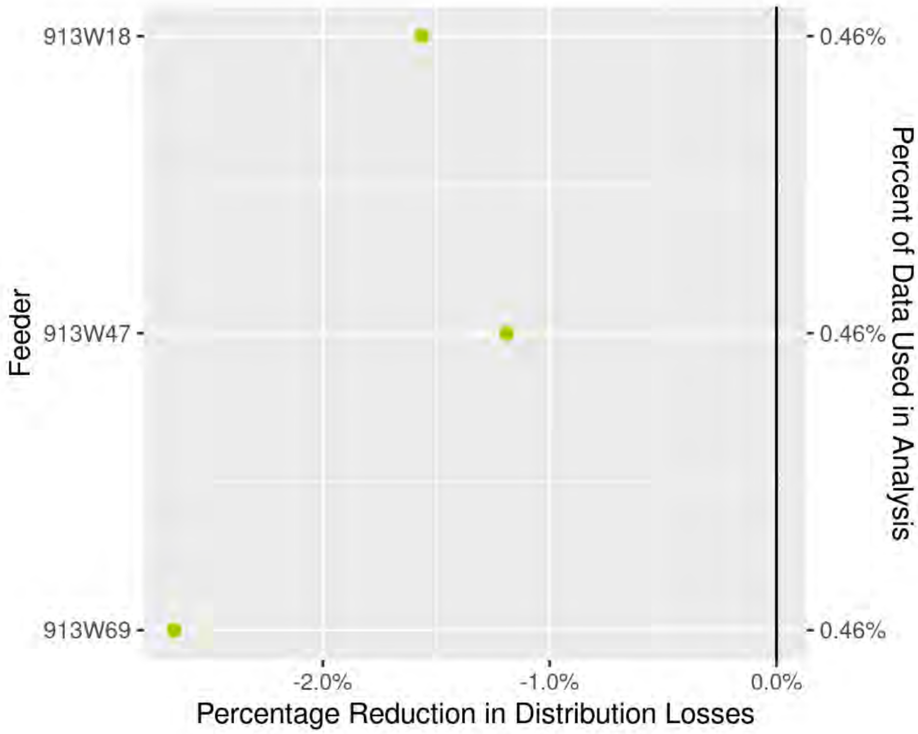
**Table 96. National Grid Reduction in Distribution Losses**

| Reduction in Distribution Losses (%)* |
|---|
| -1.95% |

* The change in distribution losses presented in this table is the load-weighted average of reduction in distribution losses estimated for each feeder.
*Source: Guidehouse analysis*

Figure 43 indicates the percentage reduction in distribution losses.

**Figure 43. National Grid Reduction In Distribution Losses (%)***




* Changes in power factor and distribution losses could not be estimated for substations going through VVO On/Off testing during Spring 2022 through Winter 2022/23 due to data quality issues. Results presented for these metrics are based off of VVO substations that completed VVO On/Off testing prior to this evaluation period. For this evaluation period, the only substation to conclude On/Off testing is Stoughton.

*Source: Guidehouse analysis*

***PM-5: Power Factor***

Guidehouse evaluated the impact on power factor associated with VVO during the Spring 2022 – Winter 2022/23 M&V period. Changes in power factor were analyzed during periods where power was greater than 75% of feeder-specific annual demand. Table 97 details the evaluated change in power factor for each National Grid feeder with sufficient data quality.[62]

Changes in power factor could not be estimated for feeders going through VVO On/Off testing during the Spring 2022 – Winter 2022/23 M&V period due to data outages and prolonged pauses to On/Off testing during periods of greater demand. Therefore, the results in Table 97 and Figure 44 only include VVO feeders that completed On/Off testing prior to the Spring 2022 – Winter 2022/23 M&V period (i.e., Stoughton) and informed by last year's estimates.

[62] There were some feeders with very little data where kW was greater than 75% of annual peak load for kVA. These feeders were ultimately removed from the power factor models, as they had fewer than 100 hours available for use in regression modeling.

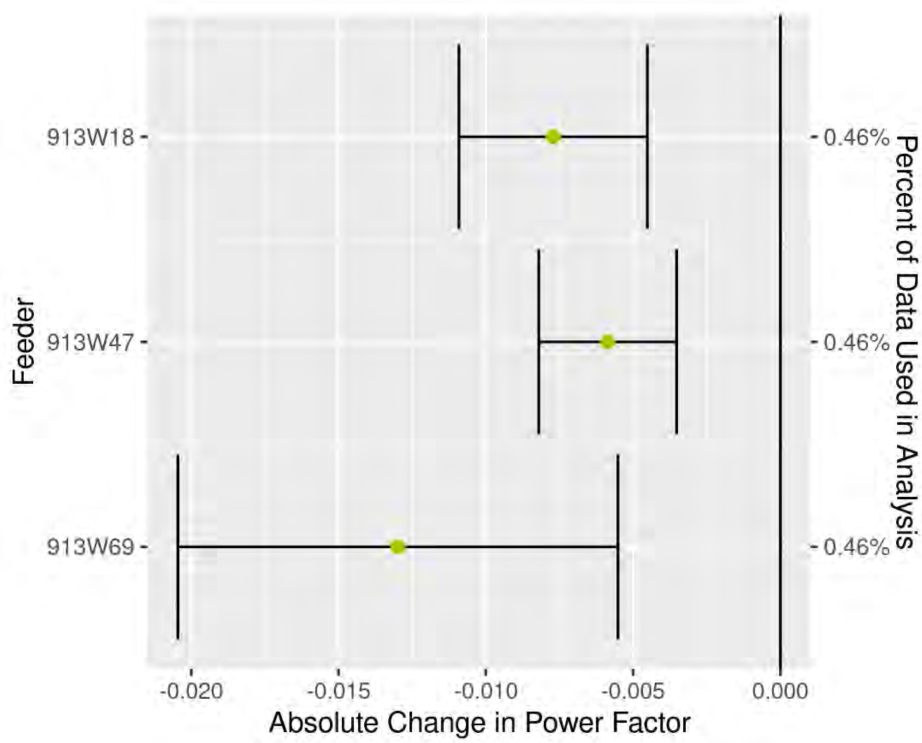
**Table 97. National Grid VVO Average Hourly Power Factor Change***

| Change in Power Factor | Change in Power Factor (%) |
|---|---|
| -0.01 ± 0.002 | -0.96 ± 0.20% |

* Power factor change presented in this table is the load-weighted average of power factor changes estimated for each feeder.
*Source: Guidehouse analysis*

Figure 44 indicates the change in power factor for each National Grid feeder in absolute terms, with green points indicating each feeder's absolute power factor change. The whiskers overlaid on each feeder's absolute power factor change estimate provide the associated 90% confidence intervals. Where the confidence interval crosses the zero line, results may be interpreted as statistically insignificant.

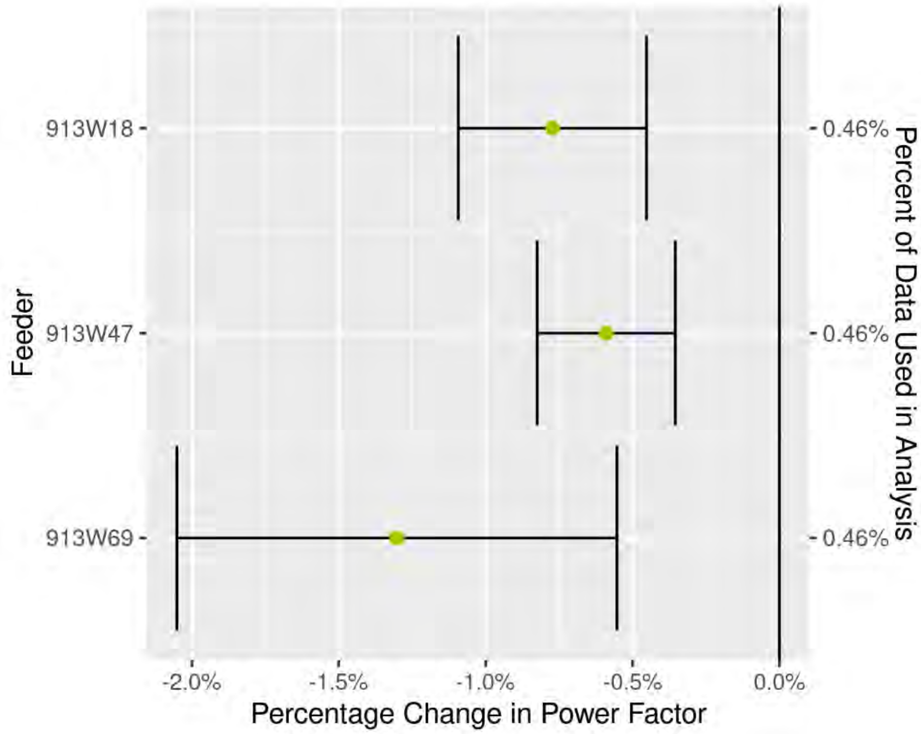
**Figure 44. National Grid Absolute Change in Power Factor***




* Changes in power factor and distribution losses could not be estimated for substations going through VVO On/Off testing during Spring 2022 through Winter 2022/23 due to data quality issues. Results presented for these metrics are based off VVO substations that completed VVO On/Off testing prior to this evaluation period. For this evaluation period, the only substation to conclude On/Off testing is Stoughton.
*Source: Guidehouse analysis*

Figure 45 indicates the change in power factor for each National Grid feeder in percentage terms, with green points indicating each feeder's percentage power factor change. The whiskers overlaid on each feeder's percentage power factor change estimate provide the associated 90% confidence intervals. Where the confidence interval crosses the zero line, results may be interpreted as statistically insignificant.

**Figure 45. National Grid Percentage Change in Power Factor***




* Changes in power factor and distribution losses could not be estimated for substations going through VVO On/Off testing during Spring 2022 through Winter 2022/23 due to data quality issues. Results presented for these metrics are based off of VVO substations that completed VVO On/Off testing prior to this evaluation period. For this evaluation period, the only substation to conclude On/Off testing is Stoughton.

*Source: Guidehouse analysis*

### *PM-6: GHG Emissions*

After evaluating energy savings attributed to VVO, Guidehouse calculated the resulting emissions reductions. For 2022, emissions reductions were determined by to be 0.34 metric tons of emissions per MWh. This was calculated drawing the 2019 value from DPU 18-110 – DPU 18-119, Massachusetts Joint Statewide Electric and Gas Three Year Energy Efficiency Plan for 2019 – 2021, the 2025 value from DPU 21-120 – DPU 21-129, Massachusetts Joint Statewide Electric and Gas Three-Year Energy Efficiency Plan for 2022-2024, and then interpolating the 2022 value from these two sources.[63]

Table 98 provides emissions reductions associated with VVO, with 90% confidence bounds indicated by the ± figure.

[63] 2019 Emissions factors can be found on page 201 of Massachusetts Joint Statewide Electric and Gas Three Year Energy Efficiency Plans for 2019 – 2021 https://ma-eeac.org/wp-content/uploads/Exh.-1-Final-Plan-10-31-18-With-Appendices-no-bulk.pdf. 2025 emissions factors can be found on page 326 of Massachusetts Joint Statewide Electric and Gas Three Year Energy Efficiency Plans for 2022 – 2024 https://ma-eeac.org/wp-content/uploads/Exhibit-1-Three-Year-Plan-2022-2024-11-1-21-w-App-1.pdf

**Table 98. National Grid VVO Emissions Reductions During Actual VVO On Hours**

| Metric | $CO_2$ |
|---|---|
| Spring 2022 – Winter 2022/23 Emissions Reduction | 645 ± 103 tons |

*Source: Guidehouse analysis*

***PM-7: Voltage Complaints***

Guidehouse received voltage complaint logs from National Grid to facilitate Performance Metrics analysis. Guidehouse tabulated voltage complaints received by VVO feeder between 2016 and Q1 2023, as well as the Spring 2022 – Winter 2022/23 M&V period.[64] Discussion below highlights key observations for voltage complaints, comparing the count of voltage complaints received during Spring 2022 – Winter 2022/23 to the average number of voltage complaints from the 2016–2017 baseline period.

Table 99 summarizes voltage complaints for the Easton substation. Looking at 2016–2017 baseline period,[65] there were about 15 voltage complaints per year. Based on voltage complaints data received, a total of 12 voltage complaints were reported along the Easton feeders during 2022, slightly below the baseline period average number of complaints per year.

**Table 99. Count of Voltage Complaints for Easton**

| Number of Voltage Complaints | 92W43 | 92W44 | 92W54 | 92W78 | 92W79 | Total |
|---|---|---|---|---|---|---|
| Customers* | 1,973 | 1,779 | 2,284 | 1,993 | 1,655 | **9,684** |
| **Baseline†** | **0** | **3** | **4** | **3** | **5** | **15** |
| **2022** | **1** | **2** | **4** | **2** | **3** | **12** |

* Count of customers served by each feeder and the baseline number of voltage complaints was extracted from the 2022 D.P.U 23-30 Report, Appendix 22-25.

*Source: Guidehouse analysis*

Table 100 summarizes voltage complaints for the East Bridgewater substation. Looking at 2016–2017 baseline period, there were about 25 voltage complaints per year. Based on voltage complaints data received, a total of 25 voltage complaints were reported along the East Bridgewater feeders during 2022, representing no change from the baseline period average number of complaints per year.

[64] Since 2016 is the earliest date at which voltage complaints data are available, Guidehouse limited its summary of voltage complaints to January 1, 2016 through February 28, 2023.

[65] Guidehouse presents a comparison of complaints between the 2016–2017 period and winter 2020/21 M&V period. For new VVO feeders that begin receiving VVO investments beginning in 2021, Guidehouse recommends that a 3-year moving average (i.e. 2019–2021) be used instead of an average for the time period spanning 2016 through 2017, as conditions in 2016 through 2017 may not accurately reflect baseline conditions immediately preceding deployment of VVO investments.

**Table 100. Count of Voltage Complaints for East Bridgewater**

| Number of Voltage Complaints | 797W1 | 797W19 | 797W20 | 797W23 | 797W24 | 797W29 | 797W42 | **Total** |
|---|---|---|---|---|---|---|---|---|
| Customers* | 2,821 | 2,563 | 1,717 | 2,650 | 2,583 | 2,338 | 1,239 | **15,911** |
| **Baseline†** | **7** | **1** | **5** | **1** | **5** | **3** | **4** | **25** |
| **2022** | **4** | **2** | **5** | **5** | **7** | **2** | **0** | **25** |

* Count of customers served by each feeder and the baseline number of voltage complaints was extracted from the 2022 D.P.U 23-30 Report, Appendix 22-25.

*Source: Guidehouse analysis*

Table 101 summarizes voltage complaints for the East Methuen substation. Voltage complaints vary considerably across years and VVO feeders, ranging from 14 complaints in 2019 to 35 complaints in 2016. Looking at 2016–2017 baseline period, there were 59 voltage complaints received, amounting to about 30 voltage complaints per year. Based on voltage complaints data received, a total of 15 voltage complaints were reported along the East Methuen feeders during 2022, 50% below the baseline period average number of complaints per year.

**Table 101. Count of Voltage Complaints for East Methuen Substation**

| Number of Voltage Complaints | 74L1 | 74L2 | 74L3 | 74L4 | 74L5 | 74L6 | Total |
|---|---|---|---|---|---|---|---|
| Customers* | 3,088 | 1,574 | 3,355 | 1,609 | 3,162 | 1,781 | **14,569** |
| 2016 | 2 | 5 | 10 | 7 | 9 | 2 | **35** |
| 2017 | 8 | 1 | 5 | 2 | 6 | 2 | **24** |
| **Baseline†** | **5** | **3** | **8** | **5** | **8** | **2** | **30** |
| 2018 | 3 | 0 | 2 | 3 | 5 | 3 | **16** |
| 2019 | 5 | 0 | 2 | 2 | 3 | 2 | **14** |
| 2020 | 1 | 1 | 7 | 3 | 2 | 2 | **16** |
| 2021 | 3 | 0 | 2 | 1 | 3 | 1 | **10** |
| **2022** | **2** | **3** | **7** | **1** | **1** | **1** | **15** |

* Count of customers served by each feeder was extracted from the 2022 D.P.U 23-30 Report, Appendix 22-25.
† The baseline number of voltage complaints is calculated as the average number of voltage complaints between 2016 and 2017, rounded up to the nearest whole number

*Source: Guidehouse analysis*

Table 102 summarizes voltage complaints for the Maplewood substation. Voltage complaints vary considerably across years and VVO feeders, ranging from 20 complaints in 2016 to 50 complaints in 2019. Looking at 2016–2017 baseline period, there were 51 voltage complaints received, amounting to about 26 voltage complaints per year. Based on voltage complaints data received, a total of 41 voltage complaints were reported along the Maplewood feeders during the 2022, above the baseline period average number of complaints per year.

**Table 102. Count of Voltage Complaints for Maplewood Substation**

| Number of Voltage Complaints | 16W1 | 16W2 | 16W3 | 16W4 | 16W5 | 16W6 | 16W7 | 16W8 | Total |
|---|---|---|---|---|---|---|---|---|---|
| Customers* | 3,683 | 4,674 | 3,352 | 1,131 | 1,710 | 5,627 | 3,891 | 3,427 | **27,495** |
| 2016 | 4 | 3 | 0 | 2 | 3 | 4 | 2 | 2 | **20** |
| 2017 | 6 | 3 | 2 | 0 | 5 | 6 | 4 | 5 | **31** |
| **Baseline†** | **5** | **3** | **1** | **1** | **4** | **5** | **3** | **4** | **26** |
| 2018 | 6 | 3 | 1 | 4 | 1 | 6 | 6 | 7 | **34** |
| 2019 | 7 | 10 | 5 | 3 | 1 | 8 | 6 | 10 | **50** |
| 2020 | 6 | 7 | 4 | 4 | 3 | 10 | 6 | 8 | **48** |
| 2021 | 2 | 7 | 0 | 1 | 1 | 4 | 3 | 3 | **21** |
| **2022** | **3** | **6** | **0** | **3** | **0** | **7** | **4** | **18** | **41** |

* Count of customers served by each feeder was extracted from the 2022 D.P.U 23-30 Report, Appendix 22-25.
† The baseline number of voltage complaints is calculated as the average number of voltage complaints between 2016 and 2017, rounded up to the nearest whole number

*Source: Guidehouse analysis*

Table 103 summarizes voltage complaints for the Stoughton substation. Voltage complaints vary considerably across years and VVO feeders, ranging from 3 complaints in 2021 to 32 complaints in 2019. Looking at 2016–2017 baseline period, there were 52 voltage complaints received, amounting to about 26 voltage complaints per year. Based on voltage complaints data received, a total of 22 voltage complaints were reported along the Stoughton feeders during the 2022, below the baseline period average number of complaints per year

**Table 103. Count of Voltage Complaints for Stoughton Substation**

| Number of Voltage Complaints | 913W17 | 913W18 | 913W43 | 913W47 | 913W67 | 913W69 | Total |
|---|---|---|---|---|---|---|---|
| Customers* | 1,350 | 1,504 | 2,132 | 1,796 | 755 | 3,603 | **11,140** |
| 2016 | 2 | 7 | 5 | 5 | 2 | 11 | **32** |
| 2017 | 1 | 8 | 5 | 1 | 1 | 4 | **20** |
| **Baseline†** | **2** | **8** | **5** | **3** | **2** | **8** | **26** |
| 2018 | 8 | 1 | 6 | 0 | 1 | 7 | **23** |
| 2019 | 4 | 3 | 4 | 2 | 0 | 1 | **14** |
| 2020 | 3 | 3 | 3 | 6 | 6 | 3 | **24** |
| 2021 | 1 | 2 | 0 | 0 | 0 | 0 | **3** |
| **2022** | **0** | **3** | **7** | **6** | **2** | **4** | **22** |

* Count of customers served by each feeder was extracted from the 2022 D.P.U 23-30 Report, Appendix 22-25.
† The baseline number of voltage complaints is calculated as the average number of voltage complaints between 2016 and 2017, rounded up to the nearest whole number

*Source: Guidehouse analysis*

Table 104 summarizes voltage complaints for the West Salem substation. Looking at 2016–2017 baseline period, there were 41 voltage complaints per year. Based on voltage complaints data received, a total of 23 voltage complaints were reported along the West Salem feeders during 2022, quite below the baseline period average number of complaints per year.

**Table 104. Count of Voltage Complaints for West Salem Substation**

| Number of Voltage Complaints | 29W1 | 29W2 | 29W3 | 29W4 | 29W5 | 29W6 | Total |
|---|---|---|---|---|---|---|---|
| Customers* | 3,788 | 1,653 | 4,286 | 2,700 | 2,915 | 1,426 | 16,768 |
| **Baseline†** | **16** | **4** | **8** | **1** | **9** | **3** | **41** |
| **2022** | **9** | **1** | **5** | **3** | **3** | **2** | **23** |

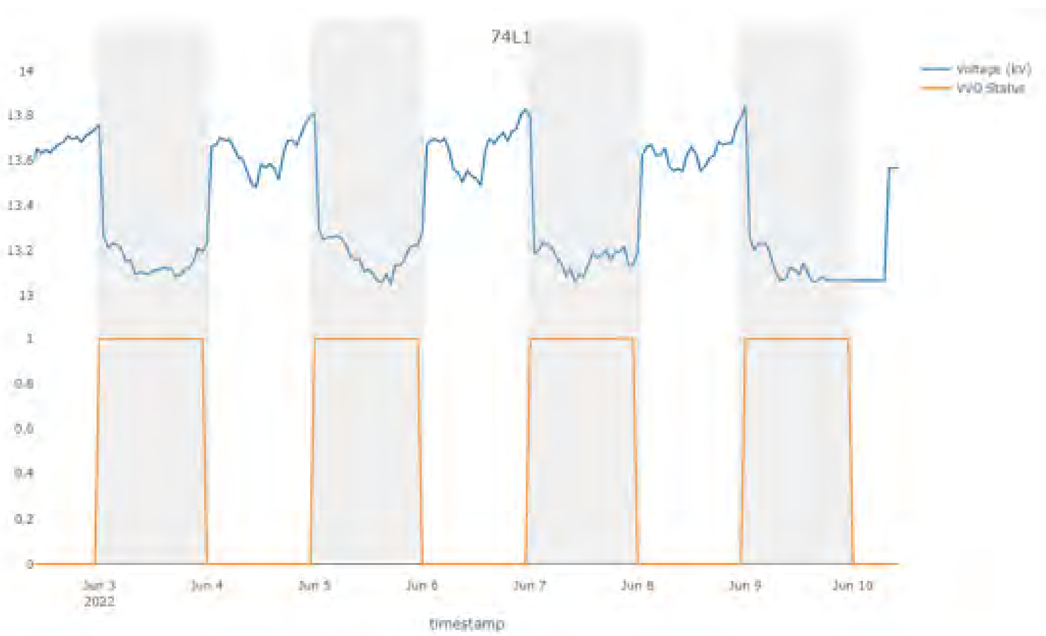
* Count of customers served by each feeder and the baseline number of voltage complaints was extracted from the 2022 D.P.U 23-30 Report, Appendix 22-25.

*Source: Guidehouse analysis*

### *4.2.3.4 Additional Investigation of West Salem Feeders*

When feeders are undergoing VVO On/Off testing, Guidehouse usually expects to see head-end voltage levels cycling with VVO On/Off status, with voltage levels remaining somewhat higher when VVO is disengaged (e.g., 13.8 Volts) and remaining somewhat lower when VVO is engaged (e.g., 13.2 Volts). An example of the expected voltage response to VVO is shown in Figure 46 below highlights voltage (in blue) and VVO On/Off status (in orange, where VVO status equal to one indicates VVO is engaged) observed for the feeder 74L1 from June 3, 2022 through June 10, 2022.

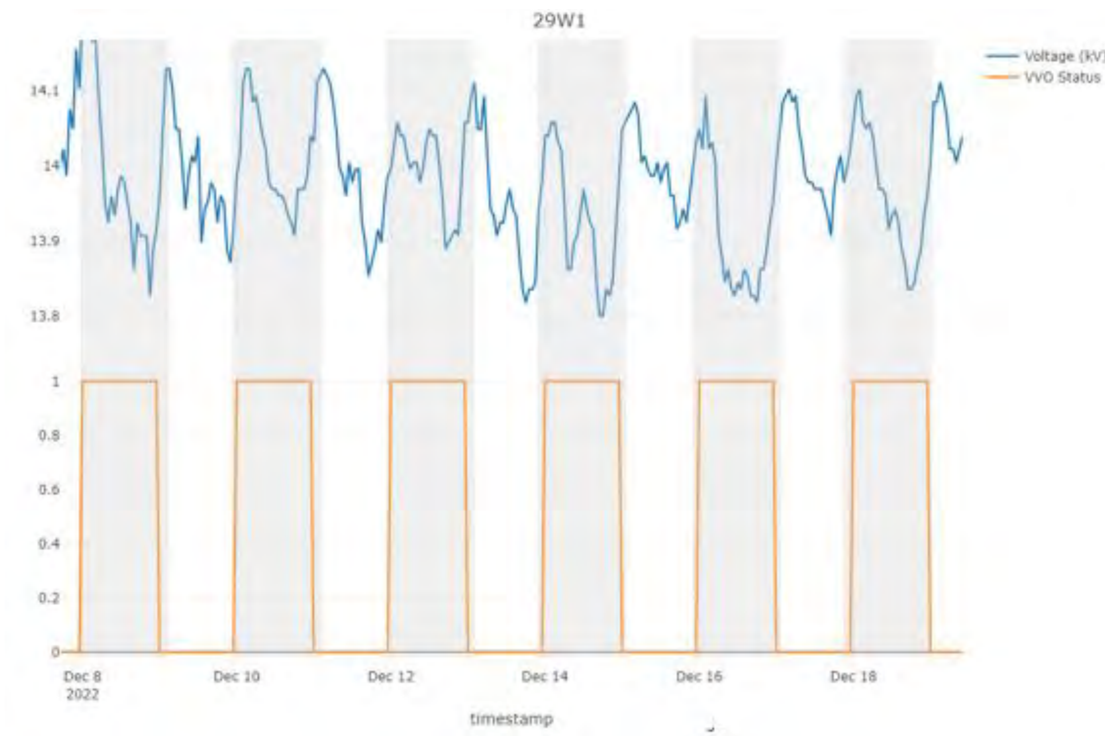
**Figure 46. VVO On/Off Testing at Feeder 74L1**




*Source: Guidehouse analysis*

However, Guidehouse has identified additional cases for feeders at the East Bridgewater, Maplewood, and West Salem substations where VVO signals did not correspond with reductions in voltage. One such case is presented in Figure 47 for the feeder 29W1, where voltage (in blue) and VVO On/Off status (in orange, where VVO status equal to one indicates VVO is engaged) are plotted together for the period spanning December 8, 2022, through December 18, 2022.

**Figure 47. VVO On/Off Testing at Feeder 29W1**




*Source: Guidehouse analysis*

Figure 47 illustrates that voltage did not fluctuate as expected during VVO On/Off testing throughout the period spanning December 8, 2022, through December 18, 2022. This reduced assessed impacts of VVO across numerous feeders (e.g., feeders at the East Bridgewater, Maplewood, and West Salem substations), as VVO was marked as engaged but was not yielding clear voltage benefits. Guidehouse recommends that National Grid investigate what may be driving these voltage patterns and what, if any, changes to VVO need to occur to ensure that VVO is correctly regulating voltage when VVO is engaged.

### *4.2.3.5 Key Findings and Recommendations*

Guidehouse's VVO evaluation findings indicate that VVO allowed National Grid to realize energy savings and voltage reductions during the Spring 2022 – Winter 2022/23 M&V period. More specifically:

- National Grid VVO feeders realized 0.84% energy savings and 0.62% voltage reductions when VVO was engaged. East Methuen 74L1, 74L3, and 74L5 feeders realized greatest energy and voltage benefits, with 2.5% voltage reduction when VVO was engaged.
- National Grid VVO feeders experienced a statistically significant increase (2.41%) in peak demand when VVO was engaged. In addition, insufficient data during periods of higher demand limited the number of feeders for which Guidehouse could estimate changes in power factor and distribution losses associated with VVO.

In 2023 and beyond, Guidehouse recommends that National Grid:

- Ensure VVO On/Off testing is running according to plan, with limited pauses to the VVO On/Off testing schedule. Across the VVO feeders, one-quarter to one-half of data points were removed due to extended pauses in VVO On/Off testing. For some feeders, this resulted in the vast majority of provided data to be unusable for components of this evaluation (e.g., for estimation of distribution loss and power factor reductions). Sustained On/Off testing will increase the amount of usable data in the evaluation and improve the ability for Guidehouse to provide a comprehensive evaluation of VVO performance metrics.
- Confirm adjustments to VVO On/Off testing schedule for any VVO feeders prior to implementation. VVO On/Off testing is designed similarly to a Randomized Controlled Trial (RCT), and adjustments to the testing schedule could, potentially, hinder the effectiveness of the testing design and cause biases to evaluation results. Ensuring there is proper balance in the number of VVO on and off hours throughout the evaluation period will allow for Guidehouse to provide a comprehensive and accurate evaluation of VVO performance metrics.
- Continue to investigate how to improve outcomes across VVO feeders. Many feeders underwent no material change in voltage. Correspondingly, energy reduction estimates were small-to-insignificant. These observations may indicate flaws in the VVO control scheme for these feeders. In order to improve VVO performance, Guidehouse recommends that the EDCs continue their efforts to investigate root causes to shortcomings in the VVO control schemes and work with distribution engineers and the VVO vendors to respond accordingly. If needed, Guidehouse can conduct in-depth case studies at these substations further understand shortcomings in the VVO control scheme.

# 5. Key Findings and Recommendations

The subsections that follow present key findings for VVO Infrastructure Metrics, VVO Performance Metrics, and recommendations for the VVO investment area for each of the EDCs.

## 5.1 Key Findings for VVO Infrastructure Metrics

Guidehouse's review of Eversource's VVO progress on Term 1 revealed that Eversource was approximately on-track with planned spend and deployment outlined in their *2021 GMP Term Report*. However, some spend and deployment remain in order to complete activities from Term 1. Key findings related to Eversource's progress include:

Device Deployment

- Eversource made headway on deploying 2021 investments in 2022, with Capacitor Banks and Grid Monitoring Line Sensors comprising the bulk of deployed devices. Eversource exceeded plans (25 devices) for Capacitor Banks, as refinements made during the planning and design process placed more priority on Capacitor Banks, less on Regulators, for VVO operation. At the close of 2022, Eversource was awaiting delivery of 3 ordered VVO Regulators from its vendor. Line Sensor and Micro-capacitor deployment also fell short of plans.

Total Spend

- Eversource made substantial progress on PY 2021 work that was planned for 2022. Total spend through the end of 2022 was approximately on track with plans for all device types, with total spend on VVO ($16.87M) being slightly below planned spend ($17.23M) laid out for Term 1.

VVO Enablement

- Eversource completed deployment of VVO at four of its six Term 1 plan substations (Agawam, Piper, Podick, and Silver) by the end of 2021, and conducted On/Off testing at these substations throughout 2022. Eversource stopped VVO On/Off testing on these four substations in May 2023, transitioning towards leaving VVO in its enabled state moving forward. Meanwhile, the Gunn and Oswald substations will be VVO enabled in 2023, with On/Off testing to begin shortly thereafter.

PY 2022's VVO Infrastructure Metrics findings show that the EDCs are at varying stages in VVO deployment for Term 2. Details pertaining to device deployment progress, total spend, and VVO enablement progress are shown below:

Device Deployment:

- Eversource did not meet VVO deployment goals for PY 2022. Eversource progress on VVO investments targeted for 2022 through 2025 was comprised of progressing engineering/design work for all VVO device types, as well as planning for future VVO deployments, while awaiting DPU decisions on continued VVO investment for 2022 through 2025. Given limited deployment on Term 2 investments in 2022, Eversource has adjusted plans for the remainder of Term 2, with the majority of deployment and spend activity projected to occur in 2024 and 2025. At the technology-level, planned deployment has declined for Regulators, Line Sensors, and Microcapacitors, and planned Capacitor Bank deployment has increased slightly. Capacitor Bank deployment has been revised upwards to reflect refinements made during the planning and design process.

- National Grid conducted less deployment than initially planned in PY 2022. A late-2022 DPU decision on preauthorizing 2022 through 2025 investment activity, resource constraints, and vendor lead times were all key contributors to this outcome. In response to lower-than-expected deployment in 2022, National Grid has accelerated its deployment timeline for 2023 through 2025. National Grid has also adjusted total deployment plans for numerous device types, increasing projected deployment for Capacitor Banks, Line Sensors, and LTC Controls, while reducing projected deployment for Regulators. National Grid cites that these revisions are primarily due to the VVO planning work that has been conducted since the 2022-2025 GMP was filed.
- Unitil deployment was below plans for 2022, with variation by technology. Unitil was on-track with deployment of VVO Capacitor Banks and Line Sensors in 2022, deploying 100% and 210% of planned units, respectively. However, deployment was under plans for Regulators and LTC Controls. Lower deployment than plans for these technologies may be attributed to Unitil's efforts to resolve LTC radio and control issues and cancelation of 4 deployments that were found to be unnecessary. Unitil has adjusted deployment plans for the remainder of Term 2 to conduct most deployment during 2023 and 2025. Additionally, Unitil has reduced its planned deployments of VVO Regulators and Capacitor Banks, as Unitil reassessed deployment plans and determined there were fewer Regulator and Capacitor Bank deployments needed than initially planned. Work in 2024 will be limited to material orders in preparation for construction work at the Beech Street substation.

Total Spend:

- Eversource spend on Term 2 investments amounted to $0.04M, short of the $8.70M that was initially planned for 2022. Given limited deployment and spend on Term 2 investments in 2022, as well as ongoing vendor delays in fulfilling material orders, Eversource has adjusted plans for the remainder of Term 2. In 2023, Eversource will be conducting additional design work, submitting material orders, and, when material orders are received, deploying VVO investments. Eversource has projected that most spend activity will occur in 2024 and 2025.
- National Grid spend on VVO was below plans for 2022. The majority of spend occurred on Capacitor Banks, while spend on Regulators and Line Sensors was well below plans. Lower-than-anticipated spend on Line Sensors can, in part, be attributed to National Grid's previous line sensor vendor discontinuing their selected model. For VVO Regulators, vendor delays in fulfilling material orders was a key contributor to lower spend than initially planned. In response to its 2022 experience with Line Sensors and Regulators, National Grid has begun to increase diversification of vendors that it sources materials from.
- Unitil spend on VVO was below initial plans. Unitil met 48% of its planned spend for Regulators. Spend and deployment of all other devices met or exceeded initial plans. Spend plans for the remainder of Term 2 have been revised downwards across all device types. Reduced spend on Regulators and Capacitor Banks can be attributed to a reduction in the units that Unitil plans to deploy, as well as lower than expected costs for deployment of Regulators. Reduced spend on LTC Controls and Line Sensors may be tied to process efficiencies implemented in 2022 that brought unit costs below plans. Most spend is

planned for 2023 and 2025, with work in 2024 limited to material orders in preparation for construction work at the Beech Street substation.

VVO Enablement:

- For its Term 2 substations, Eversource is currently in the VVO Investment phase, and is conducting engineering / design work for the selected substations. Eversource anticipates completing deployment during 2024 and 2025. Once VVO investments are deployed, Eversource plans to conduct VVO On/Off testing, with testing start dates ranging from July 2024 through July 2025. Once VVO On/Off testing has begun, Eversource anticipates conducting this testing for 9 – 12 months to collect one summer, one winter, and one shoulder season of testing data.
- National Grid conducted VVO On/Off testing at its East Methuen and Maplewood Term 1 substations throughout 2022. Among its Term 2 substations, National Grid conducted On/Off testing at the East Bridgewater substation throughout 2022, as VVO deployment was completed at the substation in 2021. Additionally, National Grid completed VVO deployment at the Easton and West Salem substations and began VVO On/Off for these substations in winter 2022/23 and spring 2022, respectively. National Grid projects that it will complete VVO deployment and enable VVO at its remaining Term 2 substations in 2023.
- Unitil completed VVO deployment for its Term 1 substation (Townsend) in 2021, enabling VVO on December 1, 2021, and On/Off testing is expected to begin in spring 2023. Among its Term 2 substations, Unitil completed deploying VVO investments at the Summer Street substation and enabled VVO in December 2022, with VVO On/Off testing projected to begin at the substation in December 2023. Lunenburg and West Townsend are currently receiving VVO investments and Unitil plans to enable VVO at the substations in January and November 2024, respectively. Unitil then plans to conduct On/Off testing at the substations beginning in December 2024. For its remaining substations, Unitil is currently conducting planning and engineering/design work for its Beech Street, Pleasant Street, and Princeton Road substations. These substations are expected to be enabled after the close of Term 2 in 2026 and 2027.

## 5.2 Key Findings for VVO Performance Metrics

Findings from the evaluation of Performance Metrics indicate that VVO allowed Eversource and National Grid to realize energy savings and voltage reductions during the Spring 2022 – Winter 2022/23 M&V period. It can be difficult to compare the results from Performance Metrics analysis between Eversource and National Grid. For example, there are differences in the granularity of telemetry (e.g., 15-minute versus 1 hour), data quality at different times of the year. As such, data cleaning can cause certain portions of the M&V period to be represented more for one EDC than the other. Additionally, there are numerous differences in DG penetration, customer types, and geographic areas served by Eversource and National Grid feeders that limit the ability to directly compare Eversource and National Grid VVO outcomes. Key Findings from the evaluation of Performance Metrics are as follows:

- During the Spring 2022 – Winter 2022/23 M&V period, Eversource's Agawam, Piper, Podick, and Silver substations realized 879 MWh (0.41%) energy savings and 1.52 V (1.24%) voltage reduction associated with VVO. The CVR Factor, which provides an estimate of energy savings possible with voltage reductions, was 0.60. During the same

M&V period, National Grid's East Methuen, East Bridgewater, Easton, Maplewood, Stoughton, and West Salem substations realized 1,867 MWh (0.84%) energy savings and 0.08 kV (0.62%) voltage reduction associated with VVO. National Grid's CVR factor was 0.36.

- Eversource energy savings of 879 MWh yielded a 299 short ton reduction of $CO_2$ emissions. National Grid energy savings of 1,867 MWh yielded a 645 short ton reduction in $CO_2$ emissions.
- Eversource and National Grid VVO feeders experienced a minimal benefit associated with peak load, power factor, and distribution losses. Eversource VVO feeders experienced a statistically significant increase (0.70%) in peak load, a statistically significant decrease (0.06%) in power factor, and a minimal decrease in distribution losses when VVO was engaged. National Grid VVO feeders experienced a statistically significant increase in peak load of 2.41%, a small decrease (0.43%) in power factor, and a minimal increase in distribution losses when VVO was engaged.
- For Eversource, a total of 53 voltage complaints were received from customers connected to the Agawam, Piper, Podick, and Silver VVO feeders during the Spring 2022 – Winter 2022/23 M&V period. This is a 13% decrease relative to the baseline number of voltage complaints measured between 2015 and 2017 (61 complaints). For National Grid, a total of 136 voltage complaints were received from customers connected to the East Methuen, East Bridgewater, Maplewood, West Salem, and Stoughton VVO feeders during the period. This is a 16% decrease relative to the average voltage complaints per year received between 2016 – 2017. For both EDCs, there is not sufficient evidence to support changes in voltage complaints being attributed to VVO.

