Public Service Company of New Hampshire d/b/a Eversource Energy
Docket No. DE 22-030

Date Request Received: May 26, 2022 | **Date of Response: June 09, 2022**
Data Request No. DOE 1--008 | **Page 1 of 1**

Request from: Department of Energy

Witness: Plante, David L

Request:

For the project listed below, please provide the Pre-construction Authorization PAF and any Supplemental PAF. If not listed on the PAFs, indicate and describe what alternatives were considered, including NWAs. Additionally, please specify the percentage of total project costs contributed by each of the following: competitively bid, sole sourced, preferred supplier contracts, internal resources, internal indirect charges, and other.
Emerald Street Substation No. A14W01

Response:

Please see Attachment DOE 1-7 (A), Table 1 for the detail on specific total project costs contributed by each of the required cost classifications. Table 2 in Attachment DOE 1-7 (A) provides a description of the alternatives considered, including NWAs, if applicable.

Please see Attachment DOE 1-8 for the PAF for this project.

Supplement Request Form

Approved at May 03, 2019 EPAC

Link to Meeting Minutes

Date Prepared: April 17, 2019	**Project Title: Emerald Street Substation Rebuild**
Company/Companies: Eversource NH	**Project ID Number: A14W01**
Organization: NH Operations	**Plant Class / (F.P. Type): Distribution Substation**
Project Initiator: Thelma Brown	**Project Type: Specific**
Project Manager: Alan Roe	**Capital Investment Part of Original Operating Plan? Y**
Project Sponsor: John Zicko	**O&M Expenses Part of the Original Operating Plan? N/A**
Current Authorized Amount: $11,011K	**Estimated in service date(s): December 31, 2020**
Supplement Request: $5,824K	**PAC: Not Required**
Total Request: $16,835K	**TCA: Not Required**

Supplemental Justification

Distribution Project

In September 2014, TPS-14-165-NH was approved for the construction of a new North Keene substation and the rebuild of Emerald Street substation in Keene, NH. North Keene substation was placed in service in October 2016. TAF # NH-160001-TDS Rev. 0 requested $1,000K for preliminary engineering to rebuild the Emerald Street substation and was approved in PowerPlan on December 19, 2016. A PAF for equipment purchase and additional approved engineering was approved $5.3M in PowerPlan on June 5, 2017. A PAF for full funding for the Distribution portion of the Emerald Street rebuild project was approved in PowerPlan on December 12, 2017 for the current authorized amount of $11,011K.

The original Distribution scope of work, which has not significantly changed, includes the removal of (4) four (of five) transformers, the installation of (2) two new 115/12.47kV transformers, the removal of the existing 12.47kV switchgear, and the installation of new metalclad switchgear along with new protection and control equipment.

Transmission Project

Approval to proceed with the Transmission portion of the rebuild of Emerald Street was provided in October 2017. $50K was approved for preliminary engineering for the Transmission portion of the project to rebuild the Emerald Street substation on February 14, 2017. On April 25, 2018, the PAF for full funding for the Emerald Street rebuild project was approved at EPAC. The project was approved in PowerPlan on June 14, 2018 for the current authorized amount of $1,664K.

The original Transmission scope of work included the installation of three (3) 115kV CCVTs, the replacement of the existing primary bus differential relay, and the addition of a secondary bus differential relay.

In October 2018, it was proposed to expand the scope of the project to include the replacement of several obsolete relays and to add a single 115kV line tie circuit breaker. The relays were added to the scope because the Emerald Street 115kV protection scheme includes several electromechanical relays identified as obsolete by the Eversource Asset Strategy Program for protective relays (RF-AS-9017, Rev. 3). Additionally, the 115kV bus protection and breaker failure schemes are a legacy design that do not meet the current standard.

The addition of a single 115kV line tie was proposed because during the development of the construction outage sequence, the Electric System Control Center (ESCC) highlighted the risk of unacceptable loss of customer load for an N-1-1 contingency. To mitigate this risk, a sub-set of the project team from System Planning, Substation Engineering, Operations, and Project Management proposed a 115kV line tie between the A152 and D108 lines to address these SCLL issues. The permanent line tie circuit breaker replaces a temporary line tie circuit switch which was installed but subsequently removed.

When System Planning studies scheduled outages in the short-term, cascading load (offloading an affected area to increase local system capacity for restoration efforts) is acceptable as the review is of an N-1-1 scenario. Current system planning criteria for N-1 distribution studies does not allow cascading load transfers and directs system improvements based on system restrictions found. Restoration switching for contingencies during an Emerald Street Substation 115 kV Bus 2 outage was reviewed with and without cascading switching. When a planned outage occurs between Greggs and Emerald Street, the ESCC (Electric System Control Center) usually institutes some pre-contingent switching to reduce customer exposure. The following review looked at the system as-is without any pre-contingent switching.

Greggs F162 Contingency – 36,952 customers affected (84 MW)

Loss of Weare, Jackman, North Keene, and Emerald Street 115 kV Bus 1

Cascading load not allowed: All customers can be restored during every season except summer (June-early September) (ISO loading at or less than 17,500 MW) with at most 25 switching actions. At summer peak, approximately 7,983 customers would remain without power.

Cascading load allowed: Due to line overloads and system voltage below limits, cascading load does not provide additional benefit.

Vernon K186/N186 Contingency – 10,267 customers affected (24 MW)

Loss of Chestnut Hill and Swanzey

Cascading load not allowed: All customers fed from Swanzey can be restored with at most 4 switching actions during summer peak load levels. However, due to Chestnut Hill's location, it does not have any 34.5 kV circuit ties to other sources. 6,878 customers would remain without power.

Cascading load allowed: Chestnut Hill remaining isolated is a transmission source issue. The ability to cascade load or not does not apply to this contingency scenario.

Monadnock T198 Contingency – 3,449 customers affected (25 MW)

Loss of Emerald Street 115 kV Bus 3

Cascading load not allowed: With not all breakers at Emerald Street having SCADA control, 1,771 customers cannot be restored until manual switching at Emerald Street is performed. With manual switching, all customers can be restored following loss of the T198 source to 115 kV Bus 3.

Cascading load allowed: The lack of SCADA control on the W2A and W9A reclosers at Emerald Street Substation prohibit full restoration of all customers. Being able to cascade load would bear no impact on this issue.

To address the above findings, it is proposed to continue with the Distribution project as planned based on the approved PAF dated 9/25/17. The scope of the Transmission project would be expanded to add a 115kV circuit breaker tie between the A152 and D108 lines plus two additional circuit breakers added in the 115kV bus to replace existing switches. These two bus tie breakers will be operated via SCADA for switching operations only and will not be tied into the existing bus protection systems. The addition of 115kV bus tie breakers at the Keene substation improves customer reliability and ease of maintenance. For any single bus contingency, all customers can be restored via SCADA switching within 5 minutes. Without bus tie breakers, the single bus SCLL strands approximately 2500 customers due to distribution limitations. Ease of maintenance is increased when a bus section is required OOS. Without bus tie breakers, removing a section of bus from service requires offloading multiple transformers. The revised scope was approved by the chair of the Solution Design Committee on March 26, 2019.

While the addition of the proposed 115kV line tie will only be used during construction and for maintenance, ISO-NE will require a new I.3.9 submission. This has been discussed with ISO-NE and no issues are anticipated. The additional bus tie breakers will not be provided with protective relaying and therefore create no new contingencies. As such an I.3.9 submission is not required for the bus tie addition. All work at Emerald Street is classed as Local and no TCA is required.

A supplemental request for an additional $3,930K for a total request of $5,594K for the Transmission portion of the Emerald Street project accompanies this document. The scope of work for the Transmission project now includes the installation of three (3) 115kV CCVTs and a second 115kV bus differential relay, the replacement of the existing 115kV bus differential relay, the replacement of various obsolete relays and the installation of three (3) 115kV circuit breakers, associated disconnects and protection and control equipment.

The operational requirement for the line and bus tie breakers increased the cost of the Transmission project. It also impacted the cost of the Distribution project because it requires the creation of multiple engineering drawing packages and extends the duration of the project.

Project Status

As of the end of March 2019, the project has invested $6,082K with additional commitments of $2,500K for work done but not yet invoiced. Commitments include $1,061K for remaining switchgear payments due in April 2019. Total spend to-date plus commitments is approximately $8,582K out of $11,011K authorized.

Civil and electrical IFC drawings have been issued to the Contractor and construction started on January 7, 2019. The new switchgear arrived on site on April 10, 2019 and the two (2) replacement transformers have been delivered to the site.

This supplement requests approval of $5,824K for a total request of $16,835K, an increase of 46% over the current authorized amount. The primary driver for the additional cost is due to unforeseen construction costs, the need to split the P&C drawings into several phases due to an extended outage schedule and associated additional labor costs due to a longer construction schedule. The details for the increase are explained below.

Cumulative effect of Changes since September 2017

Justification for Additional Resources

The reasons for the project authorization supplement of $5,824K are summarized below:

1) **Company Labor ($202K):** The original construction schedule was based on an in-service date of December 2018. With the requirement to construct a new 115kV line tie for the transmission portion of the project, the project duration has increased and the final in-service date for the Distribution portion of the project is now December 2020. The longer construction schedule increases the amount of time needed for Construction supervision and safety coverage. It also increases the amount of Engineering time needed to review and comment on multiple drawing packages.

2) **Project Management ($62K):** The estimate for Project Management services in September 2017 was based on the hours needed to complete the project in December 2018. Because the Transmission portion of the project scope has expanded, the construction sequence for the Distribution portion of the project was extended until December 2018**.** The forecasted PM costs have increased from $125K to $187K.

3) **Engineering ($299K)**: The estimate for Engineering design has increased from $460K to $759K due to the need to generate multiple IFC drawing packages associated with the phased approach needed to incorporate the 115kV line tie into the overall project scope. Initially a single construction sequence was envisaged which only required one-set of P&C drawings. Because it was not operationally acceptable to take 115kV Bus 1 and Bus 2 outages, an additional 115kV line tie breaker is needed. This work will create a significant break in the schedule and requires multiple sets of P&C drawings. The original scope of work for the engineering design vendor did not include these multiple drawing revisions. In addition, due to the location of abandoned cables a duct bank design needed to be revised. Other unforeseen changes include:

    - Eversource contracted Leidos Engineering to provide the engineering design for the Emerald Street rebuild project. This included all engineering to interface with the AZZ metal clad switchgear design. As the project developed, it became clear that fifty-two drawings beyond those originally provided to AZZ would need to be updated by Leidos to allow AZZ to develop their design. This work was outside of Leidos' original scope.

- VHB was contracted to provide the site plans for the project, but the detailed design of the fence and additional retaining wall was not included in either VHBs or Leidos' scope of work. It was agreed to request Leidos to incorporate this into their contract as they had all the site civil drawings under their control.
- Eversource provided AZZ with conceptual P&C application diagrams as part of the bid specification. The intention was that AZZ would take the application drawings provided by Leidos and complete them as part of their scope. However, AZZ did not have the capability to update the application diagrams and Leidos was requested to complete the application drawings. Prior to final payment we will request AZZ credit the cost of completing these drawings.

The estimate for Engineering has also been increased to meet the request for the P&C Engineers on the project team to bring an Owner's Engineer on to the project to review P&C designs.

4) **Construction ($2,434K):** In the September 2017 PAF, the forecasted cost for construction was estimated at $2,379K. The contracted price was higher than forecast due to the complexity of the construction sequence and several unforeseen items that were not captured in the original construction contract scope of work, including:

- Additional exploratory vacuum excavation was required to safely locate live 12.47kV cables and abandoned power and control cables near a proposed new duct bank;
- Winter work caused by delaying the start of construction from September 2018 to January 2019. The delay was required due to internal budget constraints;
- Installation of temporary services for the switchgear and transformers. To test and commission the new switchgear, a temporary service is needed to provide light, HVAC and to power the battery chargers. To prevent damage due to moisture, temporary power to the four heaters in each of the two new transformers is required;
- Additional grounding needed outside the substation fence to avoid potential step and touch issues;
- Because the construction contract was issued using 70% design documents, there was an adjustment to the quantity of materials between the drawings issued for bidding and the final issued for construction drawings. The additional materials also require additional labor for installation;
- Ground heating for soil sampling. The number and location of soil samples for pre-characterization were based on the 70% design drawings and estimated foundation depths. Once detailed foundation drawings were issued, and additional foundations were identified for the line and bus tie breakers, additional samples were needed. Because of the schedule it was necessary to heat frozen ground so that the samples could be taken prior to excavation and soil removal;

- Soil Management & Disposal – during project development, contaminated soils were confirmed relative to planned excavations which increased forecasted soil management and disposal costs. $134K was previously budgeted for soil management; however, this forecast has since been increased to $190K for the preparation of the soil management plan, site inspections during construction and disposal of contaminated soils. Additional contaminants and hazardous materials on site that have been or are expected to be removed or remediated include: Transite pipe, asbestos sheets, asbestos coated wiring, abandoned lead sheathed cable and petroleum contaminated groundwater;
- Lifting & handling – the two transformers were delivered in March 2018 based on the originally planned in-service date of December 2018. With the overall schedule delays the transformers will have to be stored temporarily and moved a second time. The cost to move the new transformers a second time was not anticipated in September 2017. Based on proposals received, $222K is included in the current forecast to move the new transformers from their temporary storage position to their permanent location. This forecast also includes the cost to remove the old transformers and switchgear prior to scrapping; and
- Permitting support – the cost to support the development of the site plans has increased from an estimated $50K in September 2017 to $115K. The increase is due to the addition of a pre-construction sound survey, a ground penetrating radar survey and additional design for the proposed retaining wall. Permitting also includes weekly environmental compliance monitoring during construction which is required to ensure the Contractor is complying with all mandatory environmental legislation and permit requirements. Incremental request $65K.

The current construction forecast also includes $250K for potential future change orders, final landscaping, control building renovations, paving and potential de-watering.

5) **Testing ($1,276K):** The cut-over schedule currently has more than 50 weeks of back-to-back outages which is longer than previously indicated in the schedule issued for bidding purposes. Additionally, the P&C engineering team proposed the use of a load bank to test the polarity and ratio of the current transformers prior to in-service load testing. The rental of the load bank adds to the testing costs and was not anticipated in September 2017. The role of the testing contractor has expanded in recent years, which although reduced the number of unwanted trips, it has resulted in the cost for testing services increasing beyond those anticipated in September 2017.

6) **Commissioning ($351K):** With the complexity of the cut-over sequence, the services of a Lead Commissioning Engineer (LCE) were secured early to assist with construction sequencing, reviewing design documents to ensure constructability, identifying the outage requirements and reviewing testing plans, etc. Bringing the LCE on to the project much earlier in the sequence was not anticipated in the September 2017 PAF. The current forecast has been increased to $601K to cover LCE support prior to construction and during the construction, testing and commissioning phase.

7) **Material (-$1,025K):** The September 2017 forecast for materials was high. There are small increases in the switchgear and transformer costs compared to the 2017 forecast, but these increases are offset by reductions in cable costs and other miscellaneous material cost reductions. Because of the delays to the project, the new transformers have been filled with oil temporarily which incurred an additional $66K for oil and labor.

8) **Removal ($161K):** Since September 2017, the estimate for removal costs has increased to better reflect the amount of material to be removed (switchgear, steelwork, redundant wood poles, transformers and associated oil removal). The original forecast also included a credit of $50K for investment recovery which is no longer anticipated. It is likely to cost more to scrap all the materials than we would recover from salvage costs.

9) **Miscellaneous (-$33K):** The September 2017 forecast included $206K for miscellaneous project charges including employee expenses (accommodation, meals, etc.). The miscellaneous forecast has been reduced at this stage.

10) **Property Tax ($444K):** In September 2017 property taxes were not included in the project estimate. To date, the project has incurred $174K in property taxes with a further $270K estimated through November 2020.

Total incremental request for direct costs **$4,171K**

11) **Indirect costs ($1,455K):** In the September 2017 PAF, indirect costs were forecasted to be $1,824K. To date, the project has incurred $1,709K in adders and is expected to incur an additional $1,570K to the end of the project. The indirect cost increase is primarily driven by the increase in direct costs.

12) **AFUDC ($199K):** In the September 2017 PAF, AFUDC charges for the project were originally estimated at $174K. Actual AFUDC charges incurred to date are $55K with an additional $318K forecast for the remainder of the project.

Total incremental request for indirect costs **$1,654K**, resulting in an overall Supplement Request of **$5,824K**.

Please see the previously authorized documents attached.

Supplement Cost Breakdown (Local Costs)

Note: Dollar values are in thousands:

Line item Category	Original Estimate ($K)	New Estimate ($K)	Variance ($K)
1) Internal Labor	128	330	202
2) Project Management	125	187	62
3) Engineering	460	759	299
4) Construction	2,379	4,813	2,434
5) Testing	250	1,526	1,276
6) Commissioning	250	601	351
7) Material	4,829	3,804	(1,025)
8) Removal	385	546	161
9) Miscellaneous	206	173	(33)
10) Property taxes	0	444	444
Total Directs	**9,012**	**13,183**	**4,171**
11) Indirect	1,824	3,279	1,455
12) AFUDC	174	373	199
Total Indirect	**1,998**	**3,652**	**1,654**
Total ($K rounded)	**11,011**	**16,835**	**5,824**

Supplement Cost Summary (Local Costs)

Note: Dollar values are in thousands:

	Prior Authorized	Supplement Request	Total
Capital Additions - Direct	$8,628	$4,009	$12,637
Less Customer Contribution	$0	$0	$0
Removals net of Salvage ____%	$385	$161	$546
Total Direct Spending	$9,013	$4,170	$13,183
Capital Additions - Indirect	$1,824	$1,455	$3,279
AFUDC	$174	$199	$373
Total Capital Request	$11,011	$5,824	$16,835
O&M	$0	$0	$0
Total Request	**$11,011**	**$5,824**	**$16,835**

Note: Dollar values are in thousands:

Total Supplement Request by year view:

Request by Year	Year 2019	Year 2020	Total
Capital Additions - Direct	$2,000	$2,009	$4,009
Less Customer Contribution	$0	$0	$0
Removals net of Salvage ____%	$0	$161	$161
Total Direct Spending	$2,000	$2,170	$4,170
Capital Additions - Indirect	$728	$727	$1,455
AFUDC	$100	$99	$199
Total Capital Request	$2,828	$2,996	$5,824
O&M	$0	$0	$0
Total Request	**$2,828**	**$2,996**	**$5,824**

Operations Project Authorization Form

Date Prepared: **09/25/17**	Project Title: **Emerald Street**
Company/ies: **Eversource NH**	Project ID Number: **A14W01 (D) & T1347A (T)**
Organization: **NH Operations**	Class(es) of Plant: **Distribution & Transmission**
Project Initiator: **Charles Christensen, PE**	Project Category: **Substation**
Project Manager: **Alan Roe**	Project Type: ***Specific***
Project Sponsor: **James Eilenberger**	Project Purpose: **Replace obsolete equipment**
Estimated in service date: **12/31/18**	If Transmission Project: **Non-PTF**
Eng. /Constr. Resources Budgeted? **Yes**	Capital Investment Part of Original Operating Plan? **Yes**
	O&M Expenses Part of the Original Operating Plan? **No**

Project Authorization

Project authorization must be in accordance with the approval levels included in the Delegation of Authority Policy (DOA).

If Subsidiary Board approval is required, document the review by Enterprise Risk Management (ERM) and Financial Planning and Analysis (FP&A)

ERM: ______________________________

FP&A: ______________________________

Executive Summary

The project scope includes

1) Removing four (4) 115-12.47kV transformers (TB3 will remain)
2) Removing existing 15kV switchgear and associated equipment
3) Install two (2) new 115-12.47kV 30MVA transformers
4) Install nine (9) 115kV CCVTs
5) Install new 15kV switchgear with integral control room and associated systems
6) Adding a second 115kV bus differential protection
7) Replacing obsolete and non-standard 115kV relaying

The joint T&D TAF for this project was approved at the 11/19/16 Technical Review Committee. That approval allowed engineering design to proceed at a cost of $1,000k split $950k (D) and $50k (T).

An initial PAF document was subsequently approved on 03/09/17 for an additional $4,300k to proceed with ordering long lead time materials (transformers and 15kV metal clad switchgear). The Distribution authorized amount was increased from $950k to $5,250k and the Transmission authorized amount remained at $50k.

This PAF now requests full funding of $12,400k (T - $1,400k D - $11,000k) for the project based on known commitments for engineering, Eversource supplied material and firm pricing for the 15kV switchgear. It includes estimates for civil, electrical / P&C construction and Vendor supplied materials. Contingency amounts of $244k and $100k are included in the D & T estimates respectively. The $12,400k estimate is inside the +/-25% of the approved TAF of $10,000k ($7,500 - $12,500).

Since the original TAF, Transmission P&C Engineering has recommended the replacement of several obsolete and non-standard relays at an estimated cost of $750,000. Recommended relay replacements are:

- T1980 breaker failure system: 50/62/BF-T1980: SEL-501 (non-standard breaker failure relay)
- A1520 breaker failure system: 50/BF-A1520: CHC electromechanical BF overcurrent relay; 62/BF-A1520: auxiliary BF timer
- T1980 reclosing system: 79/T1980: ACR electromechanical reclosing relay with 79Y
- A1520 reclosing system: 79/A1520: ACR electromechanical reclosing relay with 79Y
- Currently, all the 115kV breaker failure relays hit a single/shared 86/BF lockout, which is a legacy/non-standard scheme. P&C Engineering recommends replacement with individual lockout coils for each breaker failure relay to match current standards.
- T198 and A152 line relay POTT keying schemes are currently over leased phone lines (via RFL-9745) to Monadnock and Chestnut Hill, respectively. P&C Engineering and Telecommunications Engineering recommend transferring those schemes to the more reliable Eversource fiber.

Based on spend to date, the estimated cost to complete the Distribution portion of the project is $10,820k and $1,354k for Transmission.

Project Costs Summary

See APS3 and APS8 requirements and consult with Plant Accounting for capital/O&M determination. Use published loaders for benefits, materials, and invoices, maintained by the Director, Budget and Internal Reporting.
Note: Dollar values are in thousands

A14W01 *($k)*	**Prior Authorized**	**2017**	**2018**	**Totals**
Capital Additions - Direct	$12	$819	$7,797	$8,628
Less Customer Contribution	$0	$0	$0	$0
Removals net of Salvage___%	$0	$0	$385	$385
Total – Direct Spending	$12	$819	$8,182	$9,013
Capital Additions – Indirect	$0	$197	$1,627	$1,824
Subtotal Request	$12	$1,016	$9,809	$10,837
AFUDC	$0	$3	$171	$174
Total Capital Request	$12	$1,019	$9,980	$11,011
O&M	$0	$0	$0	$0
Total Request	$12	$1,019	$9,980	$11,011

T1347A *($k)*	**Prior Authorized**	**2017**	**2018**	**Totals**
Capital Additions - Direct	$0	$86	$1,253	$1,339
Less Customer Contribution	$0	$0	$0	$0
Removals net of Salvage___%	$0	$0	$60	$60
Total – Direct Spending	$0	$86	$1,313	$1,399
Capital Additions – Indirect	$0	$6	$12	$18
Subtotal Request	$0	$92	$1,325	$1,417
AFUDC	$0	$1	$8	$9
Total Capital Request	$0	$93	$1,333	$1,426
O&M	$0	$0	$0	$0
Total Request	$0	$93	$1,333	$1,426

Prior Distribution authorized amount is for $950k approved at TRC on 11/19/16.
An additional $4,300 for transformer and switchgear purchase was approved at CPAC on 03/09/17.

Prior Transmission authorized amount is $50k that was approved at TRC on 11/19/16.

Financial Evaluation

Provide the following financial information (attach additional detail if summarized items are significant or additional information is needed). Note: Dollar values are in thousands

Distribution Project (A14W01)

Direct Capital Costs	2016	2017	2018	Total
Straight Time Labor	$1	$56	$81	$138
Overtime Labor	$0	$0	$0	$0
Outside Services	$11	$485	$2,969	$3,465
Materials	$0	$276	$4,553	$4,829
Other, including contingency amounts	$0	$2	$579	$581
Total	$12	$819	$8,182	$9,013

Indirect Capital Costs	2016	2017	2018	Total
Indirects/Overheads (including benefits)	$0	$197	$1,627	$1,824
Capitalized interest or AFUDC, if any	$0	$3	$171	$174
Total	$0	$200	$1,798	$1,998

Total Capital Costs	$12	$1,019	$9,980	$11,011
Less Total Customer Contribution	$0	$0	$0	$0
Total Capital Project Costs	**$12**	**$1,019**	**$9,980**	**$11,011**
Total O&M Project Costs	$0	$0	$0	$0

Transmission Project (T1347A)

Direct Capital Costs	2016	2017	2018	Total
Straight Time Labor	$0	$8	$12	$20
Overtime Labor	$0	$0	$0	$0
Outside Services	$0	$77	$1,081	$1,158
Materials	$0	$0	$60	$60
Other, including contingency amounts	$0	$0	$160	$160
Total	$0	$85	$1,313	$1,398

Indirect Capital Costs	2016	2017	2018	Total
Indirects/Overheads (including benefits)	$0	$6	$12	$18
Capitalized interest or AFUDC, if any	$0	$0	$8	$8
Total	$0	$6	$20	$26

Total Capital Costs	$0	$91	$1,333	$1,424
Less Total Customer Contribution	$0	$0	$0	$0
Total Capital Project Costs	**$0**	**$91**	**$1,333**	**$1,424**
Total O&M Project Costs	$0	$0	$0	$0

- Straight time forecast is based on original project estimate.
- Outside services forecast is based on committed contracts (engineering and project management) plus forecast costs for civil, electrical / P&C construction and testing, etc.
- Material costs are based on $1,371k for transformer purchase plus $1,797k for 15kV switchgear. $1,738k for Eversource purchased materials and miscellaneous vendor supplied materials.

This is NOT a new customer project

Future Financial Impacts:

Provide below the estimated future costs that will result from the project:
Note: Dollar values are in thousands:

Future Costs	Year 20__	Year 20__	Year20__	Year 20__+	Total Future Project Costs
Capital	$ -	$ -	$ -	$ -	$ -
O&M	-	-	-	-	-
Other	-	-	-	-	-
TOTAL	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

<u>If this is other than a Reliability Project, please complete the section below; N/A</u>

Provide below the estimated financial benefits that will result from the project:
Note: Dollar values are in thousands:

Future Benefits	Year 20__	Year 20__	Year20__	Year 20__+	Total Future Project Benefits
Capital	$ -	$ -	$ -	$ -	$ -
O&M	-	-	-	-	-
Other	-	-	-	-	-
TOTAL	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Describe the estimated future Capital, O&M and/or Other benefits noted above:

What functional area(s) will these benefits be reflected in?____________________________________
A representative from the respective functional area is required to be included as a project approver.

Asset Retirement Obligation (ARO) and/ or Environmental Cleanup Costs (Environmental Liabilities):

An ARO is a current legal obligation to remove or retire property, plant or equipment at some point in the future. Please refer to APS8 or contact Plant Accounting for further detail.