## 5.3 Recommendations

In 2023 and beyond, Guidehouse recommends that Eversource and National Grid:

- Ensure VVO On/Off testing is running according to plan, with limited pauses to the VVO On/Off testing schedule. Across the VVO feeders, one-quarter to one-half of data points were removed due to extended pauses in VVO On/Off testing. For some feeders, this resulted in the vast majority of provided data to be unusable for components of this evaluation (e.g., for estimation of distribution loss and power factor reductions). Sustained On/Off testing will increase the amount of usable data in the evaluation and improve the ability for Guidehouse to provide a comprehensive evaluation of VVO performance metrics.
- Confirm adjustments to VVO On/Off testing schedule for any VVO feeders prior to implementation. VVO On/Off testing is designed similarly to a Randomized Controlled Trial (RCT), and adjustments to the testing schedule could, potentially, hinder the effectiveness of the testing design and cause biases to evaluation results. Ensuring there is proper balance in the number of VVO on and off hours throughout the evaluation period will allow for Guidehouse to provide a comprehensive and accurate evaluation of VVO performance metrics.
- Continue to investigate how to improve outcomes across VVO feeders. Many feeders across the EDCs underwent no material change in voltage. Correspondingly, energy reduction estimates were small-to-insignificant. These observations may indicate flaws in the VVO control scheme for these feeders. In order to improve VVO performance, Guidehouse recommends that the EDCs continue their efforts to investigate root causes to

shortcomings in the VVO control schemes and work with distribution engineers and the VVO vendors to respond accordingly. If needed, Guidehouse can conduct in-depth case studies at these substations further understand shortcomings in the VVO control scheme.

# Appendix A. Additional Feeder Characteristics by EDC

## A.1 Eversource Additional Feeder Characteristics

**Table A-1. Additional Eversource Feeder Characteristics**

| Substation | Feeder | Avg Customer Loading (kVA/customer) | Customer Density (customer/mi.) | Load Density (MVA/mi.) | DG Penetration (DG MW/MVA) |
|---|---|---|---|---|---|
| **Term 1 Feeders** | | | | | |
| Agawam (13.8 kV) | 16C11 | 7.11 | 55 | 0.39 | 0.23 |
| | 16C12 | 146.25 | 13 | 1.84 | 0.17 |
| | 16C14 | 7.17 | 105 | 0.76 | 0.02 |
| | 16C15 | 9.45 | 113 | 1.06 | 0.01 |
| | 16C16 | 4.56 | 115 | 0.52 | 0.22 |
| | 16C17 | 4.02 | 81 | 0.33 | 0.13 |
| | 16C18 | 3.37 | 145 | 0.49 | 0.08 |
| Piper (13.8 kV) | 21N4 | 5.26 | 69 | 0.37 | 0.14 |
| | 21N5 | 14.60 | 56 | 0.82 | 0.02 |
| | 21N6 | 14.87 | 52 | 0.78 | 0.05 |
| | 21N7 | 7,000 | 0 | 2.90 | 0.00 |
| | 21N8 | 21.72 | 63 | 1.38 | 0.01 |
| | 21N9 | 5.32 | 101 | 0.54 | 0.08 |
| Podick (13.8 kV) | 18G2 | 1,589 | 2 | 3.18 | 0.00 |
| | 18G3 | 5.98 | 57 | 0.34 | 0.08 |
| | 18G4 | 4.69 | 67 | 0.32 | 0.52 |
| | 18G5 | 5.79 | 44 | 0.26 | 0.22 |
| | 18G6 | 7.84 | 34 | 0.27 | 0.36 |
| | 18G7 | 4.63 | 35 | 0.16 | 1.13 |
| | 18G8 | 11.39 | 23 | 0.27 | 0.70 |
| Silver (13.8 kV) | 30A1 | 5.68 | 68 | 0.38 | 0.11 |
| | 30A2 | 5.60 | 187 | 1.05 | 0.03 |
| | 30A3 | 48.95 | 20 | 0.99 | 0.43 |
| | 30A4 | 13.73 | 74 | 1.01 | 0.03 |
| | 30A5 | 7.05 | 77 | 0.55 | 0.08 |
| | 30A6 | 8.04 | 51 | 0.41 | 0.28 |
| Gunn (23 kV) | 15A1 | 5.79 | 40 | 0.23 | 0.19 |
| | 15A2 | 8.49 | 97 | 0.83 | 0.22 |
| | 15A3 | 4.47 | 39 | 0.17 | 0.60 |
| | 15A5 | 5.31 | 110 | 0.58 | 0.11 |
| Oswald (23 kV) | 30B5 | 6.13 | 72 | 0.44 | 0.33 |
| | 30B7 | 8.33 | 23 | 0.19 | 0.88 |
| **Term 2 Feeders** | | | | | |
| Amherst | 17K1 | 2.47 | 85 | 0.21 | 2.62 |

| Substation | Feeder | Avg Customer Loading (kVA/customer) | Customer Density (customer/mi.) | Load Density (MVA/mi.) | DG Penetration (DG MW/MVA) |
|---|---|---|---|---|---|
| (13.8 kV) | 17K2 | 2.25 | 40 | 0.09 | 0.85 |
| | 17K3 | 2.22 | 110 | 0.25 | 0.21 |
| | 17K4 | 4.17 | 117 | 0.49 | 0.93 |
| | 17K5 | 4.45 | 57 | 0.25 | 0.15 |
| | 17K6 | 5.63 | 65 | 0.36 | 0.53 |
| | 17K7 | 1.45 | 76 | 0.11 | 0.26 |
| | 17K8 | 2.20 | 48 | 0.11 | 0.65 |
| Breckwood (13.8 kV) | 20A11 | N/A | 0 | 1.59 | 0.00 |
| | 20A12 | 2.73 | 88 | 0.24 | 0.09 |
| | 20A13 | 2.31 | 149 | 0.34 | 0.23 |
| | 20A14 | 3.08 | 88 | 0.27 | 0.37 |
| | 20A21 | 2.86 | 96 | 0.27 | 0.23 |
| | 20A22 | 2.59 | 127 | 0.33 | 0.18 |
| | 20A23 | 2.39 | 100 | 0.24 | 0.20 |
| | 20A31 | 2.70 | 105 | 0.28 | 0.07 |
| | 20A32 | 2.27 | 119 | 0.27 | 0.35 |
| | 20A33 | 3.38 | 130 | 0.44 | 0.18 |
| | 20A34 | 3.12 | 85 | 0.26 | 0.35 |
| | 20A35 | 2.74 | 101 | 0.28 | 0.23 |
| Cross Road (13.2 kV) | 2-522-522 | 3.54 | 26 | 0.09 | 1.13 |
| | 2-523-523 | 2.72 | 27 | 0.07 | 0.72 |
| | 2-524-524 | 1.61 | 16 | 0.03 | 0.99 |
| | 2-525-525 | 1,652 | 1 | 1.40 | 1.21 |
| | 2-528-528 | N/A | 0 | 0.06 | 0.50 |
| Cumberland (13.8 kV) | 22B1 | 6.10 | 26 | 0.16 | 0.29 |
| | 22B2 | 2.64 | 102 | 0.27 | 0.20 |
| | 22B3 | 3.21 | 38 | 0.12 | 0.89 |
| | 22B4 | 3.15 | 50 | 0.16 | 1.26 |
| | 22B5 | 2.00 | 17 | 0.03 | 3.70 |
| | 22B6 | N/A | 0 | 0.77 | 0.00 |
| | 22B7 | 3.08 | 24 | 0.07 | 0.38 |
| | 22B8 | N/A | 125 | N/A | N/A |
| Doreen | 19A1 | 1.32 | 68 | 0.09 | 0.64 |

| Substation | Feeder | Avg Customer Loading (kVA/customer) | Customer Density (customer/mi.) | Load Density (MVA/mi.) | DG Penetration (DG MW/MVA) |
|---|---|---|---|---|---|
| (23 kV) | 19A2 | 1.47 | 76 | 0.11 | 0.42 |
| | 19A3 | 18.18 | 11 | 0.21 | 1.34 |
| | 19A4 | 28.13 | 27 | 0.75 | 1.11 |
| | 19A5 | 4.50 | 43 | 0.20 | 0.38 |
| | 19A6 | 1,367 | 1 | 0.75 | 0.43 |
| | 19A7 | 1.36 | 133 | 0.18 | 0.18 |
| | 19A8 | 1.14 | 134 | 0.15 | 0.28 |
| Duxbury (4.16 kV) | 3-24A-34J1 | 21.21 | 47 | 1.00 | 0.03 |
| | 3-24A-34J2 | 51.73 | 56 | 2.92 | 0.00 |
| | 3-24A-35J1 | 20.51 | 33 | 0.68 | 0.01 |
| | 3-24A-35J2 | N/A | 0 | 0.00 | N/A |
| Franconia (13.8 kV) | 22H11 | N/A | 0 | 0.00 | N/A |
| | 22H12 | 4.18 | 63 | 0.26 | 0.32 |
| | 22H13 | 4.32 | 61 | 0.26 | 0.10 |
| | 22H14 | 2.63 | 113 | 0.30 | 0.10 |
| | 22H15 | 2.05 | 180 | 0.37 | 0.12 |
| | 22H16 | 2.00 | 181 | 0.36 | 0.15 |
| | 22H17 | 3.26 | 88 | 0.29 | 0.07 |
| | 22H18 | 4.24 | 333 | 1.41 | 0.01 |
| Industrial Park (13.2 kV) | 2-101-101 | 348.02 | 6 | 2.01 | 0.26 |
| | 2-102-102 | 6.52 | 51 | 0.33 | 1.02 |
| | 2-102-608 | 3.06 | 47 | 0.14 | 0.30 |
| | 2-103-103 | 340.14 | 2 | 0.73 | 0.85 |
| | 2-104-104 | 3.87 | 83 | 0.32 | 0.39 |
| | 2-105-105 | 3.13 | 119 | 0.37 | 0.22 |
| | 2-106-106 | 1,498 | 2 | 3.35 | 0.00 |
| | 2-106-160 | 1.13 | 82 | 0.09 | 0.64 |
| | 2-106-161 | 2.90 | 84 | 0.24 | 0.31 |
| | 2-107-107 | 12.51 | 17 | 0.22 | 2.05 |
| | 2-108-108 | N/A | 0 | 0.29 | 1.19 |
| | 2-151-151 | 312.09 | 5 | 1.51 | 0.90 |
| | 2-152-152 | N/A | 0 | 3.69 | 0.00 |
| Mashpee (22.8 kV) | 4-71-455 | 2.13 | 36 | 0.08 | 0.58 |
| | 4-71-71 | 1,538 | 42 | 64.40 | 0.00 |
| | 4-77B-456 | 3.48 | 44 | 0.15 | 0.14 |
| | 4-77B-77B | 41.32 | 39 | 1.61 | 0.00 |
| Montague | 21C1 | 4.87 | 25 | 0.12 | 0.93 |

| Substation | Feeder | Avg Customer Loading (kVA/customer) | Customer Density (customer/mi.) | Load Density (MVA/mi.) | DG Penetration (DG MW/MVA) |
|---|---|---|---|---|---|
| (13.8 kV) | 21C2 | 6.93 | 45 | 0.31 | 1.27 |
| | 21C3 | N/A | 0 | 0.00 | N/A |
| | 21C4 | 3.97 | 111 | 0.44 | 0.17 |
| | 21C5 | 2.01 | 33 | 0.07 | 0.22 |
| | 21C6 | 1.82 | 102 | 0.19 | 8.68 |
| | 21C7 | 1.98 | 25 | 0.05 | 0.44 |
| | 21C8 | 3.04 | 44 | 0.13 | 3.02 |
| Orchard (13.8 kV) | 27A10 | 2.00 | 125 | 0.25 | 1.52 |
| | 27A11 | 4,600 | 1 | 2.90 | 0.00 |
| | 27A12 | 767 | 4 | 2.96 | 1.66 |
| | 27A13 | 3.80 | 163 | 0.62 | 0.79 |
| | 27A14 | N/A | 0 | 1.85 | 0.00 |
| | 27A15 | 200 | 0 | 0.02 | 0.00 |
| | 27A16 | N/A | 0 | 1.66 | 0.00 |
| | 27A17 | N/A | 0 | 1.69 | 0.00 |
| | 27A4 | 2.92 | 105 | 0.31 | 0.21 |
| | 27A5 | 8.16 | 42 | 0.34 | 0.43 |
| | 27A6 | 2.39 | 162 | 0.39 | 0.67 |
| | 27A7 | 3.63 | 98 | 0.36 | 0.16 |
| Wareham (22.8 kV) | 3-85-85 | 6.39 | 32 | 0.21 | 0.41 |
| | 3-85-928 | 5.74 | 29 | 0.17 | 1.34 |
| | 3-85-957 | 3.55 | 24 | 0.09 | 0.26 |
| | 3-86-966 | 5.88 | 42 | 0.24 | 0.59 |

Note: Values presented in this table were published on April 24, 2023 and are reflective of data collected through the end of 2022.
*Source: Guidehouse analysis of 2022 GMP Term Report, Appendix 1 filed April 24, 2023. EDCs provided distributed generation data.*

## A.2 National Grid Additional Feeder Characteristics

**Table A-2. Additional National Grid Feeder Characteristics**

| Substation | Feeder | Avg Customer Loading (kVA/customer) | Customer Density (customer/mi.) | Load Density (MVA/mi.) | DG Penetration (DG MW/MVA) |
|---|---|---|---|---|---|
| Term 1 Feeders | | | | | |
| East Methuen (13.2 kV) | 74L1 | 6.04 | 80 | 0.48 | 0.31 |
| | 74L2 | 6.17 | 94 | 0.58 | 0.09 |
| | 74L3 | 3.39 | 171 | 0.58 | 0.17 |
| | 74L4 | 5.94 | 186 | 1.10 | 0.12 |
| | 74L5 | 3.47 | 58 | 0.20 | 0.12 |
| | 74L6 | 6.80 | 211 | 1.43 | 0.06 |

| Substation | Feeder | Avg Customer Loading (kVA/customer) | Customer Density (customer/mi.) | Load Density (MVA/mi.) | DG Penetration (DG MW/MVA) |
|---|---|---|---|---|---|
| Stoughton (13.8 kV) | 913W17 | 9.38 | 95 | 0.90 | 0.14 |
| | 913W18 | 6.75 | 127 | 0.86 | 0.07 |
| | 913W43 | 6.30 | 67 | 0.42 | 0.11 |
| | 913W47 | 8.08 | 112 | 0.90 | 0.04 |
| | 913W67 | 17.79 | 60 | 1.07 | 0.07 |
| | 913W69 | 3.73 | 114 | 0.43 | 0.12 |
| Maplewood (13.8 kV) | 16W1 | 3.28 | 212 | 0.70 | 0.11 |
| | 16W2 | 2.09 | 432 | 0.90 | 0.11 |
| | 16W3 | 3.78 | 248 | 0.94 | 0.05 |
| | 16W4 | 11.20 | 146 | 1.64 | 0.07 |
| | 16W5 | 7.20 | 254 | 1.83 | 0.08 |
| | 16W6 | 2.25 | 238 | 0.54 | 0.16 |
| | 16W7 | 3.26 | 272 | 0.89 | 0.15 |
| | 16W8 | 3.70 | 217 | 0.80 | 0.15 |
| Term 2 Feeders | | | | | |
| East Bridgewater (13.8 kV) | 797W1 | 5.19 | 79 | 0.41 | 0.10 |
| | 797W19 | 5.66 | 68 | 0.38 | 0.19 |
| | 797W20 | 8.21 | 55 | 0.45 | 0.05 |
| | 797W23 | 5.47 | 64 | 0.35 | 0.12 |
| | 797W24 | 5.62 | 48 | 0.27 | 0.10 |
| | 797W29 | 6.21 | 63 | 0.39 | 0.19 |
| | 797W42 | 11.38 | 58 | 0.66 | 0.14 |
| East Dracut (13.8 kV) | 75L1 | 3.20 | 183 | 0.58 | 0.10 |
| | 75L2 | 4.21 | 67 | 0.28 | 0.10 |
| | 75L3 | 5.21 | 46 | 0.24 | 0.18 |
| | 75L4 | 28.65 | 44 | 1.27 | 0.02 |
| | 75L5 | 2.73 | 190 | 0.52 | 0.11 |
| | 75L6 | 7.93 | 58 | 0.46 | 0.08 |
| Easton | 92W43 | 5.15 | 71 | 0.36 | 0.11 |

| Substation | Feeder | Avg Customer Loading (kVA/customer) | Customer Density (customer/mi.) | Load Density (MVA/mi.) | DG Penetration (DG MW/MVA) |
|---|---|---|---|---|---|
| (13.8 kV) | 92W44 | 7.55 | 68 | 0.51 | 0.10 |
| | 92W54 | 4.45 | 68 | 0.30 | 0.78 |
| | 92W78 | 6.24 | 52 | 0.33 | 0.07 |
| | 92W79 | 7.51 | 69 | 0.52 | 0.43 |
| Melrose (13.8 kV) | 25W1 | 7.82 | 85 | 0.66 | 0.19 |
| | 25W2 | 10.18 | 74 | 0.75 | 0.06 |
| | 25W3 | 15.41 | 84 | 1.30 | 0.07 |
| | 25W4 | 2.58 | 217 | 0.56 | 0.10 |
| | 25W5 | 3.24 | 193 | 0.63 | 0.11 |
| West Salem (13.8 kV) | 29W1 | 3.31 | 162 | 0.54 | 0.19 |
| | 29W2 | 6.80 | 105 | 0.71 | 0.06 |
| | 29W3 | 2.90 | 281 | 0.81 | 0.11 |
| | 29W4 | 4.16 | 152 | 0.63 | 0.19 |
| | 29W5 | 3.53 | 244 | 0.86 | 0.13 |
| | 29W6 | 8.88 | 83 | 0.74 | 0.10 |
| Westboro (13.8 kV) | 312W1 | 5.56 | 75 | 0.42 | 0.16 |
| | 312W2 | 71.03 | 21 | 1.46 | 0.24 |
| | 312W3 | 6.81 | 72 | 0.49 | 0.09 |
| | 312W4 | 4.79 | 48 | 0.23 | 0.40 |
| | 312W5 | 29.88 | 31 | 0.93 | 0.07 |

Note: Values presented in this table were published on April 24, 2023 and are reflective of data collected through the end of 2022.
*Source: Guidehouse analysis of 2022 GMP Term Report, Appendix 1 filed April 24, 2023 EDCs provided distributed generation data.*

## A.3 Unitil Additional Feeder Characteristics

**Table A-3. Additional Unitil Feeder Characteristics**

| Substation | Feeder | Avg Customer Loading (kVA/customer) | Customer Density (customer/mi.) | Load Density (MVA/mi.) | DG Penetration (DG MW/MVA) |
|---|---|---|---|---|---|
| Term 1 Feeders | | | | | |
| Townsend (13.8 kV) | 15W15 | 8,844 | 6 | 55.20 | 0.00 |
| | 15W16 | 5.76 | 36 | 0.21 | 0.35 |
| | 15W17 | 15.41 | 50 | 0.77 | 0.36 |
| Term 2 Feeders | | | | | |
| Summer Street (13.8 kV) | 40W38 | 137.28 | 110 | 15.16 | 0.05 |
| | 40W39 | 24.93 | 46 | 1.14 | 0.21 |
| | 40W40 | 6.06 | 86 | 0.52 | 0.23 |
| | 40W42 | 4.98 | 153 | 0.76 | 0.20 |
| Lunenburg | 30W30 | 6.44 | 31 | 0.20 | 0.32 |

| Substation | Feeder | Avg Customer Loading (kVA/customer) | Customer Density (customer/mi.) | Load Density (MVA/mi.) | DG Penetration (DG MW/MVA) |
|---|---|---|---|---|---|
| (13.8 kV) | 30W31 | 6.01 | 37 | 0.22 | 0.94 |
| West Townsend (13.8 kV) | 39W18 | 6.63 | 38 | 0.25 | 0.00 |
| | 39W19 | 5.72 | 22 | 0.12 | 0.00 |

Note: Values presented in this table were published on April 24, 2023 and are reflective of data collected through the end of 2022.
*Source: Guidehouse analysis of 2022 GMP Term Report, Appendix 1 filed April 24, 2023 EDCs provided distributed generation data.*

# Appendix B. Detailed Information for Performance Metrics Analysis

## B.1 Conservation Voltage Reduction Factor

One informative metric associated with VVO is the conservation voltage reduction (CVR) factor, which reveals the percentage of energy savings that can be expected for each percentage of voltage reduction. Equation 5-1 highlights how the CVR factor is calculated using an estimated percentage change in energy and percentage change in voltage.

**Equation 5-1. CVR Factor Calculation**

$$CVRf = \frac{\%\Delta\, Energy}{\%\Delta\, Voltage}$$

## B.2 Regression Methodology for Estimating VVO-Related Energy and Voltage Changes

For feeders going through VVO On/Off testing during the Spring 2022 – Winter 2022/23 M&V period, Guidehouse conducted regression modeling to assess the impacts of VVO on measured feeder-level real power and voltage. To estimate the impact of VVO on feeder-level real power and voltage observed during the Spring 2022 – Winter 2022/23 M&V period, Guidehouse estimated a regression model of real power and a regression model of voltage for each individual feeder. Equation 5-2 and Equation 5-3[66] summarizes the regression model specification used to estimate real power and voltage as a function of VVO.

**Equation 5-2. Regression Model of Energy and Voltage**

$$\begin{aligned}\{kW_{it}, V_{it}\} = {} & \beta_1 lagged\,\{kW_{it}, V_{it}\} + \beta_2 Spring_{it} + \beta_3 Summer_{it} + \beta_4 Fall_{it} + \beta_5 Winter_{it} \\ & + \beta_6 VVO_{it} * Spring_{it} + \beta_7 VVO_{it} * Summer_{it} + \beta_8 VVO_{it} * Fall_{it} + \beta_9 VVO_{it} \\ & * Winter_{it} + \beta_{10} Daylight_{it} + \sum_{wknd=1}^{2} \beta_{11wknd} * \tau_{wknd} + \sum_{m=1}^{12} \beta_{12m} * \tau_m \\ & + \sum_{wknd,h=1}^{48} \beta_{13wknd,h} * \tau_{wknd,h} + \sum_{h=1}^{24} \beta_{14h} * \tau_h * Cloud_{it} * Daylight_{it} \\ & + \sum_{h=1}^{24} \beta_{15h} * \tau_h * HDH_{it} + \sum_{h=1}^{24} \beta_{16h} * \tau_h * CDH_{it} + \beta_{17} DR\,Flag_t + \varepsilon_{it}\end{aligned}$$

[66] Given that the Easton substation did not start VVO On/Off testing until Winter 2022/23, Guidehouse ran a separate model to estimate energy and voltage changes for this substation that does not include seasonal terms (e.g., Spring, Summer, Fall, and Winter).

Where:

| | |
|---|---|
| $i, t, h, wknd, and\ m$ | index feeder, time-interval, each of the 24 hours of the day, weekend, and month of year respectively. |
| $kW_{it}$ | is real power (kW) measured at feeder $i$ at time $t$. |
| $V_{it}$ | is voltage (V) measured at feeder $i$ at time $t$. |
| $lagged\ kW_{it}$ | is real power (kW) measured at feeder $i$ at time $t - 24$. The corresponding coefficient, $\beta_1$, captures the degree to which any given hour *t's* real power is correlated with real power 24 hours prior. |
| $lagged\ V_{it}$ | is voltage (V) measured at feeder $i$ at time $t - 24$. The corresponding coefficient, $\beta_2$, captures the degree to which hour *t* voltage is correlated with voltage 24 hours prior. |
| $Spring_{it}$ | is an indicator equal to 1 when feeder $i$ at time $t$ falls within March 1 through May 31, 2022. The corresponding coefficient $\beta_2$ captures the average real power and voltage observed during the Spring season. |
| $Summer_{it}$ | is an indicator equal to 1 when feeder $i$ at time $t$ falls within June 1 through August 31, 2022. The corresponding coefficient $\beta_3$ captures the average real power and voltage observed during the Summer season. |
| $Fall_{it}$ | is an indicator equal to 1 when feeder $i$ at time $t$ falls within September 1 through November 30, 2022. The corresponding coefficient $\beta_4$ captures the average real power and voltage observed during the Fall season. |
| $Winter_{it}$ | is an indicator equal to 1 when feeder $i$ at time $t$ falls within December 1, 2022 through February 28, 2023. The corresponding coefficient $\beta_5$ captures the average real power and voltage observed during The Winter season. |
| $VVO_{it}$ | is an indicator equal to 1 when VVO is engaged for feeder $i$ at time $t$. The coefficient $\beta_6$ captures the average hourly impact of VVO on real power or voltage during the Spring season; the coefficient $\beta_7$ captures the average hourly impact of VVO on real power or voltage during the Summer season; the coefficient $\beta_8$.captures the average hourly impact of VVO on real power or voltage during the Fall season; and the coefficient $\beta_9$ captures the average hourly impact of VVO on real power or voltage during the Winter season. A combination of $\beta_6, \beta_7, \beta_8, \text{and } \beta_9$ captures the average hourly impact of VVO on real power or voltage during the entire analysis period. |
| $Daylight_{it}$ | is an indicator equal to 1 when feeder $i$ at time $t$ falls within a daylight hour. The coefficient $\beta_{10}$ captures the average real power or voltage |

observed during daylight hours when distributed solar facilities are producing electricity.

$\tau_{wknd}$ — are fixed effects for a weekday or weekend. The corresponding $\beta_{11wknd}$ coefficients capture the average daily real power or voltage for a weekday or weekend.

$\tau_m$ — are fixed effects for each month $m$. The corresponding $\beta_{12m}$ coefficients capture the average monthly real power or voltage for each month of the Spring 2022 – Winter 2022/23 analysis period.

$\tau_{wknd,h}$ — are hourly fixed effects for each weekday or weekend $wknd$ and each hour of day $h$ combination. The corresponding $\beta_{13wknd,h}$ coefficients capture the average real power or voltage for each weekday or weekend and hour of day combination.

$\tau_h$ — are hourly fixed effects for each hour of day $h$. The corresponding $\beta_{14h}$ coefficients capture the average hourly real power or voltage for each hour across the Spring 2022 – Winter 2022/23 analysis period.

$Cloud_{it}$ — is a categorical variable denoting hourly cloud cover conditions recorded by NOAA, intended to control for distributed solar generation connected to VVO feeders. Cloud cover multiplied by $Daylight_{it}$ and $\tau_h$ forces the regression model to provide an estimate of real power or voltage associated with distributed solar during each daylight hour. The coefficient $\beta_{14h}$ captures this average real power or voltage observed during daylight hours when distributed solar facilities are producing electricity.

$CDH_{it}$ — are cooling degree-hours (CDH), base 65°F, for feeder $i$ at time $t$ to capture the impacts of temperature on cooling load for each hour of day $h$. The corresponding coefficients $\beta_{15h}$ captures the impact of CDH on real power or voltage for each hour of day $h$.

$HDH_{it}$ — are heating degree-hours (CDH), base 65°F, for feeder $i$ at time $t$ to capture the impacts of temperature on heating load for each hour of day $h$. The corresponding coefficients $\beta_{16h}$ captures the impact of HDH on real power or voltage for each hour of day $h$.

$DR\ Flag_t$ — is an indicator equal to 1 when a demand response event occurred at time $t$. The coefficient $\beta_{17}$ captures the average hourly impact of VVO on real power or voltage during the demand response events.

$\epsilon_{it}$ — is an error term for feeder $i$ at time $t$ and captures unexplained variation in real power or voltage.

**Equation 5-3. Regression Model of Energy and Voltage (Easton Substation)**

$$\{kW_{it}, V_{it}\} = \beta_1 lagged\ \{kW_{it}, V_{it}\} + \beta_2 VVO_{it} + \beta_3 Daylight_{it} + \sum_{wknd=1}^{2} \beta_{4wknd} * \tau_{wknd} + \sum_{m=1}^{12} \beta_{5m} * \tau_m$$
$$+ \sum_{wknd,h=1}^{48} \beta_{6wknd,h} * \tau_{wknd,h} + \sum_{h=1}^{24} \beta_{7h} * \tau_h * Cloud_{it} * Daylight_{it} + \sum_{h=1}^{24} \beta_{8h} * \tau_h * HDH_{it}$$
$$+ \sum_{h=1}^{24} \beta_{9h} * \tau_h * CDH_{it} + \beta_{10} DR\ Flag_t + \epsilon_{it}$$

Where:

| | |
|---|---|
| $i, t, h, wknd, and\ m$ | index feeder, time-interval, each of the 24 hours of the day, weekend, and month of year respectively. |
| $kW_{it}$ | is real power (kW) measured at feeder $i$ at time $t$. |
| $V_{it}$ | is voltage (V) measured at feeder $i$ at time $t$. |
| $lagged\ kW_{it}$ | is real power (kW) measured at feeder $i$ at time $t - 24$. |
| $lagged\ V_{it}$ | is voltage (V) measured at feeder $i$ at time $t - 24$. |
| $VVO_{it}$ | is an indicator equal to 1 when VVO is engaged for feeder $i$ at time $t$. $\beta_2$ captures the average hourly impact of VVO on real power or voltage while Easton was going through VV On/Off testing. |
| $Daylight_{it}$ | is an indicator equal to 1 when feeder $i$ at time $t$ falls within a daylight hour. The coefficient $\beta_3$ captures the average real power or voltage observed during daylight hours when distributed solar facilities are producing electricity. |
| $\tau_{wknd}$ | are fixed effects for a weekday or weekend. The corresponding $\beta_{4wknd}$ coefficients capture the average daily real power or voltage for a weekday or weekend. |
| $\tau_m$ | are fixed effects for each month $m$. The corresponding $\beta_{5m}$ coefficients capture the average monthly real power or voltage for each month while Easton was going through VVO On/Off testing. |
| $\tau_{wknd,h}$ | are hourly fixed effects for each weekday or weekend $wknd$ and each hour of day $h$ combination. The corresponding $\beta_{6wknd,h}$ coefficients |

capture the average real power or voltage for each weekday or weekend and hour of day combination.

$\tau_h$ — are hourly fixed effects for each hour of day $h$. The corresponding $\beta_{7h}$ coefficients capture the average hourly real power or voltage for each hour while Easton was going through VVO On/Off testing.

$Cloud_{it}$ — is a categorical variable denoting hourly cloud cover conditions recorded by NOAA, intended to control for distributed solar generation connected to VVO feeders. Cloud cover multiplied by $Daylight_{it}$ and $\tau_h$ forces the regression model to provide an estimate of real power or voltage associated with distributed solar during each daylight hour. The coefficient $\beta_{8h}$ captures this average real power or voltage observed during daylight hours when distributed solar facilities are producing electricity.

$CDH_{it}$ — are cooling degree-hours (CDH), base 65°F, for feeder $i$ at time $t$ to capture the impacts of temperature on cooling load for each hour of day $h$. The corresponding coefficients $\beta_{9h}$ captures the impact of CDH on real power or voltage for each hour of day $h$.

$HDH_{it}$ — are heating degree-hours (CDH), base 65°F, for feeder $i$ at time $t$ to capture the impacts of temperature on heating load for each hour of day $h$. The corresponding coefficients $\beta_{10h}$ captures the impact of HDH on real power or voltage for each hour of day $h$.

$DR\ Flag_t$ — is an indicator equal to 1 when a demand response event occurred at time $t$. The coefficient $\beta_{17}$ captures the average hourly impact of VVO on real power or voltage during the demand response events.

$\epsilon_{it}$ — is an error term for feeder $i$ at time $t$ and captures unexplained variation in real power or voltage.

## B.3 Methodology for Estimating VVO Energy Savings for Feeders that Completed On/Off Testing

For the VVO substations that completed VVO On/Off testing prior to the Spring 2022 – Winter 2022/23 M&V period, Guidehouse did not estimate energy impacts using a regression methodology. Instead, Guidehouse estimated energy impacts using energy impact estimates from the most-recent period (i.e., Spring 2021 – Winter 2021/22) in which the substation conducted VVO On/Off testing. For the Spring 2022 – Winter 2022/23 evaluation period, there was only one National Grid substation that completed VVO On/Off testing, which included 6 feeders.

To estimate energy savings, Guidehouse conducted the following four steps:

1. Calculated average hourly energy demand per feeder and peak energy period (i.e., Summer Peak, Summer Off-Peak, Winter Peak, Winter Off-Peak) while VVO was turned off during the current M&V period (i.e., Spring 2022 – Winter 2022/23)

2. Calculated the total number of hours where VVO was turned on per feeder and peak energy period (i.e., Summer Peak, Summer Off-Peak, Winter Peak, Winter Off-Peak) during the current M&V period (i.e., Spring 2022 – Winter 2022/23)

3. Calculated estimated average hourly energy reductions for each feeder for each peak energy period. This was calculated by taking the product of (a) percent energy reductions estimates per peak energy period from Spring 2021 – Winter 2021/22 (the last period where the feeder conducted VVO On/Off testing), and (b) average hourly energy demand per feeder and peak energy period (i.e., Summer Peak, Summer Off-Peak, Winter Peak, Winter Off-Peak) while VVO was turned off during the current evaluation period (i.e., Spring 2022 – Winter 2022/23).

4. Calculated the weighted average hourly energy reductions per feeder. This weighted average was calculated based on the total number of hours where VVO was turned on per feeder and peak energy period (e.g., Summer Peak, Summer Off-Peak, Winter Peak, Winter Off-Peak) during the current evaluation period (i.e., Spring 2022 – Winter 2022/23).

Once weighted average hourly energy reductions were calculated for each of these feeders, Guidehouse multiplied these values by the total number of hours where VVO was turned on per feeder during the current M&V period (i.e., Spring 2022 – Winter 2022/23) to generate total energy reduction estimates per feeder during the Spring 2022 – Winter 2022/23 M&V period.

## B.4 Regression Methodology for Estimating VVO-Related Peak Load Changes

Equation 5-4 summarizes the regression model specification used to estimate peak load as a function of VVO for the feeders that went through VVO On/Off testing during the Spring 2022 – Winter 2022/23 M&V period.

**Equation 5-4. Regression Model of Peak Load**

$$Peak_{it} = \beta_1 VVO_{it} + \sum_{d=1}^{7} \beta_{2d} * \tau_d + \sum_{h=1}^{24} \beta_{3h} * \tau_h * Cloud_{it} + \beta_4 CDH_{it} + \beta_5 HDH_{it} + \beta_6 DR\ Flag_t + \epsilon_{it}$$

Where:

| | |
|---|---|
| $i, t, h, d$ | index feeder, time-interval, each of the 24 hours of the day, and day of week respectively. |
| $Peak\ kW_{it}$ | is peak load (kW) measured at feeder $i$ at time $t$. |
| $VVO_{it}$ | is an indicator equal to 1 when VVO is engaged for feeder $i$ at time $t$. The coefficient $\beta_1$ captures the average hourly impact of VVO on peak load during the entire analysis period. |
| $\tau_d$ | are fixed effects for each day of the week $d$. The corresponding $\beta_{2d}$ coefficients capture the average daily peak load for each day of the week. |
| $\tau_h$ | are hourly fixed effects for each hour $h$. The corresponding $\beta_{4h}$ coefficients capture the average hourly peak load across the Spring 2022 – Winter 2022/23 analysis period. |
| $Cloud_{it}$ | is a categorical variable denoting hourly cloud cover conditions recorded by NOAA, intended to control for distributed solar generation connected to VVO feeders. Cloud cover multiplied by $\tau_h$ forces the regression model to provide an estimate of peak load associated with distributed solar during each peak load hour of the day. The coefficient $\beta_{3h}$ captures this average peak load observed during daylight hours when distributed solar facilities are producing electricity. |
| $CDH_{it}$ | are cooling degree-hours (CDH), base 65°F, for feeder $i$ at time $t$ to capture the impacts of temperature on cooling load. The corresponding coefficient $\beta_4$ captures the impact of CDH on peak load. |
| $HDH_{it}$ | are heating degree-hours (HDH), base 65°F, for feeder $i$ at time $t$ to capture the impacts of temperature on heating load. The corresponding coefficient $\beta_5$ captures the impact of HDH on peak load. |
| $DR\ Flag_t$ | is an indicator equal to 1 when a demand response event occurred at time $t$. The coefficient $\beta_6$ captures the average hourly impact of VVO on real power or voltage during the demand response events. |
| $\epsilon_{it}$ | is an error term for feeder $i$ at time $t$ and captures unexplained variation in peak load. |

## B.5 Methodology for Estimating VVO-Related Peak Load Changes for Feeders that Completed On/Off Testing

For the feeders that did not undergo VVO On/Off testing during the Spring 2022 – Winter 2022/23 evaluation period, Guidehouse calculated estimated peak load changes by taking the product of (a) average hourly energy per feeder during peak load period that occurred Spring 2022 – Winter 2022/23 while VVO was turned off and (b) the estimated percentage reduction in peak load percentage from the last period where the feeder underwent VVO On/Off testing. For the Spring 2022 – Winter 2022/23 evaluation period, there was only one National Grid substation that completed VVO On/Off testing, which included 6 feeders.

## B.6 Regression Methodology for Power Factor

Equation 5-5 summarizes the regression model specification used to estimate power factor as a function of VVO for the feeders that went through VVO On/Off testing during the Spring 2022 – Winter 2022/23 M&V period.

**Equation 5-5. Regression Model of Power Factor**

$$PF_{it} = \beta_1 VVO_{it} + \sum_{d=1}^{7} \beta_{2d} * \tau_d + \sum_{h=1}^{24} \beta_{3h} * \tau_h * Cloud_{it} + \beta_4 HDH_{it} + \beta_5 CDH_{it} + \beta_6 DR\ Flag_t + \epsilon_{it}$$

Where:

| | |
|---|---|
| $i, t, h, d$ | index feeder, time-interval, each of the 24 hours of the day, and day of week respectively. |
| $PF_{it}$ | is power factor measured at feeder $i$ at time $t$. |
| $VVO_{it}$ | is an indicator equal to 1 when VVO is engaged for feeder $i$ at time $t$. The coefficient $\beta_1$ captures the average hourly impact of VVO on power factor during the entire analysis period. |
| $\tau_d$ | are fixed effects for each day of the week $d$. The corresponding $\beta_{2d}$ coefficients capture the average daily power factor for each day of the week. |
| $\tau_h$ | are hourly fixed effects for each hour $h$. The corresponding $\beta_{3h}$ coefficients capture the average hourly power factor across the Spring 2022 – Winter 2022/23 analysis period. |
| $Cloud_{it}$ | is a categorical variable denoting hourly cloud cover conditions recorded by NOAA, intended to control for distributed solar generation connected to VVO feeders. Cloud cover multiplied by $Daylight_{it}$ and $\tau_h$ forces the regression model to provide an estimate of power factor associated with distributed solar during each daylight hour. The |

| | |
|---|---|
| | coefficient $\beta_{3h}$ captures this average power factor observed during daylight hours when distributed solar facilities are producing electricity. |
| $HDH_{it}$ | are heating degree-hours (HDH), base 65°F, for feeder $i$ at time $t$ to capture the impacts of temperature on heating load. The corresponding coefficient $\beta_4$ captures the impact of HDH on power factor. |
| $CDH_{it}$ | are cooling degree-hours (CDH), base 65°F, for feeder $i$ at time $t$ to capture the impacts of temperature on cooling load. The corresponding coefficient $\beta_5$ captures the impact of CDH on power factor. |
| $DR\ Flag_t$ | is an indicator equal to 1 when a demand response event occurred at time $t$. The coefficient $\beta_6$ captures the average hourly impact of VVO on power factor during the demand response events. |
| $\epsilon_{it}$ | is an error term for feeder $i$ at time $t$ and captures unexplained variation in power factor. |

## B.7 Methodology for Estimating VVO-Related Power Factor Changes for Feeders that Completed On/Off Testing

For the feeders that did not go through VVO On/Off testing during the Spring 2022 – Winter 2022/23 evaluation period, Guidehouse leveraged the estimates for power factor change from the last period where the feeder went through VVO On/Off testing. Power factor change estimates provided last year were interpreted as the average hourly impact of VVO on power factor for each feeder. Given that power factor is not affected based on the number of hours when VVO is On, the results from when the feeder underwent VVO On/Off testing applied to when the feeder completes VVO On/Off testing as well. For the Spring 2022 – Winter 2022/23 evaluation period, there was only one National Grid substation that completed VVO On/Off testing, which included 6 feeders.