Is there an ARO associated with this project? If yes, please provide details: **No**

Are there other environmental cleanup costs associated with this project? If yes, please provide details. **Forecast includes $50k for soil disposal based on an assumption of 1,000 tons at $35/ton haulage and $10/ton disposal costs.**

Operations Project Authorization Form

Date Prepared: **09/25/17**	Project Title: **Emerald Street**
Company/ies: **Eversource NH**	Project ID Number: **A14W01 (D) & T1347A (T)**
Organization: **NH Operations**	Class(es) of Plant: **Distribution & Transmission**
Project Initiator: **Charles Christensen, PE**	Project Category: **Substation**
Project Manager: **Alan Roe**	Project Type: ***Specific***
Project Sponsor: **James Eilenberger**	Project Purpose: **Replace obsolete equipment**
Estimated in service date: **12/31/18**	If Transmission Project: **Non-PTF**
Eng. /Constr. Resources Budgeted? **Yes**	Capital Investment Part of Original Operating Plan? **Yes**
	O&M Expenses Part of the Original Operating Plan? **No**

Project Authorization

Project authorization must be in accordance with the approval levels included in the Delegation of Authority Policy (DOA).

If Subsidiary Board approval is required, document the review by Enterprise Risk Management (ERM) and Financial Planning and Analysis (FP&A)

ERM: ____

FP&A: ____

Executive Summary

The project scope includes

1) Removing four (4) 115-12.47kV transformers (TB3 will remain)
2) Removing existing 15kV switchgear and associated equipment
3) Install two (2) new 115-12.47kV 30MVA transformers
4) Install nine (9) 115kV CCVTs
5) Install new 15kV switchgear with integral control room and associated systems
6) Adding a second 115kV bus differential protection
7) Replacing obsolete and non-standard 115kV relaying

The joint T&D TAF for this project was approved at the 11/19/16 Technical Review Committee. That approval allowed engineering design to proceed at a cost of $1,000k split $950k (D) and $50k (T).

An initial PAF document was subsequently approved on 03/09/17 for an additional $4,300k to proceed with ordering long lead time materials (transformers and 15kV metal clad switchgear). The Distribution authorized amount was increased from $950k to $5,250k and the Transmission authorized amount remained at $50k.

This PAF now requests full funding of $12,400k (T - $1,400k D - $11,000k) for the project based on known commitments for engineering, Eversource supplied material and firm pricing for the 15kV switchgear. It includes estimates for civil, electrical / P&C construction and Vendor supplied materials. Contingency amounts of $244k and $100k are included in the D & T estimates respectively. The $12,400k estimate is inside the +/-25% of the approved TAF of $10,000k ($7,500 - $12,500).

Since the original TAF, Transmission P&C Engineering has recommended the replacement of several obsolete and non-standard relays at an estimated cost of $750,000. Recommended relay replacements are:

- T1980 breaker failure system: 50/62/BF-T1980: SEL-501 (non-standard breaker failure relay)
- A1520 breaker failure system: 50/BF-A1520: CHC electromechanical BF overcurrent relay; 62/BF-A1520: auxiliary BF timer
- T1980 reclosing system: 79/T1980: ACR electromechanical reclosing relay with 79Y
- A1520 reclosing system: 79/A1520: ACR electromechanical reclosing relay with 79Y
- Currently, all the 115kV breaker failure relays hit a single/shared 86/BF lockout, which is a legacy/non-standard scheme. P&C Engineering recommends replacement with individual lockout coils for each breaker failure relay to match current standards.
- T198 and A152 line relay POTT keying schemes are currently over leased phone lines (via RFL-9745) to Monadnock and Chestnut Hill, respectively. P&C Engineering and Telecommunications Engineering recommend transferring those schemes to the more reliable Eversource fiber.

Based on spend to date, the estimated cost to complete the Distribution portion of the project is $10,820k and $1,354k for Transmission.

Project Costs Summary

See APS3 and APS8 requirements and consult with Plant Accounting for capital/O&M determination. Use published loaders for benefits, materials, and invoices, maintained by the Director, Budget and Internal Reporting.
Note: Dollar values are in thousands

A14W01 *($k)*	**Prior Authorized**	**2017**	**2018**	**Totals**
Capital Additions - Direct	$12	$819	$7,797	$8,628
Less Customer Contribution	$0	$0	$0	$0
Removals net of Salvage___%	$0	$0	$385	$385
Total – Direct Spending	$12	$819	$8,182	$9,013
Capital Additions – Indirect	$0	$197	$1,627	$1,824
Subtotal Request	$12	$1,016	$9,809	$10,837
AFUDC	$0	$3	$171	$174
Total Capital Request	$12	$1,019	$9,980	$11,011
O&M	$0	$0	$0	$0
Total Request	$12	$1,019	$9,980	$11,011

T1347A *($k)*	**Prior Authorized**	**2017**	**2018**	**Totals**
Capital Additions - Direct	$0	$86	$1,253	$1,339
Less Customer Contribution	$0	$0	$0	$0
Removals net of Salvage___%	$0	$0	$60	$60
Total – Direct Spending	$0	$86	$1,313	$1,399
Capital Additions – Indirect	$0	$6	$12	$18
Subtotal Request	$0	$92	$1,325	$1,417
AFUDC	$0	$1	$8	$9
Total Capital Request	$0	$93	$1,333	$1,426
O&M	$0	$0	$0	$0
Total Request	$0	$93	$1,333	$1,426

Prior Distribution authorized amount is for $950k approved at TRC on 11/19/16.
An additional $4,300 for transformer and switchgear purchase was approved at CPAC on 03/09/17.

Prior Transmission authorized amount is $50k that was approved at TRC on 11/19/16.

Financial Evaluation

Provide the following financial information (attach additional detail if summarized items are significant or additional information is needed). Note: Dollar values are in thousands

Distribution Project (A14W01)

Direct Capital Costs	**2016**	**2017**	**2018**	**Total**
Straight Time Labor	$1	$56	$81	$138
Overtime Labor	$0	$0	$0	$0
Outside Services	$11	$485	$2,969	$3,465
Materials	$0	$276	$4,553	$4,829
Other, including contingency amounts	$0	$2	$579	$581
Total	$12	$819	$8,182	$9,013

Indirect Capital Costs	**2016**	**2017**	**2018**	**Total**
Indirects/Overheads (including benefits)	$0	$197	$1,627	$1,824
Capitalized interest or AFUDC, if any	$0	$3	$171	$174
Total	$0	$200	$1,798	$1,998

Total Capital Costs	$12	$1,019	$9,980	$11,011
Less Total Customer Contribution	$0	$0	$0	$0
Total Capital Project Costs	**$12**	**$1,019**	**$9,980**	**$11,011**
Total O&M Project Costs	$0	$0	$0	$0

Transmission Project (T1347A)

Direct Capital Costs	2016	2017	2018	Total
Straight Time Labor	$0	$8	$12	$20
Overtime Labor	$0	$0	$0	$0
Outside Services	$0	$77	$1,081	$1,158
Materials	$0	$0	$60	$60
Other, including contingency amounts	$0	$0	$160	$160
Total	$0	$85	$1,313	$1,398

Indirect Capital Costs	2016	2017	2018	Total
Indirects/Overheads (including benefits)	$0	$6	$12	$18
Capitalized interest or AFUDC, if any	$0	$0	$8	$8
Total	$0	$6	$20	$26
Total Capital Costs	$0	$91	$1,333	$1,424
Less Total Customer Contribution	$0	$0	$0	$0
Total Capital Project Costs	**$0**	**$91**	**$1,333**	**$1,424**
Total O&M Project Costs	$0	$0	$0	$0

- Straight time forecast is based on original project estimate.
- Outside services forecast is based on committed contracts (engineering and project management) plus forecast costs for civil, electrical / P&C construction and testing, etc.
- Material costs are based on $1,371k for transformer purchase plus $1,797k for 15kV switchgear. $1,738k for Eversource purchased materials and miscellaneous vendor supplied materials.

This is NOT a new customer project

Future Financial Impacts:

Provide below the estimated future costs that will result from the project:
Note: Dollar values are in thousands:

Future Costs	Year 20__	Year 20__	Year20__	Year 20__+	Total Future Project Costs
Capital	$ -	$ -	$ -	$ -	$ -
O&M	-	-	-	-	-
Other	-	-	-	-	-
TOTAL	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

<u>If this is other than a Reliability Project, please complete the section below; N/A</u>

Provide below the estimated financial benefits that will result from the project:
Note: Dollar values are in thousands:

Future Benefits	Year 20__	Year 20__	Year20__	Year 20__+	Total Future Project Benefits
Capital	$ -	$ -	$ -	$ -	$ -
O&M	-	-	-	-	-
Other	-	-	-	-	-
TOTAL	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Describe the estimated future Capital, O&M and/or Other benefits noted above:

What functional area(s) will these benefits be reflected in?___________________________________
A representative from the respective functional area is required to be included as a project approver.

Asset Retirement Obligation (ARO) and/ or Environmental Cleanup Costs (Environmental Liabilities):

An ARO is a current legal obligation to remove or retire property, plant or equipment at some point in the future. Please refer to APS8 or contact Plant Accounting for further detail.

Is there an ARO associated with this project? If yes, please provide details: **No**

Are there other environmental cleanup costs associated with this project? If yes, please provide details. **Forecast includes $50k for soil disposal based on an assumption of 1,000 tons at $35/ton haulage and $10/ton disposal costs.**

Operations Project Authorization Form

TAF # NH-160001-TDS

Date Prepared: March 10, 2017	Project Title: Emerald Street SS Rebuild
Company/ies: Eversource NH	Project ID Number: A14W01 (D) & T1347A (T)
Organization: NH Operations	Class(es) of Plant: Distribution & Transmission
Project Initiator: Charles Christensen, PE	Project Category: Substation
Project Manager: Thelma Brown	Project Type: *Specific*
Project Sponsor: James Eilenberger	Project Purpose: part of regulatory tracked program? N
Estimated in service date: December 31, 2018	If Transmission Project: Non-PTF
Eng. /Constr. Resources Budgeted? Yes	Capital Investment Part of Original Operating Plan? Yes
	O&M Expenses Part of the Original Operating Plan? NA

Project Authorization

Project authorization must be in accordance with the approval levels included in the Delegation of Authority Policy (DOA).

If Subsidiary Board approval is required, document the review by Enterprise Risk Management (ERM) and Financial Planning and Analysis (FP&A)

ERM: ____________________

FP&A: ____________________

Executive Summary

This project is currently approved for $1,000,000 for engineering (see attached TAF). The approval for the transformers and switchgear in addition to the engineering previously approved adds up to the request for a total of $5,300,000 for this project.

This PAF is a request for approval to place long lead-time materials on order for the Emerald Street SS rebuild project. This request includes material funding of $4,300,000 for:

> Two 30MVA 115-12.47kV transformers. Transformers are estimated at $900,000 each for a total of $1,800,000. The lead time for transformers is approximately 52 weeks. The transformer needs to be delivered to the project in Q2 2018.
>
> 12.47kV Metalclad switchgear including fifteen (15) breakers and a control house enclosure. This switchgear is estimated at $2,500,000. The lead time for switchgear is approximately 52 weeks. The switchgear needs to be delivered to the project in Q2 2018.

This project is for the rebuild of the existing substation. Much of the equipment at Emerald Street substation is more than 50 years old. There are five 115-12.47kV transformers feeding the 15kV switchgear which was installed around 1949. There are issues with equipment condition, fault duty, and flooding at the site that will be addressed with this project.

The risk in procuring the transformers if the project does not go forward is limited. This transformer is the standard voltage used in the western part of the Eversource NH system. If this project is not approved the transformers will become system spares and be available for replacement of a failed unit. There are currently 7 of these units in-service including the 5 at Emerald Street SS. In the event it is decided to cancel the order within 20 weeks of placing it, the risk is a partial cost of the transformers. Below is a typical cancellation schedule for a recent transformer purchase.

Cancellation Schedule

The Purchaser may cancel order only upon written notice and upon payment to the Seller of reasonable and proper cancellation charges. These charges will be based on the following schedule unless separate written agreement is made with Seller:

Time frame is from PO date or letter of Intent date.

0	to	10 weeks	20% of the transformer Selling price
>10	to	20 weeks	80% of the transformer Selling price
>20	to	30 weeks	100% of the transformer Selling price

The risk in procuring the switchgear if the project does not go forward is substantial. There may be cancellation policies that can be negotiated but it is recognized that the approval to procure the switchgear should indicate a preference for the project to go forward, although it could be delayed due to funding in 2018 which would push the in-service date out. A $250,000 deposit payment on the switchgear is due in 2017.

Project Costs Summary

Note: Dollar values are in thousands

Distribution Project A14W01

	Prior Authorized	2017	2018	2020+	Totals
Capital Additions - Direct	$ 860	$ 250	$ 4,050	$ -	$ 5,160
Less Customer Contribution	-	-	-	-	-
Removals net of Salvage ____%	-	-	-	-	-
Total - Direct Spending	$ 860	$ 250	$ 4,050	$ -	$ 5,160
Capital Additions - Indirect	130	-	-	-	130
Subtotal Request	$ 990	$ 250	$ 4,050	$ -	$ 5,290
AFUDC	10	-	-	-	10
Total Capital Request	$ 1,000	$ 250	$ 4,050	$ -	$ 5,300
O&M	-	-	-	-	-
Total Request	$ 1,000	$ 250	$ 4,050	$ -	$ 5,300

Transmission Project T1347A

	Prior Authorized	2017	2018	2020+	Totals
Capital Additions - Direct	$ 45	$ -	$ -	$ -	$ 45
Less Customer Contribution	-	-	-	-	-
Removals net of Salvage ____%	-	-	-	-	-
Total - Direct Spending	$ 45	$ -	$ -	$ -	$ 45
Capital Additions - Indirect	5	-	-	-	5
Subtotal Request	$ 50	$ -	$ -	$ -	$ 50
AFUDC	-	-	-	-	-
Total Capital Request	$ 50	$ -	$ -	$ -	$ 50
O&M	-	-	-	-	-
Total Request	$ 50	$ -	$ -	$ -	$ 50

Financial Evaluation

Provide the following financial information (attach additional detail if summarized items are significant or additional information is needed). Note: Dollar values are in thousands

Distribution Project A14W01

Direct Capital Costs	Year 1	Year 2	Year 3+	Total
Straight Time Labor	60			60
Overtime Labor				
Outside Services	800			800
Materials	250	4,050		4,300
Other, including contingency amounts (describe)				
Total	1,110	4,050		5,160

Indirect Capital Costs	Year 1	Year 2	Year 3+	Total
Indirects/Overheads (including benefits)	130			130
Capitalized interest or AFUDC, if any	10			10
Total	140			140

Total Capital Costs	1,250	4,050		5,300
Less Total Customer Contribution				
Total Capital Project Costs	1,250	4,050		5,300
Total O&M Project Costs				

Transmission Project T1347A

Direct Capital Costs	Year 1	Year 2	Year 3+	Total
Straight Time Labor	5			5
Overtime Labor				
Outside Services	40			40
Materials				
Other, including contingency amounts (describe)				
Total	45			45

Indirect Capital Costs	Year 1	Year 2	Year 3+	Total
Indirects/Overheads (including benefits)	4			4
Capitalized interest or AFUDC, if any	1			1
Total	5			5

Total Capital Costs	50			50
Less Total Customer Contribution				
Total Capital Project Costs	50			50
Total O&M Project Costs				

Note: Explain unique payment provisions, if applicable

Future Financial Impacts:

Provide below the estimated future costs that will result from the project:
Note: Dollar values are in thousands:

Future Costs	Year 2017	Year 2018	Year20__	Year 20__+	Total Future Project Costs
Capital	$ 1,000	$ 9,000	$ -	$ -	$ 10,000
O&M	-	-	-	-	-
Other	-	-	-	-	-
TOTAL	**$ 1,000**	**$ 9,000**	**$ -**	**$ -**	**$ 10,000**

Total distribution cost of the project is estimated to be $10,000,000. This is proposed for 2018 construction.

What functional area(s) will these future costs be funded in?___NH Operations___
A representative from the respective functional area is required to be included as a project approver.

If this is other than a Reliability Project, please complete the section below;

Provide below the estimated financial benefits that will result from the project:

Note: Dollar values are in thousands:

Future Benefits	**Year 20__**	**Year 20__**	**Year20__**	**Year 20__+**	**Total Future Project Benefits**
Capital	$ -	$ -	$ -	$ -	$ -
O&M	-	-	-	-	-
Other	-	-	-	-	-
TOTAL	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Describe the estimated future Capital, O&M and/or Other benefits noted above:

This project is to replace aging equipment and address operational concerns with the existing substation.

What functional area(s) will these benefits be reflected in?_____NH Operations_____________

A representative from the respective functional area is required to be included as a project approver.

Asset Retirement Obligation (ARO) and/ or Environmental Cleanup Costs (Environmental Liabilities):

An ARO is a current legal obligation to remove or retire property, plant or equipment at some point in the future. Please refer to APS8 or contact Plant Accounting for further detail.

Is there an ARO associated with this project? If yes, please provide details: No

Are there other environmental cleanup costs associated with this project? If yes, please provide details.

This project is located at a former MPG site and handling of the subsurface materials during construction will need to be monitored. Formal cleanup of the site is complete but this needs to be considered for construction.

Technical Authorization Form

TAF # NH-160001-TDS Rev. 0

Date Prepared: November 18, 2016	Project Title: Emerald Street SS Rebuild
Company/ies: Eversource, NH	Project ID Number: A14W01 (D) & T1347A (T)
Organization: NH Operations	Class(es) of Plant: Distribution & Transmission
Project Initiator: Charles Christensen, PE	Project Category: Substation
Project Owner/Manager: Thelma Brown	Project Type: *Specific*
Project Sponsor: James Eilenberger	Project Purpose: part of regulatory tracked program? No
Estimated in service date: December 31, 2018	If Transmission Project: *Non-PTF*
Authorization Type: *Conceptual Engineering*	Authorization Amount: $1,000,000 for Engineering

Project Need Statement *(Description of Issue)*

In 2012 an area study was performed to determine how to best address the area loading and retirement of equipment at the Emerald Street SS. The study recommended two substation projects to replace the existing equipment currently concentrated at the Emerald Street SS in Keene: 1) a new 115-12.47kV substation in the north section of Keene; and 2) a new/rebuilt 115-12.47kV substation on Emerald Street, at the site of the existing substation. This approach places sources closer to the load, addresses aging and overduty equipment, and provides two separate electrical sources to the area.

In November 2016 the North Keene SS was put in-service. This TAF is for the second phase of the 2012 solution, a project which will replace and/or rebuild the existing Emerald Street SS in Keene.

Project Objectives

1. <u>Retire aging infrastructure.</u>

Much of the equipment at Emerald Street substation is more than 50 years old. There are five 115-12.47kV transformers feeding the 15kV switchgear which was installed around 1949.

The testing and maintenance on the transformers has identified that the 47 year old TB-12 is in the worst shape of the transformers with degraded oil and it is recommended that the transformer be reconditioned or replaced. Three of the transformers are more than 50 years old.

Besides the age and condition of the 67 year old switchgear, there is a concern about the fault duty of the equipment. Operating in the normal , the bus 1 and bus 2 switchgear breakers are at 85.40% to 98.62% of their interrupting rating. Because of the fault duty the bus tie breaker must remain open in the switchgear which limits loading on one bus for the failure of a single transformer.

2. <u>Flood Mitigation</u>

The Ashuelot River is near Emerald Street SS and has been identified as a flood threat. When there has been flooding in the Keene area the river level has come up to the south west corner of the substation but not actually flooded the yard. The 500 year flood plain does penetrate the south west corner of the substation. The plan to rebuild the substation will include grading and retaining walls to prevent potential flooding.

3. <u>115kV Bus Differential Protection</u>

This project will include adding a 2nd 115kV bus differential protection to Emerald Street SS. Emerald Street Substation is classified as a NERC Bulk Electric System (BES) element and is subject to the maintenance and testing requirements outlined in NERC Standard PRC-005-2. This testing includes the trip testing of the 115kV bus differential protection scheme. The existing system lacks redundancy to permit the triup testing without de-energizing the distribution load served by this substation. . The new construction includes adding the equipment and protection to eliminate this exposure to customers. This 2nd 115kV bus differential scheme installation was defined and approved in 2013 in accordance with the NERC Standard PRC-005-2 relay test requiremens for BES elements. The project was deferred to allow coordination with the proposed transformer changes.

Project Scope

1) Remove four (4) 115-12.47kV transformers (TB3 will remain)
2) Remove existing 15kV switchgear and associated equipment
3) Install two (2) 115-12.47kV 30MVA transformers
4) Install six (6) 115kV CCVTs
5) Install new switchgear with integral control room and associated systems
6) Install underground control cable raceway systems from the existing control house to new switchgear/control house
7) Install new fence and grounding
8) Regrade yard and install a retaining wall to address 500 year flood levels
9) Install yard lighting
10) Install CIP security measures including cameras
11) Protection and control system upgrades including 2nd 115kV bus differential scheme.
12) Install new batteries and monitoring system.

Background / Justification

In 2012 an area study was performed to determine how to best address the loading and retirement of equipment at the Emerald Street SS. The study recommended that two new 115 kV to 12.47 kV substations be built to replace the existing equipment currently concentrated at the Emerald Street SS in Keene: one in the North section of Keene; and one on Emerald Street, adjacent to the existing substation. This approach places sources closer to the load, reduces fault current, and provides two separately located electrical sources to the area.

In November 2016 the North Keene SS was put in-service. This TAF is for the second phase of the study, a project which will replace and/or rebuild the existing Emerald Street SS in Keene. In addition to providing for future peak load in the area, the transformation at Emerald Street SS will be sized to back up North Keene SS which currently has only one transformer but two express lines between the substations.

The switchgear was installed in 1949 and is 67 years old. The transformers were installed at different times and four of the five will be retired by this project:

Transformer	Size(MVA)	Age (yrs)
TB18	12.5	61
TB23	12.5	59
TB7	20	52
TB12	20	47
TB3	20	16 (to remain)

Three of the transformers are over 50 but TB12 condition is of the most concern. The oil fluid quality in the main tank of TB12 is wet, has poor dielectric strength, is dark in color and oxidized, and has low interfacial tension.

Emerald Street (Keene) Substation currently has five 115 kV to 12.47 kV transformers feeding three switchgear busses that cannot be tied together. There are operational issues with the switchgear which limit the flexibility to use bus ties. Closing a bus tie breaker to put three or more transformers on the combined bus puts seven of eight feeder breakers well above their interrupting ability. This is a potential safety risk and limits the loadability and reliability of the substation. Additionally, there are many advantages to upgrading the relay protection as part of the project. In most cases, the existing relaying is as old as the switchgear being replaced, is inflexible as to settings, and gives no remote (or local) access to fault information for event investigation.

This project will include adding a 2nd 115kV bus differential protection to Emerald Street SS. This 2nd 115kV bus differential scheme installation was defined and approved in 2013 in accordance with the NERC Standard PRC-005-2 relay test requiremens for BES elements. The project was deferred to allow coordination with the proposed transformer changes.

Business Process and / or Technical Improvements:

This project addresses aging infrastructure, equipment fault duty, and flood mitigation. It is also a part of the overall area plan and strategy to provide a reliable backup to North Keene SS and provide for future growth.

Cost Estimate and Assumptions

The total price of this project is estimated to cost:

Distribution:	9,500,000
Transmission:	500,000
Total:	$10,000,000

($7,500,000 - $12,500,000) (-25% +25%)

Alternatives Considered with Cost Estimates

Note that this PAF addresses step two in the Alternative recommended in the 2012 Keene Area Study.

Alternative 1: Do nothing.
Emerald Street SS equipment is aging. By doing nothing there is more exposure to customer outages for failure of equipment. The failure of an existing transformer without the proposed 115kV differential system protection results in an outage for all customers fed from Emerald Street SS. Estimated cost for Alternative 1: $0.

Alternative 2: Install a second 115-12.47kV transformer at North Keene SS.
This solution will provide capacity and transformer redundancy at North Keene SS. However, as shown on Attachment A – All circuits were originally fed out of Emerald Street as a hub. North Keene bisects two of the circuits and provides a ROW backup feed to Emerald Street. While this could work load-wise it puts a majority of the circuits on two lines fed from Keene to Emerald Street which is much more exposure to line outages. This may require a switching station at Emerald Street, Keene, potentially switchgear. If this alternative was preferred, additional ROW lines and breakers from North Keene SS are recommended. Estimated cost for Alternative 2: $5,000,000

Alternative 3: Construct a new 115-12.47kV South Keene SS.
North Keene SS was constructed to feed the circuits to the north of Emerald Street SS. A second substation could be constructed south of Keene to address the load. Originally this solution was not preferred partially because of the difficulty of finding a location that is not within the 100 year flood plain. Estimated cost for Alternative 3: $15,000,000

Alternative 4: Construct the Emerald Street SS with one 115-12.47 transformer instead of two. This alternative will save approximately $1,000,000. It does remove a level of reliability from the solution. This also limits future growth. Between the North Keene SS and Emerald Street SS projects, the effective capacity in the Keene area will be reduced by 5MVA if a second transformer is not installed with this project. Estimated cost for Alternative 4: $9,000,000.

Project Schedule

Milestone/Phase Name	Estimated Completion Date
TAF Approval	12/15/16
Scoping Document Development	12/31/16
Engineering & Design	9/1/17
PAF Approval	9/1/17
Construction	12/1/18
Substation tested, In-Service and Complete	12/1/18

Regulatory Approvals

ISO-NE Level 1 approval for the distribution transformer replacements will be required.

Permitting required by the City of Keene, the State of New Hampshire or US Regulatory Departments

Permitting for excavations on the site of a former MPG site.

Risks and Risk Mitigation Plans

The difficulty of constructing, in effect, around an active station. This will be mitigated by getting a thorough engineering design including identification of phasing for construction and a complete constructability reviews.

Outages cancelled due to unplanned events on the system resulting in schedule delay and potential labor cost to remobilize.

- Mitigation Plan - Establish and manage outages using proven coordination teams; 1) Construction Management 2) Coordination Meetings 3) Outage Planning and Risk Mitigation Meeting 4) Utilization of the circuit ties to North Keene Substation and 5) Deploying a mobile substation (MX66 – CL&P mobile) as required.

Internal and external resource availability for engineering.

- Effort is being exerted to balance engineering and review work between internal resources and external resources.

- Lack of sufficient, qualified, local construction labor results in the need to import labor which potentially increases costs or lengthen the schedule which will result in project delays.
    - Develop overall strategy for construction allocation.

References

Keene Area Study Report

Scope Document

One-Line Diagrams, Attachments, and Images

[ONE-LINE DIAGRAM REDACTED]

[redacted]

One-line - Removals

[ONE-LINE DIAGRAM REDACTED]

[redacted]

One-line - Additions

ATTACHMENT A - KEENE AREA CIRCUITS

[ONE-LINE DIAGRAM REDACTED]

[redacted]

KEEGAN WERLIN LLP

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July 15, 2022

Paul Dexter, Esq.
New Hampshire Department of Energy
21 S. Fruit Street, Suite 10
Concord, New Hampshire 03301

Re: Docket No. DE 22-030
Public Service Company of New Hampshire d/b/a Eversource Energy
Petition for Third Step Adjustment

Dear Mr. Dexter:

Enclosed on behalf of the Public Service Company of New Hampshire d/b/a Eversource Energy (the "Company"), please find the Company's outstanding responses to the Department of Energy's Technical Session Data Requests. Specifically, the Company provides its responses to TS 1-006 and TS 1-012; this completes the Company's response to this set of Data Requests. Please note that Attachment TS 1-006A includes confidential, critical energy infrastructure information. The confidential version of this attachment will be provided under separate cover.

Please contact me if you have any questions. Thank you for your attention to this filing.