## B.8 Distribution Losses Methodology

Guidehouse evaluated change in distribution losses as a function of VVO during the Spring 2022 – Winter 2022/23 M&V period. To estimate the impact of VVO on feeder-level distribution losses, Guidehouse used a distribution losses equation for each individual feeder.[67] Equation 5-6 summarizes the equation used to estimate the change in distribution losses as a function of VVO for the VVO feeders that went through VVO On/Off testing during the Spring 2022 – Winter 2022/23 M&V period.

**Equation 5-6. Distribution Losses Equation**

$$\%\ Loss\ Reduction = 100 - 100\left(\frac{PF_{VVO\ off}}{PF_{VVO\ On}}\right)^2$$

[67] https://www.nepsi.com/resources/calculators/loss-reduction-with-power-factor-correction.htm

Where:

| | |
|---|---|
| $PF_{VVO\ Off}$ | Power factor when VVO is in the disengaged state. |
| $PF_{VVO\ On}$ | Power factor when VVO is in the engaged state. |

## B.9 Methodology for Estimating VVO-Related Distribution Loss Changes for Feeders that Completed On/Off Testing

For the feeders that did not undergo VVO On/Off testing during the Spring 2022 – Winter 2022/23 evaluation period, Guidehouse leveraged the estimates for distribution losses change from the last period where the feeder went through VVO On/Off testing. Given that distribution losses estimates provided were in percentage terms, the metric is unitless and is not affected based on the number of hours when VVO is On. As such, the results from when the feeder went through VVO On/Off testing can be applied to when the feeder completes VVO On/Off testing as well. For the Spring 2022 – Winter 2022/23 evaluation period, there was only one National Grid substation that completed VVO On/Off testing, which included 6 feeders.

## B.10 Overall Data Attrition from Data Cleaning

The tables in this section provide a detailed summary of data attrition from cleaning steps applied to analysis datasets. Detailed data attrition results are provided separately by EDC and substation.

### B.10.1 Eversource

**Table B-1. Count of Quarter-Hours Remaining by Data Cleaning Step for Agawam**

| Data Cleaning Step | 16C11 | 16C12 | 16C14 | 16C15 | 16C16 | 16C17 | 16C18 |
|---|---|---|---|---|---|---|---|
| Initial Dataset (Spring 2022 – Winter 2022/23) | **35,040** | **35,040** | **35,040** | **35,040** | **35,040** | **35,040** | **35,040** |
| 1. Remove Long Events | 4,629 | 4,629 | 6,756 | 6,756 | 6,756 | 6,755 | 6,755 |
| 2. Remove Interpolated | 6,460 | 1,398 | 1,050 | 1,089 | 1,093 | 890 | 886 |
| 3. Remove Repeated | 2,789 | 844 | 487 | 541 | 442 | 178 | 204 |
| 4. Remove Outliers | 982 | 654 | 308 | 358 | 295 | 620 | 421 |
| Final Dataset | 20,180 | 27,515 | 26,439 | 26,296 | 26,454 | 26,597 | 26,774 |
| Observations Removed | **14,860** | **7,525** | **8,601** | **8,744** | **8,586** | **8,443** | **8,266** |

*Source: Guidehouse analysis*

**Table B-2. Count of VVO On, VVO Off, and Removed Quarter-Hours for Agawam**

| Number of Quarter-Hours | 16C11 | 16C12 | 16C14 | 16C15 | 16C16 | 16C17 | 16C18 |
|---|---|---|---|---|---|---|---|
| VVO On *Weekday* | 7,076 | 9,302 | 9,142 | 9,104 | 9,178 | 9,185 | 9,333 |
| VVO On *Weekend* | 2,889 | 3,769 | 3,984 | 3,980 | 3,960 | 4,059 | 4,050 |
| VVO Off *Weekday* | 7,473 | 10,722 | 9,845 | 9,766 | 9,875 | 9,844 | 9,974 |
| VVO Off *Weekend* | 2,741 | 3,721 | 3,467 | 3,445 | 3,440 | 3,508 | 3,416 |
| Removed | 14,860 | 7,525 | 8,601 | 8,744 | 8,586 | 8,443 | 8,266 |
| Spring 2022 – Winter 2022/23 Total | 35,040 | 35,040 | 35,040 | 35,040 | 35,040 | 35,040 | 35,040 |

*Source: Guidehouse analysis*

**Table B-3. Count of Quarter-Hours Remaining by Data Cleaning Step for Piper**

| Data Cleaning Step | 21N4 | 21N5 | 21N6 | 21N7 | 21N8 | 21N9 |
|---|---|---|---|---|---|---|
| Initial Dataset (Spring 2022 – Winter 2022/23) | **35,040** | **35,040** | **35,040** | **35,040** | **35,040** | **35,040** |
| 1. Remove Long Events | 1,912 | 1,912 | 1,912 | 1,912 | 1,912 | 1,912 |
| 2. Remove Interpolated | 950 | 7,216 | 796 | 924 | 832 | 1,537 |
| 3. Remove Repeated | 316 | 1,708 | 189 | 273 | 156 | 880 |
| 4. Remove Outlier | 534 | 596 | 242 | 1,897 | 179 | 15,742 |
| Final Dataset | 31,328 | 23,608 | 31,901 | 30,034 | 31,961 | 14,969 |
| Observations Removed | **3,712** | **11,432** | **3,139** | **5,006** | **3,079** | **20,071** |

*Source: Guidehouse analysis*

**Table B-4. Count of VVO On, VVO Off, and Removed Quarter-Hours for Piper**

| Number of Quarter-Hours | 21N4 | 21N5 | 21N6 | 21N7 | 21N8 | 21N9 |
|---|---|---|---|---|---|---|
| VVO On *Weekday* | 11,016 | 8,607 | 11,183 | 10,978 | 11,211 | 5,220 |
| VVO On *Weekend* | 4,823 | 3,778 | 4,921 | 4,574 | 4,914 | 2,350 |
| VVO Off *Weekday* | 11,322 | 8,292 | 11,473 | 10,559 | 11,530 | 5,570 |
| VVO Off *Weekend* | 4,167 | 2,931 | 4,324 | 3,923 | 4,306 | 1,829 |
| Removed | 3,712 | 11,432 | 3,139 | 5,006 | 3,079 | 20,071 |
| Spring 2022 – Winter 2022/23 Total | 35,040 | 35,040 | 35,040 | 35,040 | 35,040 | 35,040 |

*Source: Guidehouse analysis*

**Table B-5. Count of Quarter-Hours Remaining by Data Cleaning Step for Podick**

| Data Cleaning Step | 18G2 | 18G2 | 18G4 | 18G5 | 18G6 | 18G7 | 18G8 |
|---|---|---|---|---|---|---|---|
| Initial Dataset (Spring 2022 – Winter 2022/23) | **35,040** | **35,040** | **35,040** | **35,040** | **35,040** | **35,040** | **35,040** |
| 1. Remove Long Events | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2. Remove Interpolated | 8,448 | 8,448 | 8,448 | 8,448 | 8,769 | 8,769 | 8,769 |
| 3. Remove Repeated | 4,557 | 1,727 | 956 | 1,357 | 6,277 | 1,651 | 545 |
| 4. Remove Outliers | 2,942 | 920 | 361 | 676 | 3,667 | 781 | 256 |
| Final Dataset | 18,822 | 23,352 | 24,688 | 23,931 | 15,810 | 23,010 | 21,511 |
| Observations Removed | **16,218** | **11,688** | **10,352** | **11,109** | **19,230** | **12,030** | **13,529** |

*Source: Guidehouse analysis*

**Table B-6. Count of VVO On, VVO Off, and Removed Quarter-Hours for Podick**

| Number of Quarter-Hours | 18G2 | 18G3 | 18G4 | 18G5 | 18G6 | 18G7 | 18G8 |
|---|---|---|---|---|---|---|---|
| VVO On *Weekday* | 6,903 | 8,561 | 8,951 | 8,702 | 5,809 | 8,659 | 7,787 |
| VVO On *Weekend* | 3,143 | 3,834 | 4,123 | 3,977 | 2,622 | 3,751 | 3,452 |
| VVO Off *Weekday* | 6,415 | 8,006 | 8,387 | 8,133 | 5,049 | 7,532 | 7,346 |
| VVO Off *Weekend* | 2,361 | 2,951 | 3,227 | 3,119 | 2,330 | 3,068 | 2,926 |
| Removed | 16,218 | 11,688 | 10,352 | 11,109 | 19,230 | 12,030 | 13,529 |
| Spring 2022 – Winter 2022/23 Total | 35,040 | 35,040 | 35,040 | 35,040 | 35,040 | 35,040 | 35,040 |

*Source: Guidehouse analysis*

**Table B-7. Count of Quarter-Hours Remaining by Data Cleaning Step for Silver**

| Data Cleaning Step | 30A1 | 30A2 | 30A3 | 30A4 | 30A5 | 30A6 |
|---|---|---|---|---|---|---|
| Initial Dataset (Spring 2022 – Winter 2022/23) | **35,040** | **35,040** | **35,040** | **35,040** | **35,040** | **35,040** |
| 1. Remove Missing VVO Status | 0 | 0 | 0 | 0 | 0 | 0 |
| 2. Remove Long Events | 14,147 | 3,564 | 14,147 | 3,564 | 14,147 | 3,564 |
| 3. Remove Interpolated | 5,843 | 5,507 | 8,371 | 6,415 | 1,133 | 7,576 |
| 4. Remove Repeated | 567 | 1,151 | 1,501 | 274 | 663 | 1,253 |
| 5. Remove Outliers | 243 | 611 | 119 | 635 | 884 | 799 |
| Final Dataset | **14,240** | **24,207** | **10,902** | **24,152** | **18,213** | **21,848** |
| Observations Removed | **20,800** | **10,833** | **24,138** | **10,888** | **16,827** | **13,192** |

*Source: Guidehouse analysis*

**Table B-8. Count of VVO On, VVO Off, and Removed Quarter-Hours for Silver**

| Number of Quarter-Hours | 30A1 | 30A2 | 30A3 | 30A4 | 30A5 | 30A6 |
|---|---|---|---|---|---|---|
| VVO On *Weekday* | 4,660 | 8,150 | 3,396 | 8,025 | 6,051 | 7,144 |
| VVO On *Weekend* | 1,934 | 3,512 | 1,606 | 3,250 | 2,600 | 3,136 |
| VVO Off *Weekday* | 5,608 | 9,264 | 4,516 | 9,467 | 7,129 | 8,447 |
| VVO Off *Weekend* | 2,038 | 3,281 | 1,384 | 3,410 | 2,433 | 3,121 |
| Removed | 20,800 | 10,833 | 24,138 | 10,888 | 16,827 | 13,192 |
| Spring 2022 – Winter 2022/23 Total | 35,040 | 35,040 | 35,040 | 35,040 | 35,040 | 35,040 |

*Source: Guidehouse analysis*

## B.10.2 National Grid

**Table B-9. Count of Hours Remaining by Data Cleaning Step for Easton**

| Data Cleaning Step | 92W43 | 92W44 | 92W54 | 92W78 | 92W79 |
|---|---|---|---|---|---|
| Initial Dataset (Spring 2022 – Winter 2022/23) | **1,152** | **1,152** | **1,152** | **1,152** | **1,152** |
| 1. Remove Missing VVO Status | 0 | 0 | 0 | 0 | 0 |
| 2. Remove Long Events | 661 | 661 | 661 | 661 | 661 |
| 3. Remove Interpolated | 1 | 1 | 1 | 1 | 1 |
| 4. Remove Repeated | 0 | 0 | 0 | 0 | 0 |
| 5. Remove Outliers | 0 | 0 | 0 | 0 | 0 |
| Final Dataset | 490 | 490 | 490 | 490 | 490 |
| Observations Removed | **662** | **662** | **662** | **662** | **662** |

*Source: Guidehouse analysis*

**Table B-10. Count of VVO On, VVO Off, and Removed Hours for Easton**

| Number of Hours | 92W43 | 92W44 | 92W54 | 92W78 | 92W79 |
|---|---|---|---|---|---|
| VVO On *Weekday* | 159 | 159 | 159 | 159 | 159 |
| VVO On *Weekend* | 96 | 96 | 96 | 96 | 96 |
| VVO Off *Weekday* | 235 | 235 | 235 | 235 | 235 |
| VVO Off *Weekend* | 0 | 0 | 0 | 0 | 0 |
| Removed | 662 | 662 | 662 | 662 | 662 |
| Spring 2022 – Winter 2022/23 Total | 1,152 | 1,152 | 1,152 | 1,152 | 1,152 |

*Source: Guidehouse analysis*

**Table B-11. Count of Hours Remaining by Data Cleaning Step for East Bridgewater**

| Data Cleaning Step | 797W1 | 797W19 | 797W20 | 797W23 | 797W24 | 797W29 | 797W42 |
|---|---|---|---|---|---|---|---|
| Initial Dataset (Spring 2022 – Winter 2022/23) | **8,760** | **8,760** | **8,760** | **8,760** | **8,760** | **8,760** | **8,760** |
| 1. Remove Missing VVO Status | 2,670 | 2,670 | 2,670 | 2,670 | 2,670 | 2,670 | 2,670 |
| 2. Remove Long Events | 3,502 | 3,363 | 3,363 | 3,502 | 3,363 | 3,502 | 3,502 |
| 3. Remove Interpolated | 0 | 53 | 53 | 0 | 53 | 0 | 0 |
| 4. Remove Repeated | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. Remove Outliers | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Final Dataset | 2,588 | 2,674 | 2,674 | 2,588 | 2,674 | 2,588 | 2,588 |
| Observations Removed | 6,172 | 6,086 | 6,086 | 6,172 | 6,086 | 6,172 | 6,172 |

*Source: Guidehouse analysis*

**Table B-12. Count of VVO On, VVO Off, and Removed Hours for East Bridgewater**

| Number of Hours | 797W1 | 797W19 | 797W20 | 797W23 | 797W24 | 797W29 | 797W42 |
|---|---|---|---|---|---|---|---|
| VVO On *Weekday* | 968 | 1,012 | 1,012 | 968 | 1,012 | 968 | 968 |
| VVO On *Weekend* | 310 | 311 | 311 | 310 | 311 | 310 | 310 |
| VVO Off *Weekday* | 969 | 1,045 | 1,045 | 969 | 1,045 | 969 | 967 |
| VVO Off *Weekend* | 341 | 306 | 306 | 341 | 306 | 341 | 343 |
| Removed | **6,172** | **6,086** | **6,086** | **6,172** | **6,086** | **6,172** | **6,172** |
| Spring 2022 – Winter 2022/23 Total | 8,760 | 8,760 | 8,760 | 8,760 | 8,760 | 8,760 | 8,760 |

*Source: Guidehouse analysis*

**Table B-13. Count of Hours Remaining by Data Cleaning Step for East Methuen**

| Data Cleaning Step | 74L1 | 74L2 | 74L3 | 74L4 | 74L5 | 74L6 |
|---|---|---|---|---|---|---|
| Initial Dataset (Spring 2022 – Winter 22/23) | **8,760** | **8,760** | **8,760** | **8,760** | **8,760** | **8,760** |
| 1. Remove Missing VVO Status | 2,670 | 2,670 | 2,670 | 2,670 | 2,670 | 2,670 |
| 2. Remove Long Events | 2,005 | 2,155 | 2,005 | 2,155 | 2,005 | 2,155 |
| 3. Remove Interpolated | 28 | 16 | 28 | 16 | 28 | 16 |
| 4. Remove Repeated | 3 | 3 | 3 | 3 | 3 | 3 |
| 5. Remove Outliers | 0 | 0 | 0 | 0 | 0 | 0 |
| Final Dataset | 4,054 | 3,916 | 4,054 | 3,916 | 4,054 | 3,916 |
| Observations Removed | **4,706** | **4,844** | **4,706** | **4,844** | **4,706** | **4,844** |

*Source: Guidehouse analysis*

**Table B-14. Count of VVO On, VVO Off, and Removed Hours for East Methuen**

| Number of Hours | 74L1 | 74L2 | 74L3 | 74L4 | 74L5 | 74L6 |
|---|---|---|---|---|---|---|
| VVO On *Weekday* | 1,789 | 1,529 | 1,789 | 1,529 | 1,789 | 1,529 |
| VVO On *Weekend* | 573 | 479 | 573 | 479 | 573 | 479 |
| VVO Off *Weekday* | 1,268 | 1,441 | 1,268 | 1,441 | 1,268 | 1,441 |
| VVO Off *Weekend* | 424 | 467 | 424 | 467 | 424 | 467 |
| Removed | 4,706 | 4,844 | 4,706 | 4,844 | 4,706 | 4,844 |
| Spring 2022 – Winter 2022/23 Total | 8,760 | 8,760 | 8,760 | 8,760 | 8,760 | 8,760 |

*Source: Guidehouse analysis*

**Table B-15. Count of Hours Remaining by Data Cleaning Step for Maplewood**

| Data Cleaning Step | 16W1 | 16W2 | 16W3 | 16W4 | 16W5 | 16W6 | 16W7 | 16W8 |
|---|---|---|---|---|---|---|---|---|
| Initial Dataset (Spring 2022 – Winter 2022/23) | 8,760 | 8,760 | 8,760 | 8,760 | 8,760 | 8,760 | 8,760 | 8,760 |
| 1. Remove Missing VVO Status | 2,670 | 2,670 | 2,670 | 2,670 | 2,670 | 2,670 | 2,670 | 2,670 |
| 2. Remove Long and Short Events | 3,778 | 5,583 | 3,778 | 5,583 | 3,778 | 5,583 | 3,778 | 5,583 |
| 3. Remove Interpolated | 0 | 0 | 0 | 0 | 0 | 0 | 91 | 0 |
| 4. Remove Repeated | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 |
| 5. Remove Outliers | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Final Dataset | 2,312 | 507 | 2,312 | 507 | 2,312 | 507 | 2,219 | 507 |
| Observations Removed | **6,448** | **8,253** | **6,448** | **8,253** | **6,448** | **8,253** | **6,541** | **8,253** |

*Source: Guidehouse analysis*

**Table B-16. Count of VVO On, VVO Off, and Removed Hours for Maplewood**

| Number of Hours | 16W1 | 16W2 | 16W3 | 16W4 | 16W5 | 16W6 | 16W7 | 16W8 |
|---|---|---|---|---|---|---|---|---|
| VVO On *Weekday* | 947 | 128 | 947 | 128 | 947 | 128 | 923 | 128 |
| VVO On *Weekend* | 228 | 24 | 228 | 24 | 228 | 24 | 204 | 24 |
| VVO Off *Weekday* | 885 | 331 | 885 | 331 | 885 | 331 | 864 | 331 |
| VVO Off *Weekend* | 252 | 24 | 252 | 24 | 252 | 24 | 228 | 24 |
| Removed | 6,448 | 8,253 | 6,448 | 8,253 | 6,448 | 8,253 | 6,541 | 8,253 |
| Spring 2022 – Winter 2022/23 Total | **8,760** | **8,760** | **8,760** | **8,760** | **8,760** | **8,760** | **8,760** | **8,760** |

*Source: Guidehouse analysis*

**Table B-17. Count of Hours Remaining by Data Cleaning Step for West Salem**

| Data Cleaning Step | 29W1 | 29W2 | 29W3 | 29W4 | 29W5 | 29W6 |
|---|---|---|---|---|---|---|
| Initial Dataset (Spring 2022 – Winter 2022/23) | 6,576 | 6,576 | 6,576 | 6,576 | 6,576 | 6,576 |
| 1. Remove Missing VVO Status | 2,831 | 2,838 | 2,833 | 2,833 | 2,829 | 2,797 |
| 2. Remove Long Events | 1,387 | 1,102 | 1,294 | 1,181 | 1,464 | 2,194 |
| 3. Remove Interpolated | 0 | 0 | 1 | 1 | 1 | 1 |
| 4. Remove Repeated | 0 | 0 | 1 | 0 | 0 | 0 |
| 5. Remove Outliers | 0 | 0 | 0 | 0 | 0 | 0 |
| Final Dataset | 2,358 | 2,636 | 2,449 | 2,562 | 2,283 | 1,585 |
| Observations Removed | **4,218** | **3,940** | **4,127** | **4,014** | **4,293** | **4,991** |

*Source: Guidehouse analysis*

**Table B-18. Count of VVO On, VVO Off, and Removed Hours for West Salem**

| Number of Hours | 29W1 | 29W2 | 29W3 | 29W4 | 29W5 | 29W6 |
|---|---|---|---|---|---|---|
| VVO On *Weekday* | 879 | 982 | 898 | 970 | 856 | 604 |
| VVO On *Weekend* | 230 | 276 | 276 | 253 | 277 | 148 |
| VVO Off *Weekday* | 1,056 | 1,139 | 1,059 | 1,123 | 980 | 755 |
| VVO Off *Weekend* | 193 | 239 | 216 | 216 | 170 | 78 |
| Removed | 4,218 | 3,940 | 4,127 | 4,014 | 4,293 | 4,991 |
| Spring 2022 – Winter 2022/23 Total | **6,576** | **6,576** | **6,576** | **6,576** | **6,576** | **6,576** |

*Source: Guidehouse analysis*

## B.11 Detailed Performance Metrics Results

This section details feeder-specific performance metrics estimates for the Spring 2022 – Winter 2022/23 period by VVO feeder. Results are provided separately by EDC.

### B.11.1 Eversource

**Table B-19. Eversource Performance Metrics Results by Feeder**

| Feeder | Energy Baseline (MWh) | Net Energy Reduction (MWh)* † | Voltage Reduction (V) | CVRf | Peak Load Reduction (kW) | Distribution Loss Reduction (%) | Power Factor Change | GHG Reductions (CO2) † |
|---|---|---|---|---|---|---|---|---|
| 16C11 | 7,502 | 16 ± 5 | 2.58 ± 0.03 | 0.9 | -24 ± 31 | -- | - | 5 ± 2 |
| 16C12 | 24,627 | 34 ± 7 | 2.27 ± 0.02 | 0.7 | 98 ± 47 | 0.94 | 0.004 ± 0.001 | 12 ± 2 |
| 16C14 | 22,558 | 23 ± 5 | 1.41 ± 0.02 | 0.8 | 135 ± 31 | - | - | 8 ± 2 |
| 16C15 | 19,560 | 14 ± 3 | 1.4 ± 0.02 | 0.5 | -13 ± 21 | -0.49 | -0.002 ± <0.001 | 5 ± 1 |
| 16C16 | 35,182 | 21 ± 7 | 1.42 ± 0.02 | 0.5 | -169 ± 99 | 0.07 | <0.001 ± <0.001 | 7 ± 3 |
| 16C17 | 24,679 | 41 ± 8 | 1.42 ± 0.02 | 1.3 | -138 ± 133 | -0.2 | -0.001 ± <0.001 | 14 ± 3 |
| 16C18 | 19,286 | 10 ± 5 | 1.43 ± 0.02 | 0.4 | -133 ± 52 | - | - | 3 ± 2 |
| 18G2 | 2,990 | -4 ± 1 | 0.25 ± 0.03 | -5.2 | -12 ± 7 | -0.01 | <0.001 ± 0.001 | -1 ± 0 |
| 18G3 | 17,621 | -4 ± 7 | 0.16 ± 0.02 | -1.3 | 27 ± 121 | -0.04 | <0.001 ± <0.001 | -1 ± 2 |
| 18G4 | 13,742 | -11 ± 14 | 0.16 ± 0.02 | -5.3 | 137 ± 170 | - | - | -4 ± 5 |
| 18G5 | 15,869 | -1 ± 13 | 0.16 ± 0.02 | -0.3 | -4 ± 176 | - | - | 0 ± 5 |
| 18G6 | 16,257 | -5 ± 14 | 0.58 ± 0.05 | -0.6 | -8 ± 121 | - | - | -2 ± 5 |
| 18G7 | 10,485 | -5 ± 20 | 0.35 ± 0.03 | -1.4 | -425 ± 283 | -0.11 | -0.001 ± <0.001 | -2 ± 7 |
| 18G8 | 29,110 | -37 ± 22 | 0.37 ± 0.03 | -3.7 | -172 ± 168 | 0.23 | 0.001 ± <0.001 | -12 ± 8 |
| 21N4 | 19,606 | 23 ± 6 | 2.71 ± 0.03 | 0.5 | -56 ± 72 | - | - | 8 ± 2 |
| 21N5 | 32,160 | 10 ± 2 | 2.95 ± 0.03 | 0.1 | 207 ± 74 | - | - | 3 ± 1 |
| 21N6 | 16,074 | 16 ± 3 | 2.92 ± 0.03 | 0.4 | 17 ± 42 | -0.37 | -0.002 ± <0.001 | 5 ± 1 |
| 21N7 | 29,070 | -4 ± 8 | 2.92 ± 0.03 | 0 | -38 ± 34 | -0.16 | -0.001 ± 0.003 | -1 ± 3 |
| 21N8 | 38,995 | 26 ± 7 | 2.92 ± 0.03 | 0.2 | 33 ± 46 | -0.08 | <0.001 ± 0.001 | 9 ± 2 |
| 21N9 | 24,009 | 22 ± 5 | 3.07 ± 0.05 | 0.3 | -100 ± 58 | - | - | 7 ± 2 |

| Feeder | Energy Baseline (MWh) | Net Energy Reduction (MWh)* † | Voltage Reduction (V) | CVRf | Peak Load Reduction (kW) | Distribution Loss Reduction (%) | Power Factor Change | GHG Reductions (CO2) † |
|---|---|---|---|---|---|---|---|---|
| 30A1 | 26,590 | 26 ± 19 | 0.84 ± 0.03 | 1.3 | -137 ± 59 | - | - | 9 ± 6 |
| 30A2 | 12,956 | 14 ± 4 | 0.14 ± 0.02 | 8.2 | -49 ± 56 | - | - | 5 ± 1 |
| 30A3 | 19,086 | 37 ± 24 | 1.11 ± 0.36 | 1.9 | -92 ± 464 | - | - | 13 ± 8 |
| 30A4 | 16,111 | -11 ± 9 | 0.15 ± 0.02 | -4.8 | -232 ± 91 | 0.04 | <0.001 ± <0.001 | -4 ± 3 |
| 30A5 | 4,544 | 6 ± 2 | 0.73 ± 0.02 | 1.9 | 0 ± 0 | - | - | 2 ± 1 |
| 30A6 | 26,324 | -14 ± 5 | 0.16 ± 0.02 | -3.4 | -286 ± 580 | - | - | -5 ± 2 |
| Overall* | 524,992 | 879 ± 184 | 1.52 ± 0.01 | -0.18 | -1,435 ± 903 | 0.01% | <0.001± <0.001 | 299 ± 63 |

* Overall energy savings is the sum of each feeder's energy savings, and due to model noise, a manual sum of savings across periods may not equal the amount provided in the Total row. Overall voltage reductions and CVR factors provided are load-weighted averages of these estimates provided for each feeder. Aggregate CVRf value presented here is the load-weighted average of every feeder-specific CVRf estimate for which there was enough data to estimate CVRf. This differs from the inclusion criteria applied to aggregate CVRf values presented in *Table* Table 79 and Table 94. Similarly, aggregate peak load reduction is the load-weighted average of every feeder-specific peak load reduction estimate for which there was enough data to estimate peak load reduction. This differs from the inclusion criteria applied to aggregate peak load reduction values presented in *Table* Table 80 and Table 95.
† Calculation uses actual number of VVO On hours spanning the analysis period. Actual VVO On Hours are the number of hours VVO was engaged between March 1, 2022 and February 28, 2023.

*Source: Guidehouse analysis*

## B.11.2 National Grid

**Table B-20. National Grid Performance Metrics Results by Feeder***

| Feeder | Energy Baseline (MWh) | Net Energy Reduction (MWh)†‡ | Voltage Reduction (kV) | CVRf | Peak Load Reduction (kW) | Distribution Loss Reduction (%) | Power Factor Change | GHG Reductions (CO2)‡ |
|---|---|---|---|---|---|---|---|---|
| 16W1 | 30,699 | -4 ± 24 | 0.05 ± <0.001 | -0.3 | -302 ± 334 | - | - | -1 ± 8 |
| 16W3 | 31,288 | -48 ± 22 | 0.05 ± <0.001 | -3.5 | -193 ± 220 | - | - | -16 ± 7 |
| 16W5 | 19,329 | -5 ± 15 | 0.05 ± <0.001 | -0.6 | -197 ± 200 | - | - | -2 ± 5 |
| 16W7 | 35,103 | -17 ± 25 | 0.05 ± 0.01 | -1.1 | -582 ± 388 | - | - | -6 ± 9 |
| 29W1 | 37,577 | -53 ± 35 | 0.02 ± 0.01 | -7 | -494 ± 378 | - | - | -18 ± 12 |
| 29W2 | 19,272 | 29 ± 24 | <0.001 ± <0.001 | -40 | -236 ± 218 | - | - | 10 ± 8 |
| 29W3 | 41,240 | 82 ± 26 | 0.03 ± 0.01 | 7.6 | -99 ± 271 | - | - | 28 ± 9 |
| 29W4 | 30,585 | 87 ± 27 | <0.001 ± <0.001 | -90 | -240 ± 250 | - | - | 29 ± 9 |
| 29W5 | 38,941 | 89 ± 34 | 0.04 ± 0.01 | 7.8 | 182 ± 305 | - | - | 30 ± 12 |
| 29W6 | 28,225 | 73 ± 28 | -0.01 ± 0.01 | -28.1 | 50 ± 194 | - | - | 25 ± 10 |
| 74L1 | 35,699 | 92 ± 32 | 0.34 ± 0.01 | 0.9 | -156 ± 415 | - | - | 31 ± 11 |
| 74L2 | 22,748 | 11 ± 17 | 0.13 ± 0.01 | 0.5 | -53 ± 129 | - | - | 4 ± 6 |
| 74L3 | 25,622 | 50 ± 20 | 0.34 ± 0.01 | 0.7 | -100 ± 225 | - | - | 17 ± 7 |
| 74L4 | 28,739 | 16 ± 20 | 0.13 ± 0.01 | 0.5 | -139 ± 135 | - | - | 6 ± 7 |
| 74L5 | 25,151 | 38 ± 19 | 0.34 ± 0.01 | 0.5 | -220 ± 300 | - | - | 13 ± 6 |
| 74L6 | 21,148 | 31 ± 15 | 0.13 ± 0.01 | 1.3 | -35 ± 94 | - | - | 10 ± 5 |
| 797W1 | 29,904 | 47 ± 47 | -0.01 ± <0.001 | -15 | - | - | - | 16 ± 16 |
| 797W19 | 26,886 | 27 ± 27 | 0.1 ± 0.01 | 1.3 | 69 ± 368 | - | - | 9 ± 9 |
| 797W20 | 40,544 | 106 ± 33 | 0.1 ± 0.01 | 3.3 | 151 ± 230 | - | - | 36 ± 11 |
| 797W23 | 28,363 | -11 ± 27 | -0.01 ± <0.001 | 3.6 | - | - | - | -4 ± 9 |
| 797W24 | 34,820 | 21 ± 34 | 0.1 ± 0.01 | 0.8 | 215 ± 318 | - | - | 7 ± 12 |
| 797W29 | 25,735 | 26 ± 27 | -0.01 ± <0.001 | -9.5 | - | - | - | 9 ± 9 |
| 797W42 | 11,706 | 8 ± 16 | -0.01 ± <0.001 | -6.9 | - | - | - | 3 ± 6 |
| 913W17 | 12,900 | 9 ± 12 | - | - | 9 ± 103 | - | - | 3 ± 4 |
| 913W18 | 12,851 | 16 ± 9 | - | - | -18 ± 73 | -1.6 | -0.008 ± 0.003 | 5 ± 3 |

| Feeder | Energy Baseline (MWh) | Net Energy Reduction (MWh)†‡ | Voltage Reduction (kV) | CVRf | Peak Load Reduction (kW) | Distribution Loss Reduction (%) | Power Factor Change | GHG Reductions (CO2)‡ |
|---|---|---|---|---|---|---|---|---|
| 913W43 | 13,940 | 15 ± 16 | - | - | -55 ± 134 | - | - | 5 ± 5 |
| 913W47 | 15,213 | 14 ± 11 | - | - | -51 ± 89 | -1.2 | -0.006 ± 0.002 | 5 ± 4 |
| 913W67 | 5,523 | 4 ± 6 | - | - | -18 ± 50 | - | - | 1 ± 2 |
| 913W69 | 23,391 | 14 ± 20 | - | - | -102 ± 164 | -2.7 | -0.013 ± 0.007 | 5 ± 7 |
| 92W43 | 26,146 | 122 ± 42 | 0.25 ± 0.02 | 2.1 | - | - | - | 41 ± 14 |
| 92W44 | 36,938 | 95 ± 43 | 0.25 ± 0.02 | 1.2 | - | - | - | 32 ± 15 |
| 92W54 | 24,153 | 250 ± 124 | 0.25 ± 0.02 | 4.6 | - | - | - | 85 ± 42 |
| Overall† | 882,631 | 1,867 ± 302 | 0.08 ± <0.001 | -6.64 | -2,615 ± 1,234 | -1.95 | -0.01 ± 0.002 | 645 ± 103 |

* A value of "-" for any one season has been provided for feeders without sufficient data in that specific season.

† Overall energy savings is the sum of each feeder's energy savings, and due to model noise, a manual sum of savings across periods may not equal the amount provided in the Total row. Overall voltage reductions and CVR factors provided are load-weighted averages of these estimates provided for each feeder. Aggregate CVRf value presented here is the load-weighted average of every feeder-specific CVRf value for which there was enough data to estimate CVRf. This differs from the inclusion criteria applied to aggregate CVRf values presented in Table  and Table 94. Similarly, aggregate peak load reduction is the load-weighted average of every feeder-specific peak load reduction estimate for which there was enough data to estimate peak load reduction. This differs from the inclusion criteria applied to aggregate peak load reduction values presented in Table  and Table 95.

‡ Calculation uses actual number of VVO On hours spanning the analysis period. Actual VVO On Hours are the number of hours VVO was engaged between March 1, 2022 and February 28, 2023.

*Source: Guidehouse analysis*

## B.12 Feeder MW Percent of Peak MVA

This section details feeder-specific comparisons of feeder demand in the clean analysis data and feeder annual peak MVA. Each table details each feeder's average demand during the entire analysis period, average demand during the summer peak period,[68] and annual peak MVA.[69] The average feeder demand during the entire analysis period and during the summer peak period are then compared to annual peak MVA by taking the ratio of these values to annual peak MVA. Results are provided separately by EDC.

### B.12.1 Eversource

**Table B-21. Eversource Feeder MW Percent of Peak MVA by Feeder**

| Feeder | Average MW (Spring 2022 – Winter 2022/23†) | Average MW (Summer Peak‡) | Annual Peak MVA¶ | Average MW Percent of Peak MVA (Spring 2022 – Winter 2022/23) | Average MW Percent of Peak MVA (Summer Peak) |
|---|---|---|---|---|---|
| 16C11 | 0.84 | 1.33 | 5.8 | 14% | 23% |
| 16C12 | 2.80 | 3.15 | 4.4 | 64% | 72% |
| 16C14 | 2.56 | 3.90 | 6.3 | 41% | 62% |
| 16C15 | 2.22 | 3.05 | 4.1 | 54% | 74% |
| 16C16 | 4.00 | 4.70 | 7.4 | 54% | 64% |
| 16C17 | 2.79 | 3.90 | 7.0 | 40% | 56% |
| 16C18 | 2.19 | 2.97 | 6.3 | 35% | 47% |
| 18G2 | 0.34 | 0.33 | 0.5 | 68% | 66% |
| 18G3 | 2.01 | 1.77 | 4.0 | 50% | 44% |
| 18G4 | 1.58 | -0.15 | 4.7 | 34% | -3% |
| 18G5 | 1.81 | 0.75 | 5.8 | 31% | 13% |
| 18G6 | 1.85 | 1.53 | 5.0 | 37% | 31% |
| 18G7 | 1.19 | -1.26 | 4.5 | 26% | -28% |
| 18G8 | 3.33 | 2.07 | 7.5 | 44% | 28% |
| 21N4 | 2.23 | 3.61 | 6.8 | 33% | 53% |
| 21N5 | 3.67 | 4.18 | 8.4 | 44% | 50% |
| 21N6 | 1.83 | 3.07 | 4.3 | 43% | 71% |
| 21N7 | 3.32 | 4.11 | 4.8 | 69% | 86% |
| 21N8 | 4.44 | 5.67 | 6.8 | 65% | 83% |
| 21N9 | 2.73 | 3.41 | 6.4 | 43% | 53% |
| 30A1 | 3.03 | 3.75 | 6.8 | 45% | 55% |
| 30A2 | 1.47 | 1.52 | 8.8 | 17% | 17% |
| 30A3 | 2.16 | 3.35 | 7.8 | 28% | 43% |

[68] Summer peak is defined in this evaluation as 1:00 p.m. to 5:00 p.m. ET from June 1 to August 31 on non-holiday weekdays.