Sincerely,

Jessica Buno Ralston

Jessica Buno Ralston

cc: Discovery Service List, Docket DE 22-030

Public Service Company of New Hampshire d/b/a Eversource Energy
Docket No. DE 22-030

Date Request Received: June 28, 2022 **Date of Response: July 15, 2022**
Data Request No. TS 1-006 **Page 1 of 5**

Request from: Department of Energy

Witness: Renaud, Paul R, Dipaola-Tromba, John P, Dickie, Brian J, Plante, David L

Request:

Reference DOE 1-08, Emerald Street Substation. Please provide the following information:

a) A copy of the load study referenced at the tech session justifying this project.

b) Explanation as to why this project should not be treated as a "growth project" under the terms for step adjustments in the Settlement Agreement in Docket DE 19-057.

c) Explanation as to why the engineering cost overruns were not known or knowable at the time of designing and scoping the project.

d) Final cost breakdown between distribution costs and transmission costs for the project confirming that no transmission costs were included in the plant-in-service amount for 2021of $19.5 million.

Response:

a) The Keene area load study is attached as Confidential Attachment TS 1-006A.

Attachment TS 1-006A contains confidential energy infrastructure information. Accordingly, consistent with Puc 203.08(d), Eversource states that is has a good faith basis for confidential treatment of the material provided in Attachment TS 1-006A. The Company will submit a motion for confidential treatment prior to hearings in this proceeding.

b) Upgrades at Emerald Street substation did not increase the transformer capacity of the station and therefore the Emerald Street substation project was not a "growth project".
The Emerald Street substation project (previously referred to as Keene substation) was the second project proposed as a result of a comprehensive area study. While transformer loading was one factor considered in the Keene Area Distribution System Study, as noted in the study's Executive Summary, the more urgent factor was the fact that the available fault current at the substation exceeded the interrupting rating of two of the transformer breakers and much of the switchgear. Another urgent factor was equipment obsolescence. Four of the five transformers

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at the Emerald Street substation were between 45 and 60 years old; based on the useful life expectancy of 55 years for distribution substation equipment this meant that 90% of the distribution equipment was considered obsolete. One of the transformers actually failed during the construction phase of the project, demonstrating the urgent need to address the condition of this equipment. The 2012 study is provided in response to part (a) of this data request and provides details of the many deficiencies of the Emerald Street substation.

To address these deficiencies, the North Keene substation was constructed to provide a second source to the nearly 16,000 customers served in the greater Keene area and to allow load to be served during construction activities at Emerald Street substation. The upgrades at Emerald Street included replacing the 1940/1950's vintage switchgear with automated, properly rated switchgear and to replace four 1950/1960's vintage power transformers (total of 69.8 MVA) with two 30 MVA transformers. The substation upgrades at Emerald Street substation addressed underrated equipment, asset condition, and aged equipment as well as improving the overall design of the substation.

c) The Company does not agree with the characterization within the question that there were "engineering cost overruns" that were not "known or knowable" at the time the project was initially contemplated. It is important to note that while the project first received full funding in 2017, it was with the understanding that several components of the project estimate were based on 2016 estimates and in several instances did not have actual contract pricing in hand to completely inform this first full funding estimate. This is consistent with the Company's policies and processes at the time for advancing projects, particularly for projects of this magnitude and complexity. The Company's project identification, approval, and management processes are intentionally designed to be iterative and flexible in order to accommodate changing circumstances and to incorporate new information, while maintaining rigorous cost containment imperatives and oversight at appropriate levels of Company management, generally based on project cost and / or the dollar amount or percentage of project cost changes. In certain cases, initial full funding approvals for projects such as the Emerald Street project are required to be revisited, as part of the normal course of business and project lifecycle, in order to incorporate updated contracting information, among other elements. This is the case with the initial full funding authorization for the Emerald Street substation project and is documented in the funding request made in 2017 which indicates that only some components of the request were based on known commitments and others were estimates.

In March 2019, after securing contract pricing, a revised full funding request (via the 5/3/19 SRF) was submitted and approved by the EPAC Committee. This funding request brought the total project authorization amount to $16.8 million, which is what is considered by the Company as the Full Funding amount for the project.

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From 2017 to 2019, while the detailed project engineering, contracting and major equipment procurement progressed, more information became available to further refine details of the engineering required to achieve the project objectives. This refinement was an expected part of the process, as described above, rather than a "cost overrun" as characterized in the question.

However, this refinement process did result in an increase in the estimated cost of engineering by approximately $300k between the initial full funding request completed in 2017 and the Full Funding amount developed and authorized in 2019. This increase of $300k (or approximately 2 percent of the total project authorization amount of $16.8 million), was attributable to several factors that were not known or knowable at the time that engineering was initially contracted:

i. The bid specification for the detailed substation engineering included a requirement that the engineering vendor assist with the preparation of a "general specification for power/control enclosures with metalclad switchgear to issue to equipment suppliers" and also went on to explain that the engineering vendor was responsible for engineering "where not part of the metalclad design". Leidos, in their proposal, attempted to clarify this demarcation or responsibility, taking on engineering drawings they felt were to be done by the engineering vendor and identifying drawings they felt would be done by the switchgear manufacturer. After award of the engineering contract, Eversource decided that preparing these drawings in advance and including with the switchgear specification would provide the Company with the best and most complete bid responses. This resulted in a change order for Leidos to complete these drawings. In theory, this also resulted in better bids for the switchgear, as the vendors did not need to prepare them, and this reduced the number of assumptions that the bidders would need to make in preparing their proposals. ($40,146)

ii. The engineering scope of fencing and a retaining wall was inadvertently omitted from both the site engineering and substation engineering contracts (contract gap) and needed to be added back in as an engineering scope change. This was known project scope but was overlooked during the contracting process. ($16,850)

iii. The engineering package needed to be split into multiple "issued for construction" packages to support the construction sequencing and outage plan. At the time of the engineering contracting (April 2017), the construction sequencing was not known and the need to split the engineering into multiple packages could not have reasonably been anticipated. ($170,434)

iv. Modifications to the oil containment system were required after discovering a discrepancy in the nameplate volume of transformer oil. ($5,432)

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v. An additional engineering vendor (RLC Engineering) was brought on to assist with owner review of P&C design deliverables due to internal labor constraints. This task was initially intended to be performed by in-house resources. ($54,900)

d. The Company has controls and processes in place to ensure that transmission costs are not charged to distribution work orders, and vice versa. The Company does this by keeping the project scope and accounting work orders separate, such that costs associated with transmission work is recorded to certain accounting work orders, and costs associated with distribution work is recorded to separate accounting work orders. All team members are provided with the proper accounting for each project to properly account for their time as well as for preparing requests to order services and materials. There are various review and approval processes for time and invoices to ensure that project costs are properly allocated.

As a further measure of assurance that costs are accurately charged between transmission and distribution, the project manager and cost analyst for these projects performed a detailed review of project cost accounting to ensure that all charges were charged to the correct project in anticipation of the project closeout process which is performed after the projects are placed in service. Any errors identified through the course of this review were corrected in advance of the in-service date. After the in-service date, the Company undertakes a formal reconciliation to close out the project and unitize the assets, moving the project from Account 106 (Construction Completed Not Classified) to Account 101 (Plant in Service). This reconciliation serves as a further check to ensure that costs are accurately charged to the appropriate plant accounts, and appropriately charged to distribution and transmission. This review is currently in process, but not complete. The analyst performing this work has reported that thus far, no significant anomalies have been detected. However, in the event that this reconciliation process identifies charges that need to be reclassified, accounting entries will be made. This is why it is common to find both charges and credits to projects a year or more after the in-service date.

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Line Item Category	A14W01 12/31/2021	A14W01 6/30/2022	T1347A 12/31/2021	T1347A 6/30/2022
1. ROW / Easements / Land Acq	-	-	-	-
2. Environmental Approvals / Permits	-	-	-	-
3. Outreach	45	45	-	-
4. Siting Approval / Permits	-	-	-	-
5. Engineering / Design	1,398	1,422	1,284	1,292
6. Materials (Eversource Purchased)	790	766	287	210
7. Construction (Incl Matl's by contractors)	7,831	7,831	1,126	1,110
8. Testing / Commissioning	2,208	2,164	207	443
9. Project Mgmt Team	366	366	170	170
10. Removals	723	723	301	328
11. Other - Escalation	1,080	1,080	431	431
12. Risks	-	-	-	-
Total Directs W/ Risks	**14,441**	**14,397**	**3,806**	**3,984**
13. Indirects / Overhead	4,441	4,439	963	1,029
14. AFUDC	1,378	1,378	250	250
Total Project	**5,819**	**5,817**	**1,213**	**1,279**
15. Contingency	-	-	-	-
Total Capital Request	**20,259**	**20,214**	**5,019**	**5,263**
16. Reimbursable	-	-	-	-
Project Total	**20,259**	**20,214**	**5,019**	**5,263**

Public Service
of New Hampshire

The Northeast Utilities System

SYSTEM PLANNING & STRATEGY

Keene Area

Distribution System Study

May 2, 2012

Approved: James C. Eilenberger

Confidential

Table of Contents

Executive Summary

One of the recommendations of the 2011 Ten Year Load Flow Study was to perform a comprehensive study of the Keene area distribution system. This study analyzes the 12.47 kV distribution system in the greater Keene area.

The distribution system in this area is served entirely at 12.47 kV and fed by Keene and Swanzey Substations, serving approximately 20,000 PSNH customers. This area is presently experiencing a 3.1% load growth which is expected to continue for the foreseeable future.

Keene Substation is currently crowded with five 115 kV to 12.47 kV transformers which are heavily loaded and nearing their TFRAT ratings. Of a more urgent nature is the fact that the available fault current at the Keene Substation exceeds the interrupting rating of two of the transformer breakers and much of the switchgear. Moreover, the equipment at Keene Substation is old and obsolete.

It is recommended that two new 115 kV to 12.47 kV substations be built to replace the existing equipment currently concentrated at the Keene Substation on Emerald St: one on Emerald St, adjacent to the existing substation; and one in the North section of Keene. This approach will place the sources closer to the load, reduce fault current, and provide separated electrical sources to the area. As the load continues to increase in this area, an additional transformer will be required at the new Keene Substation.

Respectfully submitted:

Rich Rudolf, Team Lead
Krista Butterfield
Mark Fraser
Steve Hall
Bob Mission
Marc Pilotte
Ingrid Rahaim

I. Introduction

This study addresses the recommendation that was made in the 2011 Ten Year Load Flow Study to complete a comprehensive study of the Keene Area distribution system. The existing system configuration, equipment limitations, system loading and area load growth rate are used to assess future system requirements. The objective of this study is to develop recommendations that address the long term loading requirements and equipment issues.

Since the electric system feeding the greater Keene area is entirely islanded and separated from PSNH's 34.5kV distribution system, this study focuses on serving this area with a 12.47 kV distribution system.

II. System Background

This report summarizes the work of the Keene Area Planning Study Team as it considered the dynamics of the electrical system serving the greater Keene area. Several alternatives were considered by the group. Ultimately, System Planning & Strategy recommends moving forward with the construction of a new North Keene Substation and the rebuilding of the existing Keene Substation to modern standards. These proposed projects will effectively address existing loading, equipment rating deficiencies, obsolescence, power quality, and reliability issues.

III System Analysis

A. Area Problems & Limitations

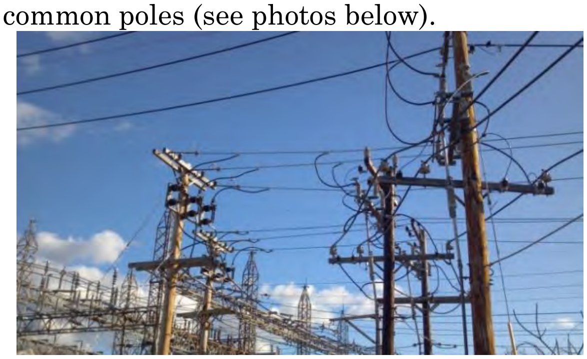
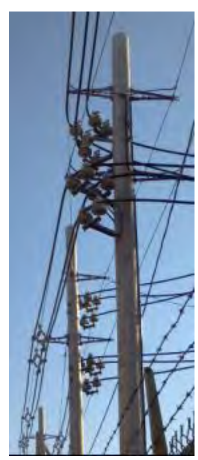
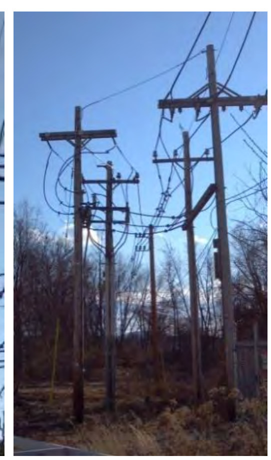
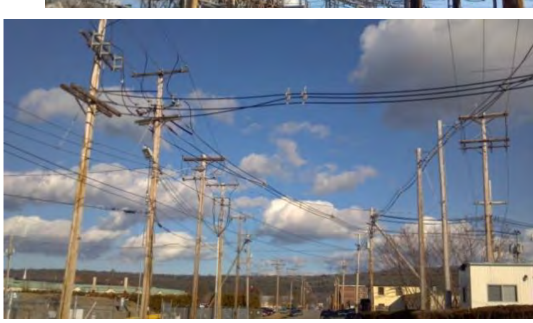
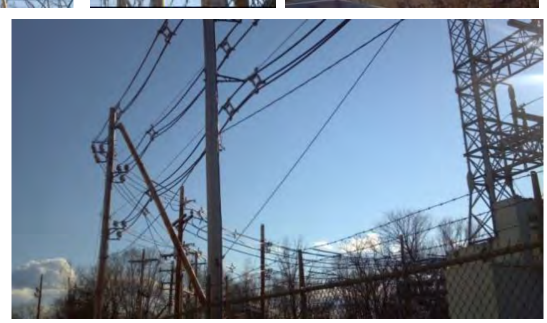
1. **Single Source** – All Keene circuits emanate from one location (Emerald St). This condition could subject multiple circuits to outages from a single event.
2. **Power Quality** – Customers who are sensitive to power quality are affected by disturbances on other Keene Substation circuits due to the interconnected nature of the substation.