[69] Annual peak MVA was drawn from 2022 GMP Term Report, Appendix 1 filed April 24, 2023.

| Feeder | Average MW (Spring 2022 – Winter 2022/23†) | Average MW (Summer Peak‡) | Annual Peak MVA¶ | Average MW Percent of Peak MVA (Spring 2022 – Winter 2022/23) | Average MW Percent of Peak MVA (Summer Peak) |
|---|---|---|---|---|---|
| 30A4 | 1.84 | 4.17 | 4.6 | 40% | 91% |
| 30A5 | 0.52 | 0.48 | 4.4 | 12% | 11% |
| 30A6 | 3.01 | 2.72 | 5.5 | 55% | 49% |

† Calculations are based off of clean analysis data.
‡ Summer peak is defined in this evaluation as 1:00 p.m. to 5:00 p.m. ET from June 1 to August 31 on non-holiday weekdays.
¶ Annual peak MVA was drawn from 2022 GMP Term Report, Appendix 1 filed April 24, 2023.
*Source: Guidehouse analysis*

## B.12.2 National Grid

**Table B-22. National Grid Feeder MW Percent of Peak MVA by Feeder**

| Feeder | Average MW (Spring 2022 – Winter 2022/23*) | Average MW (Summer Peak†) | Annual Peak MVA‡ | Average MW Percent of Peak MVA (Spring 2022 – Winter 2022/23) | Average MW Percent of Peak MVA (Summer Peak) |
|---|---|---|---|---|---|
| 16W1 | 3.58 | 4.66 | 9.6 | 37% | 49% |
| 16W2 | 3.76 | - | 8.6 | 44% | - |
| 16W3 | 3.65 | 4.83 | 7.6 | 48% | 64% |
| 16W4 | 2.57 | - | 9.2 | 28% | - |
| 16W5 | 2.27 | 3.37 | 5.7 | 40% | 59% |
| 16W6 | 4.82 | - | 14.3 | 34% | - |
| 16W7 | 4.13 | - | 10.9 | 38% | - |
| 16W8 | 3.55 | - | 9.6 | 37% | - |
| 29W1 | 4.30 | 4.70 | 10.7 | 40% | 44% |
| 29W2 | 2.19 | 2.89 | 6.0 | 37% | 48% |
| 29W3 | 4.68 | 5.36 | 10.3 | 45% | 52% |
| 29W4 | 3.43 | 3.60 | 8.2 | 42% | 44% |
| 29W5 | 4.43 | 4.36 | 10.5 | 42% | 42% |
| 29W6 | 3.18 | 4.09 | 6.8 | 47% | 60% |
| 74L1 | 4.11 | 5.59 | 12.1 | 34% | 46% |
| 74L2 | 2.60 | 3.95 | 6.7 | 39% | 59% |
| 74L3 | 2.94 | 3.63 | 8.2 | 36% | 44% |
| 74L4 | 3.29 | 4.20 | 6.6 | 50% | 64% |
| 74L5 | 2.91 | 4.49 | 10.7 | 27% | 42% |
| 74L6 | 2.42 | 3.00 | 5.0 | 48% | 60% |
| 797W1 | 3.45 | 3.72 | 10.4 | 33% | 36% |
| 797W19 | 3.10 | 3.91 | 8.3 | 37% | 47% |
| 797W20 | 4.63 | 6.80 | 9.7 | 48% | 70% |
| 797W23 | 3.30 | 4.20 | 9.7 | 34% | 43% |

| Feeder | Average MW (Spring 2022 – Winter 2022/23*) | Average MW (Summer Peak†) | Annual Peak MVA‡ | Average MW Percent of Peak MVA (Spring 2022 – Winter 2022/23) | Average MW Percent of Peak MVA (Summer Peak) |
|---|---|---|---|---|---|
| 797W24 | 3.98 | 5.11 | 9.7 | 41% | 53% |
| 797W29 | 2.98 | 3.70 | 8.3 | 36% | 45% |
| 797W42 | 1.35 | 1.78 | 8.3 | 16% | 21% |
| 913W17 | 2.06 | 2.60 | 5.5 | 37% | 47% |
| 913W18 | 2.07 | 2.69 | 4.6 | 45% | 58% |
| 913W43 | 2.28 | 3.38 | 7.1 | 32% | 48% |
| 913W47 | 2.48 | 3.41 | 5.8 | 43% | 59% |
| 913W67 | 0.90 | 1.22 | 3.0 | 30% | 41% |
| 913W69 | 3.82 | 5.64 | 9.9 | 39% | 57% |
| 92W43 | 3.03 | - | 7.1 | 39% | - |
| 92W44 | 4.23 | - | 9.0 | 43% | - |
| 92W54 | 2.78 | - | 7.3 | 47% | - |
| 92W78 | 2.39 | - | 7.9 | 38% | - |
| 92W79 | 2.48 | - | 6.4 | 30% | - |

† Calculations are based off of clean analysis data.
‡ Summer peak is defined by ISO-NE as 1:00 p.m. to 5:00 p.m. ET from June 1 to August 31 on non-holiday weekdays.
¶ Annual peak MVA was drawn from 2022 GMP Term Report, Appendix 1 filed April 24, 2023.
*Source: Guidehouse analysis*

## B.13 VVO Energy Savings and Voltage Reductions by Season

At the request of Eversource, in this section Guidehouse provides energy savings and voltage reductions attributed to VVO for each season from Spring 2022 through Winter 2022/23. Each table provides the energy savings and voltage reductions, and the associated 90 percent confidence bounds. A value of "-" for any one season has been provided for feeders without sufficient data in that specific season. Estimates are provided by feeder for Eversource and National Grid separately.

### B.13.1 Eversource

**Table B-23. Eversource Energy Savings by Feeder and Season**

| Feeder* | Spring 2022 | | Summer 2022 | | Fall 2022 | | Winter 2022/23 | |
|---|---|---|---|---|---|---|---|---|
| | MWh†‡ | %¶ | MWh†‡ | %¶ | MWh†‡ | %¶ | MWh†‡ | %¶ |
| 16C11 | 6.9 ± 8.9 | 1.5 ± 1.9 | 23.9 ± 8.4 | 2.2 ± 0.8 | -15.2 ± 8.0 | -1.8 ± 0.9 | 54.6 ± 9.9 | 7.8 ± 1.4 |
| 16C12 | -34.3 ± 11.7 | -1.8 ± 0.6 | 46.8 ± 14.9 | 1.6 ± 0.5 | 85.8 ± 14.1 | 2.9 ± 0.5 | 29.4 ± 14.2 | 1.0 ± 0.5 |
| 16C14 | 16.5 ± 5.4 | 1.7 ± 0.6 | 65.1 ± 9.2 | 2.2 ± 0.3 | -12.9 ± 9.7 | -0.5 ± 0.4 | 15.8 ± 8.9 | 0.6 ± 0.3 |
| 16C15 | 7.6 ± 3.1 | 0.9 ± 0.4 | 25.9 ± 5.2 | 1.0 ± 0.2 | 9.2 ± 5.5 | 0.4 ± 0.2 | 7.8 ± 5.0 | 0.3 ± 0.2 |
| 16C16 | -7.6 ± 8.6 | -0.7 ± 0.8 | 42.8 ± 14.7 | 1.0 ± 0.3 | -2.5 ± 15.8 | -0.1 ± 0.3 | 44.5 ± 14.4 | 0.9 ± 0.3 |
| 16C17 | -27.4 ± 9.8 | -3.1 ± 1.1 | 58.1 ± 16.7 | 1.7 ± 0.5 | -3.4 ± 17.7 | -0.1 ± 0.6 | 123.8 ± 16.7 | 3.8 ± 0.5 |
| 16C18 | 4.9 ± 5.3 | 0.7 ± 0.7 | 36.2 ± 8.9 | 1.3 ± 0.3 | -4.8 ± 9.4 | -0.2 ± 0.4 | 1.6 ± 8.7 | 0.1 ± 0.3 |
| 18G2 | -3.7 ± 1.6 | -0.9 ± 0.4 | 6.1 ± 1.8 | 2.9 ± 0.8 | -7.2 ± 1.8 | -2.5 ± 0.6 | -7.4 ± 1.8 | -2.3 ± 0.6 |
| 18G3 | -18.9 ± 12.5 | -0.9 ± 0.6 | 73.3 ± 13.2 | 5.2 ± 0.9 | -22.4 ± 12.3 | -1.3 ± 0.7 | -23.4 ± 13.1 | -1.0 ± 0.6 |
| 18G4 | -27.2 ± 25.8 | -1.9 ± 1.8 | 100.8 ± 24.7 | 11.2 ± 2.7 | -58.5 ± 24.9 | -4.3 ± 1.8 | -37.7 ± 26.8 | -1.7 ± 1.2 |
| 18G5 | -38.3 ± 24.9 | -2.2 ± 1.4 | 100.3 ± 23.7 | 7.1 ± 1.7 | -64.5 ± 24.4 | -4.4 ± 1.7 | 18.3 ± 26.1 | 0.8 ± 1.2 |
| 18G6 | -42.6 ± 23.7 | -2.3 ± 1.3 | 11.9 ± 22.5 | 0.6 ± 1.2 | 0.4 ± 29.2 | 0.0 ± 1.8 | 27.9 ± 28.6 | 2.0 ± 2.1 |
| 18G7 | -14.2 ± 35.4 | -1.5 ± 3.6 | 60.6 ± 37.4 | 5.8 ± 3.6 | -49.0 ± 34.5 | -5.0 ± 3.5 | -7.5 ± 34 | -0.5 ± 2.2 |
| 18G8 | -99.6 ± 38.7 | -2.6 ± 1.0 | 110.9 ± 38.1 | 3.2 ± 1.1 | -73.2 ± 37.7 | -2.6 ± 1.4 | - | - |
| 21N4 | -4.4 ± 12.1 | -0.2 ± 0.6 | 69.8 ± 12.3 | 2.3 ± 0.4 | 4.6 ± 12.9 | 0.2 ± 0.6 | 31.7 ± 12.2 | 1.3 ± 0.5 |
| 21N5 | 1.0 ± 4.7 | 0.0 ± 0.1 | 81.3 ± 6.2 | 2.2 ± 0.2 | -4.6 ± 5.1 | -0.1 ± 0.1 | -4.8 ± 4.4 | -0.1 ± 0.1 |
| 21N6 | 12.8 ± 6.8 | 0.7 ± 0.4 | 43.6 ± 7.0 | 1.9 ± 0.3 | -7.4 ± 7.3 | -0.4 ± 0.4 | 19.2 ± 6.8 | 1.0 ± 0.3 |
| 21N7 | 8.9 ± 17.1 | 0.3 ± 0.5 | 24.8 ± 16.9 | 0.7 ± 0.5 | -91.8 ± 17.9 | -2.6 ± 0.5 | 45.1 ± 18.4 | 1.2 ± 0.5 |
| 21N8 | 38.9 ± 13.9 | 0.8 ± 0.3 | 62.8 ± 14.1 | 1.3 ± 0.3 | 9.6 ± 14.9 | 0.2 ± 0.3 | 0.2 ± 13.9 | 0.0 ± 0.3 |
| 21N9 | 6.2 ± 13.5 | 0.2 ± 0.5 | 76.8 ± 10.2 | 2.5 ± 0.3 | -20.1 ± 11.7 | -0.7 ± 0.4 | 13.1 ± 12.3 | 0.4 ± 0.4 |

| Feeder* | Spring 2022 | | Summer 2022 | | Fall 2022 | | Winter 2022/23 | |
|---|---|---|---|---|---|---|---|---|
| | MWh†‡ | %¶ | MWh†‡ | %¶ | MWh†‡ | %¶ | MWh†‡ | %¶ |
| 30A1 | - | - | 10.7 ± 26.8 | 0.3 ± 0.8 | 47.3 ± 25.0 | 1.9 ± 1.0 | -103.9 ± 66.7 | -5.4 ± 3.5 |
| 30A2 | 9.9 ± 8.1 | 1.1 ± 0.9 | 63.0 ± 9.7 | 4.3 ± 0.7 | -3.7 ± 7.6 | -0.2 ± 0.4 | 2.3 ± 6.2 | 0.1 ± 0.4 |
| 30A3 | - | - | 22.6 ± 122 | 1.4 ± 7.5 | -64.3 ± 28.5 | -3.9 ± 1.7 | 191.0 ± 30.2 | 9.5 ± 1.5 |
| 30A4 | -51.2 ± 16.2 | -3.1 ± 1.0 | 16.6 ± 16.6 | 0.6 ± 0.6 | -20.4 ± 14.9 | -1.6 ± 1.2 | 131.9 ± 38.9 | 11.5 ± 3.4 |
| 30A5 | - | - | -0.7 ± 2.4 | -0.2 ± 0.6 | 7.3 ± 2.4 | 1.5 ± 0.5 | 7.8 ± 1.9 | 2.0 ± 0.5 |
| 30A6 | -26.4 ± 9.5 | -0.9 ± 0.3 | 22.7 ± 15.3 | 0.8 ± 0.5 | -29.4 ± 9.6 | -1.0 ± 0.3 | 1.1 ± 8.1 | 0.0 ± 0.3 |
| Overall* | -282 ± 81 | -0.6 ± 0.2 | 1,257 ± 151 | 2.1 ± 0.3 | -391 ± 93 | -0.7 ± 0.2 | 582 ± 11 | 1.1 ± 0.3 |

† Total energy savings provided for each period is the sum of each feeder's energy savings within that period. Due to model noise, a manual sum of savings across periods may not equal the amount provided in the Total row.
‡ Calculation uses actual number of VVO On hours spanning the analysis period. Actual VVO On Hours are the number of hours VVO was engaged in the raw analysis data between March 1, 2022 and February 28, 2023.
¶ Percentage energy savings provided for each period is the load-weighted average of percentage savings estimated for each feeder.
Estimates with a "-" represent a feeder/season for which there was not enough useable data to estimate impacts.
*Source: Guidehouse analysis*

**Table B-24. Eversource Voltage Reductions by Feeder and Season***

| Feeder | Spring 2022 | | Summer 2022 | | Fall 2022 | | Winter 2022 | |
|---|---|---|---|---|---|---|---|---|
| | V | % | V | % | V | % | V | % |
| 16C11 | 0.00 ± 0.08 | 0.00 ± 0.07 | 2.64 ± 0.05 | 2.14 ± 0.04 | 2.87 ± 0.05 | 2.32 ± 0.04 | 3.44 ± 0.07 | 2.80 ± 0.05 |
| 16C12 | -0.03 ± 0.05 | -0.02 ± 0.04 | 2.55 ± 0.05 | 2.06 ± 0.04 | 2.78 ± 0.04 | 2.24 ± 0.03 | 2.99 ± 0.05 | 2.42 ± 0.04 |
| 16C14 | 1.84 ± 0.07 | 1.49 ± 0.06 | 1.80 ± 0.05 | 1.45 ± 0.04 | 0.93 ± 0.04 | 0.75 ± 0.04 | 1.41 ± 0.05 | 1.14 ± 0.04 |
| 16C15 | 1.82 ± 0.07 | 1.47 ± 0.06 | 1.81 ± 0.05 | 1.46 ± 0.04 | 0.92 ± 0.04 | 0.74 ± 0.03 | 1.39 ± 0.04 | 1.12 ± 0.04 |
| 16C16 | 1.86 ± 0.07 | 1.50 ± 0.06 | 1.81 ± 0.05 | 1.47 ± 0.04 | 0.92 ± 0.04 | 0.74 ± 0.03 | 1.40 ± 0.04 | 1.13 ± 0.04 |
| 16C17 | 1.85 ± 0.07 | 1.50 ± 0.06 | 1.82 ± 0.05 | 1.47 ± 0.04 | 0.90 ± 0.04 | 0.73 ± 0.03 | 1.45 ± 0.05 | 1.17 ± 0.04 |
| 16C18 | 1.83 ± 0.07 | 1.48 ± 0.06 | 1.83 ± 0.05 | 1.48 ± 0.04 | 0.93 ± 0.04 | 0.76 ± 0.03 | 1.41 ± 0.04 | 1.15 ± 0.04 |
| 18G2 | -0.01 ± 0.05 | 0.00 ± 0.04 | 1.48 ± 0.09 | 1.23 ± 0.07 | 0.12 ± 0.07 | 0.10 ± 0.06 | -0.01 ± 0.07 | -0.01 ± 0.06 |
| 18G3 | 0.01 ± 0.03 | 0.01 ± 0.03 | 1.05 ± 0.05 | 0.87 ± 0.04 | 0.03 ± 0.04 | 0.02 ± 0.03 | -0.03 ± 0.04 | -0.02 ± 0.03 |
| 18G4 | 0.01 ± 0.03 | 0.01 ± 0.03 | 0.89 ± 0.05 | 0.74 ± 0.04 | 0.02 ± 0.04 | 0.01 ± 0.03 | -0.02 ± 0.04 | -0.02 ± 0.03 |
| 18G5 | 0.00 ± 0.03 | 0.00 ± 0.03 | 0.88 ± 0.05 | 0.73 ± 0.04 | 0.03 ± 0.04 | 0.03 ± 0.03 | -0.01 ± 0.04 | -0.01 ± 0.03 |
| 18G6 | 0.09 ± 0.08 | 0.07 ± 0.07 | 1.58 ± 0.09 | 1.28 ± 0.07 | 0.10 ± 0.13 | 0.08 ± 0.10 | 0.03 ± 0.19 | 0.02 ± 0.15 |
| 18G7 | 0.06 ± 0.04 | 0.05 ± 0.04 | 1.26 ± 0.05 | 1.01 ± 0.04 | 0.01 ± 0.05 | 0.01 ± 0.04 | 0.09 ± 0.08 | 0.07 ± 0.06 |
| 18G8 | 0.07 ± 0.05 | 0.06 ± 0.04 | 1.06 ± 0.05 | 0.86 ± 0.04 | 0.01 ± 0.05 | 0.01 ± 0.04 | - | - |
| 21N4 | 2.51 ± 0.05 | 2.03 ± 0.04 | 2.48 ± 0.06 | 2.01 ± 0.05 | 2.65 ± 0.05 | 2.14 ± 0.04 | 3.18 ± 0.06 | 2.58 ± 0.05 |
| 21N5 | 2.73 ± 0.06 | 2.22 ± 0.05 | 3.31 ± 0.08 | 2.71 ± 0.07 | 2.75 ± 0.06 | 2.24 ± 0.05 | 3.15 ± 0.06 | 2.57 ± 0.05 |
| 21N6 | 2.69 ± 0.05 | 2.18 ± 0.04 | 2.75 ± 0.05 | 2.23 ± 0.04 | 3.01 ± 0.05 | 2.44 ± 0.04 | 3.22 ± 0.05 | 2.61 ± 0.04 |
| 21N7 | 2.67 ± 0.05 | 2.16 ± 0.04 | 2.73 ± 0.06 | 2.22 ± 0.04 | 3.01 ± 0.05 | 2.43 ± 0.04 | 3.30 ± 0.06 | 2.68 ± 0.05 |
| 21N8 | 2.71 ± 0.05 | 2.20 ± 0.04 | 2.73 ± 0.05 | 2.21 ± 0.04 | 3.00 ± 0.05 | 2.43 ± 0.04 | 3.21 ± 0.05 | 2.60 ± 0.04 |
| 21N9 | 3.00 ± 0.11 | 2.43 ± 0.09 | 3.01 ± 0.09 | 2.44 ± 0.07 | 3.13 ± 0.09 | 2.53 ± 0.07 | 3.14 ± 0.10 | 2.55 ± 0.08 |
| 30A1 | - | - | 0.58 ± 0.04 | 0.47 ± 0.03 | 0.99 ± 0.03 | 0.80 ± 0.03 | 1.54 ± 0.15 | 1.25 ± 0.12 |
| 30A2 | 0.07 ± 0.03 | 0.06 ± 0.02 | 0.37 ± 0.04 | 0.30 ± 0.03 | 0.12 ± 0.03 | 0.10 ± 0.03 | 0.08 ± 0.03 | 0.07 ± 0.03 |
| 30A3 | - | - | 2.81 ± 1.96 | 3.39 ± 2.37 | 1.08 ± 0.41 | 0.89 ± 0.34 | 0.80 ± 0.71 | 0.65 ± 0.58 |
| 30A4 | 0.08 ± 0.03 | 0.06 ± 0.02 | 0.27 ± 0.03 | 0.22 ± 0.03 | 0.12 ± 0.03 | 0.10 ± 0.03 | 0.15 ± 0.1 | 0.12 ± 0.08 |
| 30A5 | - | - | 0.57 ± 0.04 | 0.46 ± 0.03 | 1.05 ± 0.04 | 0.85 ± 0.03 | 0.43 ± 0.05 | 0.35 ± 0.04 |
| 30A6 | 0.08 ± 0.03 | 0.07 ± 0.03 | 0.53 ± 0.06 | 0.43 ± 0.05 | 0.18 ± 0.04 | 0.15 ± 0.03 | 0.07 ± 0.04 | 0.06 ± 0.03 |
| Overall* | 1.43 ± 0.01 | 1.16 ± 0.01 | 1.85 ± 0.05 | 1.40 ± 0.02 | 1.13 ± 0.01 | 1.53 ± 0.07 | 1.57 ± 0.02 | 1.28 ± 0.03 |

* Overall kV and percent voltage savings provided for each period is the load-weighted average of kV and percent savings estimated for each feeder.
Estimates with a “-“ represent a feeder/season for which there was not enough useable data to estimate impacts.
*Source: Guidehouse analysis*

## B.13.2 National Grid

**Table B-25. National Grid Energy Savings by Feeder and Season**

| Feeder | Spring 2022 | | Summer 2022 | | Fall 2022 | | Winter 2022/23 | |
|---|---|---|---|---|---|---|---|---|
| | MWh*† | % | MWh*† | % | MWh*† | % | MWh*† | % |
| 16W1 | -18.2 ± 18.7 | -1.0 ± 1.0 | 35.8 ± 13.7 | 3.8 ± 1.4 | -31.7 ± 13.1 | -7.7 ± 3.2 | 1.6 ± 11.9 | 0.2 ± 1.2 |
| 16W3 | -35.9 ± 17.0 | -1.9 ± 0.9 | 23.8 ± 12.5 | 2.6 ± 1.4 | -34.7 ± 11.9 | -7.8 ± 2.7 | -16.7 ± 10.8 | -1.6 ± 1.1 |
| 16W5 | -20.3 ± 11.4 | -1.8 ± 1.0 | 21.9 ± 8.4 | 3.6 ± 1.4 | -11.6 ± 8.0 | -3.9 ± 2.7 | 1.1 ± 7.3 | 0.2 ± 1.1 |
| 16W7 | -33.2 ± 20.1 | -1.6 ± 1.0 | 29.0 ± 13.9 | 2.5 ± 1.2 | -22.4 ± 13.3 | -4.2 ± 2.5 | -0.1 ± 12.3 | 0.0 ± 1.1 |
| 29W1 | **West Salem did not undergo testing in Spring 2022** | | -94.7 ± 22.7 | -5.4 ± 1.3 | 34.6 ± 21.0 | 4.4 ± 2.7 | 9.1 ± 57.4 | 0.2 ± 1.1 |
| 29W2 | | | -35.3 ± 21.3 | -2.7 ± 1.6 | 27.5 ± 15.9 | 6.5 ± 3.8 | 98.0 ± 43.1 | 3.8 ± 1.7 |
| 29W3 | | | 33.0 ± 19.9 | 1.4 ± 0.8 | 46.4 ± 14.9 | 5.3 ± 1.7 | 53.3 ± 41.4 | 1.0 ± 0.8 |
| 29W4 | | | 6.1 ± 22.5 | 0.3 ± 1.2 | 55.6 ± 17.4 | 8.5 ± 2.6 | 115.5 ± 47.4 | 2.6 ± 1.1 |
| 29W5 | | | 53.9 ± 26.4 | 2.1 ± 1.0 | 33.3 ± 18.9 | 3.8 ± 2.1 | 38.2 ± 49.9 | 1.0 ± 1.3 |
| 29W6 | | | 17.7 ± 15.0 | 1.4 ± 1.2 | 16.1 ± 11.8 | 2.6 ± 1.9 | 70.9 ± 34.3 | 3.6 ± 1.7 |
| 74L1 | 40.9 ± 43.4 | 1.3 ± 1.3 | 40.2 ± 27.0 | 1.9 ± 1.3 | 96.9 ± 24.6 | 9.7 ± 2.5 | 64.7 ± 91.8 | 1.1 ± 1.6 |
| 74L2 | -37.2 ± 28.5 | -1.5 ± 1.1 | 34.9 ± 19.2 | 1.7 ± 0.9 | 17.7 ± 13.4 | 3.4 ± 2.6 | -7.3 ± 67.5 | -0.2 ± 1.5 |
| 74L3 | 23.7 ± 27.4 | 1.0 ± 1.2 | 33.7 ± 17 | 2.4 ± 1.2 | 51.4 ± 15.5 | 8.3 ± 2.5 | 10.1 ± 57.9 | 0.2 ± 1.3 |
| 74L4 | -25.4 ± 34.6 | -0.8 ± 1.0 | 1.2 ± 23.3 | 0.0 ± 0.9 | 59.8 ± 16.3 | 8.2 ± 2.2 | -15.4 ± 81.8 | -0.3 ± 1.6 |
| 74L5 | -5.4 ± 25.3 | -0.2 ± 1.1 | 36.3 ± 15.7 | 2.3 ± 1.0 | 46.3 ± 14.3 | 7.5 ± 2.3 | 9.7 ± 53.5 | 0.2 ± 1.3 |
| 74L6 | 5.7 ± 25.9 | 0.2 ± 1.1 | 28.6 ± 17.4 | 1.5 ± 0.9 | 33.8 ± 12.2 | 6.4 ± 2.3 | -6.2 ± 61.4 | -0.1 ± 1.4 |
| 797W1 | -12.3 ± 49.1 | -0.5 ± 2.0 | 17.8 ± 25.8 | 4.2 ± 6.1 | 28.5 ± 23.1 | 5.2 ± 4.2 | 88.5 ± 104.7 | 1.6 ± 1.9 |
| 797W19 | 53.6 ± 34.2 | 2.5 ± 1.6 | -12.8 ± 18.5 | -1.2 ± 1.7 | 30.5 ± 15.2 | 5.4 ± 2.7 | -18.9 ± 24.9 | -1.1 ± 1.4 |
| 797W20 | 166.0 ± 41.7 | 4.8 ± 1.2 | 19.7 ± 22.6 | 1.2 ± 1.3 | 21.2 ± 18.5 | 2.4 ± 2.1 | 1.2 ± 30.4 | 0.1 ± 1.3 |
| 797W23 | 15.4 ± 28.1 | 0.6 ± 1.1 | 8.0 ± 14.7 | 1.8 ± 3.4 | 9.4 ± 13.2 | 1.9 ± 2.6 | -166.5 ± 60.1 | -3.8 ± 1.4 |
| 797W24 | 28.8 ± 42.8 | 1.0 ± 1.5 | -2.5 ± 23.1 | -0.2 ± 1.6 | 40.9 ± 19.0 | 5.8 ± 2.7 | -38.2 ± 31.2 | -1.8 ± 1.5 |
| 797W29 | 16.6 ± 27.7 | 0.8 ± 1.3 | 14.0 ± 14.5 | 3.6 ± 3.7 | 17.2 ± 13.0 | 3.6 ± 2.7 | -46.2 ± 59.1 | -1.1 ± 1.4 |
| 797W42 | 6.4 ± 16.9 | 0.7 ± 1.8 | 6.5 ± 8.9 | 3.5 ± 4.7 | 2.4 ± 7.9 | 1.2 ± 4.0 | -9.9 ± 36.1 | -0.5 ± 1.8 |
| 92W43 | **Easton did not undergo testing in Spring – Fall 2022** | | | | | | 48.6 ± 16.8 | 3.8 ± 1.3 |
| 92W44 | | | | | | | 38.0 ± 17.2 | 2.2 ± 1.0 |
| 92W54 | | | | | | | 100.1 ± 49.6 | 8.3 ± 4.1 |

| Feeder | Spring 2022 | | Summer 2022 | | Fall 2022 | | Winter 2022/23 | |
|---|---|---|---|---|---|---|---|---|
| | MWh*† | % | MWh*† | % | MWh*† | % | MWh*† | % |
| 92W78 | | | | | | | 43.2 ± 13.8 | 4.2 ± 1.3 |
| 92W79 | | | | | | | 66.7 ± 33.8 | 6.3 ± 3.2 |
| Overall* | 169 ± 127 | 0.4 ± 0.3 | 317 ± 92 | 1.4 ± 0.4 | 569 ± 76 | 3.3 ± 0.6 | 533 ± 263 | 0.9 ± 0.3 |

* Total energy savings provided for each period is the sum of each feeder's energy savings within that period. Due to model noise, a manual sum of savings across periods may not equal the amount provided in the Total row.

† Calculation uses actual number of VVO On hours spanning the analysis period for each feeder. Actual VVO On Hours are the number of hours VVO was engaged in the raw analysis data during each feeder's testing period within the Spring 2022 – Winter 2023 evaluation period.

*Source: Guidehouse analysis*

### Table B-26. National Grid Voltage Reductions by Feeder and Season

| Feeder | Spring 2022 | | Summer 2022 | | Fall 2022 | | Winter 2022/23 | |
|---|---|---|---|---|---|---|---|---|
| | kV | % | kV | % | kV | % | kV | % |
| 16W1 | 0.03 ± 0.01 | 0.24 ± 0.04 | 0.03 ± 0.01 | 0.21 ± 0.09 | 0.02 ± 0.02 | 0.18 ± 0.13 | 0.13 ± 0.01 | 0.90 ± 0.07 |
| 16W3 | 0.03 ± 0.01 | 0.24 ± 0.04 | 0.03 ± 0.01 | 0.20 ± 0.09 | 0.02 ± 0.02 | 0.17 ± 0.13 | 0.13 ± 0.01 | 0.89 ± 0.07 |
| 16W5 | 0.03 ± 0.01 | 0.24 ± 0.04 | 0.03 ± 0.01 | 0.20 ± 0.09 | 0.02 ± 0.02 | 0.17 ± 0.13 | 0.13 ± 0.01 | 0.90 ± 0.07 |
| 16W7 | 0.03 ± 0.01 | 0.25 ± 0.05 | 0.03 ± 0.01 | 0.21 ± 0.09 | 0.02 ± 0.02 | 0.17 ± 0.13 | 0.12 ± 0.01 | 0.88 ± 0.07 |
| 29W1 | **West Salem did not undergo testing in Spring 2022** | | 0.03 ± 0.01 | 0.20 ± 0.06 | 0.04 ± 0.02 | 0.29 ± 0.11 | 0.02 ± 0.01 | 0.12 ± 0.05 |
| 29W2 | | | 0.00 ± 0.01 | 0.02 ± 0.05 | -0.02 ± 0.01 | -0.12 ± 0.09 | -0.01 ± 0.01 | -0.05 ± 0.05 |
| 29W3 | | | 0.02 ± 0.01 | 0.16 ± 0.07 | 0.09 ± 0.02 | 0.64 ± 0.12 | 0.02 ± 0.01 | 0.15 ± 0.06 |
| 29W4 | | | 0.01 ± 0.01 | 0.04 ± 0.06 | -0.02 ± 0.01 | -0.13 ± 0.10 | -0.01 ± 0.01 | -0.05 ± 0.05 |
| 29W5 | | | 0.03 ± 0.01 | 0.20 ± 0.06 | 0.07 ± 0.02 | 0.53 ± 0.12 | 0.03 ± 0.01 | 0.19 ± 0.09 |
| 29W6 | | | 0.01 ± 0.01 | 0.04 ± 0.08 | -0.02 ± 0.01 | -0.12 ± 0.11 | -0.03 ± 0.01 | -0.24 ± 0.11 |
| 74L1 | 0.34 ± 0.01 | 2.54 ± 0.08 | 0.40 ± 0.02 | 2.93 ± 0.12 | 0.30 ± 0.02 | 2.19 ± 0.18 | 0.31 ± 0.02 | 2.30 ± 0.12 |
| 74L2 | 0.13 ± 0.01 | 0.97 ± 0.05 | 0.12 ± 0.01 | 0.92 ± 0.05 | 0.13 ± 0.01 | 0.93 ± 0.10 | 0.12 ± 0.01 | 0.88 ± 0.07 |
| 74L3 | 0.34 ± 0.01 | 2.54 ± 0.08 | 0.40 ± 0.02 | 2.93 ± 0.12 | 0.30 ± 0.02 | 2.19 ± 0.18 | 0.31 ± 0.02 | 2.30 ± 0.12 |
| 74L4 | 0.13 ± 0.01 | 0.97 ± 0.05 | 0.12 ± 0.01 | 0.92 ± 0.05 | 0.13 ± 0.01 | 0.93 ± 0.10 | 0.12 ± 0.01 | 0.88 ± 0.07 |
| 74L5 | 0.34 ± 0.01 | 2.54 ± 0.08 | 0.40 ± 0.02 | 2.93 ± 0.12 | 0.30 ± 0.02 | 2.19 ± 0.18 | 0.31 ± 0.02 | 2.30 ± 0.12 |
| 74L6 | 0.13 ± 0.01 | 0.97 ± 0.05 | 0.12 ± 0.01 | 0.92 ± 0.05 | 0.13 ± 0.01 | 0.93 ± 0.10 | 0.12 ± 0.01 | 0.88 ± 0.07 |
| 797W1 | -0.03 ± 0.01 | -0.20 ± 0.04 | -0.08 ± 0.02 | -0.53 ± 0.17 | -0.03 ± 0.01 | -0.23 ± 0.10 | 0.05 ± 0.01 | 0.37 ± 0.06 |
| 797W19 | 0.15 ± 0.01 | 1.05 ± 0.07 | 0.05 ± 0.01 | 0.35 ± 0.09 | 0.11 ± 0.02 | 0.81 ± 0.12 | 0.07 ± 0.01 | 0.47 ± 0.08 |
| 797W20 | 0.15 ± 0.01 | 1.05 ± 0.07 | 0.05 ± 0.01 | 0.35 ± 0.09 | 0.12 ± 0.02 | 0.81 ± 0.12 | 0.07 ± 0.01 | 0.47 ± 0.08 |
| 797W23 | -0.03 ± 0.01 | -0.20 ± 0.04 | -0.08 ± 0.02 | -0.54 ± 0.17 | -0.03 ± 0.01 | -0.23 ± 0.10 | 0.05 ± 0.01 | 0.37 ± 0.06 |
| 797W24 | 0.15 ± 0.01 | 1.05 ± 0.07 | 0.05 ± 0.01 | 0.35 ± 0.09 | 0.11 ± 0.02 | 0.81 ± 0.12 | 0.07 ± 0.01 | 0.47 ± 0.08 |
| 797W29 | -0.03 ± 0.01 | -0.21 ± 0.04 | -0.08 ± 0.02 | -0.54 ± 0.17 | -0.03 ± 0.01 | -0.23 ± 0.10 | 0.05 ± 0.01 | 0.37 ± 0.06 |
| 797W42 | -0.03 ± 0.01 | -0.21 ± 0.04 | -0.07 ± 0.02 | -0.53 ± 0.17 | -0.03 ± 0.01 | -0.23 ± 0.10 | 0.05 ± 0.01 | 0.37 ± 0.06 |
| 92W43 | **Easton did not undergo testing in Spring – Fall 2022** | | | | | | 0.25 ± 0.02 | 1.81 ± 0.14 |
| 92W44 | | | | | | | 0.25 ± 0.02 | 1.80 ± 0.14 |
| 92W54 | | | | | | | 0.25 ± 0.02 | 1.81 ± 0.14 |
| 92W78 | | | | | | | 0.25 ± 0.02 | 1.81 ± 0.14 |

| Feeder | Spring 2022 | | Summer 2022 | | Fall 2022 | | Winter 2022/23 | |
|---|---|---|---|---|---|---|---|---|
| | kV | % | kV | % | kV | % | kV | % |
| 92W79 | | | | | | | 0.26 ± 0.02 | 1.81 ± 0.14 |
| Overall* | 0.12 ± 0.00 | 0.84 ± 0.02 | 0.56 ± 0.02 | 0.22 ± 0.01 | 0.08 ± 0.00 | 0.58 ± 0.03 | 0.12 ± 0.00 | 0.86 ± 0.02 |

* kV and percent voltage savings provided for each period is the load-weighted average of kV and percent savings estimated for each feeder.
*Source: Guidehouse analysis*

## B.14 Seasonal Data Attrition from Data Cleaning

This section details data attrition from data cleaning for each season from Spring 2022 through Winter 2022/23. Tables provide the number of observations received, then the observations remaining after data cleaning by season and by feeder. Tables are provided separately by EDC.

### B.14.1 Eversource

**Table B-27. Eversource Data Attrition by Feeder and Season**

| | Spring 2022 | | Summer 2022 | | Fall 2022 | | Winter 2022/23 | |
|---|---|---|---|---|---|---|---|---|
| Feeder | Obs* Received | Obs Remaining | Obs Received | Obs Remaining | Obs Received | Obs Remaining | Obs Received | Obs Remaining |
| 16C11 | 8,828 | 2,544 | 8,832 | 5,907 | 8,736 | 6,890 | 8,640 | 4,835 |
| 16C12 | 8,828 | 5,014 | 8,832 | 6,803 | 8,736 | 7,843 | 8,640 | 7,851 |
| 16C14 | 8,828 | 3,131 | 8,832 | 7,029 | 8,736 | 8,215 | 8,640 | 8,060 |
| 16C15 | 8,828 | 3,020 | 8,832 | 7,064 | 8,736 | 8,162 | 8,640 | 8,046 |
| 16C16 | 8,828 | 3,144 | 8,832 | 7,118 | 8,736 | 8,142 | 8,640 | 8,046 |
| 16C17 | 8,829 | 3,167 | 8,832 | 7,195 | 8,736 | 8,378 | 8,640 | 7,853 |
| 16C18 | 8,829 | 3,150 | 8,832 | 7,143 | 8,736 | 8,324 | 8,640 | 8,153 |
| 18G2 | 8,828 | 6,847 | 8,832 | 3,141 | 8,736 | 4,328 | 8,640 | 4,502 |
| 18G3 | 8,828 | 8,102 | 8,832 | 3,557 | 8,736 | 5,862 | 8,640 | 5,827 |
| 18G4 | 8,828 | 8,246 | 8,832 | 4,290 | 8,736 | 6,102 | 8,640 | 6,046 |
| 18G5 | 8,828 | 8,069 | 8,832 | 4,189 | 8,736 | 5,863 | 8,640 | 5,806 |
| 18G6 | 8,828 | 6,222 | 8,832 | 5,679 | 8,736 | 2,573 | 8,640 | 1,332 |
| 18G7 | 8,828 | 8,018 | 8,832 | 5,655 | 8,736 | 5,908 | 8,640 | 3,425 |
| 18G8 | 8,828 | 8,341 | 8,832 | 6,689 | 8,736 | 6,106 | 8,640 | 0 |
| 21N4 | 8,828 | 8,142 | 8,832 | 7,201 | 8,736 | 7,959 | 8,640 | 8,022 |
| 21N5 | 8,828 | 6,528 | 8,832 | 3,513 | 8,736 | 6,296 | 8,640 | 7,267 |
| 21N6 | 8,828 | 8,338 | 8,832 | 7,239 | 8,736 | 8,015 | 8,640 | 8,305 |
| 21N7 | 8,828 | 7,945 | 8,832 | 7,225 | 8,736 | 7,918 | 8,640 | 6,942 |
| 21N8 | 8,828 | 8,361 | 8,832 | 7,325 | 8,736 | 8,022 | 8,640 | 8,249 |
| 21N9 | 8,829 | 2,823 | 8,832 | 4,535 | 8,736 | 4,116 | 8,640 | 3,491 |
| 30A1 | 0 | 0 | 8,832 | 5,714 | 8,736 | 8,097 | 8,640 | 425 |
| 30A2 | 8,828 | 7,338 | 8,832 | 4,491 | 8,736 | 6,012 | 8,640 | 6,362 |
| 30A3 | 0 | 0 | 8,832 | 726 | 8,736 | 7,475 | 8,640 | 2,697 |
| 30A4 | 8,828 | 8,498 | 8,832 | 7,156 | 8,736 | 7,416 | 8,640 | 1,078 |
| 30A5 | 0 | 0 | 8,832 | 5,913 | 8,736 | 7,606 | 8,640 | 4,690 |
| 30A6 | 8,828 | 7,707 | 8,832 | 2,744 | 8,736 | 5,723 | 8,640 | 5,670 |

* Refers to observations
*Source: Guidehouse analysis*

## B.14.2 National Grid

**Table B-28. National Grid Data Attrition by Feeder and Season**

| | Spring 2022 | | Summer 2022 | | Fall 2022 | | Winter 2022/23 | |
|---|---|---|---|---|---|---|---|---|
| Feeder | Hours Received | Hours Remaining | Hours Received | Hours Remaining | Hours Received | Hours Remaining | Hours Received | Hours Remaining |
| 16W1 | 2,208 | 1,167 | 2,208 | 406 | 2,185 | 199 | 2,160 | 540 |
| 16W2 | 2,208 | 60 | 1,777 | 0 | 1,337 | 0 | 2,160 | 447 |
| 16W3 | 2,208 | 1,167 | 2,208 | 406 | 2,185 | 199 | 2,160 | 540 |
| 16W4 | 2,208 | 60 | 1,777 | 0 | 1,337 | 0 | 2,160 | 447 |
| 16W5 | 2,208 | 1,167 | 2,208 | 406 | 2,185 | 199 | 2,160 | 540 |
| 16W6 | 2,208 | 60 | 1,777 | 0 | 1,337 | 0 | 2,160 | 447 |
| 16W7 | 2,208 | 1,074 | 2,208 | 406 | 2,185 | 199 | 2,160 | 540 |
| 16W8 | 2,208 | 60 | 1,777 | 0 | 1,337 | 0 | 2,160 | 447 |
| 29W1 | 0 | 0 | 2,208 | 835 | 2,185 | 374 | 2,160 | 1,149 |
| 29W2 | 0 | 0 | 2,208 | 1,085 | 2,184 | 415 | 2,160 | 1,136 |
| 29W3 | 0 | 0 | 2,208 | 952 | 2,186 | 359 | 2,160 | 1,138 |
| 29W4 | 0 | 0 | 2,208 | 998 | 2,184 | 415 | 2,160 | 1,149 |
| 29W5 | 0 | 0 | 2,208 | 1,178 | 2,184 | 413 | 2,160 | 692 |
| 29W6 | 0 | 0 | 2,208 | 714 | 2,185 | 414 | 2,160 | 457 |
| 74L1 | 2,208 | 1,578 | 2,208 | 811 | 2,185 | 382 | 2,160 | 1,283 |
| 74L2 | 2,208 | 1,568 | 2,208 | 1,310 | 2,185 | 381 | 2,160 | 657 |
| 74L3 | 2,208 | 1,578 | 2,208 | 811 | 2,185 | 382 | 2,160 | 1,283 |
| 74L4 | 2,208 | 1,568 | 2,208 | 1,310 | 2,185 | 381 | 2,160 | 657 |
| 74L5 | 2,208 | 1,578 | 2,208 | 811 | 2,185 | 382 | 2,160 | 1,283 |
| 74L6 | 2,208 | 1,568 | 2,208 | 1,310 | 2,185 | 381 | 2,160 | 657 |
| 797W1 | 2,208 | 1,429 | 2,208 | 168 | 2,185 | 360 | 2,160 | 631 |
| 797W19 | 2,208 | 939 | 2,208 | 641 | 2,185 | 381 | 2,160 | 713 |
| 797W20 | 2,208 | 939 | 2,208 | 641 | 2,185 | 381 | 2,160 | 713 |
| 797W23 | 2,208 | 1,429 | 2,208 | 168 | 2,185 | 360 | 2,160 | 631 |
| 797W24 | 2,208 | 939 | 2,208 | 641 | 2,185 | 381 | 2,160 | 713 |
| 797W29 | 2,208 | 1,429 | 2,208 | 168 | 2,185 | 360 | 2,160 | 631 |
| 797W42 | 2,208 | 1,429 | 2,208 | 168 | 2,185 | 360 | 2,160 | 631 |
| 92W43 | 0 | 0 | 0 | 0 | 0 | 0 | 1,152 | 490 |
| 92W44 | 0 | 0 | 0 | 0 | 0 | 0 | 1,152 | 490 |
| 92W54 | 0 | 0 | 0 | 0 | 0 | 0 | 1,152 | 490 |
| 92W78 | 0 | 0 | 0 | 0 | 0 | 0 | 1,152 | 490 |
| 92W79 | 0 | 0 | 0 | 0 | 0 | 0 | 1,152 | 490 |

*Source: Guidehouse analysis*

# Transformer Reverse Power Capability

## GENERAL

Any proposed DG that has the potential to cause reverse power flow through an Eversource substation transformer will require a System Impact Study (SIS). The SIS will specifically address the ability of the transformer to accommodate reverse power flow. The following items will be evaluated:

*Note*: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

## SYSTEM VOLTAGE CONTROL

A precursor to transformer excitation problems is the loss of the ability to control voltage due to various factors such as system configuration, generator location, system impedances, transformer impedance, customer load, reactive power flows, and generation output. The system impact study shall determine if system voltage control can be maintained at various boundary conditions.

In addition, the nature of the generation source shall be evaluated for impact on system voltage and transformer Load Tap Changer (LTC) operation. For example, large photovoltaic sources whose outputs can vary significantly and rapidly will impact the ability to control distribution customer voltage, and can cause excessive LTC operations. Sudden large changes in DG output that are faster than the LTC's capability to maintain voltage within the allowable range can also result in overexcitation.

## LTC DESIGN

1. Reactive Type use a preventive autotransformer to limit circulating current when on bridging tap positions. This type of LTC can handle reverse power with no restrictions.
2. Resistive Type use one or two resistors to limit circulating current when bridging tap positions.
   a. Single resistor types cannot handle reverse power because of the manner in which load and circulating currents and voltages (recovery voltage) sum at the main arcing contacts – in one direction of operation. Single resistor type LTC's are unsuitable for DG / reverse power application. At a minimum, replacement of the LTC is required. Typically, however, the entire transformer must be replaced, as retrofit of another LTC type is a large involved job that requires input from both the transformer manufacturer and LTC manufacturer, and major modification to the transformer.
   b. Two resistor type LTCs can handle reverse power with no restrictions.

## LTC CONTROLLER TYPE

The controller will be evaluated for the ability to recognize reverse flow and to respond with appropriate control strategies.

Voltage and current inputs must be available to the LTC controller.

LTC controllers are to be designed to sense the reverse power/positive feedback condition, and react appropriately.

Any LTC controller configuration that is not appropriate for reverse power must be replaced with a suitable controller with both voltage and current inputs.

## LTC CONTROL SETTINGS

The choice of proper control strategy will depend on whether the aggregate of DG's connected to an individual transformer can "push" the transformer secondary voltage around under light load conditions that result in reverse power flow back to the transmission system (i.e., supply of VAR's by DG's).

Controllers shall have a variety of settings that can be used to “tune” LTC operation to the conditions encountered at a particular location. Such settings can be used to make location specific adjustments to LTC controller operation. The establishment of these settings will be dependent on case−by−case analysis of DG type and penetration.

**CAPACITY LIMIT**

Unless constrained by other more limiting DG policies, intermittent reverse power flow will be permitted up to 95 percent of the transformer’s top nameplate ampere rating with maximum cooling operational. The reverse power flow limit is based strictly on the transformer nameplate, with no consideration given to any forward power load on the transformer.

A possible consequence of allowing reverse power flow at a high percentage of the transformer nameplate rating is that the thermal aging rate of the transformer insulation will be increased, which may impact the lifespan of the transformer. Transformer insulation thermal aging is dependent on a combination of insulation temperature and time, as described in *IEEE Std. C57.91*, “IEEE Guide for Loading Mineral−Oil−Immersed Transformers and Step−Voltage Regulators.” Reverse power flow that will significantly add to the transformer insulation loss of life on a routine basis, based on the transformer specification and the insulation aging description in the latest version of *IEEE Std. C57.91*, must be evaluated. This evaluation will consider the calculated transformer insulation loss of life based on site specific ambient temperature and maximum aggregate DG power generation coincident with minimum distribution customer load on the distribution bus. Calculated loss of life that exceeds one percent per year will require further investigation of methods to mitigate the increased loss of life.

DG sources must supply a balanced three−phase output such that there would never be a situation where a substation transformer could experience forward power flow on one or more phases while experiencing reverse power flow on the other phase(s).

Please see the **Eversource DER Briefing Sheet – Transformer Reverse Power Capability** for additional background information.

**DER-PG 2022**
(Revision 00)

# Distributed Energy Resources Planning Guide

Approved: December ##, 2022

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## Updating Standards documents

Users of this standard should be aware that these documents may be superseded at any time by the issuance of new editions or may be amended from time to time through the issuance of amendments. The official standard, at any point, consist of the current edition of the document together with any amendment.

In order to determine whether a given document is the current edition and whether it has been amended, visit the standard Bookshelf Site or contact System Planning.

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# INTRODUCTION AND SCOPE

This Distributed Energy Resource Planning Guide (DERPG) has been developed to describe the planning criteria and analyses used to study the impact of Distributed Energy Resources ("DER") seeking to interconnect to the Eversource Energy ("Company") Electric Power Systems ("EPS"). A consistent and uniform approach to DER Planning will ensure the reliability of the EPS is maintained and the quality of service to all customers meets expectations. The Planning Guide is aligned with applicable safety codes, regulatory requirements, and industry standards and provides uniform criteria and design standards across the Eversource Service Territory for all aspects of the DER Planning process.

The planning criteria and analyses described herein are used to ensure that DER do not degrade the safety, performance, or reliability of the EPS. This document is a guide, and the Company reserves the right to change its policies, procedures and standards when deemed necessary to maintain the reliability of the EPS and the safety of the Company's customers, workforce, and general public.

Eversource has established administrative processes for interconnecting all types and sizes of DER installations. As the level of customer and developer interest advances beyond the initial inquiry phase, a formal review process takes place in which the potential impact of a given site on the Eversource EPS is reviewed. This review may include the execution of a formal System Impact Study Agreement (SISA) and may result in general and specific requirements for certain design aspects of the DER. These requirements typically include electrical protection and control design and configuration, interface transformer configuration, required modifications to local Eversource facilities (including conductor upgrades and substation modifications), metering and supervisory control and data acquisition ("SCADA") requirements, and in some cases operating constraints for the proposed DER.

Additional Documents Under Development [this text will be removed when we publish]:

Job Aid - FERC or other "Fast Track" Screens – how to apply; how to determine when a full study can be waived

Job Aid – How to Conduct an SIS (steps to implement each of the study elements in Section 6 of this DERPG)

SIS Template – all three states should use a similar report format & content

Job Aid – Synergi – how to model voltage regulating devices (LTC, VREG, Caps, DVAR) and advanced inverter functions (e.g., Volt/VAR)

# APPLICABILITY

This guide applies to DER seeking to interconnect to the Eversource system in CT, MA or NH at distribution voltage, i.e., facilities rated at less than 69 kV. Distribution System Impact Studies (D-SIS or SIS) will be performed per these guidelines regardless of whether the Interconnection Request falls under State or FERC jurisdiction. Facilities rated at 69 kV and greater are generally considered transmission. Transmission System Impact Studies are performed in accordance with ISO-NE planning procedures and are out of scope for this document. At the discretion of the Company or in accordance with local tariffs, certain DER (typically those serving residential and small commercial customers) will be screened for system impact without the need for a full System Impact Study. To the extent this document conflicts with local regulations or tariffs, the regulation or tariff will be controlling.

# 1.0 GENERAL REQUIREMENTS

## 1.1 Documents and Standards

DER Planning engineers shall be cognizant of the following:

**For Massachusetts:**

- Eversource distributed generation interconnection tariffs, Standards for Interconnection of Distributed Generation, M.D.P.U. No. 55 for both Eversource Western MA and Eversource Eastern MA ("Interconnection Tariff").
- MA Technical Standards Review Group & MA Common Technical Standards Manual

**For New Hampshire:**

- Guidelines for Generator Interconnections
- Interconnection Standards for Inverters up to 100 KVA
- New Hampshire Code of Administrative Rules, Chapter Puc 900
- OP-0045 NH-LCC Minimum Telemetering and Communication Requirements of Merchant Generators

**For Connecticut:**

- The Connecticut Light and Power and The United Illuminating Guidelines for Generator Interconnection, Fast Track and Study Process.
- Docket No. 03-01-15RE04 (Guidelines for the Interconnection of Residential Single-Phase Certified Inverter-Based Generating Facilities of 20 kW (ac) or Less)

**For all States:**

- Eversource Distribution System Planning Guide (DSPG)
- Eversource Distribution System Engineering Manual (DSEM)
- The latest approved version of the Eversource DER Information and Technical Requirement document, which is posted on the internet for use by DER customer and developers
- The latest approved version of the IEEE 1547 (Standard for Interconnecting Distributed Resources with Electric Power Systems) and IEEE 1547.1 (Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces) adopted by Eversource.

- Latest approved version of UL (Underwriters Laboratories) 1741 (Inverters, Converters, Controllers, and Interconnection System Equipment for use with Distributed Energy Resources.
- Effective June 1, 2018, all inverter-based projects are subject to ISO-NE ride-through requirements. To comply with these requirements, inverters shall be certified per the requirements of UL 1741 SA as a grid support utility interactive inverter and shall have the voltage and frequency trip settings and ride-through capability described in the ISO-NE Inverter Source Requirement Document. Additional background is provided in the presentation to the ISO-NE Planning Advisory Committee on February 14, 2018. [see also DSEM 19-1.5]. Compliance with UL 1741 SB is a pending requirement that is expected to be implemented in 2022.
- ISO-NE Document and Procedures, including:
- Operating Procedure No. 12 – Voltage and Reactive Control
- Operating Procedure No. 14 – Technical Requirements for Generators, Demand Resources, Asset Related Demands and Alternative Technology Regulation Resources
- Operating Procedure No. 17 – Load Power Factor Correction
- Operating Procedure No. 18 – Metering and Telemetering Criteria
- ISO-NE Planning Procedure 5-1 – Procedure for Review of Governance Participant's Proposed Plans (Section I.3.9 Applications: Requirements, Procedures, and Forms); and
- ISO-NE Planning Procedure 5-3 – Guidelines for Conducting and Evaluating Proposed Plan Application Analyses.

## 1.2 Interconnection Requests and Required Technical Information

Without adequate technical information regarding the proposed DER, the impact study process can be delayed and inefficient. DER Planning engineers should perform a thorough review of the provided documentation before initiating the study and request appropriate updates to customer documentation that is required for study completion. Required information includes:

- DER Equipment information (type, size, make, model, requested export limitations or other equipment deratings or operational restrictions, etc.)
    - For solar Installations of any size, both inverter AC rating and the panel DC rating
- Proposed location and desired interconnection point
- PE Stamped One-Line must adequately identify the following element:
    - GSU rating, winding configuration, Z%, X/R ratio
    - Grounding method, including the above for all grounding transformer(s), if applicable, or Neutral grounding impedance Zn in Ohms if applicable.
    - Proposed Inverter Settings, Equipment Make & Model, UL 1741 SA or later indication

- Unintentional Island Detection Information
- Documents that show compliance with Transient Over-voltage requirement
- Inverter certification document & specification sheet
- Models of the DER facility shall be provided in PSCAD with any applicable Self-Protective Overvoltage function (SPOV) or other applicable function enabled to show compliance with IEEE 1547-2018 clause 7.4.2. Specific requirements will be included at a later date in an appendix to this document and are currently considered on a case-by-case basis. Models can be requested from the project sponsor at the time of application submittal, or as an SISA deliverable prior to commencing the impact study. North American default settings (e.g., 60 Hz) must be included in the model. All projects >500 kVA shall provide a model.
- DER facilities that may require a Transmission System Impact Study (T-SIS) shall provide a suitable PSS/E model of the project.

## 2.0 STUDY KICK-OFF AND SCOPING

Prior to initiating the study, DER Planning should arrange a scoping meeting with the appropriate disciplines, e.g., System Planning (T & D), Distribution Engineering, Protection & Controls, Substation Engineering, and System Operations. The scoping agenda should include:

- Proposed DER equipment and Point-of-Interconnection (POI)
- Known circuit and substation limitations
- Availability and accuracy of Eversource system model (Synergi, CYME, Aspen)
- Load allocation, feeder loading, verify regulator and cap bank location and control mode
    - System Planning should provide the gross peak and minimum day 24h profiles to be considered in the interconnection
- Existing DER on the circuit and station (including alternate configurations)
- Planned capital projects fully funded and scheduled for completion in the next year that may impact the study. The inclusion of planned capital projects should be documented in the System Impact Study Agreement (SISA). Any planned capital projects that are a pre-requisite for full DER operability must be documented in the Interconnection Agreement (IA) with appropriate timelines, terms, and conditions.
- Primary and Alternative system configurations to be studied
- Protection concerns such as DTT and fuse / device coordination
    - Determine what model will be used to evaluate fault currents and effective grounding (Synergi, CYME, Aspen).

  - Determine staff performing reviews.
- Cap Bank and Line regulator settings
- LTC controls and the potential for reverse power
- Existence of 3V0 protection at the station transformer(s)
- The impact on the transmission system and possible need for a T-SIS.
  - ISO-NE Planning Procedures dictate when a T-SIS is required. Eversource Transmission System Planning shall be consulted for all DER applications >= 5.0 MW and for projects <5.0 MW in an area with aggregate DER penetration levels considered significant.

# 3.0 DER OPERABILITY AND N-1 CRITERIA

**DER will not be permitted to operate in system configurations that were not included in either the original SIS or via subsequent evaluation.**

Distribution feeders that have been intentionally designed to provide transfer capability between bulk substations during emergency conditions shall be considered LCC lines, since they contribute to the Load Carrying Capability of that station.

DER and System Planning shall determine if the proposed DER point-of-interconnection (POI) is on an LCC line. **If the POI is located on an LCC line, the SIS must include N-1 scenarios in which the line is supplying customers that would otherwise have been isolated following the N-1 triggering event. If the POI is on a side tap off of the main LCC line, N-1 shall also apply.**

Specific guidance is below:

**1. DER locations normally sourced via a single transformer bank bulk substation**

All feeders supplied from a one-bank substation shall be considered LCC lines. Following loss of the transformer, the line would be in-service and acting as an alternative source of supply for a prolonged period. **Therefore, the SIS must include loss of the normal supply transformer.**

**2. DER locations normally sourced via multi-transformer bank bulk stations that rely on feeder transfer during N-1**

If a multibank substation exceeds nameplate capacity and relies on nearby substations following loss of a transformer, the lines that are used to reduce the substation load below nameplate are considered LCC lines. **Therefore, if the proposed POI is on the LCC line, the SIS must include loss of the largest transformer in that station.**

If the proposed POI is on a line that is not used to reduce the substation load during N-1, it is still possible for the line to be considered an LCC line due to a tie to an electrically adjacent substation. For example, a line in Station A (two banks) might be used to offload Station B (single bank) following an event at Station B. **In this case, the SIS must include loss of the transformer that was the basis for the LCC line designation (e.g., the transformer at Station B).**

**3. DER locations normally sourced via multi-transformer bank bulk stations that do not rely on feeder transfer during N-1 (i.e., self-sufficient)**

A multi-bank substation is self-sufficient during N-1 when it has adequate firm capacity (LTE) to carry the load following the loss of the largest supply transformer. Lines served by these stations are not LCC lines (unless they are designated as LCC based on the configuration at an electrically adjacent station). **If the proposed POI is not on an LCC line, the SIS need not include loss of a normal supply transformer (see note below about reverse power).**

**4. 3V0 Screening and Transformer Reverse Power Screening**

Regardless of whether the DER POI is on an LCC line, a non-LCC line, at either a Bulk or a Non-Bulk station, the System Impact Study will review loss of the largest normal supply transformer during light load to determine if 3V0 or reverse power risk is present and requires mitigation (see Section XXX for treatment of minimum load).

**5. DER locations normally sourced via non-LCC-Lines or via non-bulk stations**

For these DER applications, only the normal system configuration is included in the SIS (other than noted in #4 above).

**6. Other Considerations**

Faults on the primary feeder serving the POI and other temporary, unplanned events do not need to be considered in the SIS. These events are expected to be restored quickly and DER operability is not a primary concern during emergency system restoration. The DER may be tripped offline during these situations as needed.

Device coordination, proper fault sensing and related Protection & Control functionality (e.g. 3V0, Direct Transfer Trip, short-circuit studies) must be fully operable for all permitted configurations (normal and off-normal, i.e. N-1). As permitted by IEEE 1547-2018 (footnote 9), alternative settings may be utilized for temporary, alternative configurations.

When N-1 scenarios result in required mitigation (e.g., station upgrades, line reconductoring, 3V0, DTT, etc.) the DER customer shall be responsible for the upgrade costs. The DER customer shall not be offered the option to go off-line during any of the studied N-1 scenarios as an alternative to funding identified upgrades.

The cases to be included in the System Impact Study (N-0 and N-1) shall be discussed during the scoping meeting or otherwise and shall be documented in the SIS Agreement (SISA) and included in the SIS report.

# 4.0 EXPRESS FEEDER AND STATION FEEDER BREAKERS

## 4.1 Express Feeders

[see also DSEM 19-1.4.3]

Express feeders will be built to all normal construction and power quality standards, including proper voltage at the POI. Operation of the DER on the express feeder should not limit Eversource's ability to serve future customers from that feeder.

Future use of Express feeders to serve Eversource customers will be specifically addressed in each Interconnection Agreement.

Eversource shall use only customary practices to acquire the permits and easements that may be necessary to site an express feeder.

## 4.2 Right-of-Way Issues

[see also DSEM 19-1.4.4]

System upgrades to accommodate DER, including express feeders, shall not limit or hinder the future use of Eversource ROW. The DER developer should not be given a preliminary indication that space in an existing ROW will be available until management approval has been obtained.

Eversource ROW cannot be used for private distribution infrastructure owned by 3rd parties.

Tapping of a ROW line to bring service to a new DER customer requires review and approval by Distribution Engineering and System Operations. ROW taps can decrease area reliability, slow restoration, and result in poor availability for the DER customer.

Any lateral crossings of a ROW must be designed in accordance with Eversource standards. Ownership, maintenance, and any legal issues associated with the crossing will be included in the Interconnection Agreement or a separate agreement.

All requests to co-locate facilities parallel to, within or adjacent to Eversource transmission and distribution line corridors shall follow Eversource Administrative Procedure M2-SI-2008 (Co-Location Requests with Transmission).

### 4.3 New or Existing Breaker Positions

[see also DSEM 19-1.4.2]

Senior management shall be consulted regarding the offering of substation real estate and/or spare breaker capacity for purposes of DER interconnection. The decision to offer a substation breaker position to a new DER shall consider future expansion plans, space limitations, etc. Substation Engineering and System Planning must approve any conceptual interconnection designs that may limit future system expansion and/or reconfigurations. The Solution Design Committee (SDC) is one possible venue for this review. The DER developer should not be given a preliminary indication that a breaker position will be available until approval has been obtained.

## 5.0 VOLTAGE REGULATION BY DER

[see also DSEM 19-1.2 and DSEM 19-1.4.5]]

The DER facility shall not actively regulate the voltage of the EPS unless specifically agreed by the Company. Initial load flow simulations for inverter-based DER should be performed with the DER at fixed unity power factor (PF = 1.0). To mitigate over-voltages and/or rapid voltage changes, the DER may be modeled with a fixed, off-unity PF (i.e., absorbing VAR) that is at any point >= 0.9 as a least-cost mitigation. In areas of high penetration, or for utility-scale DER, modeling the DER with a voltage schedule may be considered after consulting with System Planning and may be required per ISO-NE OP-14 (Section II.H – Voltage Control). Typically, the voltage schedule shall be consistent with the LTC settings and/or line regulator settings. The normal system voltage at a nearby device should also be reviewed. When DER projects are to be given a voltage schedule, ensure the settings and control mode of circuit capacitor banks are modified as needed. It is also advisable to require circuit capacitor banks and/or line regulators to be upgraded with SCADA visibility and control.

Eversource is required to adhere to ISO-NE Operating Procedure OP-17 – Load Power Factor Correction. DER with operating schedules that conflict with the goals of OP-17 shall be reviewed and may require mitigation. Any DER that is expected to contribute to OP-17 violations will be required to provide appropriate VAR support to enable compliance with OP-17. Consideration shall be given to Dynamic Reactive Devices (DRD) and/or Battery Energy Storage Systems (see DSPG Section 2.11 - Battery Energy Storage Systems Design Criteria).

# 6.0 REQUIRED ELEMENTS OF THE SYSTEM IMPACT STUDY

## 6.1 Steady-State Thermal and Voltage Criteria

For all modeled cases, the addition of the DER shall not result in any equipment exceeding its normal rating. For conductor and cable, the more stringent limitations of the Eversource DSPG (Section 2.10 Feeder Upgrade) shall apply.

For all modeled cases, the addition of the DER shall not cause the voltage at any point along the EPS to deviate from +5% / -5% of nominal or to violate the voltage criteria documented in the Eversource DSPG (Section 2.4, Voltage). When evaluating Energy Storage Systems in the charging mode, primary voltage at the POI must remain above 0.983 p.u. or else mitigation is required.

Prior to performing any project study cases, one or more "pre-project" cases must be conducted to screen for existing thermal and voltage concerns. System issues identified in these pre-project cases must be mitigated in the model prior to evaluating the system impact of the DER.

The results will be presented in tables showing the voltage and loading results. Any voltage or thermal issues will be identified, and possible mitigation options will be provided such as adjustments to the voltage regulation settings, upgrade of feeder conductors, and adding reactive power control capability to the DER with due consideration of the IEEE 1547 Standard. The study report should identify the voltage regulation devices on the circuit, how they are programmed in the field, and how they were captured in the models.

If off-unity PF operation is indicated as a method to mitigate over-voltage concerns, the load flows will be re-evaluated. Increased VAR demands at the substation transformer, caused by the DG operating off-unity, will be determined and documented.

Mitigation Options – Thermal Capacity Overload

Reconductoring and other equipment upgrades to increase the normal rating are required. DER operating restrictions can be considered only with Eversource owned and operated control technology.

Mitigation Options – Voltage Issues

The Synergi model should be reviewed to ensure existing feeder voltage regulation equipment is properly modeled and configured. Control mode and/or modified settings should be considered. The model results (pre-project) should be benchmarked against actual voltage data when possible. Pre-project time-series analysis may be useful to review device operation.

DER operation in off-unity (fixed or voltage schedule) should be considered.

Voltage Regulators & Capacitor banks.

Dynamic reactive devices should be considered only if the DER does not have adequate VAR capability to mitigate the issue.

Reconductoring should be considered.

DER operating restrictions can be considered only with Eversource owned and operated control technology.

## 6.2 DER Impact on Voltage Regulating Equipment

[see also DSEM 19-1.4]

The SIS will evaluate and document the impact on Eversource voltage regulating equipment (LTCs, Caps, Line Regulators) due to DER ramping between 5% and 100% of nameplate power output. Any concerns with the operation of voltage regulation equipment shall be discussed with Distribution Engineering to evaluate if mitigation is required.

Mitigation

The Synergi model should be reviewed to ensure existing feeder voltage regulation equipment is properly modeled and configured. Control mode and/or modified settings should be considered. The model results (pre-project) should be benchmarked against actual voltage data when possible. Pre-project time-series analysis may be useful to review device operation.

DER operation in off-unity (fixed or voltage schedule) should be considered.

Dynamic reactive devices should be considered only if the DER does not have adequate VAR capability to mitigate the issue.

## 6.3 Rapid Voltage Change and Voltage Flicker

[see also DSEM 19-1.2]

Rapid Voltage Change (RVC)

Simulate an instantaneous trip of the generator from full 100% to 0% output, and vice versa. Any dynamic reactive capabilities of the inverters shall be disabled, and other voltage regulating devices on the circuit should be locked. The rapid voltage change criteria is 3% on distribution voltages per IEEE 1547-2018 clause 7.2.2. Results >2% (either in the initial simulation or after some partial mitigation) should undergo the additional flicker analyses, see below. Only the applicant DER is included in the RVC test cases.

RVC Mitigation

Dynamic reactive devices should be considered.

Reconductoring should be considered.

Ramp rate limitation (including for PV for site off-to-on violations).

Flicker Assessment

Simulate an instantaneous decrease in the generator from full 100% to 5% output, and vice versa. If the project will be operating with a voltage schedule, any dynamic reactive capabilities of the inverters shall be enabled in the model. Other voltage regulating devices on the circuit should be locked. Flicker criteria is 2% for PV. Results >2% must either be mitigated to <2% or should undergo additional flicker analyses, including the Pst and Plt review. IEEE 1547-2018 limits for EPst and PPlt should be considered. IEEE 1453 and IEC/TR 61000-3-7references may be considered if mitigation is required by the flicker criteria.

As part of the flicker evaluation, simultaneous output changes of other DER sites on the circuit may be considered for the analysis if they are the same type since a common event (such as variable cloud cover) could affect more than one DER site. The default approach is to include solar projects within ¼ mile of the solar project under study.

Ramp Rate control can be considered as a mitigation for flicker. Any mitigation that reduces the operational flexibility of the DER must be agreeable to the owner and documented in the Interconnection Service Agreement (ISA).

Flicker Mitigation

DER operation in Volt/VAR should be considered. Ensure Synergi is properly modeling the dynamic capability of the DER.

Reconductoring may be considered.

Dynamic reactive devices should be considered only if the DER does not have adequate VAR capability to mitigate the issue.

DER Ramp Rate limitation may be considered.

## 6.4 Transient Overvoltage (TOV) and Transient Analysis

[see also DSEM 19-1.2.4]

Transient overvoltage is of concern due to potential load rejection overvoltage (LROV) by inverter-based DER. There is concern that during step changes in load (such as tripping of an upstream device), the proposed inverters may cause transient over voltages in excess of 1.2pu, which can potentially cause damage to the customer's equipment, utility equipment, and/or nearby customer equipment. Due to this concern, Eversource requires that the customer demonstrate that the inverters limit their cumulative overvoltage according to the transient overvoltage curve in IEEE Std. 1547-2018 clause 7.4.2. If the inverters do not demonstrate compliance to the curve given in the standard, additional utility upgrades and/or transient analysis may be required to mitigate the overvoltage concern. The customer may demonstrate compliance by:

- Providing a copy of the most recent HECO qualified equipment list highlighting the inverter make/model and firmware that meets the above requirements.
- Providing documentation that the inverter(s) have passed the Hawaiian Electric Companies (HECO) test procedure for transient overvoltage qualifications, as evaluated by a Nationally Recognized Testing Laboratory (NRTL).
- Providing a letter from the inverter manufacturer indicating that the proposed inverter is capable of and set to trip for no higher than 1.4pu voltage in 1ms or less clearing time. *Note: "clearing time" is defined in IEEE 1547. Any implications of solely "trip time" may not sufficiently clear the TOV (e.g., a circuit breaker typically trips in 1-2 cycles, but an inverter may cease to energize by opening IGBTs in milliseconds).*
- Other means proposed by the customer/inverter manufacturer may be acceptable on a case-by-case basis.
- All documentation shall include the applicable firmware version(s). The correct firmware version shall be demonstrated by the customer during witness testing/final review. Generally, all DER installations 500kW and larger shall provide this documentation. The Company reserves the right to ask for this documentation for smaller DER projects undergoing study and/or additional review. DER projects <100kW are exempt from this data requirement.
- In future revisions, UL 1741 test procedures are anticipated to cover this requirement. In the interim, customers large enough to require an impact study or additional review are required to demonstrate compliance to avoid potential damage to customer and utility equipment. Regardless of utility documentation requirements, it is the responsibility of

the DER customer to meet all applicable standards, including but not limited to the latest version of IEEE 1547.

A Transient Analysis (using PSCAD or equivalent software) shall be performed as part of the SIS under the following conditions:

- Risk of Islanding (ROI) – unless otherwise mitigated, a dynamic study is required to further assess the ROI when a project fails the applicable screens during an impact study.
- TOV – A dynamic study is required for TOV when a DG is identified in the impact study as increasing the aggregate generation on a feeder / substation bus to >= 115% of gross minimum load. The study should also screen for potential worst-case TOV issues at mid-line devices.
- Other – A dynamic TOV study may be required for other cases where there are other system concerns, which cannot be properly evaluated inside of Synergi and require time-based analysis.

If the analysis determines that a transient over-voltage condition is caused by the DER, mitigation shall be required. The analysis shall also screen for pre-existing transient over-voltage issues.

TOV Mitigation

Self-Protection Over-Voltage enabling in the inverter

Review grounding solution and options

Surge Arrestors at POI or Station

## 6.5 Transformer Reverse Power Capability

[see also DSEM 19-1.2]

Any proposed DER facility that has the potential to cause reverse power flow through an Eversource substation transformer will require an Impact Study. The Impact Study will specifically address the ability of the transformer to accommodate reverse power flow. The following items will be evaluated:

LTC Design, Controller Type and Controller Settings: The Impact Study will evaluate the capability of the LTC and controller to accommodate reverse power conditions and to respond with appropriate control strategies.

Voltage and current inputs must be available to the LTC controller.

Any LTC controller configuration that is not appropriate for reverse power must be replaced with a suitable controller with both voltage and current inputs. The requirement to add a backup controller will also be evaluated.

For LTC evaluation all substation circuits must be modelled to ensure an LTC response to the reverse power flow from the interconnecting DG does not cause a low voltage condition

Capacity Limit: As an initial screen, unless constrained by other more limiting requirements, aggregate DER (in kVA) will be permitted up to 95% of the transformer's top nameplate ampere rating (in kVA) with maximum cooling operational. This limit is based strictly on the transformer nameplate, with no consideration given to any forward power load on the transformer. This assessment must include N-1 scenarios, i.e., loss of the largest transformer at a multi-bank station, or other N-1 configurations in which the DER is sourced from an alternate station or those in which existing or queued DER from an electrically adjacent station is transferred to the applicant DER source station (see Section 3.0 for a discussion of required N-1 scenarios).

If the initial screen is failed, an assessment will be made of the absolute minimum load that may be considered as protection against transformer backfeed in excess of the nameplate. The default minimum load for this review will be 67% of the historical minimum loading on the transformer in the configuration being analyzed. Engineering judgement will be used to consider if a more conservative assumption is required, e.g., most heavily loaded feeder is in a switched configuration.

Mitigation

Additional transformation capacity is required.

## 6.6 3V0 Assessment (Transmission Ground Fault Detection)

This section details a methodology that facilitates the identification of the following:

- Potential for Ground fault Overvoltage (GFOV),
- Condition when such a potential may be present

When it is determined that GFOV protection is required, the tripping time shall be compared with the Temporary Over Voltage characteristics of the transformer high side arresters to identify the need to replace the arresters with higher rated units and evaluate impact on the transformer BIL rating. In addition, the line arresters on the high/transmission side of the substation transformer may need to be evaluated.

This guideline provides requirements and methodology for identifying where 3V0 or other transmission-side ground fault protection may be required for bulk distribution substations. It is also applicable to the evaluation of high-side protection at non-bulk distribution substations. It considers the fact that Distributed Energy Resources (DERs) can energize a substation transformer prior to reverse power flow occurring and requires the protection when standard DER-to-minimum load ratios are exceeded under various operational system conditions. The DER-to-minimum load ratio screens are to be completed for all potential scenarios (i.e., normal and N-1 alternative configurations). The methodology included in this document will identify the need for 3V0 protection based on existing, proposed and forecasted DER penetration over both short- and long-term planning horizons.

Distribution substations are typically designed for one-way flow: to provide power to distribution customers from the transmission or sub-transmission system. The addition of Distributed Energy Resources (DER) can require additional fault protection for ground faults on the high/transmission side of distribution substation transformers. This protection is typically known as 3V0, or 59N, and detects the neutral shift that occurs when the ungrounded high side of the transformer is energized from the low side for a ground fault. Without this protection, the DER at certain penetration levels can continue to energize the substation transformer during high-side ground faults, causing potential damage to equipment and/or present a safety hazard. This policy discusses the screens for where 3V0 or other high/transmission-side ground fault protection may be required for distribution substations. It considers the fact that DERs can energize a substation transformer prior to reverse power flow occurring and requires the protection when DER to minimum load ratios are $\geq$67%, considering a single n-1 contingency scenario (feeder or transformer contingency). This will ensure high side ground faults have adequate protection in place when DERs may be capable of energizing the ground fault when the remote (source) substations have tripped.

Concerns for DERs 'back feeding' into a transmission ground fault arise before the aggregate penetration of DER can cause reverse power at a given substation transformer. The concern arises when the aggregate DER can continue to *energize* the substation transformer. Although this is possible with nearly any DER level[1], the loads can help 'swamp out' the generation in some cases, meaning 3V0 may not be required if the DER penetrations are sufficiently low enough. The existing Sandia screens for risk of islanding are the basis of the 67% threshold for determining where 3V0 is required. Where there is insufficient generation to carry the minimum load on a given substation transformer, it is expected that the DERs on all feeders will trip on the 88% trip setting[2], because the DERs are unable to hold the islanded voltage any higher. The load screens are based on the following derivation:[3]

[1] Transformer magnetization impedance requires very little current to overcome.

[2] Note that the MA Technical Standards Review Group (MA TSRG) is increasing the trip time from 2s to 3s for DERs to proactively comply with PRC 024 and ISO-NE requests for ride through for DERs

[3] Source: "Toward a new set of "Sandia screens" for risk of islanding," Michael Ropp, Northern Plains Power Technologies, August 30, 2019 presentation to EPRI Islanding Supplemental Supporters. A short on this logic is publicly available in the Sandia "Suggested Guidelines for Assessment of DG Unintentional Islanding Risk" https://energy.sandia.gov/wp-content/gallery/uploads/SAND2012-1365-v2.pdf on page 7.

$$Z_{load} = \frac{V_{nom}^2}{P_{load}},\ \textit{and therefore:}$$

$$V_{nom}^2 = Z_{load} * P_{load},\ \text{and}$$

$$V_{isl}^2 = Z_{load} * P_{DER}$$

$$\frac{V_{isl}}{V_{nom}} = \sqrt{\frac{P_{DER}}{P_{load}}} \leq 0.88$$

$$\frac{P_{DER}}{P_{load}} \leq (0.88) = 0.77$$

Where:

- $Z_{load}$ is the impedance of the loads on the given feeder(s) connected to the substation transformer
- $V_{nom}$ is the nominal voltage of the circuit
- $P_{load}$ is the power of the minimum load in kW
- $V_{isl}$ is the voltage in the resulting island

Therefore, where the ratio of DER rating to load rating is >0.77, the voltage in the potential island may remain above 0.88 per unit of the nominal voltage. A 10% safety margin is used, resulting in the 67% criteria. This margin can account for inaccuracies in DER voltage measurement, PI data measurements, and other inaccuracies.
Given that the distribution system is commonly operated in several configurations, the screening must consider N-1 contingencies for the substation transformer and/or transformer offloading for maintenance. Therefore, the screens consider two N-1 scenarios:

1. N-1 feeder level: the feeder with the largest contribution to net load on the transformer is taken out of service or transferred to another substation
2. N-1 transformer level: if the feeders on a given substation may be carried by less than all of the substation transformers at the station, one transformer should be taken out of service and the screens repeated for this scenario. In this case, an N-1 feeder criterion is not also taken.

During initial reviews of the DER proposal (or in the beginning of the impact study), the aggregate DER-to-minimum gross load ratio shall be calculated using the installed DER nameplate capacity. For penetration dominated by PV systems, the daytime minimum gross load may be used. For all other DERs (rotating machines, energy storage) that are expected to operate 24/7 or outside daylight hours, the review shall consider the 24-hour minimum gross load. For the cases given below where the aggregate DER nameplate is greater than 67% of the gross *minimum* load it is *possible* for this condition to occur, and Protection & Substations Engineering should be consulted for either a list of substations with full 3V0 installed to trip all applicable feeders offline, or to determine whether that particular substation configuration requires 3V0. The *aggregate DER* refers to the total nameplate rating of the DER existing, proposed, and forecasted, as applicable for the type of study.

$$Where: \frac{Aggregate\ DER}{Minimum\ Gross\ Load} \geq 0.67 \rightarrow 3V0\ is\ required$$

**Case 1:**

One substation transformer, one feeder:

$$Where: \frac{Aggregate\ Feeder\ A\ DER}{Feeder\ A\ Minimum\ Gross\ Load} \geq 0.67 \rightarrow 3V0\ is\ required$$

**Case 2:**

One substation transformer, three feeders:

$$Where: \frac{Feeder\ A\ DER + Feeder\ C\ DER}{Min\ Gross\ Load_A + Min\ Gross\ Load_C} \geq 0.67 \rightarrow 3V0\ is\ required$$

Where Feeder B is the heaviest *net* loaded feeder[4], considering both the aggregate DER on the feeder and the minimum gross load on the feeder. This feeder is removed from the equation to simulate the heaviest net loaded feeder being out of service.

**Case 3:**

Two substation transformers, **solid/straight bus on the low side of the transformers,** multiple feeders (where one transformer may be used to supply all feeders):

Consider the load on both transformers. Consider the following scenarios:

- N-1 transformer configuration: One substation transformer out of service, and all feeders are sourced by the single transformer. Do NOT consider the heaviest net loaded feeder out. If this screen fails, 3V0 is required on *both* transformers (as the DERs may be carried by either transformer).
- N-1 feeder configuration: For both substation transformers in service, consider the heaviest net loaded feeder out of service. If this screen fails, 3V0 is required on both transformers.