B. Substation Problems & Limitations

1. **Transformer Breaker Ratings** – Because of the existing transformer impedances and their parallel configuration, the available fault current exceeds the transformer breaker interrupting ratings for TB12 and TB18. (per manufacturer interrupting ratings of 10,000 amps.)
2. **Switchgear Ratings** – System Engineering has identified several breaker ratings which have been exceeded by available fault current. (See Appendix B – PCM report dated 6/24/2009, Vermont 115 kV Southern Loop Expansion – Short Circuit Duty Review)

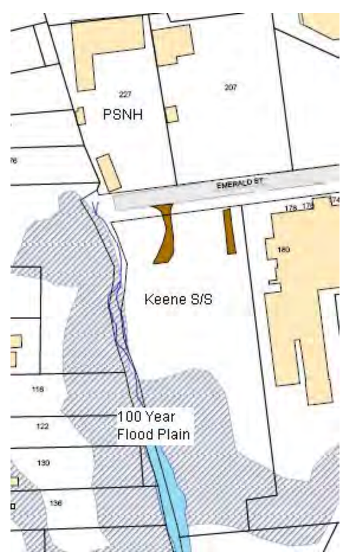
3. **Obsolescence** – Part of PSNH's strategic plan is to replace obsolete equipment. Four of the five transformers at Keene Substation are between 45 and 60 years old. Based on a useful life expectancy of 55 years for distribution substation equipment, 90% of the distribution equipment at Keene Substation is considered obsolete. Note: Transformer TB3 and its associated equipment, installed in 2000, is excluded from this category.


4. **Limited Capacity** – There is limited line and transformer capacity to serve the area effectively. By 2014, in order to switch out of some contingent transformer outages, up to five load block transfers will need to be made in order to restore all customers. This violates the requirements of Procedure ED-3002.
5. **Congested Physical Site** – The nine (9) 12.47 kV circuits leaving Keene Substation, along with their associated tie switches, encircle the substation, with double- and triple-circuited spacer cable on common poles (see photos below).

6. **Maintenance Planning** – Maintenance is difficult to schedule on the existing in-service power transformers at Keene Substation, due to loading. Exacerbating the situation is the fact that PSNH does not own a 115 kV to 12.47 kV mobile substation.

7. **Load Growth** – The Loadflow analysis indicates that additional transformation is required prior to the summer of 2014 to resolve all contingent outages without the use of a mobile transformer. With a mobile transformer available, additional transformation is then required prior to the summer of 2020 to address base case overloading conditions.
8. **Eggs All in One Basket** – The entire Keene area is fed from a single substation on Emerald St. in downtown Keene. A catastrophic event at the substation, the nearby factory or the propane supply facility across the street, could put Keene Substation out of commission for an extended period of time, with no alternative means of feeding 16,000 customers.



9. **Proximity to Flood Plain** – Maps furnished by the City of Keene indicate that the southernmost section of Keene Substation falls within the 100-year flood plain (see diagram at right). During the historic flooding event in Keene in the fall of 2005, there was sufficient threat of the substation being submerged that we proposed parking the CL&P 115 - 12 kV mobile substation on Court Street and backfeeding the majority of the city (see LGL document North Keene SS Discussion.doc). During the flooding event in the spring of 2006 – when

the Ashuelot River did overflow its banks – the high water level encroached within three feet of the footings of the fence on the substation's west side. (Sources: Keene DPW; US Army Corps of Engineers)

10. **Environmental Concerns** – Solution options which entail rebuilding the Distribution portion of the station on the 0.97 acre property across the street from the existing station will trigger an environmental evaluation for the use as a substation site. The summary of the Former Keene MGP Final Construction Report (Weston & Sampson Engineers, Inc., September 2005) states: "activity and use restrictions will include direct contact barriers and restrict future excavation and residential use of the site without further risk assessment."

C. **Loadflow Analysis** – A 12.47 kV Loadflow model was developed with all 12.47 kV circuits modeled out to their respective three phase tie points. Circuit and transformer loads were captured for 2011 and escalated out in time at an annual growth rate of 3.1%. Base case loadflows and various contingencies were run. It was determined that additional transformation is required by 2014 to prevent a contingent violation. Specifically, in 2014, it will require five load block transfers for the loss of either TB7 or TB12 at Keene Substation to reduce the loading on its respective parallel-connected transformer to within TFRAT without additional transformation. The first base case violation occurs in 2017 in which the first portion of the W110 circuit, from Keene Substation to the 110DX5 switch, is projected to exceed its 477 ACSR normal conductor rating. (See Appendix D – 12.47 kV Loadflow Synopsis)

IV Solution Options

All of the viable options listed below (Options 2 through 5) involve removal of existing obsolete transformers and switchgear at the Keene Substation, except for TB-3 and its associated circuit reclosers, W2A and W9A, which will stay in service at the South end of the substation yard. In addition, this study assumes that PSNH will complete the procurement of a 115 kV – 12.47 kV mobile substation by 2014, as back-up for a transformer failure. Otherwise, the installation of an additional 30MVA transformer will be required in order to limit the number of load block transfers to three, per ED-3002. This alternative to have a 30 MVA 115 kV to 12.47 kV transformer installed by 2014 is an unrealistic timeframe.

Option 1 – <u>34.5 kV Expansion</u> (Expand at 34.5kV to alleviate substation transformer overloads) –

Approximately 20,000 customers in the greater Keene area are presently served by the existing 115 kV – 12.47 kV distribution system. The closest 115 kV – 34.5 kV sources are Chestnut Hill Substation, Hinsdale (17 miles), Monadnock Substation, Troy (10 miles), and Jackman Substation, Hillsborough (27 miles). The possible circuit ties at the outer extremities of the Keene area are all presently single phase and would therefore not provide suitable ability to offload any significant amount of load. In addition, the deficient substation interrupting ratings issues would still exist at Keene Substation and need to be addressed. Furthermore, for reliability reasons, PSNH has been moving in the direction of expanding its 12.47 kV system where it makes sense rather than serving the area at 34.5 kV, for reliability reasons.

Option 2 – Replacement of Existing Equipment at Keene Substation (Emerald Street) Only –

The Keene (Emerald St.) Substation projects would include:

- Replace TB7, TB12, TB18, and TB23 along with associated switchgear with new equipment at a proposed substation on Emerald St, retaining existing TB3 in service at the original Emerald Street site. This option would be complicated by the requirement to remove existing distribution transformation in order to install the 115kV feed to the new substation lot.
    - **2014 work:**
        - Procure a 115 kV to 12.47 kV mobile substation
    - **2015 work:**
        - Build new 115 kV to 12.47 kV substation with two (2) 30MVA transformers adjacent to the existing Keene Substation.
        - Provide eight (8) breaker positions to feed existing circuitry now fed from the original substation site

Option 3 – Replace Existing Keene Substation and Construct New Distribution Substation (North Keene) –

The Keene (Emerald St.) Substation projects would include:

- Replace TB7, TB12, TB18, and TB23 along with associated switchgear with new equipment at a proposed substation on Emerald St, retaining existing TB3 in service at the original Emerald Street site.
    - **2014 work:**
        - Procure a 115 kV to 12.47 kV mobile substation
    - **2015 work:**
        - Build new 115 kV to 12.47 kV substation with one (1) 30MVA transformer
        - Provide 8 breaker positions to feed existing circuitry now fed from the original substation site

The North Keene Substation projects would include:

- Construct new substation to feed some of the 12.47 kV load from the North end of Keene.
    - **2013 work:**
        - Purchase property to site the new North Keene Substation
    - **2015 work:**
        - Build new 115 kV to 12.47 kV substation with one (1) 30MVA transformer
        - Provide for four feeds to the existing W13, W14, and W1 circuits

Option 4 – Replace Existing Keene Substation and Construct New Distribution Substation (South Keene) –

The Keene (Emerald St.) Substation projects would include:

- Replace TB7, TB12, TB18, and TB23 along with associated switchgear with new equipment at a proposed substation on Emerald St, retaining existing TB3 in service at the original Emerald Street site.
    - **2014 work:**
        - Procure a 115 kV to 12.47 kV mobile substation
    - **2015 work:**
        - Build new 115 kV to 12.47 kV substation with one (1) 30MVA transformer
        - Provide 8 breaker positions to feed existing circuitry now fed from the original substation site

The South Keene Substation projects would include:

- Construct new substation to feed 12.47 kV load from the South end of Keene.
    - **2013 work:**
        - Purchase property to site the new South Keene Substation
    - **2015 work:**
        - Build new 115 kV to 12.47 kV substation with one (1) 30MVA transformer
        - Provide for three feeds to the existing W15, W185 and W2 circuits
        - Provide for one feed to a future W6 circuit

Option 5 – Construct Two New Distribution Substations (South Keene and North Keene) –

The South Keene Substation projects would include:

- Replace TB7, TB12, TB18, and TB23 along with associated switchgear with new equipment at a proposed substation located in the vicinity of the 115 kV crossing of highway Route 101 in Keene, retaining existing TB3 in service at the existing Keene Substation.

- **2013 work:**
  - Purchase property to site the new South Keene Substation
- **2014 work:**
  - Procure a 115 kV to 12.47 kV mobile substation
- **2015 work:**
  - Build new 115 kV to 12.47 kV substation with one (1) 30MVA transformer
  - Provide 8 breaker positions to feed existing circuitry now fed from the original substation site
  - Construct new 12kV line (1800') to connect the new South Keene Substation to the W2 circuit on Winchester St. (Additional line construction will not be needed for the W15 or W185 circuits because both circuits already share the right-of-way crossing with the two 115 kV lines A152 and T198; see picture above.)

The North Keene Substation projects would include:

- Construct new substation to feed 12.47 kV load from the North end of Keene.
  - **2013 work:**
    - Purchase property to site the new North Keene Substation
  - **2015 work:**
    - Build new 115 kV to 12.47 kV substation with one (1) 30MVA transformer
  - **2015 work:**
    - Provide for four feeds to the existing W13, W14, and W1 circuits

Option 6 – <u>Install Distributed Generation</u> –

The installation of distributed generation could defer the base case need for additional transformation in the Keene area; however, it cannot address the equipment obsolescence and inadequate breaker interrupting ratings that presently exist. Significant work would be required at the Keene substation to make this a viable option. This option is not an effective solution.

V Recommendation

Based on the information contained in this report it is recommended that PSNH:

1. Procure 115 kV to 12.47 kV mobile substation. ISD 2014
2. Construct new North Keene Substation with one 30 MVA transformer and associated switchgear. ISD = 2015
3. Replace existing obsolete equipment at Keene Substation with one 30 MVA transformer and associated switchgear. ISD = 2015 (Note: If environmental issues are uncovered during an environmental risk assessment on the property adjacent to the existing Keene Substation, then a new South Keene substation would be a viable alternative.)

Implementation of the above recommendation will address the following outstanding issues:

- Limited line and transformer capacity to serve the area reliably.
- Maintenance is difficult to schedule on the existing in-service power transformers at Keene Substation, due to loading. Exacerbating the situation is the fact that PSNH does not own a 115 kV to 12.47 kV mobile substation.
- Current one-substation design subjects the vast majority of equipment to destruction if a catastrophic event were to occur in the vicinity of the Emerald Street site.
- Current one-substation design could potentially cause widespread power quality issues due to localized events.

If the above outstanding issues are not addressed, there is increasing concern that a major outage and continued decline in service quality will result.

PSNH's System Planning and Strategy has studied several options and evaluated them based on reliability, net present value, and system operational flexibility. (See Appendix J – Project Benefit Comparison.) The Keene solution incorporates design standards and justifications from Northeast Utilities Distribution System Engineering Manual, as well as PSNH policy ED-3002. The resulting design will be reliable and allow for future expansion as the economy continues to recover.

Appendix A — Substation Transformer Characteristics

Keene Substation

There are five power transformers in service at Keene Substation at the end of Emerald St in Keene. Details of this equipment are listed below.

Transformer TB 18

- Transformer size is 12.5 MVA, voltage class 115 kV to 12.47 kV with Δ / 'Y connected windings.
- Transformer was manufactured in 1953 and installed in 1978.
- Maximum TFRAT rating is 14 MVA.
- Loading on the transformer was 7.69 MVA (July of 2011).
- Three circuits serve a total of 6,368 PSNH customers (shared with TB12).
- The connected secondary switchgear was manufactured in 1949 and installed in 1949.
- The available fault current is at 103% of its interrupting rating of 10,000 amps.

Transformer TB 23

- Transformer size is 12.5 MVA, voltage class 115 kV to 12.47 kV with Δ / 'Y connected windings.
- Transformer was manufactured in 1954 and installed in 1968.
- Maximum TFRAT rating is 13 MVA.
- Loading on the transformer was 7.54 MVA (July of 2011).
- Four circuits serve a total of 7,582 PSNH customers (shared with TB7).
- The connected secondary switchgear was manufactured in 1954 and installed in 1954.
- The available fault current is at 47% of its interrupting rating of 22,000 amps.

Transformer TB 7

- Transformer size is 22.4 MVA, voltage class 115 kV to 12.47 kV with Δ / 'Y connected windings.
- Transformer was manufactured in 1964 and installed in 1969.
- Maximum TFRAT rating is 25 MVA.
- Loading on the transformer was 13.01 MVA (July of 2011).
- Four circuits serve a total of 7,582 PSNH customers (shared with TB23).
- The connected secondary switchgear was manufactured in 1954 and installed in 1954.
- The available fault current is at 47% of its interrupting rating of 22,000 amps.

Transformer TB 12

- Transformer size is 22.4 MVA, voltage class 115 kV to 12.47 kV with Δ / 'Y connected windings.
- Transformer was manufactured in 1969 and installed in 1969.
- Maximum TFRAT rating is 27 MVA.
- Loading on the transformer was 13.33 MVA (July of 2011).
- Three circuits serve a total of 6,368 PSNH customers (shared with TB18).
- The connected secondary switchgear was manufactured in 1949 and installed in 1949.
- The available fault current is at 103% of its interrupting rating of 10,000 amps.