**Case 4:**

[4] "Net" refers to the PI readings in most cases, which inherently include the existing DER that was online at a given time. However, when the hourly data is available, the "heaviest net loaded feeder" should be determined using feeder gross load minus feeder aggregate DER nameplate.

Two substation transformers, **Normally Open low side bus/breaker and/or separate buses,** multiple feeders (where one transformer may be used to supply all feeders):

- N-1 transformer configuration: One substation transformer out of service, and all feeders are sourced by the single transformer. Do NOT consider the heaviest loaded feeder out. If this screen fails, 3V0 is required on *both* transformers (as the DERs may be carried by either transformer).
- N-1 feeder configuration: For the transformer the DER is connecting to only, consider the heaviest net loaded feeder out of service. If this screen fails, 3V0 is required on that transformer.

In any of the cases above, if the feeder load is **not** able to be carried by a single transformer or is never planned to be switched to be carried by a single transformer, there is no need to perform that scenario. Document this in the screening for project records.

All configurations not considered above should be discussed with the System Planning, System Operations, Protection and Substations Departments to determine how the substation is operated and what conditions would cause concern for energized transmission-side ground faults.

In all cases, care should be taken to ensure that Eversource can operate its substations in all typical configurations while being covered by the 3V0 installation and/or existing ground fault protection at the substation. All the above screens MUST be performed for both the normal AND the N-1 alternate configuration(s) for a DER facility being studied (e.g., if the DER may be tied to Substation A or Substation B, the screens must be performed for BOTH Substation A and Substation B).

When performing station-level screens proactively (e.g., as part of a system-wide evaluation rather than for a specific DER application) it is also required to consider what circuits from other stations (i.e., Substation B) may be offloaded onto the station under review (i.e., Substation A). In this case, the load and DER of those circuits (from Substation B) must be part evaluation of Substation A.

**Applicable Transformer Configurations:**
This verification is always needed for delta high-side transformers, as well as any transformer configuration containing or acting as an ungrounded wye or delta that would effectively break zero sequence continuity/the ground fault current path between transmission and distribution (e.g., Yg-D-Yg, D-Yg, Y-Y, or Y-Yg). Y-ground-Y-ground transformers[5], provided there is no delta or phantom tertiary in the transformer, should pass through transmission-side voltages and currents the DER will be able to see, and are not applicable for this document. The transformer configuration and protection requirements should be determined in consultation with the

[5] Also assumes high magnetizing impedance for 3-legged core-type transformers.

Protection department or by reviewing the list of substation evaluations for 3V0 provided by the Protection department.

Mitigation

Consult with Protection & Control Engineering on possible mitigation options.

### 6.7 Effective Grounding

[see also DSEM 19-1.1]

Where Effective Grounding Is Required:

Effective grounding shall be required for all DER interconnections where any of the following is true:

- The fault current at the point of common coupling (PCC) is caused to increase by at least 10 percent of the existing value.
- Areas where fault current may already be deemed excessive.
- DER interconnections equal to or larger than 1MW.
- Anywhere there may exist a potential islanding concern regarding generation to load ratio.

Effective Grounding Methods:

To achieve effective grounding, the DER owner shall design and install an interconnection system where the ratio of the DER's reactance parameters meets the following criteria:

$2<X0/X1<3$

X0 = zero sequence reactance and X1 = positive sequence reactance at the PCC

The DER shall use one of the following methods:

- A generator step-up transformer (GSU) with a reactively grounded neutral on the high (utility) wye-connected side and a delta configuration on the low (generator) side.
    - Reactor sizing calculations confirming conformance to Eversource design requirements shall be submitted by the customer prior to scheduling of the witness test. The DER owner shall also supply specifications and ratings for all equipment as it pertains to all reactor sizing calculations.

- Note: This method is preferred with respect to ferro-resonance and harmonics concerns for most generators.

- A GSU with a grounded-wye / grounded-wye configuration and a grounding transformer on either side of the GSU (for DER that do not source ground fault current).
- A delta high (utility) side GSU configuration and a grounding transformer on the high (utility) side.

Where Effective Grounding is Not Required:

Where DER connections are not required to be effectively grounded, delta windings shall be used on the high (utility) side of the GSU. For this type of interconnection or installations with existing delta connected transformers on the utility side which are serving as a GSU, a customer provided 59N (3V0) scheme fed by PTs on the high (utility) side of the GSU shall also be required to sense over voltages on the un-faulted phases during single phase–to–ground faults upstream of the GSU. The 59N requirement is in addition to normal protection requirements specified for DER installations at Eversource.

Mitigation

The developer shall submit revised design plans that satisfy the effective grounding criteria.

## 6.8 Adverse Impact of Unintentional Islanding

[see also DSEM 19-3.1]

Unintentional Islanding by the DER of all or part of the EPS (meaning a part of the EPS is kept energized by the generating facility after the area has been de-energized) is prohibited as it may result in unsafe conditions on the EPS.

The initial screening below must be completed for all projects >200 kVA (Max AC rating)

Circuit segments to review are those created by automatic sectionalizing devices (breakers, reclosers, VCS switches).

Step 1 - Aggregate DER (any type) in segment <= 67% of Minimum Gross Load?

YES – **ROI mitigation not required. End of evaluation.** (Note: this assumes all DERs >500kVA have a POI recloser for visibility as a minimum level of mitigation).

NO – continue…

Step 2 - Synchronous machines in the line segment under review?

YES – **Mitigation and/or Further Evaluation Required (see below)**

NO – continue…

Step 3 - Inverter uses UIDM Group 1 or 2A?

YES - **ROI mitigation not required. End of evaluation.**

NO - **Mitigation and/or Further Evaluation Required (see below)**

Mitigation

Risk mitigation and evaluation options to consider include:

Full mitigation:

- perform detailed ROI study to confirm Run-on-Time < 2 seconds (PSCAD, see Section 6.4)
- Fiber or other DTT to either the DER under study or synchronous DER

Partial mitigation:

- Eversource-owned SCADA device at the POI
- SCADA-based tripping logic at POI device
- System Operating Procedures to check for islanded DER
- Block-of-close of upstream automatic sectionalizing device(s) to mitigate potential for out-of-phase reclosing into an island

## 6.9 Compliance with ISO-NE Source Requirement Document for Inverters

The SIS will review the DER project information relative to compliance with the SRD and future requirements, e.g., Ride-Through 2.0 and UL 1741 SB requirements. The study report will document the voltage and frequency settings required for compliance. The required settings and control modes must be documented on the final customer one-line diagram.

## 6.10 Short Circuit Evaluations

[see also DSEM 19-2.1]

Pre- and Post-project faults currents will be determined and documented. Equipment short circuit ratings included in the system model will be compared to the available fault calculated in ASPEN One Liner or Synergi, including potential contribution from the proposed DER in aggregation with other generation on the distribution circuits. A review of the existing protection scheme and coordination will be included.

The maximum allowable fault duty on the station bus is 10 kA without the use of reactors. The DER interconnection cannot cause the substation bus fault duty to exceed 10 kA or result in exceeding the interrupting rating of distribution line equipment. Failure of this criteria requires review by Protection and Control Engineering.

DER interconnections, in aggregate with other generation on the distribution circuit, should not contribute more than 10 percent to the maximum fault current of the distribution circuit at the point on the high voltage (primary) level nearest the proposed Point of Common Coupling (PCC). Failure of this criteria requires review by Protection and Control Engineering.

## 6.11 Short Circuit Ratio Evaluations

A short circuit ratio ("SCR") test will be performed at the Project's terminal bus (e.g., 480V or 600V) to determine the electrical strength of the external Eversource system at that location. The system is to be tested under N-2 and N-3 conditions. The N-3 condition is an operational consideration and not a design condition at this time. The minimum SCR requirement provided by the DER inverter manufacturer must be compared to the calculate SCR under all conditions.

The short-circuit MVA will be computed for different line-out conditions to determine the lowest measured SCR at the interconnecting point. The ASPEN case used should represents the minimum fault condition where all local generators in the vicinity of the project (including the Project itself) were taken out-of-service during the computation. The N-0 base case should also be performed for the pre-project condition without any loss of transmission elements.

DER Planning must coordinate with ISO-NE (for FERC jurisdictional projects) and/or Transmission System Planning to ensure that this evaluation is captured in either the Distribution SIS or the Transmission SIS.

## 6.12 Communication and SCADA Requirement

The SIS shall note any relevant requirements base on the latest approved version of the Eversource DER Information and Technical Requirement document. The SIS shall document whether Eversource will require SCADA or other real-time communication to either i) an Eversource-owned device at the POI or ii) a customer-owned device beyond the POI. In general, any DER with a maximum AC capacity greater than 500 kVA shall require a SCADA feed back to the applicable System Operations Control Center (and potentially a backup control center). SCADA will provide for remote monitoring and tripping of the DER. Exceptions may be made by local management with the concurrence of System Operations.

Job Title: Clerical Utility Worker

General Description of Job:

Performs a wide variety of clerical tasks requiring a wide knowledge of Company, Division and/or Department procedures and practices as they relate to the assigned duties.

Regular Duties:

Performs stockhandling (when needed) and clerical duties.

Miscellaneous maintenance duties.

Types a wide variety of forms, records and reports which may include confidential material. May record and transcribe dictation on a limited basis.

Performs data entry on mainframes and personal computers. Works with data bases and spreadsheets. Records and verifies a variety of data.

Maintains and updates filing systems.

Completes complex assignments which may be of a special, confidential, or infrequent nature.

Provides guidance and training.

Exercises judgment to apply standard practice to a given situation.

Handles non-routine inquiries and determines whether standard replies can be adjusted to the situation.

**The majority of duties associated with this position are clerical**. Clerical skills and the ability to work with and learn multiple business computer systems including Maximo, Click Mobile, WorkForce, TRAMS, DARS, ARCOS and several other systems related to the support of the Operations group is required. Under limited supervision, individual will primarily perform a wide variety of clerical job functions and occasionally other duties that **may** include some stock handling and miscellaneous meter inventory tasks. Individual **may** be asked to perform some minimal maintenance tasks such as salting and snow removal and will perform other duties as assigned.

Note: This description does not describe all of the responsibilities inherent in this job. It provides as much detail as necessary to distinguish this job from all other jobs. In addition, the requirements list are not all inclusive. Management has the right to make determinations based upon individual circumstances.

POSITION REQUIREMENTS:
A High School diploma or the equivalent is required. In addition, the ability to perform basic math functions, communicate effectively, follow instruction, and work without direct supervision is required. A valid motor vehicle operator’s license and a proven, safe driving record are required. A CDL-B license or the ability to obtain one is also required. The ultimate wage rate for this position is $35.37.
**NOTE: The closing date is at 12:01 a.m. on date shown; interested candidates must apply by previous day.**

License(s)/Certificate(s): Motor Vehicle Operator's License required.

A proven, safe, driving record is required.

Commercial Operator's License may be required.

Clerical Job Description

Job Title: Senior Departmental Clerk

General Description of Job:

Performs a wide variety of clerical tasks requiring a wide knowledge of Company, Division and/or Department procedures and practices as they relate to the assigned duties.

Regular Duties:

1. Performs clerical tasks such as copying data and compiling records and reports; tabulating and posting data in books; preparing, issuing and distributing receipts, bills, invoices, statements and checks; computing wages, taxes, premiums, commissions and payments; preparing inventory records; opening and sorting incoming mail, answering correspondence with standard replies; preparing outgoing mail, proofreading records and forms; receiving and processing customer and internal complaints, inquiries, and orders; and other similar activities.

2. Types a wide variety of forms, records and reports which may include confidential material. May record and transcribe dictation on a limited basis.

3. Performs data entry on mainframes and personal computers. Works with data bases and spreadsheets. Records and verifies a variety of data.

4. Maintains and updates filing systems.

5. Completes complex assignments which may be of a special, confidential or infrequent nature.

6. Provides guidance and training.

7. Exercises judgment to apply standard practice to a given situation.

8. Handles non-routine inquiries and determines whether or not standard replies can be adjusted to the situation.

Background:

Required: High school diploma or equivalent. Four (4) years directly related clerical experience.

Helpful: Associate's degree in Secretarial Sciences; courses in word processing, communications, math, personal computers.

Required Skills:

The ability to: use clear and concise written and verbal communication techniques; type accurately; work on a word processor; perform basic math functions; operate a terminal console; alphabetize; follow moderate to complex instructions; apply independent judgment in an exceptional situation; operate various office machinery; and train and instruct. Good organizational skills. Knowledge of Company policies and procedures.

License(s)/Certificate(s): None required.

Source of Direction:

Will vary according to assignment.

Note: This description does not describe all of the responsibilities inherent in this job. It provides as much detail as necessary to distinguish this job from all other jobs. In addition, the requirements list are not all inclusive. Management has the right to make determinations based upon individual circumstances.

90-2

3/15/1990

# Property Damage

# Billing & Collection

# Process Document

*Issued: July 2024*
*Revised: NA*

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INTRODUCTION

**Objective**

This document outlines the process for establishing and recovering a claim against a responsible party for causing damage to Eversource property.

**Applicability**

This process is applicable to all situations where our electrical system is damaged. The facilities can be below, on, or above ground.

**References**

This process is kept in the Property Damage Project/Process Documentation/Active Version/ Sharepoint site.

**Discussion**

This document was written to outline the overall process to be followed when pursuing a property damage claim starting with responding to an incident and finishing with recovering the company's costs to repair the damaged facilities back to normal configuration.

At the time of the incident, the company will always take the needed steps to make the situation safe and restore power. In some cases, additional "follow-up" work may need to be planned, scheduled and constructed to bring the system back to normal configuration.

**Example**

A vehicle hits and cracks a pole in the middle of the night. Power has not been loss. The pole is braced at the time of the incident. The replacement of the pole and transfer of facilities will be planned subsequently.

When the bill is submitted to Oracle as a receivable, it will also be reimbursed to the operational cost control center. The reimbursement is not contingent on the collection of the claim.

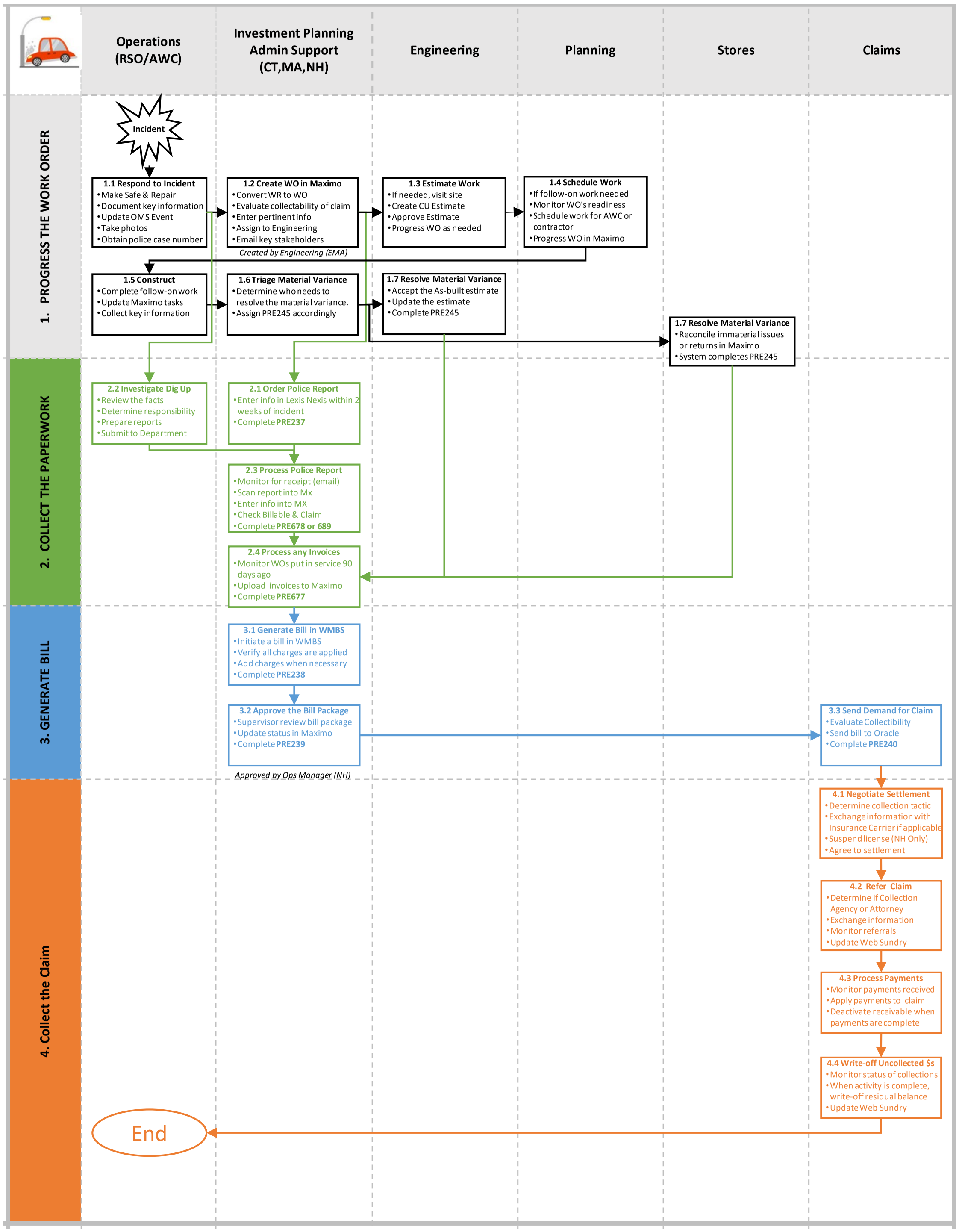
The two criterion to create a bill in the Work Management Billing System are (1) the work orders must be in the status of COMP or PCLOSE; and (2) the work type must be EM, CM, or CP.

The criteria to include a work order in the dashboard data simply requires at least one of the property damage specific prerequisites. Designers are currently instructed to use the property damage sub-work types, but on occasion and historically, Designers used other sub-work types.

The property damage prerequisites are used to manage the process from incident to billing the responsible party. It relies on the proper disposition of the prerequisites in the work management system at the appropriate time to process efficiently.

| Standard Prerequisites Number | Description | Type | Activation Status | Completion Status | Completed When | Completed By | Part of Report Criteria |
|---|---|---|---|---|---|---|---|
| PRE223 | Work by Telephone Co. | JOINTUSE | DSINPRG | WTBS | Pole installed. | Operations | No |
| PRE237 | PDB Police Report Contact & Damage Claim | DAMINV | DSINPRG | COMP | Police report ordered in Lexis Nexis portal. | Admin | Yes |
| PRE238 | PDB Summary Report Package Complete | DAMINV | FCOMP | COMP | Bill generated and documentation attached. | Admin | Yes |
| PRE239 | PDB Reviewed for Release to MX | DAMINV | FCOMP | COMP | Documentation and bill approved accurate and complete. | Admin | Yes |
| PRE240 | PDB Claims Review/Send to Oracle | DAMINV | FCOMP | COMP | Bill sent to Oracle as a receivable. | Claims | Yes |
| PRE245 | Variance Reconciliation | COMPCLOSE | FCOMP | FCOMP | Material variance is resolved. | Operations | No |
| PRE677 | Need Invoiced | BILLING | FCOMP | COMP | All invoices attached and highlighted | Admin | Yes |
| PRE678 | Police Report Received | BILLING | DSINPRG | COMP | Police report provided by Lexis Nexis and attached. | Admin | No |
| PRE689 | Dig Up Docs Attached | BILLING | DSINPRG | COMP | Dig up documentation provided and attached. | Admin | Yes |

# High Level Electric Process Flow



## Instructions

The following instructions are aligned to the high-level process flow and are meant to provide detailed activities performed during the process steps. The level of detail assumes that a user is familiar with the navigation and functionality of the various applications, including Maximo Work Order and Invoices, Work Management Billing System (WMBS), Lexis Nexis Portal and Web Sundry.

1. PROGRESS THE WORK ORDER

**1.1 Respond to the incident.**

*Operations*

| **Reference** |
|---|
| Supervisor's Briefing Sheet SBS-14-008 revision 3 outlines first responder's responsibilities related to property damage incidents. |

1.1.1 EVALUATE the situation and MAKE it safe.

1.1.2 When the incident is an underground dig up, DISPATCH the investigator to the scene.

1.1.3 DOCUMENT any information about the person/company responsible (i.e. City Garbage Truck took down service, City Plow knocked pad off of slab, ABC Construction dug up primary, Tree Company took down secondary)

1.1.4 TAKE photos of the scene to help clarify and support responsibility.

| **Example** |
|---|
| Vehicle license plate, Company name/logo on vehicle or equipment, point of contact in relation to mark outs, etc. |

1.1.5 FILL OUT a Trouble Ticket (electronically or paper) noting the following information:

- Street and Town
- Structure # (i.e. pole)
- Description of Work Completed
- Note if "Follow-Up Work" is Needed
- Materials Used
- Contractors Used or Copy of Timesheets (Check-off Box for Traffic Control)
- List all Eversource Employees On-Scene
- Police case number
- License Plate or VIN#

| **NOTE** |
|---|
| The more information obtained and provided either from the scene of the accident or from the follow-up work, the quicker the property damage bills can be processed and the quicker the company can recover their costs, which results in a operational budget reimbursement. |

1.1.6 When the incident is underground, RECORD the Dig Safe Ticket number on the trouble ticket.

1.1.7 While police are on scene, OBTAIN the summary report, police traffic duty slip, and police case number on the trouble ticket.

*Administrative (CT, WMA, NH) and Designer (EMA)*

## 1.2 Create the work order in Maximo

1.2.1 NAVIGATE to the Maximo portlet for work requests

1.2.2 CONVERT work request to a work order.

1.2.3 EVALUATE criterion of Cancellation Matrix (Attachment 1) in the Work Order Creation section and PERFORM actions outlined if appropriate.

1.2.4 CHECK "Responsible Party Unknown?" on the Billing Tab in Maximo and then SAVE, if appropriate.

*EMA Administrative will perform the next two steps when ordering the police report*

1.2.5 CHECK "Fatality?" on the Billing Tab in Maximo, if appropriate.

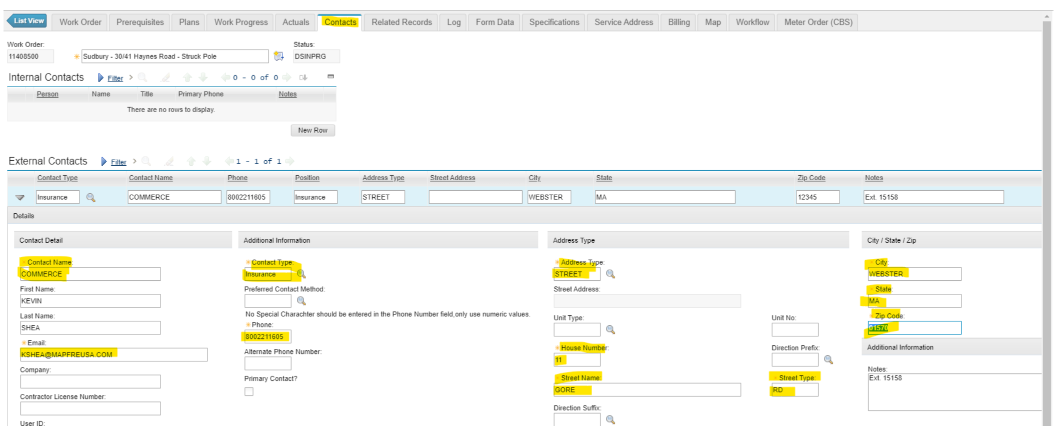
a. EMAIL pdclaims@eversource.com the work order to notify of fatality.

*Claims*

b. REVIEW police report attached to the work order.

c. CONTACT the insurance company for claim information.

d. CREATE a contact type of "Insurance" with the highlighted information shown below.




e. If no insurance is listed on the police report, DETERMINE if appropriate and who to bill.

f. CREATE a contact to reflect who should be billed, if appropriate.

g. ADVISE Admin of determination.

*Admin*

h. PROCEED with billing or cancellation as appropriate.

1.2.6 INFORM Claims the responsible party is a municipal, state or federal agency, if appropriate.

**NOTE**

Attachment 4 - State Requirements to Notice Municipals Regarding Claim describes the requirements:

- Connecticut requires notice within 6 months and action within 2 years of incident.
- Massachusetts requires notice within 2 years and suit filed within 3 years of incident.
- New Hampshire requires notice within 60 days and suit filed within 3 years of incident.

*Claims*

1.2.7 PLACE the Agency on written notice of the claim within the state's required timeframe using the department's form letter.

1.2.8 UPDATE Maximo damage notes when Notice of Claim is sent and acknowledged.

1.2.9 ATTACH Notice of Claim and Agency Acknowledgement to Maximo work order tab.

*Administrative (CT, WMA, NH) and Designer (EMA)*

1.2.10 If the work order is labor only, ADVANCE the work order to COMP in Maximo.

*Designer*

1.3 Build a design estimate in Maximo

1.3.1 DETERMINE if the information provided is adequate to build estimate.

1.3.2 If not, VISIT the site and RECORD the necessary information.

1.3.3 CREATE estimate in Maximo.

1.3.4 APPROVE estimate in Maximo.

1.3.5 PROGRESS estimate in Maximo

*Planner*

1.4 Schedule the follow-up work to be completed.

1.4.1 MONITOR the work order's readiness to be scheduled.

1.4.2 SCHEDULE the work for the Area Work Center (AWC) personnel or Outside Contractors.

1.4.3 PROGRESS work order in Maximo, as appropriate.

*Operations*

1.5 Construct the Facilities

1.5.1 GATHER and RECORD with material to perform the repair.

1.5.2 COMPLETE the permanent repair in the field.

1.5.3 UPDATE the Maximo task statuses.

1.5.4 DOCUMENT key information including if work was built as designed.

*Admin*

1.6 Triage the material variance when the system creates a prerequisite 245.

1.6.1 DETERMINE who needs to resolve the material variance.

**NOTE**

**Quantity Planned** is the Material the Designers Planned for the job. **Net Issues** is what the Storeroom issued to job. **Quantity As-built** is the material that was used for the job. **Quantity Variance** is the difference between the Net Issues and Quantity As-built.

a. When all planned quantities are 0 (zero), REASSIGN the PRE245 to Field Engineering to update the asbuilt estimate to align with what was issued to the field.

b. When all as-built quantities are 0 (zero), REASSIGN the PRE245 to Field Engineering to perform as-built acceptance.

c. When planned quantities and net issues match, but as-built quantities do not, REASSIGN to Field Engineering to perform as-built acceptance.

d. When planned quantity and as-built quantity match, but net issues do not, REASSIGN the PRE245 to the Storeroom to charge out material.

e. When more than 1 condition exists, SEND to Field Engineering first.

1.6.2 REASSIGN the PRE245 to the appropriate party in Maximo in CT, WMA & NH.

1.6.3 EMAIL the appropriate party in EMA.

*Operations*

**1.7 Resolve the Material Variance.**

**NOTE**

The steps below are not sequential.

*Admin or Designer*

1.7.1 PERFORM as-built acceptance.

*Designer*

1.7.2 REWRITE the asbuilt estimate to align with material used in the field.

*STORES*

1.7.3 ADJUST the net issues or returns to align with the estimate and material used in the field

*Admin, Designer, or System*

1.7.4 COMPLETE the PRE245 in Maximo.

## 2. COLLECT THE PAPERWORK NEEDED TO SUPPORT THE CLAIM

| **NOTE** |
| --- |
| These steps do not occur sequentially after progressing the work order but will happen in parallel at the appropriate point. |

*Admin*

**2.1 Order the police report <u>within 2 weeks</u> after creating the work order, when appropriate.**

2.1.1 SUBMIT request for police report in the Lexis Nexis portal, by entering the following information:

a. Agency Name

b. Date of Loss (DOL)

c. Claim # - <u>begin</u> with the Maximo work order followed by a hyphen then any characters can be added subsequently to help identify the claim (FWO, AWC, etc).

d. Police Case Number under report, if provided

e. Eversource as Last Name of Party 1

f. Address in Street of Loss

g. City and State

h. Vehicle Identification Number (VIN), if provided

i. Vehicle License Plate (Tag), if provided.

j. General Description under Additional Info

2.1.2 COMPLETE PRE237 in Maximo

*Designated Investigator*

**2.2 Investigate the dig up when appropriate.**

2.2.1 COORDINATE with the Utility Locator investigation, when applicable.

2.2.2 REVIEW all the relevant facts for accuracy.

2.2.3 DETERMINE the responsible party of the incident.

2.2.4 SUBMIT required documentation to the regulatory agency.

2.2.5 RETAIN the reports and supporting documentation per retention guidelines.

*Admin*

**2.3 Process the police or damage report.**

2.3.1 FOLLOW the Actions outlined in the Lexis Nexis Response Actions attachment to guide next steps.

2.3.2 EVALUATE criterion of Cancellation Matrix (Attachment 1) in the *Police Report or Dig Up Documentation Resolution* section and PERFORM actions outlined if appropriate.

2.3.3 If claim is still viable, CHECK both the "Billable?" Box and "Claim?" box in the Billing Tab in Maximo.

2.3.4 CHECK "Responsible Party Unknown?" on the Billing Tab in Maximo, if appropriate.

2.3.5 EXPORT the police report from the Lexis Nexis portal and ATTACH it to the work order in Maximo.

2.3.6 VALIDATE the Incident Date is accurate in the Damage Claims section of the Billing Tab. It will drive the Billing Deadline and Statute of Limitations.

2.3.7 FILL-OUT any other pertinent information available in the Damage Claims section of the Billing Tab.

2.3.8 SAVE your updates to the Billing Tab in Maximo.

2.3.9 VALIDATE or CHECK "Fatality?" on the Billing Tab in Maximo, if appropriate.

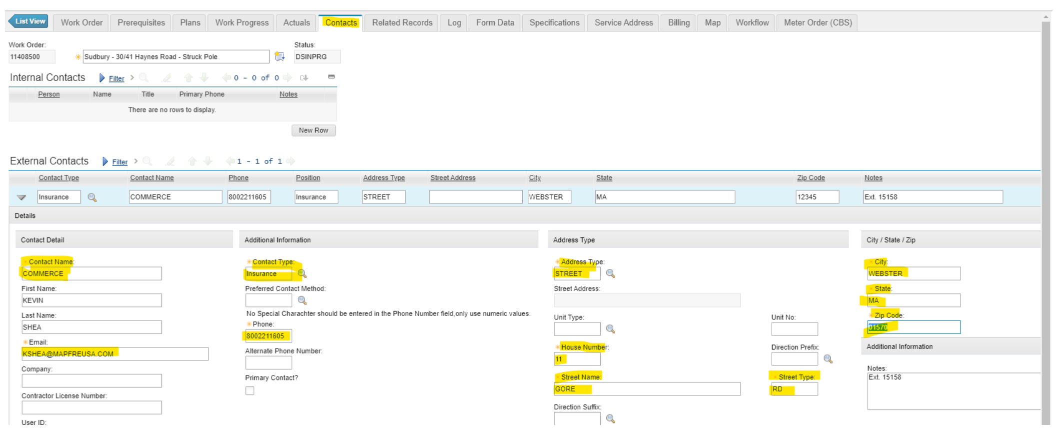
a. EMAIL pdclaims@eversource.com the work order to notify of fatality.

*Claims*

b. REVIEW the attached police report to the work order.

c. CONTACT the insurance company for the claim information.

d. CREATE a contact type of "Insurance" with the highlighted information shown below.



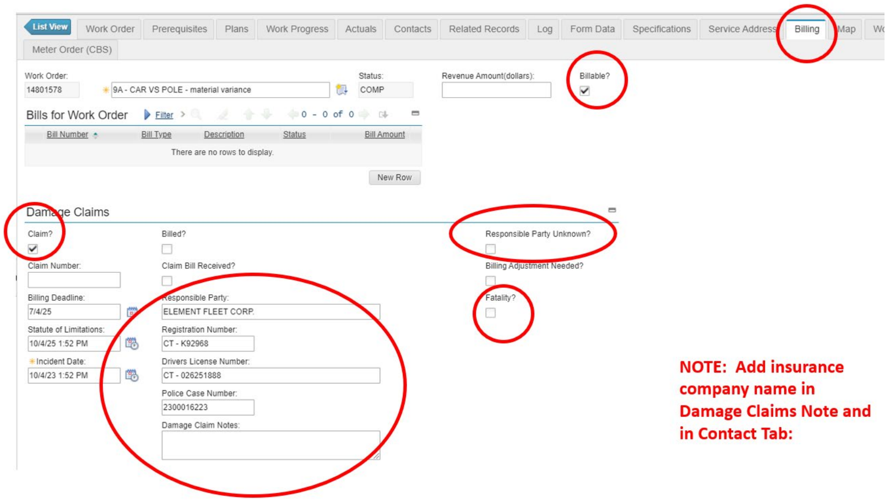

e. If no insurance is listed on the police report, DETERMINE if appropriate and who to bill.

f. CREATE a contact to reflect who should be billed, if appropriate.

g. ADVISE Admin of determination.

*Admin*

h. PROCEED with billing or cancellation as appropriate.




2.3.10 NAVIGATE to the Contacts Tab in Maximo and ADD contacts.

a. CLICK on New Row button all the way to the right in the External Contacts section.

b. ENTER required fields for a Contact Type of Vehicle Owner in the Details section that pops up.

c. SAVE the contact you added.

d. REPEAT steps a - c for a Contact Type of Operator, even if the same asVehicle Owner.

e. REPEAT steps a – c for a Contact Type of Insurance using the Insurance Company Name and Policy Number as the contact name.

| NOTE |
|---|
| All External Contacts must be entered before you Calculate & Save the bill in WMBS even if the information is the same. |

2.3.11 COMPLETE or CANCEL PRE678 (police report) or PRE689 (damage report) as guided in Lexis Nexis Response Actions or Cancellation Matrix.

*Admin*

**2.4 Attach invoices to the work order within 90 to 120 days after going in service.**

2.4.1 MONITOR for work orders that have been in service for 90 days.

2.4.2 REVIEW that work order is written and all charges have hit the work order (labor, outside services, materials, overheads and loaders).

a. NAVIGATE to the Actuals Tab

b. VALIDATE time has been charged on the Labor sub-tab.

c. VALIDATE no materials are checked as Out of Balance on the Material Variance sub-tab and there is no active PRE245.

d. VALIDATE outside services have been charged on the Services sub-tab.

| NOTE |
|---|
| You must wait until Day 2 of the monthly close of the latest charge to ensure all overheads and loaders have been applied. |

2.4.3 DETERMINE if contractor charges hit Outside Service.

a. GOTO CU Estimating (T&D) – Electric by clicking on the chevron next to Estimate Request on the Actuals Tab


b. NAVIGATE to the Summary Tab.

c. OBSERVE if contractor was added to the work order.

2.4.4 When work order contains contractor costs, LOCATE the contractor invoices in Maximo.

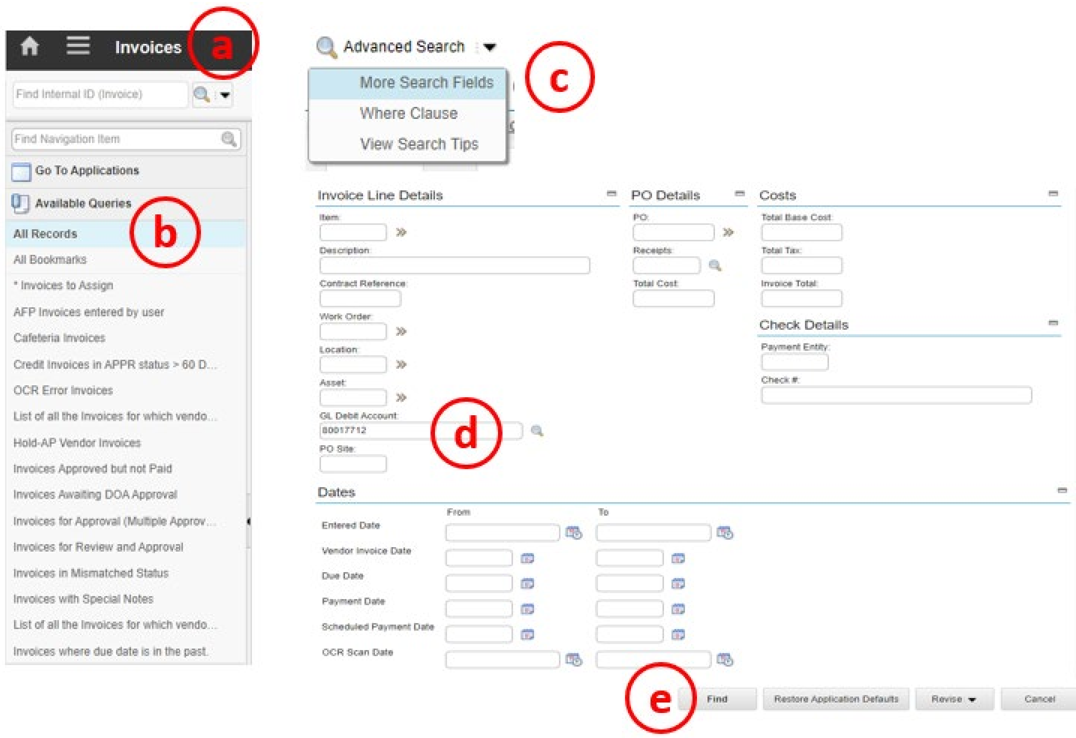
a. NAVIGATE to the Invoice Module in Maximo.

b. CLICK All Records.

c. CLICK Advance Search and then CLICK More Search Fields.

d. ENTER Maximo FWO in GL Debit Account.

e. CLICK Find.




| **NOTE** |
| --- |
| Entity, CCC, and Cost Element are not required for the search. All invoices associated with the work order will populate. |

2.4.5 EXPORT and HIGHLIGHT all applicable contractor charges to the work order.

2.4.6 ATTACH all marked up documents to the work order in Maximo.

2.4.7 COMPLETE PRE677.

## 3. GENERATE A BILL TO SUMMARIZE THE COSTS OF THE CLAIM

| **NOTE** |
|---|
| Both Steps 1 and 2 must be complete before generating the bill in WMBS. |

*Admin*

### 3.1 Create bill in the Work Management Billing System (WMBS) within 2 weeks.

- all prerequisites are done, meaning a status of blank, COMP, CAN, & CLOSE;
- work order was placed in service more than 90 days ago;
- work order status is COMP or PCLOSE; and
- work order does not meet any cancellation criterion.

| **NOTE** |
|---|
| Supervisor should review with the Claims Manager any large claim (> $10,000) with clear responsibility and insurance past the Billing Deadline but at least 30 days before Statute of Limitations before cancelling claim. The Billing Deadline is 90 days before the Statute of Limitations) |

3.1.1 INITIATE or UPDATE a bill to support a property damage claim.

a. NAVIGATE to the Work Management Billing System (WMBS) http://wms.nu.com/apps/wmbs/.