Transformer TB 3

- Transformer size is 22.4 MVA, voltage class 115 kV to 12.47 kV with Δ / 'Y connected windings.
- Transformer was manufactured in 2000 and installed in 2007.
- Maximum TFRAT rating is 26 MVA.
- Loading on the transformer was 18.05 MVA (July of 2011).
- Two circuits serve a total of 2,093 PSNH customers.
- The connected secondary switchgear was manufactured in 2000 and installed in 2000.
- The available fault current is at 56% of its interrupting rating of 12,000 amps.

Swanzey Substation

Transformer TB 2S

- Transformer size is 25 MVA, voltage class 115 kV to 13.09 kV with Δ / 'Y connected windings.
- Transformer was manufactured in 2009 and installed in 2009.
- Maximum TFRAT rating is 30 MVA.
- Loading on the transformer was 8.39 MVA (July of 2011) based on actual thermal ammeter maximum readings.
- Two circuits serve a total of 3,277 PSNH customers.
- The connected secondary switchgear was manufactured in 2009 and installed in 2009.
- The available fault current is at 31% of its interrupting rating of 24,000 amps.

Transformer TB 8S

- Transformer size is 25 MVA, voltage class 115-13.2 kV with Δ / 'Y connected windings.
- Transformer was manufactured in 1991 and installed in 2011 (not in service).
- Maximum TFRAT rating is 30 MVA.
- This transformer would be placed in-service if TB2S failed.

Appendix B Substation Switchgear Characteristics

Vermont 115KV Southern Loop Expansion - Short Circuit Duty Review (DRAFT) 6/24/09 PCM

P&CE (D) has been asked to review the impact on PSNH distribution equipment of proposed changes to the 115 KV in Vermont. The changes in Vermont are specifically defined in "ISO-NE I.3.9 Studies of the Southern Loop".

On May 6, 2008, Vermont Electric Power Company issued a report on the effects caused by the increase in fault currents which will result from the changes in Vermont. The conclusion of that report was that "there are no fault current issues on the 115KV and above voltage system in the area of the project." Potential problems were, however, identified on a 4.16KV bus at Vermont Yankee.

The review of the PSNH distribution equipment in the area of the project was done by using the same short circuit case as that used in the VELCO study and as summarized on May 6, 2008. The case name for ASPEN One-Liner purposes is "2008 NEPOOL Short Circuit Model (Feb) rev 01_ALL NRP-Fitzwilliam_Nominal.OLR on 3/10/08". The only changes made were as follows:

The Swanzey 115KV-12.47KV transformer model was changed to 15MVA per construction currently underway, and the new breaker ratings were applied.

The Jackman GSU was modeled with its estimated new impedance.

The electrical location of the Fitzwilliam 345-115KV tie was corrected per information from Alyssa Kennett.

Chestnut Hill 34.5 KV, Swanzey (new) 12.47KV, Keene 12.47KV, Monadnock 34.5 KV, and Jackman 34.5 KV were all given a preliminary review of their interrupting ratings. Of those locations, only Keene breakers were within 20% of their nominal ratings, so those breakers were given further analysis.

Keene 12.47KV Breaker Ratings Detailed

Matthew Cosgro contacted GE, who guided him to references which allowed him to detail the capability of the Keene breakers based on their nameplate information, and the application voltage (since the breakers are not nominally rated at 12.47KV). His results are shown on a spreadsheet located at K:\Deptdata\Energy Delivery\Distribution Asset Management\Equipment\Western Central\Keene SS Switchgear Nameplate and Ratings Infomation.xls. This base data was then used to develop interrupting capabilities based on in-service automatic reclose derating using standard P&CE (D) methodology previously developed for 34.5KV oil circuit breakers, and recently confirmed for these air circuit breakers. Specifically, IEEE C37.7-1952 was used for all breakers except for W1, since all but W1 were manufactured in either 1949 or 1954. W1 was manufactured in 1964, in fact has a much higher inherent capability, and was derated for reclosing using C37.010-1999. The results of this derating, along with available fault currents with and without the Vermont expansion, are shown in the spreadsheet on page 3.

By comparing this derated breaker information with today's base case, it was confirmed that the breakers are not currently operating above their theoretical interrupting capability. "Theoretical" is an operative term, however, since some of them are confirmed to be 60 years old as of this year. As shown on the attached spreadsheet, several of the breakers are currently within 5% of their theoretical interrupting ratings, the closest being within 2.56%. This data is shown in the spreadsheet as "3 Phase and L-G Fault Today".

The modestly revised VELCO case (with the changes identified above) was then run using the same fault options as PSNH currently applies to its base case. On the attached spreadsheet this column is identified as " 3 Phase + L-G Fault Future A". This still didn't push any breakers above their capability, and neither did the use of the same case using exactly the same fault options as is used for the New England wide NEPOOL case (see "3 Phase + L-G Fault Future B"), although the closest was within 1.38% of its capability.

It should be noted, however, that these results are for base case conditions, with bus tie breaker 1200 open. There are many alternate feeds to the Keene feeders which could change the results. For example, Keene State College is adding generation to feeder W9A, which poses no interrupting rating issues. For the loss or any outage of TB3, this generation could be tied to Bus #1 through W2A, adding approximately 160A of fault current to the bus total, or enough to put several breakers very close to or slightly over 100% of their capability.

Conclusion

The average increase in fault current on the Keene 12.47KV breakers due to the Vermont system expansion is 1.68%. That said, no breakers on base case are above their calculated interrupting capability today, and none are predicted to be after the Vermont 115KV system enhancements.

Further P&CE (D) Comments on Keene Breaker Ratings

The results of the Keene 12.47 KV breaker review unearthed some facts about Keene which should be documented.

As stated above, there are presently four breakers within 5% of their calculated interrupting capabilities, and a total of 10 within 10%, and there will shortly be a total of eleven breakers within 10% of their capabilities. One breaker is 45 years old, and the rest are between 55 and 60 years old.

The subject of the Keene breaker interrupting capabilities has been raised many times over the last 30 years. There has been, and still is a limit on the use of the bus tie breaker due to the feeder breaker interrupting ratings. Any three transformers in service with the bus tie breaker closed puts the feeder breakers well above their interrupting capability. At one point in the past, GE was approached about "plug and play" breaker modules with higher interrupting capabilities to replace the existing breakers. The subject review raises the question again.

One small step could be taken to increase the margin between the calculated interrupting capability and the available fault current. There are many reclosing combinations in use at Keene today. The IEEE Standard reclose cycle is CO-15 seconds-CO. More than one reclose, and/or any time shorter than 15 seconds reduces the breaker's interrupting capability. The following reclose combinations shows the impact on the breaker's nominal interrupting capability. The overall time was assumed to be less than twenty seconds (though preferably 15 seconds) per recent practice.

RECLOSE OPEN TIMES	DERATING FACTOR
1- 5 sec	.9667X
1- 7 sec	.9733X
1-10 sec	.9830X
1-15 sec	1.000X
2 - 5, 5 sec	.9111X
2 - 5, 10 sec	.9265X
2 - 7, 8 sec	.9268X
2 - 7, 13 sec	.9426X
2 - 5, 15 sec	.9425X

This chart shows that more than 5% in breaker interrupting capability can be gained by avoiding multiple short open times. It is suggested that either 1 reclose at 7 - 10 seconds (preferred) or 2 recloses totaling 20 seconds be considered on all Keene feeder breakers until the time when the breakers are changed out.

PCM
6/24/09

KEENE 12.47 KV FAULT DUTY CAPABILITIES WITH VT 115 KV SOUTHERN LOOP EXPANSION 6/24/09

A	B	C	D	E	F	G	H	J	K
YEAR MANUF	BREAKER (RECLOSE OPEN TIMES - SEC)	BRKR RTNG AT NOM'L V WITH RECLOSING	BRKR RTNG AT 1.05 PU V WITH RECLOSING	3 PHASE + L-GROUND TODAY	PCT COL "E"/ COL "D"	3 PHASE + L-GROUND FUTURE *A* (NOTE 4)	PCT COL "G"/ COL "D"	3 PHASE + L-GROUND FUTURE *B* (NOTE 5)	PCT COL "J"/ COL "D"
		AMPS	AMPS	AMPS		AMPS		AMPS	
1949	W15 (5)	11,632	11,078	9,577	86.45%	9,709	87.64%	9,783	88.31%
		11,632	11,078	10,035	90.58%	10,086	91.05%	10,163	91.74%
1949	W110 (5, 10)	11,151	10,620	9,577	90.18%	9,709	91.42%	9,783	92.12%
		11,151	10,620	10,120	95.29%	10,167	95.73%	10,251	96.53%
≤1949	W2 (5, 4)	10,921	10,401	9,577	92.08%	9,709	93.35%	9,783	94.06%
		10,921	10,401	10,120	97.30%	10,167	97.75%	10,251	98.56%
1952	W175 (15)	12,029	11,456	9,577	83.60%	9,709	84.75%	9,783	85.40%
		12,029	11,456	10,120	88.34%	10,167	88.75%	10,251	89.48%
1949	BUS #1 to 1200	12,029	11,456	9,577	83.60%	9,709	84.75%	9,783	85.40%
		12,029	11,456	10,120	88.34%	10,167	88.75%	10,251	89.48%
1954	W185 (10, 10)	11,052	10,525	9,635	91.54%	9,759	92.72%	9,831	93.41%
		11,052	10,525	10,089	95.86%	10,135	96.29%	10,211	97.02%
1954	W14 (6, 16)	11,304	10,766	9,635	89.49%	9,759	90.65%	9,831	91.32%
	(NOTE 7)	11,304	10,766	10,089	93.71%	10,135	94.14%	10,211	94.84%
1954	W13 (5, 10)	10,872	10,354	9,635	93.06%	9,759	94.25%	9,831	94.95%
		10,872	10,354	10,089	97.44%	10135	97.88%	10,211	98.62%
1964	W1 (5, 5)	21,140	20,228	9,398	46.46%	9,523	47.08%	9,596	47.44%
		24,311	23,262	9,839	42.30%	9,886	42.50%	9,962	42.83%
1949	BUS #2 to 1200	12,029	11,456	9,635	84.10%	9,759	85.19%	9,831	85.82%
		12,029	11,456	10,089	88.07%	10,135	88.47%	10,211	89.13%

NOTES:

1) Breaker data and nominal interrupting capabilities supplied by (D) Substation Engineering's Matthew Cosgro.
2) Breaker interrupting ratings "W/RECL'G" (with reclosing) were derated for reclosing based on C37.7-1952, except W1 (C37.010-1999).
3) 3P & L-G faults "TODAY" are based on the PSNH base case Psnh092.
4) 3P & L-G faults "Future A" are from the OneLiner case from VELCO via Jim DiLuca but PSNH Base Case fault options were used. See (6)
5) 3P & L-G faults "Future B" are from the OneLiner case from VELCO via Jim DiLuca; 2008 NEPOOL Case fault options were used. See (6)
6) Non VELCO revisions to the VELCO case: Fitwilliam 115 KV tie corrected, the Swanzey dist xfmr and Jackman Hydro GSU were updated.
7) W14 reclosing with 6, 16 seconds open times assume the existing 0 sec (inst) is removed as planned.

Appendix C Circuit and Substation Loading Characteristics

K:\Deptdata\Energy Delivery\System Plan&Strategy\Comprehensive Studies\Keene Area Study\Report\Study Circuit Loadings.xlsx

K:\Deptdata\Energy Delivery\Distribution Asset Management\System Loading Data\Western Central\Loadings - Keene Monadnock\SS Loading – Keene.xls

Keene S/S Circuit Loadings and Bus Arrangement

Growth Rate: 3.10%

Cust.	Bus 1	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1724	W15	4.6	4.8	4.9	5.1	5.2	5.4	5.6	5.7	5.9	6.1
2468	W110	11.4	11.8	12.2	12.5	12.9	13.3	13.7	14.2	14.6	15.1
	W2	(N.O.)									
1768	W175	8.3	8.6	8.8	9.1	9.4	9.7	10.0	10.3	10.6	11.0
5960		24.4	25.1	25.9	26.7	27.6	28.4	29.3	30.2	31.1	32.1
Cust.	Bus 2										
1069	W185	7.48	7.7	8.0	8.2	8.5	8.7	9.0	9.3	9.6	9.8
2315	W13	5.04	5.2	5.4	5.5	5.7	5.9	6.0	6.2	6.4	6.6
1744	W14	4.54	4.7	4.8	5.0	5.1	5.3	5.4	5.6	5.8	6.0
2771	W1	8.23	8.5	8.7	9.0	9.3	9.6	9.9	10.2	10.5	10.8
7899		25.3	26.1	26.9	27.7	28.6	29.5	30.4	31.3	32.3	33.3
Cust.	Bus 3										
1145	W9A	9.71	10.0	10.3	10.6	11.0	11.3	11.7	12.0	12.4	12.8
910	W2A	8.93	9.2	9.5	9.8	10.1	10.4	10.7	11.1	11.4	11.8
2055		18.6	19.2	19.8	20.4	21.1	21.7	22.4	23.1	23.8	24.5
15914	**S/S Total**	**68.3**	**70.4**	**72.6**	**74.9**	**77.2**	**79.6**	**82.0**	**84.6**	**87.2**	**89.9**

TFRATs		
bus 1		AFC
TB12	27	10300
TB18	14	
	41	
	95%	39.0
bus 2		AFC
TB23	13	10340
TB7	25	
	38	
	95%	36.1
bus 3		AFC
TB3	26	6720
	95%	24.7

2011 Circuit Loadings		
MVA	MW	MVAR
4.63	4.60	0.50
11.44	11.40	1.00
-		
8.32	8.30	0.60
24.39		
7.48	7.40	1.10
5.04	5.00	0.60
4.54	4.40	1.10
8.23	8.20	0.70
25.28		
9.71	9.50	2.00
8.93	8.90	0.70
18.64		
68.31		

Swanzey S/S Circuit Loadings

Cust.	Swanzey	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1794	4W1	4.46	4.6	4.7	4.9	5.0	5.2	5.4	5.5	5.7	5.9
1992	4W2	4.05	4.2	4.3	4.4	4.6	4.7	4.9	5.0	5.2	5.3
3786	**S/S Total**	**8.5**	**8.8**	**9.0**	**9.3**	**9.6**	**9.9**	**10.2**	**10.5**	**10.9**	**11.2**
19700	**Area Total**	**76.8**	**79.2**	**81.7**	**84.2**	**86.8**	**89.5**	**92.3**	**95.1**	**98.1**	**101.1**

Swanzey		
TB2S	30	
	95%	28.5

2011 Circuit Loadings		
4.46	4.20	1.50
4.05	3.80	1.40
8.51		
76.82		

RER 05/02/2012

Appendix D 12.47 kV Loadflow Synopsis

Development of PSS/E Model

In order to perform the load flow studies on the Keene 12.47 kV distribution, it was necessary to build the circuit model in PSS/E from scratch as, up until this point in time, the only thing modeled in PSS/E were three bus loads at Keene Substation (representing the total combined load fed from Keene Substation 12.47 kV Buses 1, 2 & 3) and one bus load at Swanzey Substation (representing the entire load fed by Swanzey Substation). It was decided that all mainline sectionalizing devices (those that could be used to transfer load from one circuit to another) would be modeled for each individual 12.47 kV circuit to accommodate the analysis required for contingency operations. The mainline section of a circuit in between sectionalizing devices would be represented as one PSS/E branch, and all collective load in between sectionalizing devices would be assigned to the downstream bus in PSS/E. All radial parts of each 12.47 kV circuit would simply be modeled in PSS/E as one collective bus load, reducing the complexity of the model which is only needed to analyze mainline issues.