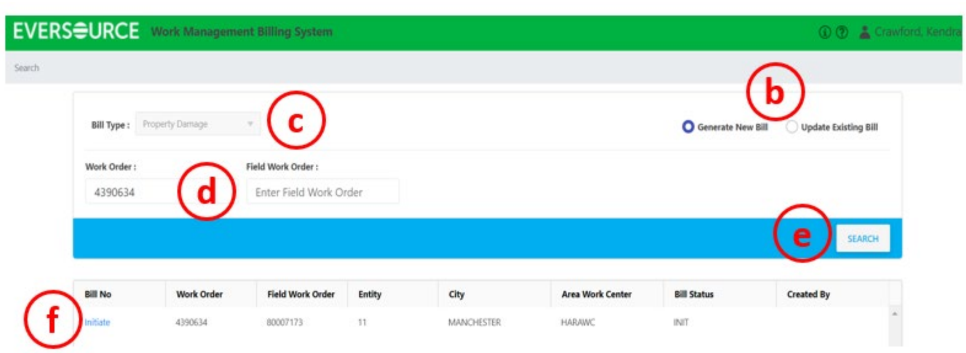
b. CLICK Update Existing Bill if you already started a bill; otherwise Generate New Bill will already be highlighted.

c. SELECT Property Damage for the Bill Type, if not preselected.

d. ENTER the Work Order and Field Work Order

e. CLICK SEARCH.

f. CLICK Initiate to generate a bill. The WMBS status will be INIT.



3.1.2 VERIFY the Work Order Details and CONTACT match Maximo information.

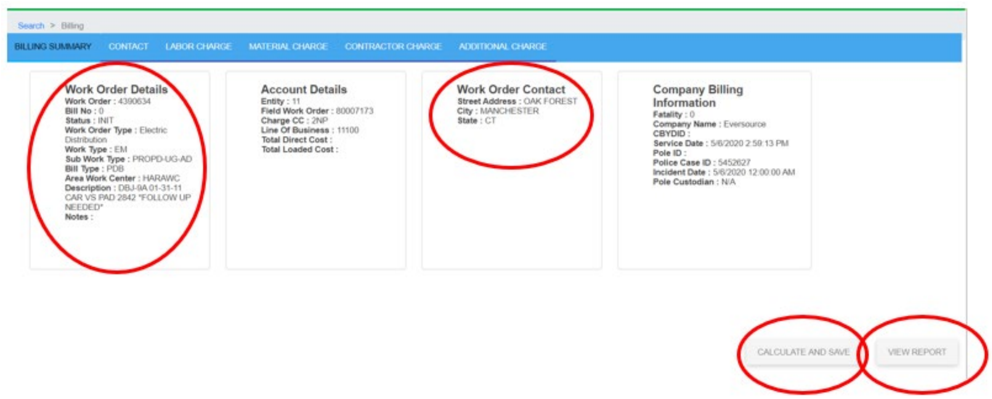
a. OPEN the Maximo Work Order Tab in a second window.

b. COMPARE information in Work Order details with Work Order Tab in Maximo.

c. CONFIRM Description says 9A-Car vs Pole or 9A-Dig-up.

3.1.3 CALCULATE and SAVE the bill in WMBS after you made all adjustments to the Actuals from the Labor Charge tab. The WMBS status will change to INPRG.

3.1.4 CLICK on View Report to see the results of the bill calculation.




3.1.5 VALIDATE all direct charges have been applied to the work order.

a. CONFIRM appropriate Transformer charges are present.

b. REFER to Appendix to compare the Hyperion Detail of Charges query results with WMBS report, when needed. Hyperion Detail of Charges reflects charges posted to Power Plan.

| **NOTE** |
| --- |
| The rows that are displayed in the Labor Charge and Material Charge tabs of WMBS are actuals. The system does not allow users to adjust those rows. You must add a manual row. You are allowed to edit a manual row that you added. |

3.1.6 DELETE charges in WMBS, if not appropriate.

- Design Contractor Invoices

3.1.7 ADD or ADJUST manual charges in WMBS, if needed.

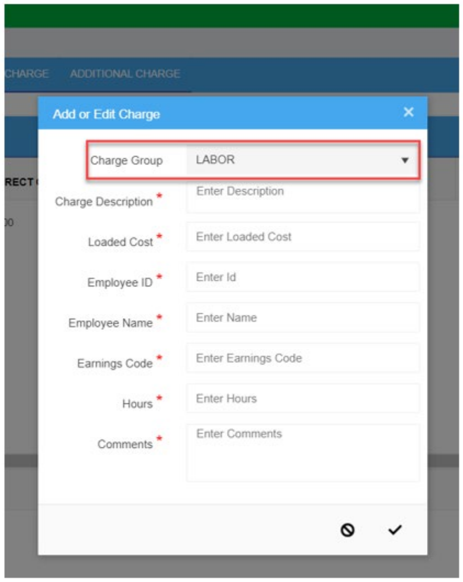
a. NAVIGATE to the Bill Summary page in WMBS.

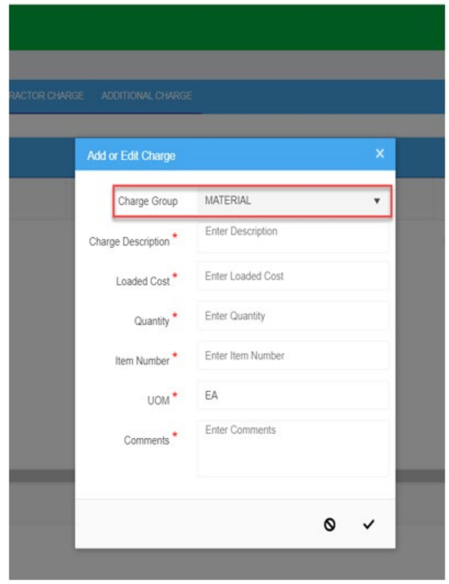
b. SELECT New Charge button on the appropriate charge tab.

c. ENTER the requested information.

d. SAVE your edits by clicking the check mark.

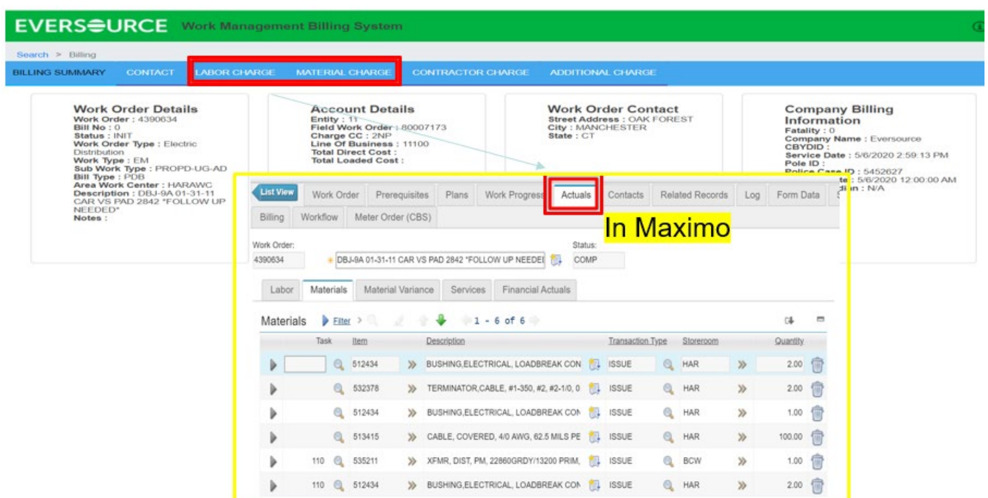
e. CLICK the pencil to edit the charge.




f. CALCULATE and SAVE the changes.

g. VALIDATE entered charges are correctly reflected.




3.1.8 ATTACH page 3 of the WMBS bill report to the work order in Maximo.

3.1.9 CONFIRM property damage claim is still viable and all supporting documents have been attached to work order in Maximo to create an electronic bill package.

- Trouble Ticket (CT, WMA & NH) or Keep Cost Report (EMA)
- Pictures
- Police Report or Dig Up Documentation
- WMBS Billing Report (page 3)

| **NOTE** |
|---|
| When the standard Police Report or Dig up Documentation are not available, any documentation from a third party that identifies the responsible party, date of the incident, location, insurance, and description of the incident can be substituted. |

| **NOTE** |
|---|
| Although Timesheets will not be required as part of the package initially, Claims may request them if needed in the future.  The Material Summary and Hyperion Detail of Charges have been removed from the package intentionally. |

3.1.10 NH only, DELIVER or EMAIL bill package to Ops Manager for approval and signature.

3.1.11 RELEASE TO MAXIMO by clicking the button at bottom right of Billing Summary page in WMBS.  The WMBS status will change to COMPL

3.1.12 COMPLETE PRE238

### 3.2 Approve the bill package is appropriate, complete and accurate within 2 weeks.

*Admin Supervisor (CT & MA)*

3.2.1 PULL UP the work order in both WMBS and Maximo .

a. NAVIGATE to Bill Summary page in the Work Management Billing System (WMBS) http://wms.nu.com/apps/wmbs/.

b. CLICK the View Report button on the bottom right side of the page.

*Admin Supervisor (CT & MA), Ops Manager (NH)*

3.2.2 VALIDATE claim is still viable.

3.2.3 EVALUATE criterion of Cancellation Matrix (Attachment 1) in the *Prio to Finalizing the Bill* section and PERFORM actions outlined if appropriate.

3.2.4 COMPLETE the following steps when claim is not viable.

a. EVALUATE criterion of Cancellation Matrix (Attachment 1) in the *Work Order Creation* section and PERFORM actions outlined as appropriate.

b. CANCEL the bill in Maximo and WMBS outlined in step 3.4.

c. CANCEL all remaining Property Damage specific prerequisites.

3.2.5 VERIFY the charges are accurate and complete.

3.2.6 COMPARE the WMBS billing report to Bill Line Details in the Billing Tab in Maximo.

3.2.7 VERIFY the supporting documentation referenced in step 3.1.9 is complete and attached to the work order .

3.2.8 RESOLVE any discrepancies found.

*Admin Supervisor (CT & MA), Admin (NH)*

3.2.9 COMPLETE the PRE239.

3.2.10 In CT & MA, EMAIL Claims the bill is ready.

| NOTE |
|---|
| As of the writing of this process, the Maximo portlet for Claims is not functioning properly. The email is needed to ensure no claims are missed. The dashboard correctly tracks all claims updated in the Maximo. |

*Claims*

**3.3 Send bill from Maximo to Oracle to record the receivable.**

3.3.1 VALIDATE the bill package is complete, accurate, and viable.

a. EVALUATE criterion of Cancellation Matrix (Attachment 1) in the *Claims Review of Package* section and PERFORM actions outlined if appropriate.

b. CONFIRM the actual bill in Maximo aligns with the supporting documentation of package.

c. ENSURE the police or damage report clearly identify the responsible party being billed.

d. Verify that all invoices are included and link to charges on the bill.

e. REVIEW Trouble tickets information is aligned with supporting information.

3.3.2 WORK with bill preparer to resolve any minor quick (within 1 business day) fixes needed.

3.3.3 RETURN to bill preparer for larger fixes that will likely take more than a day.

a. EMAIL bill preparer and COPY supervisor describing the discrepancy and action needed.

b. ADD new PRE239 to work order in Maximo.

3.3.4 SELECT the correct contact by expanding the bill under Bills for Work Order section of the Maximo Billing Tab.

| NOTE |
|---|
| There are currently two instances of Oracle. The instance used by CT, WMA, and NH is automated between Oracle and Maximo. The instance used by EMA is manual. The manual button in Maximo updates the status and tracks the date but does not send any information to ORACLE. The bill information is emailed to AcctSundryBilling AcctSundryBilling@eversource.com to create the receivable. |

3.3.5 For CT, WMA, or NH, CLICK the Send to Oracle button in the expanded section.

3.3.6 For EMA, manually SEND the Bill to Oracle while in the expanded section.

a. CHECK the “Do Not Send to Oracle?” box which will enable the Manual Bill button.

b. CLICK the Manual Bill button.

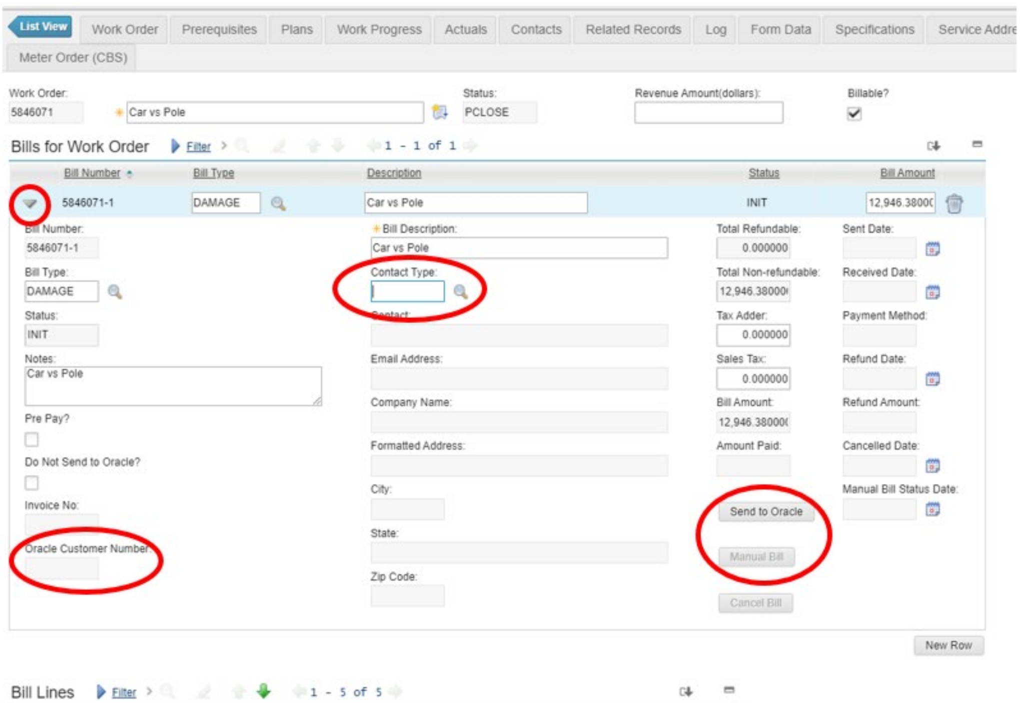
c. EMAIL the bill information AcctSundryBilling@eversource.com to create the receivable.

d. LOG the action in the Weekly Accomplishments tracker and the NSTAR tracking spreadsheet (i.e. 2007-2024 Master Keep Cost Electric.xlsx).

3.3.7 COMPLETE PRE240.

3.3.8 For CT, WMA, or NH, VALIDATE the Oracle Customer Number populated 2 business days after sending.

3.3.9 For EMA, ENTER the Oracle Customer Number in NSTAR tracking spreadsheet once received from AcctSundryBilling AcctSundryBilling@eversource.com.



### 3.4 Delete or Cancel Maximo bill or line items or WMBS bill.

**NOTE**

The steps needed to delete or cancel a bill or bill lines are determined based on the status of the of the bill in WMBS and Maximo. The following table outlines the needed actions. Where there is Maximo and WMBS steps, Maximo actions must be completed first.

| WMBS Status | Maximo Bill Status | What's happening? | Action in Maximo (Must be done first) | Action in WMBS |
|---|---|---|---|---|
| INIT | NA | WMBS pulled Bill Summary header information from Maximo | None | • Cancel Bill<br>• Or to Update Bill - Reinitiate a new bill |
| INPRG | NA | WMBS pulled charge details from PowerPlan and created billing report | None | • CANCEL Bill<br>• Or to Update Bill - CALCULATE and SAVE |
| COMPLT | INIT | WMBS released the summary bill details and Maximo created bill and bill lines | • Delete Bill or bill lines | • Make bill UNBILLABLE<br>• CANCEL Bill<br>• Or to Update Bill – Reintiate and CALCULATE and SAVE |
| | SENT | Maximo sent bill lines to Oracle and updated status. Oracle returned the Oracle Customer Number tied to receivable | • Cancel Bill | • Make bill UNBILLABLE<br>• CANCEL Bill<br>• Or to Update Bill – Reintiate a new bill<br>• Inform Claims and Sundry Billing |
| | MANUAL | Maximo changed status to recognize bill manually sent to Oracle. Bill lines emailed to Sundry Billing, who returns Custom Number tied to receivable. | | |
| | PAID | Oracle updated the status in Maximo to reflect the receivable was paid in full. | Bill cannot be deleted or cancelled | • Bill cannot be deleted or cancelled |

3.4.1 Delete a Maximo bill or bill lines in INIT status.

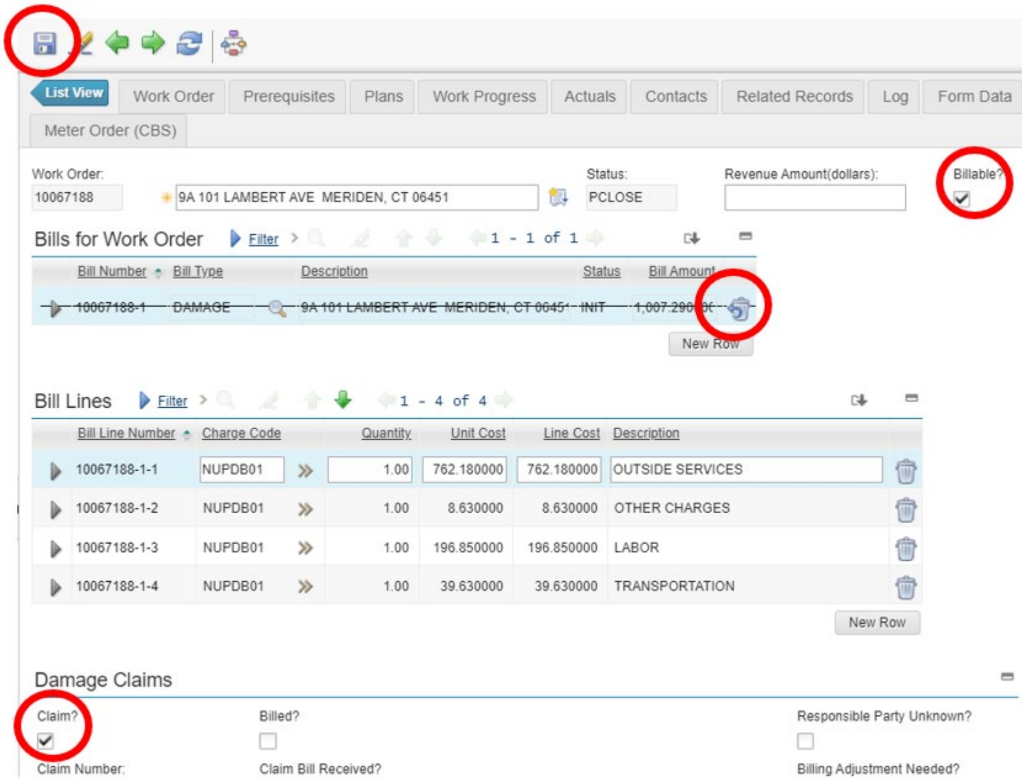
a. NAVIGATE to Billing Tab in Maximo.

b. CLICK the trash barrel to the right of the bill in the Bills for Work Order section. All billing lines will be deleted once saved.

c. If no longer billable, UNCHECK Billable and Claim? and ADD reason code from the Cancellation Matrix in the Damage Claim Notes.

d. CLICK the disk in top left corner to save the changes.

e. CANCEL all remaining property damage prerequisites.




3.4.2 CANCEL a Maximo bill in SENT or Manual status.

a. NAVIGATE to Billing Tab in Maximo.

b. CLICK on the Cancel button after expanding the bill line.

c. If no longer billable, UNCHECK Billable and Claim? and ADD reason code from the Cancellation Matrix in the Damage Claim Notes.

d. CLICK the disk in top left corner to save the changes.

e. CANCEL all remaining property damage prerequisites.

f. INFORM AcctSundryBilling AcctSundryBilling@eversource.com the bill is being canceled and the receivable should be reversed.

3.4.3 Cancel a WMBS bill in INIT or INPRG status.

a. NAVIGATE to the Bill Summary in WMBS.

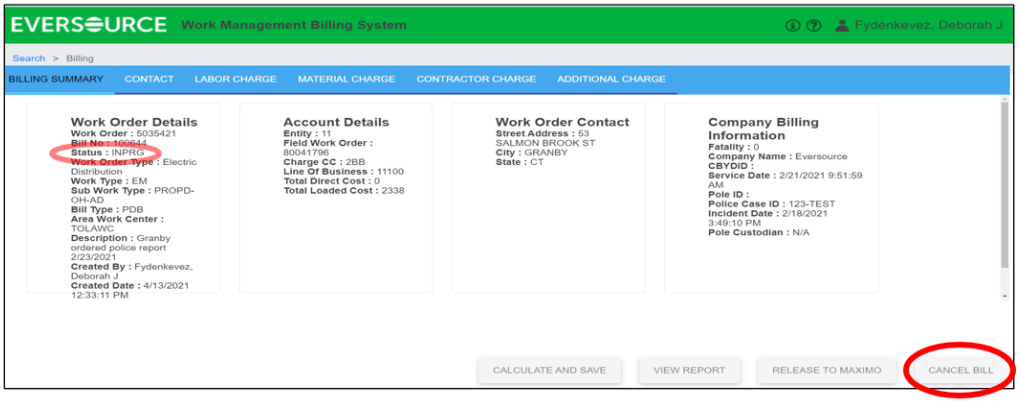
b. CLICK the CANCEL BILL button in the bottom right hand corner.

c. SELECT a cancel reason in the pop-up window.

d. ENTER a descriptive reason if other is selected.

e. SUBMIT cancel reason.

f. If needed, REINITIATE a new bill and GOTO step 3.1.





3.4.4 Cancel a WMBS bill in COMPLT status.

a. DELETE Maximo bill and GOTO step 3.4 based on the Maximo bill status.

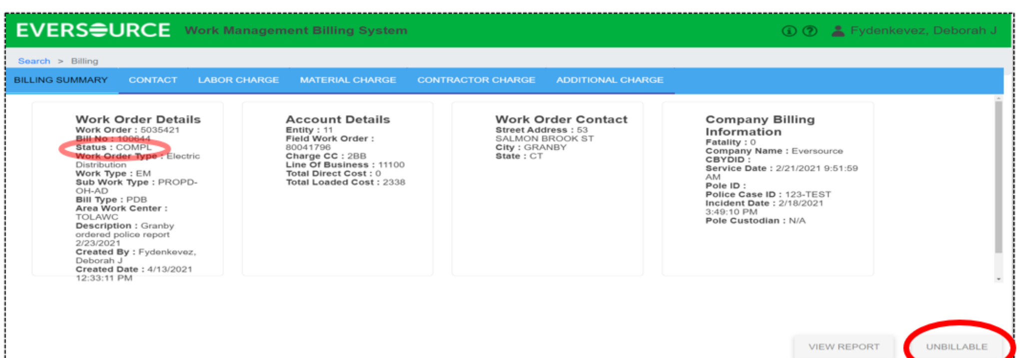
b. NAVIGATE to the Bill Summary in WMBS.

c. CLICK the UNBILLABLE button in the bottom right hand corner.

d. SELECT a cancel reason in the pop-up window.

e. ENTER a descriptive reason if other is selected.

f. SUBMIT cancel reason.



# 4. COLLECT THE RECEIVABLE FROM THE RESPONSIBLE PARTY

*Claims*

| NOTE |
|---|
| The negotiation is an iterative process with the insurance company or responsible party. Each communication, agreement and action should be noted in Web Sundry, as well as adding a reminder for future actions. |

## 4.1 Negotiate a settlement with the responsible party.

4.1.1 CONTACT insurance company and/or responsible party to make them aware of the claim and exchange information.

4.1.2 ENTER the receivable pertinent data and documentation in Web Sundry.

a. FILL IN the Account section with the OAR Number, Entity, Name, Address, and Incident Date.

b. DETERMINE the Credit Status based on the initial collection tactic by following the decision process (Attachment 3).

c. FILL IN the Summary section with the Credit Status, Original Bill Date, Original Bill Amount in.

d. FILL IN the Damage Information section with Location, Event Date and Work Request # (aka Maximo Work Order Number)

e. FILL IN the Insurance Company section, Insurance Claim #, Adjuster Name, Phone Numbers, and Email Addresses in the Insurance Information Section.

f. ATTACH the aggregated billing documentation (BD) into a single file using the following naming convention “Work Order Number-INT-BD”.

g. GENERATE letter if appropriate,

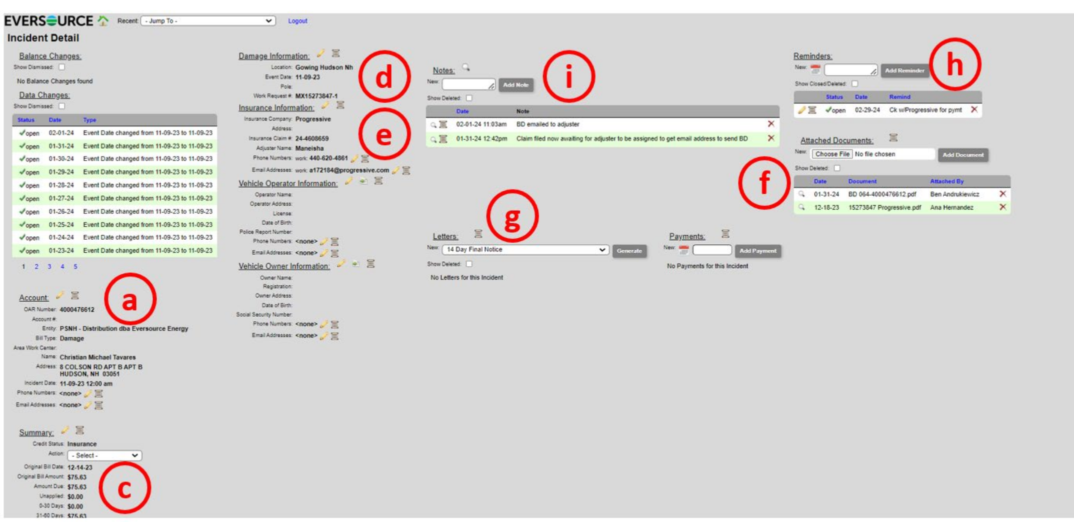
| Letter | Purpose |
|---|---|
| 14 Day Final Notice | This letter is utilized after the negligent party fails to respond to our “First Letter Request for Insurance information. |
| Arrangement with Promissory | This is a contract document with the negligent party agreeing to make monthly payments to resolve the legal debt. |
| Broken Payment Arrangement | This letter is utilized to communicate to the negligent party that they have failed honor the “Arrangement with Promissory” contract and our now delinquent. Subsequently, it advises them we will resume collection action. |
| Collection Agency | This letter is utilized when all attempts by an Eversource claims analyst to recover from the negligent party have failed. We now advise them that this matter will be pursued by our collection agency. |
| Conditional Release of License Cover Letter | This letter is utilized as a contract with the negligent party agreeing to payment installments to collect the legal debt. In exchange the negligent party’s license will be restored by the DMV. |

| | |
|---|---|
| Customer Notification of Possible License Suspension | This letter is utilized to advise the negligent party that their failure to respond to this legal debt will now result in our request to the jurisdictional DMV for license suspension. |
| Dig Up Letter | This letter is utilized as first notice to the negligent excavator to respond to Eversource’s request for insurance information relevant to the occurrence. |
| First Letter Request for Insurance Information | This letter is utilized to place a negligent party that damaged our above ground facilities on notice and request insurance information. |
| Halt Revocation | Notice to jurisdictional state DMV to cease the process of revoking the negligent party’s driver’s license. |
| Notice to City | Notice of claim sent to Municipality of intent to pursue a negligence claim. |
| Paid in Full (DMV Release) | This letter is used to communicate to the jurisdictional DMV that the negligent party has satisfied its legal debt and their driver’s license can be restored. |
| Request Revocation Broken Arrangement | This letter is utilized to communicate to the jurisdictional DMV and request a license suspension of the negligent party. |
| Second Letter | This letter is the second request for insurance information from the negligent party which damaged our above ground facilities. |
| State of NH Conditional Release Cover Letter | This letter is utilized in New Hampshire only as a contract with the negligent party agreeing to payment installments to collect the legal debt. In exchange the negligent party’s license will be restored by the New Hampshire DMV. |
| State of NH Notification to Suspend License | This letter is utilized in New Hampshire only to advise the negligent party that their failure to respond to this legal debt will now result in our request to the New Hampshire DMV for license suspension. |

h. ADD a Reminder when appropriate.

- Municipal Notice Deadline
- License Suspension (NH Only)
- Payment Expected
- Follow-up after GL Team
- Placing claim into collections
- Write-offs

i. ADD note to reflect update.



4.1.3 CONFIRM the insurance company and/or responsible party accepts responsibility.

4.1.4 ADDRESS any questions or challenges regarding responsibility or demand amount.

4.1.5 FINALIZE settlement, demand amount and payment terms.

4.1.6 RECORD transactions and payment terms in Web Sundry.

4.1.7 INPUT a reminder in Web Sundry.

4.1.8 ADD note to reflect update.

4.1.9 DECIDE next step if a reasonable settlement is NOT reached or communications break down.

*Claims*

**4.2 Refer claim as outlined in Attachment 3-Collection Tactic Decision Process.**

4.2.1 In NH only, FOLLOW the following steps:

a. WRITE-OFF any claim less than $500.

b. REFER to Collection Agency if value is between $500 to $1,000.

c. For claims greater than $1,000, SUSPEND the driver's license when negotiations and productive communication breakdown

- Suspension must be done within 2 years of incident.
- NOTIFY responsible party of a possible license suspension letter 14 days in advance.
- If no response, SUBMIT a request to NH DMV to have license revoked.
- Suspension applies pressure to responsible party to negotiate with us.
- If agreement is reached, PROVIDE a Condition Release agreement signed by responsible party and Eversource and INFORM NH DMV using a release letter.

4.2.2 In CT and MA, FOLLOW the following steps.

a. WRITE-OFF any claim less than $500.

b. FORWARD claim to a collection agency when value is between $500 and $10,000.

1) MONITOR status of collection referrals.

2) REVIEW to see if there is still activity.

3) WRITEOFF any collections where there has been no activity or communication for 6 months

4.2.3 For all states, RETAIN attorney (internal or external) for claims greater than $10,000 with preference to internal versus external counsel.

a. MONITOR status of attorney referrals.

b. ANSWER interrogatories associated with the case.

c. CONFER with attorneys regarding any settlement offers.

d. FINALIZE settlement with responsible party and court.

e. UPDATE and STATUS Web Sundry throughout the course of litigation.

4.2.4 UPDATE and NOTE Web Sundry claim status.

4.2.5 PROVIDE Collection Agency or Attorney all the supporting documentation for the claim.

4.2.6 DEACTIVATE Oracle monthly billing of receivable.

*Claims*

**4.3 Process payments made against claims.**

4.3.1 MONITOR payments made.

4.3.2 IDENTIFY account payment is associated.

4.3.3 UPDATE Web Sundry of payment.

4.3.4 When all payments are complete, CLOSE the receivable.

a. DEACTIVATE Oracle monthly billing of receivable.

b. ENTER completion status in Web Sundry as outlined in Attachment 3.

c. WRITEOFF any residual balance.

*Claims*

**4.4 Write-off uncollectible portion of claim.**

4.4.1 PROVIDE list of any writeoffs from claims by the ## of the month.

4.4.2 PROVIDE writeoff balance to AcctSundryBilling AcctSundryBilling@eversource.com.

4.4.3 UPDATE status in Web Sundry.

4.4.4 FOR EMA, UPDATE excel tracking spreadsheet.

-------------------- End of Instruction --------------------

## Summary of changes

July 2024 Published

# Attachment 1 - Claim Cancellation Matrix

(Sheet 1 of 1)

| Process Step | Reason | Reason Code | Dollar Amount | Action |
|---|---|---|---|---|
| **Work Order Creation**<br>*Actions by Bill Preparer* | **Hit and Run** and therefore no responsible party. | *HNR* | Any | 1. Cancel all claim prerequisites.<br>2. Enter "Not Billable" followed by reason code to work order description.<br>3. Uncheck "Billable" and "Claim?" on Billing Tab. |
| | The total charges are **Below Threshold** and there is no follow-up work required. | *BT* | CT & MA - $200<br>NH - $0 | |
| | Internal description or police report identifies **Low Hanging Wires**. High vehicles contacting wires do not qualify. | *LOW1* | < $50,000 | |
| | | *LOW2* | ≥ $50,000 | 4. Supervisor will validate with Manger as well as Operations and Claims that cancelling claim is only course of action left.<br>5. Note billing tab once supervisor approves<br>6. Complete steps for < $50,000. |
| **Police Report Resolution**<br>*Actions by Bill Preparer* | **No Police Report** or police report does not identify responsible party. | *NPR1* | < $10,000 considering actual and pending charges | 1. If too early to reasonably evaluate charges, place PRE678 INPRG.<br>2. Once work order status is "COMP", follow steps based on costs.<br>3. Cancel all remaining claim prerequisites.<br>4. Enter "Not Billable" followed by reason code in work order description.<br>5. Uncheck "Billable" and "Claim?" on Billing Tab. |
| | | *NPR2* | ≥ $10,000 | 6. Send Freedom of Information Letter (FOIA) to the agency to obtain police report or any other documentation they may have.<br>7. If responsible party identified, follow steps based on costs.<br>8. If responsible party NOT identified, review with Supervisor and then Complete steps for <$10,000. |
| | | *NPR3* | ≥ $50,000 | 9. Supervisor will validate with Manger as well as Operations and Claims that cancelling claim is only course of action left.<br>10. Note billing tab once supervisor approves<br>11. Complete steps for < $10,000. |
| | Low Hanging Wires | *LOW1* | < $50,000 | See instructions above in Work Order Creation. |
| | | *LOW2* | ≥ $50,000 | |
| **Dig Up Documentation Resolution**<br>*Actions by Bill Preparer* | There is **No Dig up Documentation** or the documentation does not identify responsible party | *NDUP1* | < $50,000 considering actual and pending charges | 1. If too early to reasonably evaluate charges, place PRE689 INPRG.<br>2. Once work order status is "COMP", follow steps based on costs.<br>3. Cancel all remaining claim prerequisites.<br>4. Enter "Not Billable" followed by reason code in work order description.<br>5. Uncheck "Billable" and "Claim?" on Billing Tab. |
| | | *NDUP2* | ≥ $50,000 | 6. Supervisor will validate with Manger as well as Operations and Claims that cancelling claim is only course of action left.<br>7. Note billing tab once supervisor approves.<br>8. Complete steps for < $50,000. |
| **Prior to Finalizing the Bill**<br>*Actions by Bill Preparer* | The bill has not been completed and date is **beyond** the Billing Deadline, or 90 days prior to the **Statute of Limitation** (SOL). | *SOL* | Any | 1. Review with supervisor, once approved go on to next step.<br>2. Cancel all remaining claim prerequisites and bill (if created).<br>3. Enter "Not Billable" followed by reason code and then brief explanation to work order description. |
| **Claims Review of Package**<br>*Actions by Claims Analyst* | The package is complete and appropriate but the **Claim** is determined **unbillable**. | *CLAIM1* | < $10,000 | 1. Cancel all remaining claim prerequisites and bill.<br>2. Enter "Not Billable" followed by reason code and then brief explanation to work order description.<br>3. Uncheck "Billable" and "Claim?" on Billing Tab. |
| | | *CLAIM2* | ≥ $10,000 | 4. Manger will validate with Operations and Claims that cancelling claim is only course of action left.<br>5. Note billing tab once approved.<br>6. Complete steps for < $10,000 |

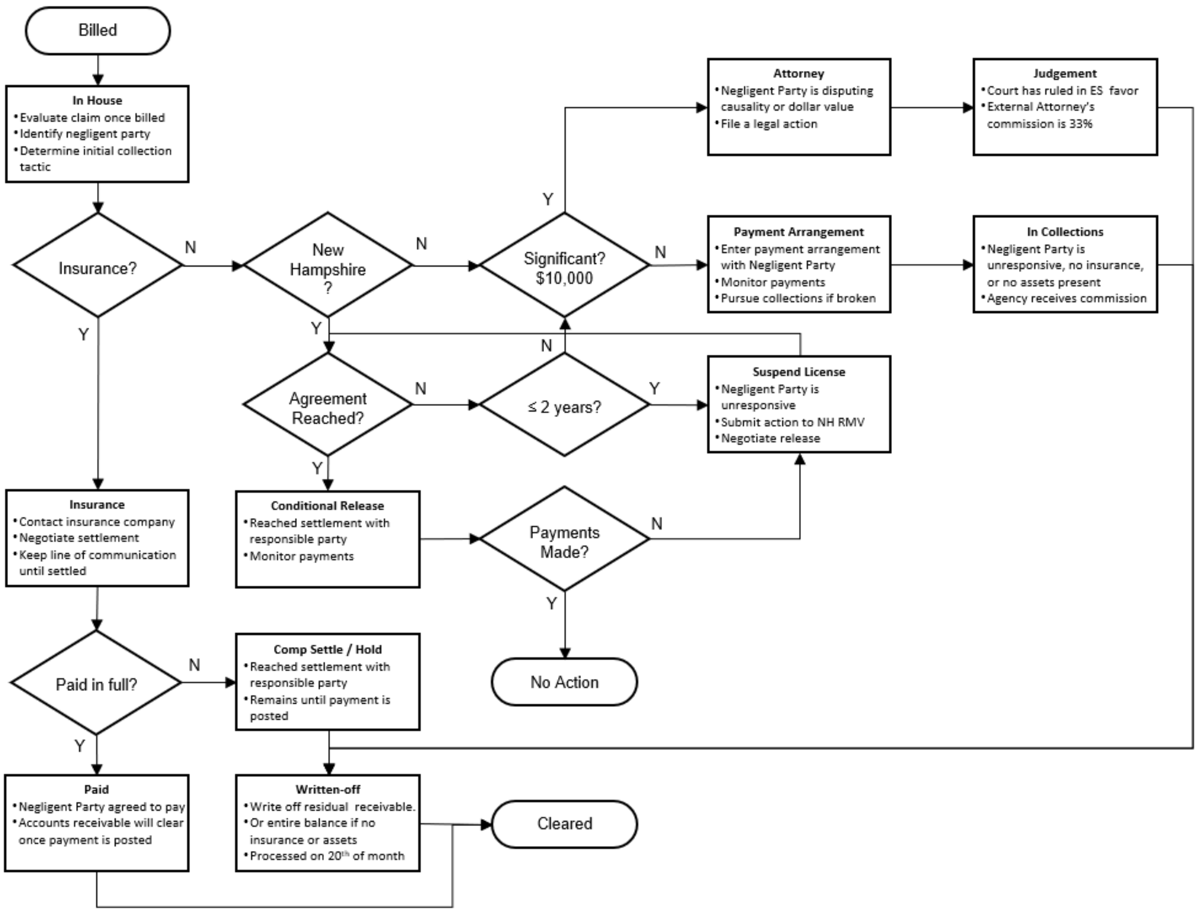
# Attachment 2 - Lexis Nexis Response Actions

(Sheet 1 of 1)

| CODE | | Reason | Description | ACTIONS |
|---|---|---|---|---|
| **COMPLETED** Lexis Nexis Code | PRAC | Police Report Attached | A report was found by police records and forwarded to you by LexisNexis. | Process police report in Maximo and complete prerequisite (678). |
| | NRFN | No Report Found | The report could not be found with the info provided. Suggestions are made as to what information would help. | Follow instructions in Property Damage Claim Cancellation Matrix. |
| | NRWN | No Report Written | Some police do not write a report for losses on private property of if the loss is under a certain value. We deliver the notification to you describing the outcome. | |
| | MISC | Miscellaneous-Not Found | When a report cannot be found for reasons out of the ordinary, you are sent a No Report Found notice with notes of explanation. This could be a situation where the officers responded, no log call was generated and **no report was written**, or it could be the agency just cannot find a report. | |
| | ARIN | Police Agency failed to respond | If a report request is distressed, two or more calls are made, and second requests are submitted if allowed. When we have been promised the report, but it still has not been received. The request is terminated, and we would forward any response once it is received. | |
| | RNRN | Report Released to Insured Only | A few agencies will not release a report to anyone other than a party involved. This is a notification to let you know we are unable to obtain this report. | Send Freedom of Information Act (FOIA) letter to obtain report. |
| | SIOI | Report Not Releasable | This code indicates the report was not releasable. If the release of the report is expected in the future, the notification describes the situation. | |
| | DURI | Duplicate Request | If you have an active request in our system and you generate another request, you are sent a notice of the duplicate and the report is not re-ordered. No charge applies. | Validate first request was submitted and acted upon accordingly. |
| **PENDING** Lexis Nexis Code | CRII | Conflicting Information on Request | Your report request had information in one section that conflicted with another section. Example: Order report from "CA HP" but the state of loss shows "NJ". No charge applies. | Resubmit request for police report with appropriate information. |
| | IISI | Insufficient Info to Order | This report cannot be ordered due to missing some critical information. A notice is generated telling you what info you need. No charge applies. | |
| | WPJR | Wrong Jurisdiction-More Info Required | Your request specified an agency, but they advised LexisNexis it was not theirs. There was insufficient info to determine the correct jurisdiction. | |
| | SRRI | Signed Release Required | Some police agencies require a party involved to sign a release allowing us to get a copy of the report. The notice contains instructions on how to get the release to us and also to re-order the report. No charge applies. | Bring to Supervisor. |
| | PDFR | Agency Failed to Respond- Reorder | If an agency states they did not receive the request, we reorder the report on your behalf. No further action is required by your adjuster. No charge applies. | No action required. |
| | RCAC | Agency Address Change | If your report was requested from an agency that has moved and comes back to us as 'No Forwarding Address', we obtain the correct address and reorder the report. No further action is required by your adjuster. No charge applies. | |
| | RCCC | Agency Requirements Change | If your report was requested from an agency that has changed their requirements since our last contact, we send you a notice and reorder the report. No further action is required by your adjuster. No charge applies. | |
| | RCER | Agency Error- Reorder | Sometimes an agency will make a mistake and requires corrective action. We coordinate the corrective action and reorder the report for you. No further action is required by your adjuster. No charge applies. | |
| | RNNF | Report Number Needed | If an agency requires a report number to do a search and it is missing from your request, we will contact the agency to obtain the report number on your behalf. If we are unable to obtain the report number, we will terminate the order with notes of explanation. No charge applies. | |
| | ROTH | Wrong Info Submitted from Client | This is the same as a NRFN, except the information submitted was not correct and the agency could not locate the report. We correct the information and resubmit the order and notification explaining the problem is delivered to the adjuster. No further action is required by your adjuster. | |
| | RRSC | LN Error | Once in a while we will make a mistake. We take corrective action, reorder your report and send you a notice advising you of the situation. No further action is required by your adjuster. No charge applies. | |
| | WJRR | Wrong Jurisdiction-Reroute | Your request specified an agency, but they advised LexisNexis it was handled by another jurisdiction. We reroute the request to the correct jurisdiction. No further action is required by your adjuster. | |

# Attachment 3 - Collection Tactic Decision Process

(Sheet 1 of 1)



# Attachment 4 – State Requirements to Notice Municipals Regarding Claim

(Sheet 1 of 1)

| STATE | LEGAL AUTHORITY | NOTICE DEADLINES | CLAIMS/ACTIONS ALLOWED | COMMENTS/EXCEPTIONS | DAMAGE CAPS |
|---|---|---|---|---|---|
| **CONNECTICUT** | **Liability of Political Subdivisions.**<br>C.G.S.A. § 52-557n. (codified qualified immunity established by common law).<br>Connecticut in minority of states that still make distinction between *governmental* acts (qualified immunity from discretionary acts requiring judgment or discretion) and *proprietary* functions (no immunity for *ministerial* acts performed in a prescribed manner without judgment or discretion).<br>Exceptions to qualified immunity:<br>(1) failure to act leads to imminent harm;<br>(2) statute provides for cause of action; and<br>(3) intentional act. | Written notice must be filed with the clerk of such municipality within six (6) months after such cause of action has accrued.<br>Statute of Limitation: An action against municipality must be commenced within two (2) years after the cause of action. C.G.S.A. § 7-101a(d).<br>Claims for injuries resulting from defective highways, sidewalks, roads, or bridges must be brought within two (2) years and notice within ninety (90) days. C.G.S.A. §§ 13a-149, 13a-144. Section 13a-149 has savings clause that forgives inaccuracy in notice if no intent to mislead. | Municipalities generally are liable for damages to persons or property caused by:<br>(1) Negligent acts by employees within the scope of their employment or official duties;<br>(2) Negligence in operation of enterprise for "special corporate benefit or pecuniary profit" (*e.g.*, water supply, sewer, municipal parking garage, or golf course); and<br>(3) Creation or participation in the creation of a nuisance.<br>C.G.S.A. § 52-557n(a)(1).<br>However, this liability is significantly limited by several exceptions.<br>Suits can be brought against state or municipality for defective or poorly maintained roads and bridges. C.G.S.A. § 13a-149.<br>For additional liability statutes, see C.G.S.A. §§ 13a-144 to 13a-153e. | No liability for acts which require the exercise of judgment or discretion as an official function of authority granted by law. C.G.S.A. § 52-557n(a)(2).<br>Other statutory exceptions covering particular activities or conditions are set forth in C.G.S.A. § 52-557n(b).<br>No immunity when performing following *governmental* functions:<br>(1) maintenance of a park system;<br>(2) construction of storm water sewers (a governmental function because it is a duty imposed by the state on municipalities to maintain highways within its limits);<br>(3) use of municipal property as a public park; and<br>(4) traditional governmental functions such as the operation of jails, public libraries, and city garbage services. | None |

| STATE | LEGAL AUTHORITY | NOTICE DEADLINES | CLAIMS/ACTIONS ALLOWED | COMMENTS/EXCEPTIONS | DAMAGE CAPS |
|---|---|---|---|---|---|
| **MASSACHUSETTS** | **Massachusetts Tort Claims Act.**<br>M.G.L.A. Ch. 258, § 2 to § 14 (1978).<br>Public employers (county, city, town, etc.) are liable for injury to property or personal injury caused by negligence of public employee in course and scope, in the same manner and to the same extent as a private individual (tort and contract). M.G.L.A. Ch. 258 § 2. | Claim must be presented in writing to executive officer of the public employer within two (2) years after the date upon which the cause of action arose and denied. Failure to act in six (6) months is deemed denial.<br>Exceptions:<br>(1) Plaintiff led to believe that presentment not an issue;<br>(2) Actual notice.<br>M.G.L.A. Ch. 258 § 4.<br>No civil action can be brought more than three (3) years after accrual.<br>M.G.L.A. 258 § 4. | Public premises owner owes duty of reasonable care to all persons lawfully on premises. *Doherty v. Belmont*, 485 N.E.2d 183 (Mass. 1985).<br>***Public Duty Rule***: The public duty doctrine is considered when an individual alleges that law enforcement personnel or other government employees are liable for injuries due to a breach of a legal duty. Unless the employee created or enhanced a risk or had a special relationship with the plaintiff, there is no recovery because the duty owed by the government to its citizens is to the public generally and not to citizens individually. *Judson v. Essex Agricultural and Technical Institute*, 635 N.E.2d 1172 (Mass. 1994). | Public employer not liable for any claim based upon an act or omission as follows:<br>(1) in the execution of a statute; or<br>(2) *discretionary* acts; or<br>(3) arising out of an intentional tort, assault, libel, slander, or misrepresentation; or<br>(4) negligent inspection of property.<br>See other exceptions at M.G.L.A. 258 § 10.<br>Discretionary function two-step test:<br>(1) Is there discretion as to what course of conduct to follow?<br>(2) Is it the type of discretion for which the Act provides immunity?<br>*Fortenbacher v. Com.*, 888 N.E.2d 377 (Mass. 2008). | Liability of public employer may not exceed $100,000 for each plaintiff.<br>Public employer not liable to levy or execution or for interest prior to judgment or for punitive damages.<br>Claims against the Massachusetts Bay Transportation Authority are not subject to the $100,000 limit.<br>M.G.L.A. Ch. 258, § 2. |

| STATE | LEGAL AUTHORITY | NOTICE DEADLINES | CLAIMS/ACTIONS ALLOWED | COMMENTS/EXCEPTIONS | DAMAGE CAPS |
|---|---|---|---|---|---|
| **NEW HAMPSHIRE** | **Bodily Injury Actions Against Governmental Units.**<br>N.H. Rev. Stat. §§ 507-B:1 to 541-B:11.<br>Municipal and county common law immunity abolished in *Merrill v. City of Manchester*, 332 A.2d 378 (N.H. 1974) (liability same as that of private corporation). | Notice of Claim must be filed within sixty (60) days of discovery of injury.<br>Suit must be filed within three (3) years of injury or damage.<br>N.H. Rev. Stat. § 507-B:7. | **General Grant of Immunity.**<br>No "governmental unit" liable except as provided in Chapter 507-B. N.H. Rev. Stat. § 507-B:5.<br>Although it doesn't address it, "discretionary function immunity:(*discretionary* vs. *ministerial*) has been regularly applied by courts:<br>• Decision to lay out roads;<br>• Traffic control; and<br>• Setting road maintenance.<br>*Maryea v. Velardi*, 135 A.3d 121 (N.H. 2016).<br>Statute doesn't completely occupy the field of municipal immunity. | Exceptions to immunity:<br>"Governmental Unit" liable for damages *arising out of ownership, occupation, maintenance or operation of all motor vehicles, and all premises.** N.H. Rev. Stat. § 507-B:2.<br>*No liability for snow, ice, or other weather hazards on premises owned, occupied, maintained, or operated, unless gross negligence. N.H. Rev. Stat. § 507-B2-b.<br>"Governmental unit" means any political subdivision. N.H. Rev. Stat. § 507-B:1(I).<br>"Political subdivision" means any village district, school district, town, city, county or unincorporated place in the state. N.H. Rev. Stat. § 541-B:1(VI). | $275,000 Per Person<br>$925,000 Per Occurrence<br>N.H. Rev. Stat. § 507-B:4. |

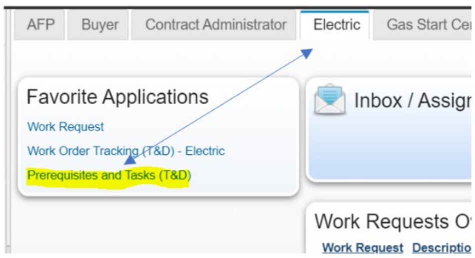
# APPENDIX

1. ALTERNATE TO PRE245-VARIANCE PORTLET

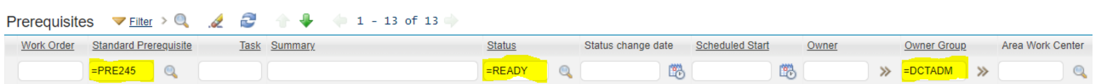
**NOTE**

If Maximo portlets are not working properly and provides a list of active PRE245-Variance Reconciliation, SKIP to step 2.6.4.

1.1.1 NAVIGATE to Prerequisites and Tasks (T&D) module in Maximo.




1.1.2 FILTER to active PRE245 – Variance Reconciliation for your owner group.




| Territory | Owner Group |
|---|---|
| Connecticut Electric | DCTADM |
| Eastern Mass Electric | DEMADM |
| Western Mass Electric | DWMADM |
| New Hampshire Electric | DNHADM |

1.1.3 EXPORT the list of work orders to excel by clicking on the symbol all the way over on the top righthand side just above the filters.

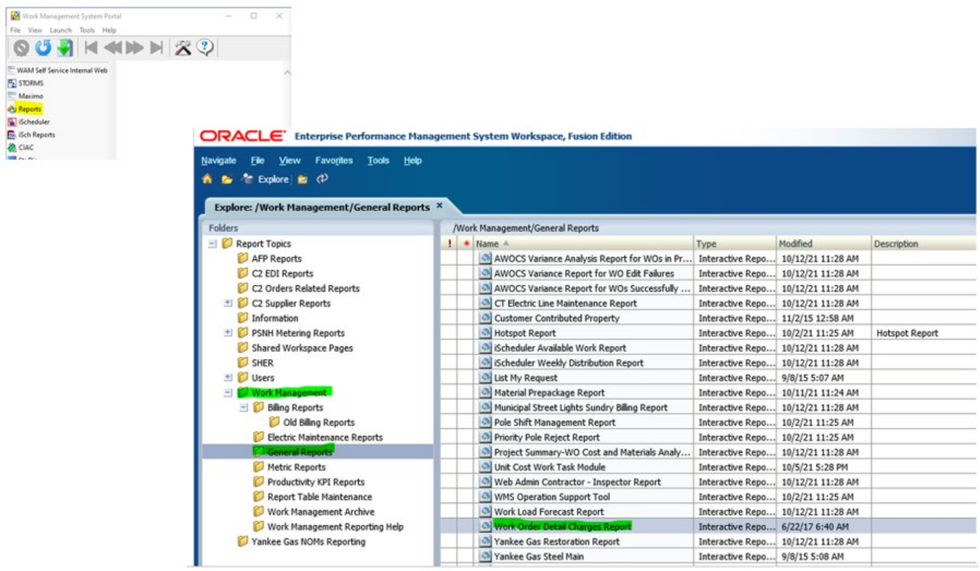
1.1.4 Using the exported file as a work list, NAVIGATE to the Material Variance sub-tab in the Actuals tab in Maximo for each work order and perform the following:

2. USING HYPERION DETAIL OF CHARGES TO COMPARE WITH WMBS BILL.

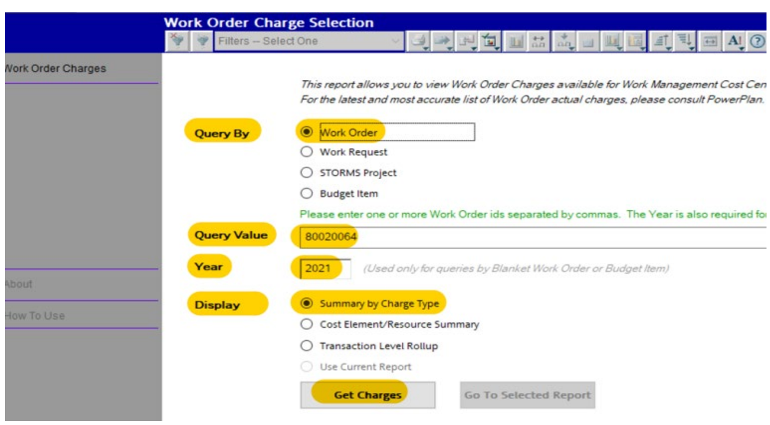
2.1.1 VALIDATE all charges in the Hyperion Detail of Charges have been applied to the work order.

a. NAVIGATE to Reports in the Work Management Portal.

b. EXPAND Work Management Folder then OPEN General reports and finally CLICK on Work Order Detail Charges Report.




c. ENTER the criterion for the query and CLICK Get Charges button where Query Value is the FWO and Year is the date of the incident.




| **NOTE** |
| --- |
| The AFUDC charge does not get included in any totals. |

Work Order Charges

Home

Hyperion Report

Quick Picks | 2.1 Summary by Charge Type and Sub Type

| Charge Type | Sub Type | Quantity | Hours | Mib Direct Amount | Amount |
|---|---|---|---|---|---|
| Loaders | AFUDC | | | 3.36 | 3.36 |
| | AS&E | | | 0.00 | 17.66 |
| | Other | | | 0.00 | 39.20 |
| NU Equipment | Construction | | 0 | 0.00 | 242.17 |
| NU Labor | Construction | | 13.25 | 595.46 | 973.97 |
| | Design | | 2.5 | 145.65 | 238.23 |
| Other Costs | | | | 0.00 | 490.00 |

Loaders = Other Charges on Billing Report = AS&E + Other
17.66 + 39.20 = 56.86

NU Equipment = Transportation Vehicles on Billing Report

NU Labor = Labor on Billing Report
= Construction + Design + Other Costs
973.97 +238.23 + 490.00 = 1702.20

WMBS Report

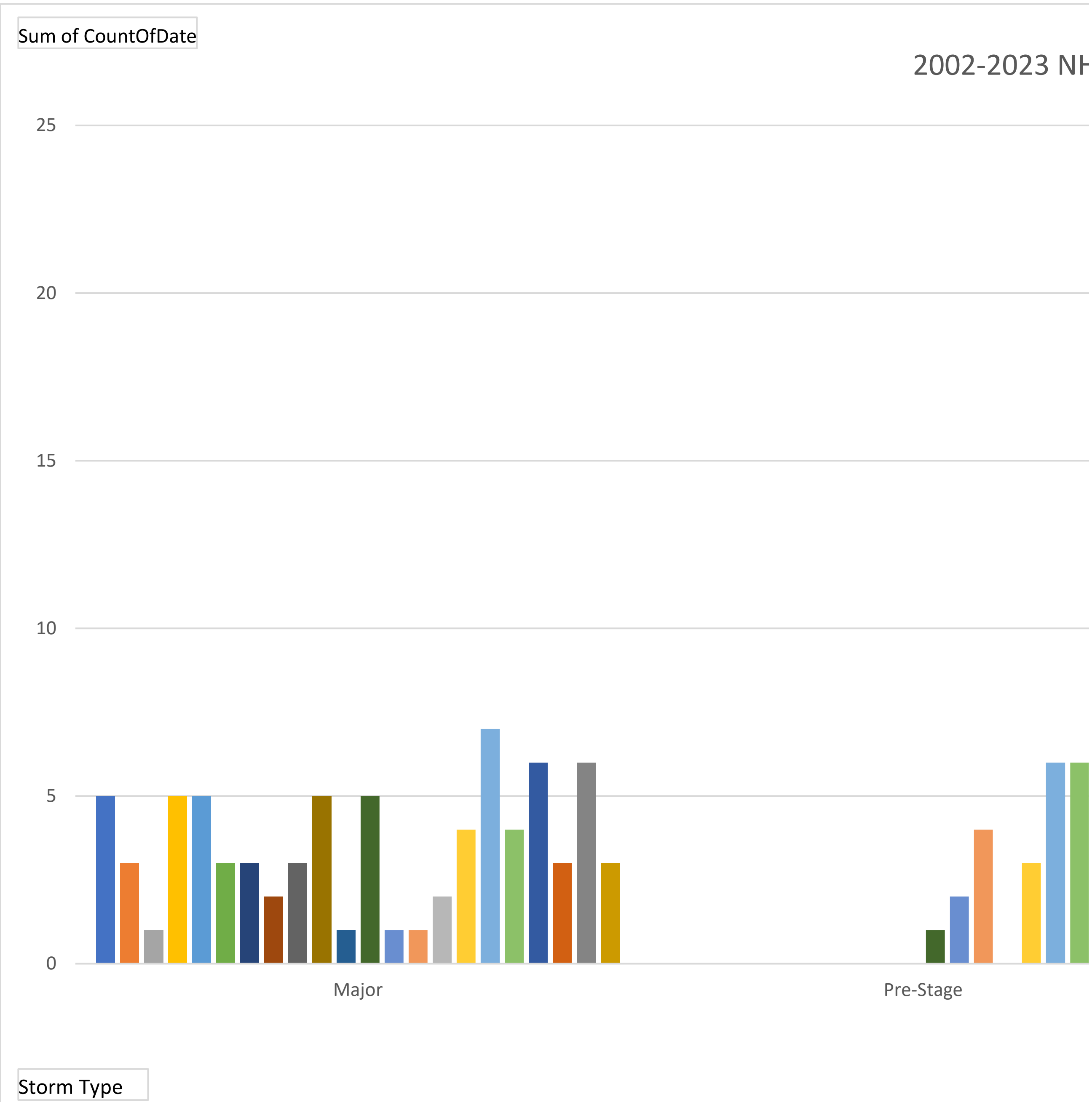
| Charge Group | Charge Description | Hours | | Amount |
|---|---|---|---|---|
| LABOR | BASE RATE | 15.75 Hrs | 5 Empl | $1,702.20 |
| | Sub Total | | | $1,702.20 |
| OTHER CHARGES | ADMINISTRATIVE SERVICES AND EXPENSES | | | $56.86 |
| | Sub Total | | | $56.86 |
| TRANSPORTATION | Vehicles | | | $242.17 |
| | Sub Total | | | $242.17 |
| Total | | | | $2,001.23 |

| Year | Storm Type | CountOfDate |
|---|---|---|
| 2002 | E | 5 |
| 2002 | W | 8 |
| 2003 | E | 3 |
| 2003 | W | 2 |
| 2004 | E | 1 |
| 2004 | W | 7 |
| 2005 | E | 5 |
| 2005 | W | 5 |
| 2006 | E | 5 |
| 2006 | S | 1 |
| 2006 | W | 6 |
| 2007 | E | 3 |
| 2007 | S | 2 |
| 2007 | W | 6 |
| 2008 | E | 3 |
| 2008 | S | 3 |
| 2008 | W | 16 |
| 2009 | E | 2 |
| 2009 | W | 2 |
| 2010 | E | 3 |
| 2010 | S | 11 |
| 2010 | W | 12 |
| 2011 | E | 5 |
| 2011 | S | 3 |
| 2011 | W | 5 |
| 2012 | E | 1 |
| 2012 | S | 10 |
| 2012 | W | 10 |
| 2013 | E | 5 |
| 2013 | P | 1 |
| 2013 | S | 12 |
| 2013 | W | 6 |
| 2014 | E | 1 |
| 2014 | P | 2 |
| 2014 | S | 14 |
| 2014 | W | 8 |
| 2015 | E | 1 |
| 2015 | P | 4 |
| 2015 | S | 6 |
| 2015 | W | 5 |
| 2016 | E | 2 |
| 2016 | S | 8 |
| 2016 | W | 12 |
| 2017 | E | 4 |
| 2017 | P | 3 |
| 2017 | S | 14 |

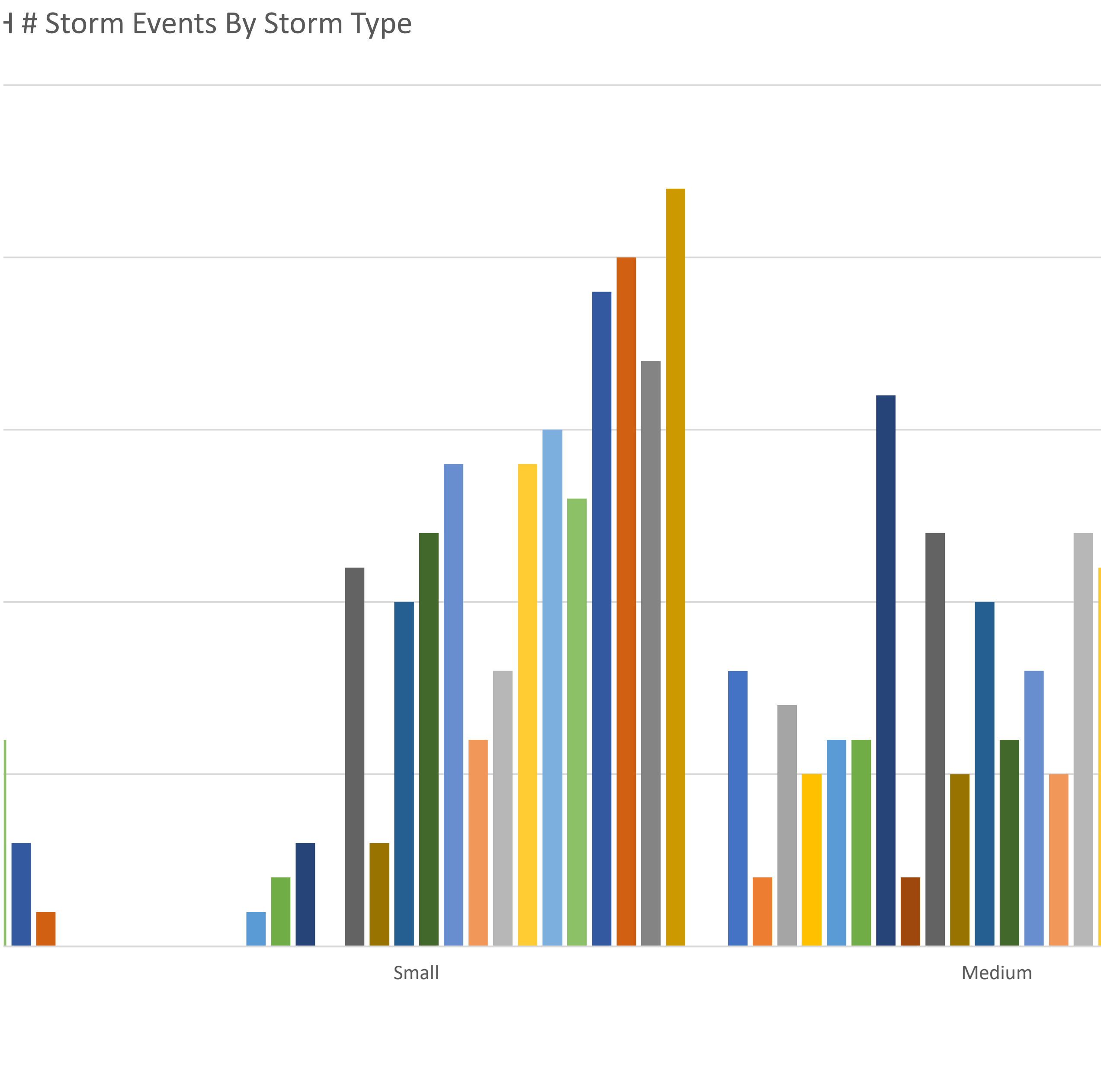
| Key |
|---|
| E=Major - IEEE MED (Major Event Day) |
| P=Pre-Stage |
| S=Small |
| W=Medium (WO) |

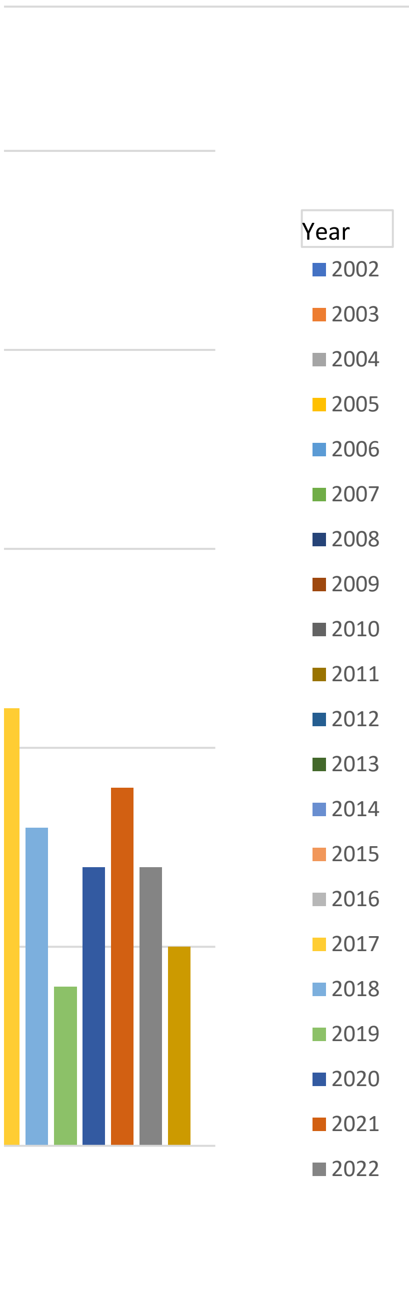
| | | |
|---|---|---|
| 2017 | W | 11 |
| 2018 | E | 7 |
| 2018 | P | 6 |
| 2018 | S | 15 |
| 2018 | W | 8 |
| 2019 | E | 4 |
| 2019 | P | 6 |
| 2019 | S | 13 |
| 2019 | W | 4 |
| 2020 | E | 6 |
| 2020 | P | 3 |
| 2020 | S | 19 |
| 2020 | W | 7 |
| 2021 | E | 3 |
| 2021 | P | 1 |
| 2021 | S | 20 |
| 2021 | W | 9 |
| 2022 | E | 6 |
| 2022 | S | 17 |
| 2022 | W | 7 |
| 2023 | E | 3 |
| 2023 | S | 22 |
| 2023 | W | 5 |

| Sum of CountOfDate | Column Labels | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Row Labels** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** |
| Major | 5 | 3 | 1 | 5 | 5 | 3 | 3 | 2 | 3 | 5 | 1 |
| Pre-Stage | | | | | | | | | | | |
| Small | | | | | 1 | 2 | 3 | | 11 | 3 | 10 |
| Medium | 8 | 2 | 7 | 5 | 6 | 6 | 16 | 2 | 12 | 5 | 10 |
| **Grand Total** | **13** | **5** | **8** | **10** | **12** | **11** | **22** | **4** | **26** | **13** | **21** |

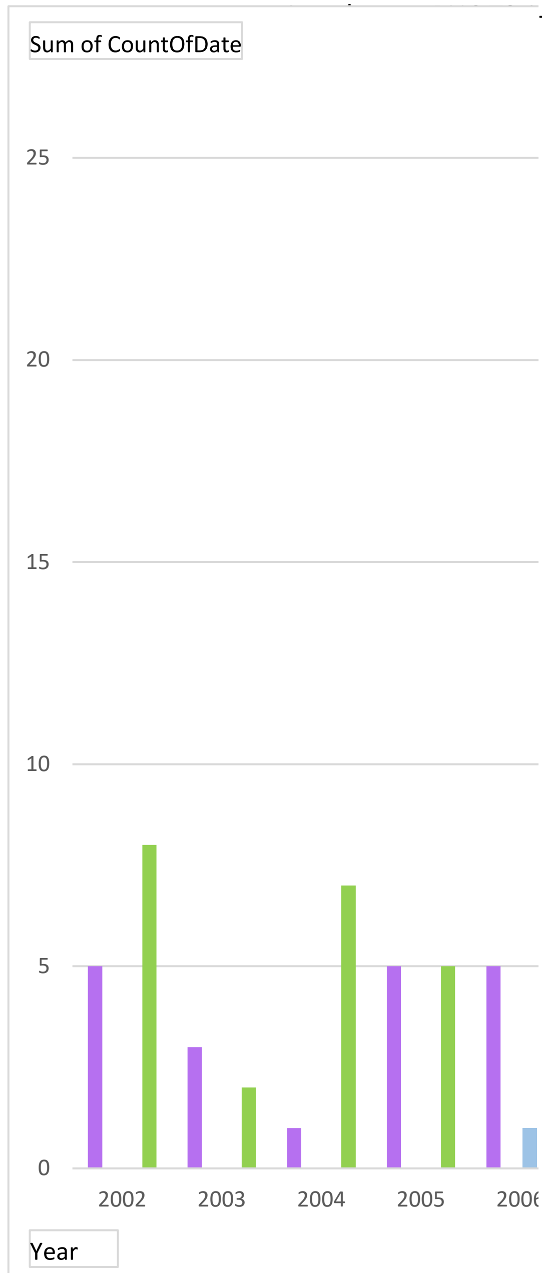


| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | Grand Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 5 | 1 | 1 | 2 | 4 | 7 | 4 | 6 | 3 | 6 | 3 | 78 |
| 1 | 2 | 4 | | 3 | 6 | 6 | 3 | 1 | | | 26 |
| 12 | 14 | 6 | 8 | 14 | 15 | 13 | 19 | 20 | 17 | 22 | 190 |
| 6 | 8 | 5 | 12 | 11 | 8 | 4 | 7 | 9 | 7 | 5 | 161 |
| **24** | **25** | **16** | **22** | **32** | **36** | **27** | **35** | **33** | **30** | **30** | **455** |

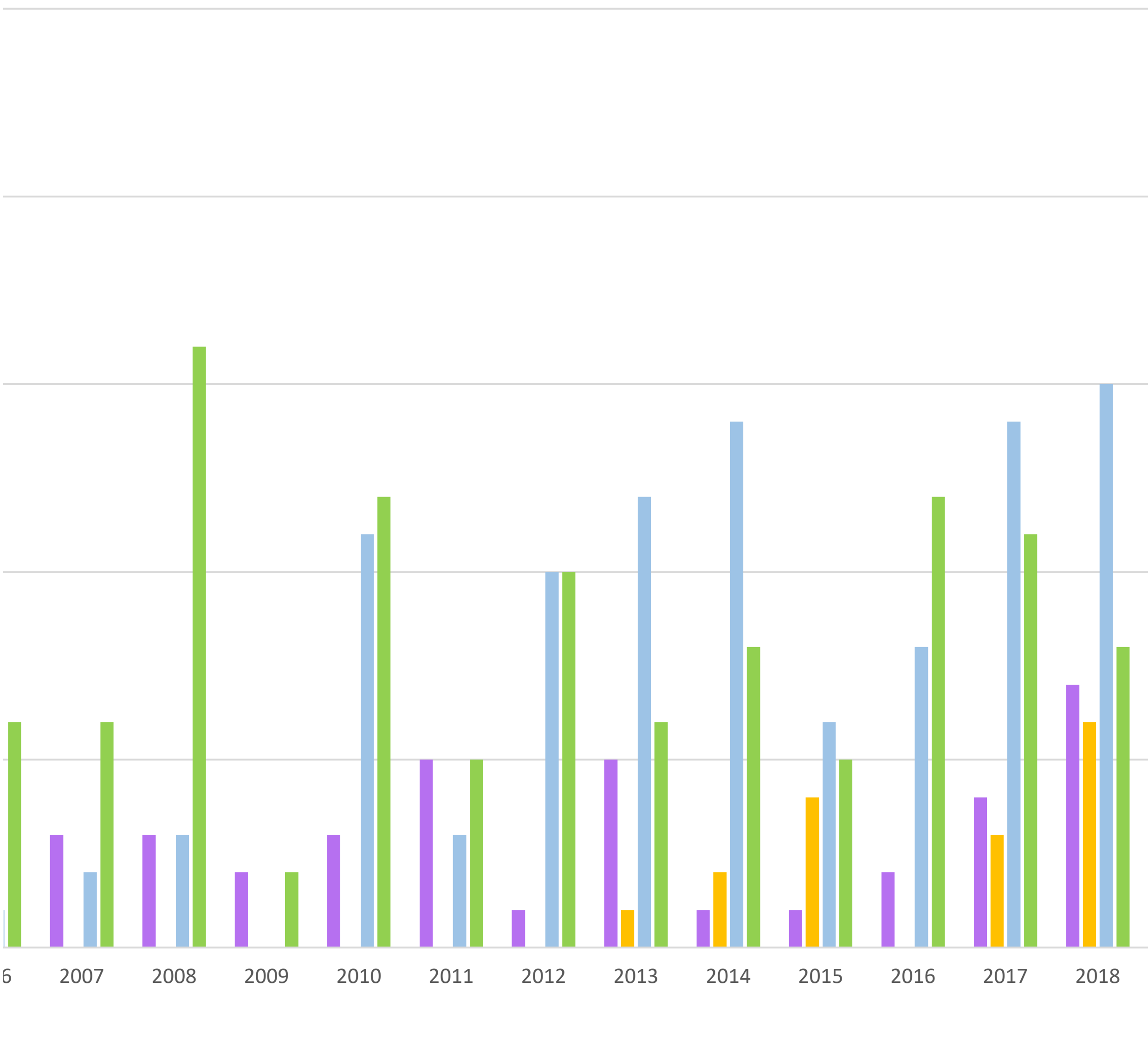


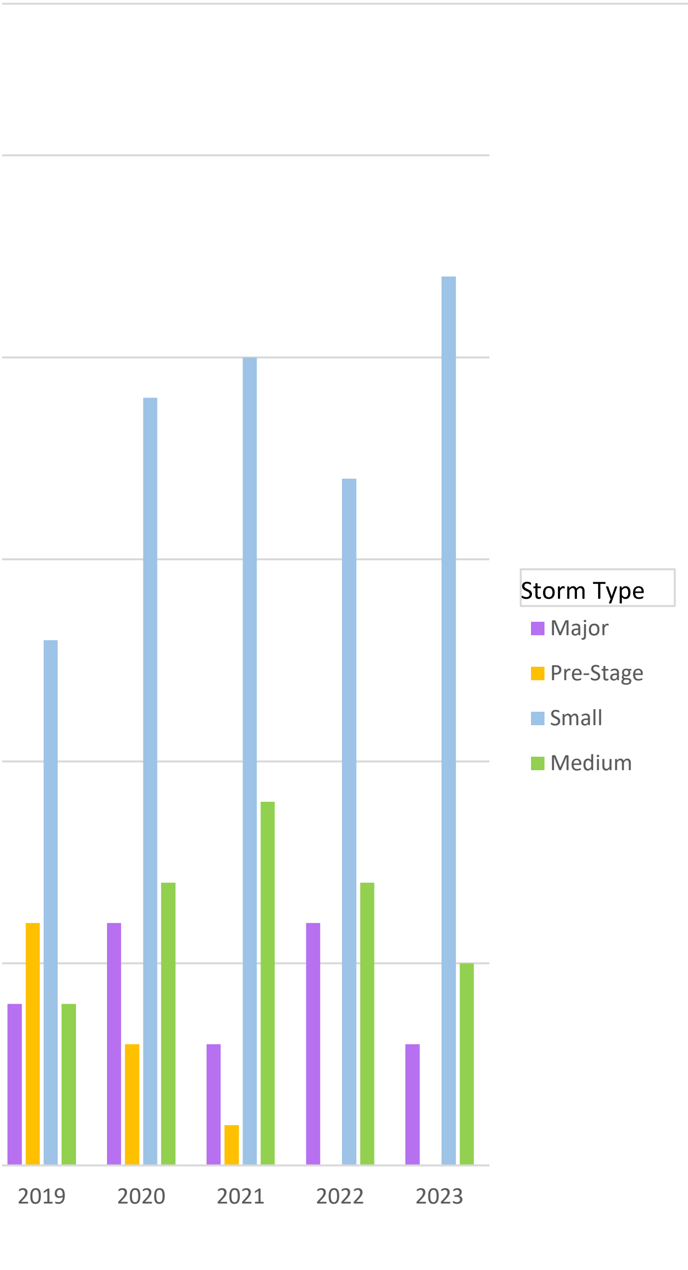

Year
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022

| Sum of CountOfDate | Column Labels | | | | |
|---|---|---|---|---|---|
| Row Labels | Majo | Pre | Sma | Medium | Grand Total |
| 2002 | 5 | | | 8 | 13 |
| 2003 | 3 | | | 2 | 5 |
| 2004 | 1 | | | 7 | 8 |
| 2005 | 5 | | | 5 | 10 |
| 2006 | 5 | | 1 | 6 | 12 |
| 2007 | 3 | | 2 | 6 | 11 |
| 2008 | 3 | | 3 | 16 | 22 |
| 2009 | 2 | | | 2 | 4 |
| 2010 | 3 | | 11 | 12 | 26 |
| 2011 | 5 | | 3 | 5 | 13 |
| 2012 | 1 | | 10 | 10 | 21 |
| 2013 | 5 | 1 | 12 | 6 | 24 |
| 2014 | 1 | 2 | 14 | 8 | 25 |
| 2015 | 1 | 4 | 6 | 5 | 16 |
| 2016 | 2 | | 8 | 12 | 22 |
| 2017 | 4 | 3 | 14 | 11 | 32 |
| 2018 | 7 | 6 | 15 | 8 | 36 |
| 2019 | 4 | 6 | 13 | 4 | 27 |
| 2020 | 6 | 3 | 19 | 7 | 35 |
| 2021 | 3 | 1 | 20 | 9 | 33 |
| 2022 | 6 | | 17 | 7 | 30 |
| 2023 | 3 | | 22 | 5 | 30 |
| **Grand Total** | **78** | **26** | **190** | **161** | **455** |



2002-2023 NH # Storm Events By Storm Type




2019
2020
2021
2022
2023
Storm Type
Major
Pre-Stage
Small
Medium