All conductor data utilized to calculate branch impedances in PSS/E were gathered from the most recent Keene AWC prints (with input from Field Engineering where discrepancies arose), and all load data utilized for the PSS/E bus loads were taken from the most recent substation load database, provided by Field Engineering, as well as from load data in Field Engineering's Aspen Distriview circuit models (depicting how load is allocated throughout each individual circuit).

It was then decided to employ an annual load growth rate specific to the Keene 12.47 kV distribution in order to reflect a more localized load growth pattern for the load flow analysis. Similar to the summer peak load forecasting performed tor the 12 load flow areas in PSS/E for System Planning & Strategy's Ten-Year Study, the load forecast calculation methodology used in Procedure ED-3029 was utilized to calculate an annual growth rate specific to the Keene 12.47 kV distribution using the total combined annual peak loads of the six 115 kV to 12.47 kV transformers feeding the Keene 12.47 kV distribution. It should be noted, however, that only seven years of historical load data was used in this forecasting calculation, as opposed to ten year's worth of load data as prescribed in ED-3029, as that was all that was available. Nonetheless, upon executing the ED-3029 forecast calculation with the available load data, an annual load growth rate of 3.1% was calculated for the Keene 12.47 kV distribution, which is used to scale all future year loads in the Keene load flow analysis.

Load Flow Analysis

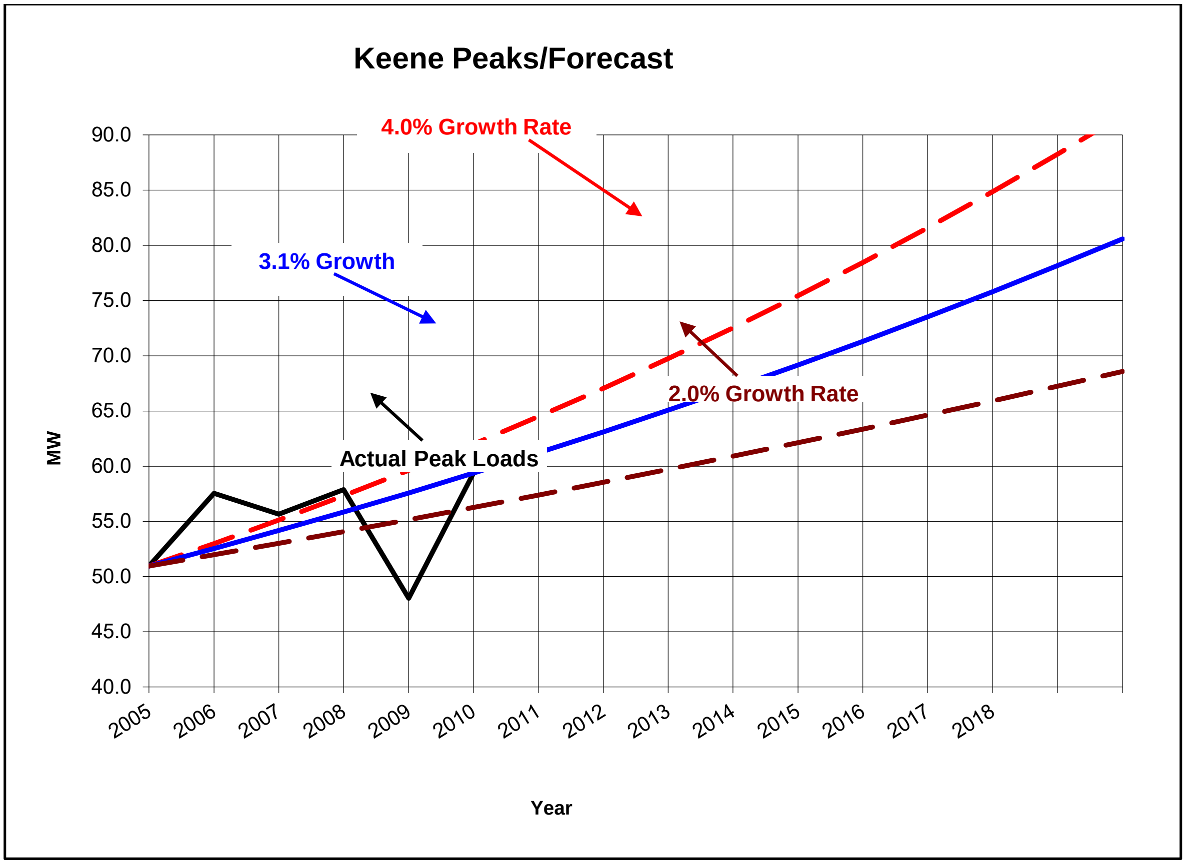
With a proper load flow model developed for the Keene 12.47 kV distribution, the load flow analysis could now be performed, beginning with an initial base case model for 2011. From a purely base case perspective (only looking at base case loading and voltage) and only scaling up the loads from year to year without making any other changes to the model, there are no load flow violations until the year 2017. At this point in time, it is projected that the first 6,300' of the W110 circuit from Keene Substation to the 110DX5 switch (477 ACSR) exceeds its normal rating. Without making any changes to the model and continuing to scale the loads, the next violation occurs in 2020 when TB3 at Keene Substation is projected to exceed 95% of its 26 MVA TFRAT rating. Also, in that same year, it is projected that the first 1,050' of the W2 circuit from Keene Substation (336 ACSR) exceeds its normal rating.

However, when also taking contingency analysis into account, the first load flow violation is actually expected to occur in 2014 upon contingent loss of either TB7 or TB12 at Keene Substation. Both scenarios simulate the loss of a 22.4 MVA transformer (TB7 or TB12) while the smaller 12.5 MVA parallel-connected transformer (TB23 or TB18 respectively) becomes overloaded. Both contingency scenarios also require five load block transfers in order to reduce the loading on TB23 or TB18 to within their respective TFRAT ratings. In order to limit the number of load block transfers to three in either of these contingency scenarios, load would need to be isolated. However, the accepted load isolation criteria utilized for 34.5 kV contingencies, as illustrated in procedure ED-3002, can't be employed for contingencies on the Keene 12.47 kV distribution because PSNH currently doesn't have a dedicated 115 kV to 12.47 kV mobile transformer. Therefore, no load isolation is acceptable for contingencies involving the Keene 12.47 kV distribution, which means 2014 is the first year where an area solution needs to be determined for the existing distribution.

Going one step further as an added measure, it was decided to see if the W6 circuit installation in the 115 kV right-of-way between Keene Substation and Swanzey Substation (currently in the capital budget to be in-service for 2015) would solve the aforementioned contingency violations seen in 2014, assuming the W6 line would be in-service for 2014. With the W6 line added to the PSS/E model, the same contingency analysis was performed. Having the additional W6 line available does enable the number of load block transfers to be reduced from five to three to relieve the overloading of TB23 for loss of TB7, resolving the previous violation. However, for loss of TB12, it still requires five load block transfers to relieve the overloading of TB18. The reason for this is that the W6 line, as proposed, would be normally fed by the parallel-connected TB12 and TB18 transformers and would be utilized to feed the Keene State College load that's currently served by the W9 circuit. This approximate 4 MW load swap to the W6 line would increase the base case loading on the TB12/TB18 transformers. Therefore, for a contingent loss of the larger TB12, this additional W6 load actually contributes to the overloading of TB18, thus increasing the amount of load needing to be transferred to reduce the loading on TB18 to within TFRAT. Subsequently, the number of load block transfers needed to accomplish this in 2014 remains at five.

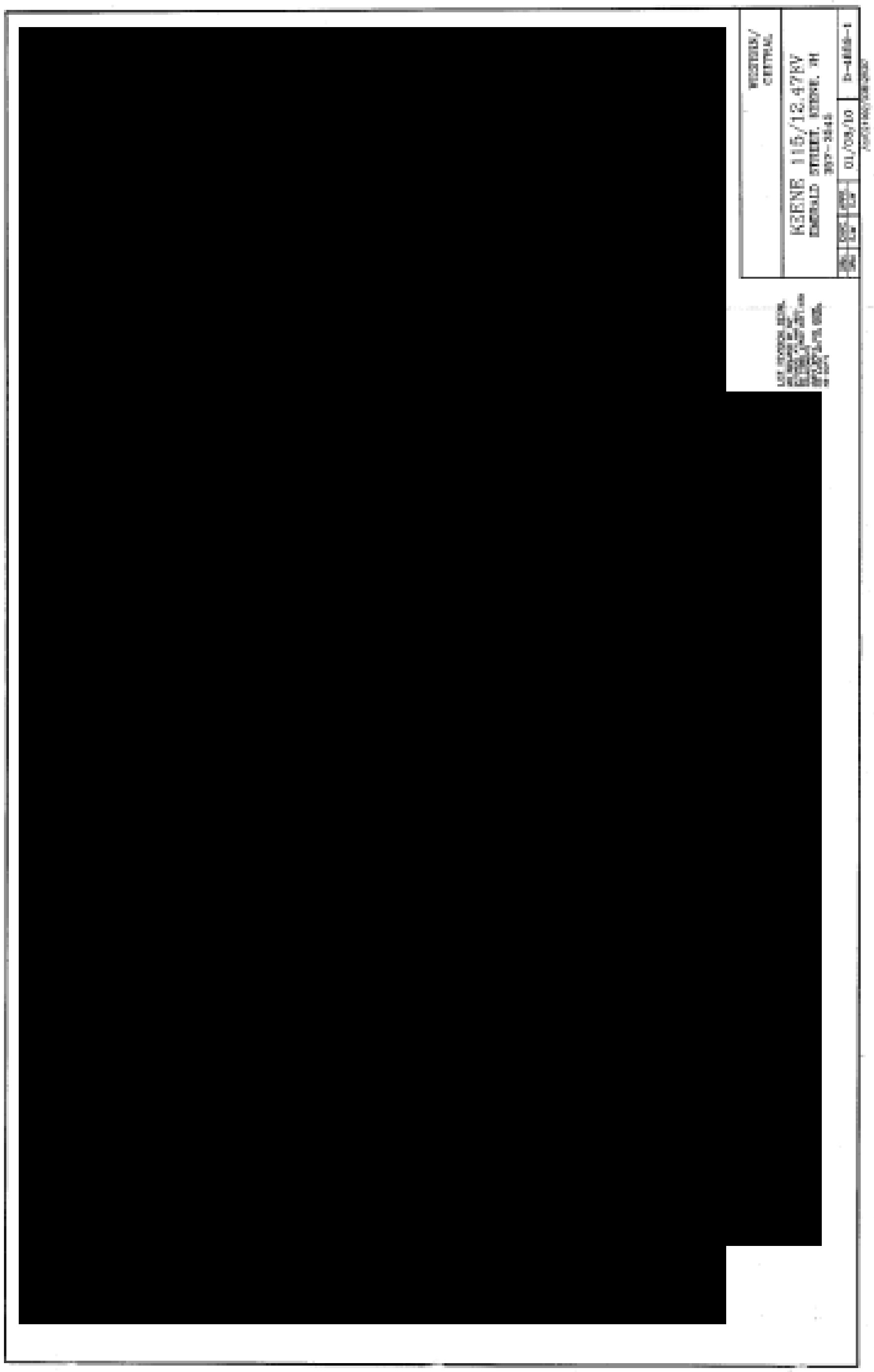
It has therefore been determined that some type of solution needs to be implemented by 2014 in order to prevent violating any design criteria. Since requiring a solution by 2014 doesn't provide adequate time for a long-term permanent construction solution, and since the violation needing to be resolved is a contingency violation rather than a base case loading violation, it is recommended that PSNH acquires a dedicated 115 kV to 12.47 kV mobile transformer. This will not only restore load for certain Keene 12.47 kV contingencies and buy us time until the first base case loading violation is expected in 2017, but having a 115 kV to 12.47 kV mobile transformer readily available will also benefit the Derry area which also has 115 kV to 12.47 kV transformation.

Keene Area Peak Load Forecast:



Appendix E — Keene Substation One-Line Diagram

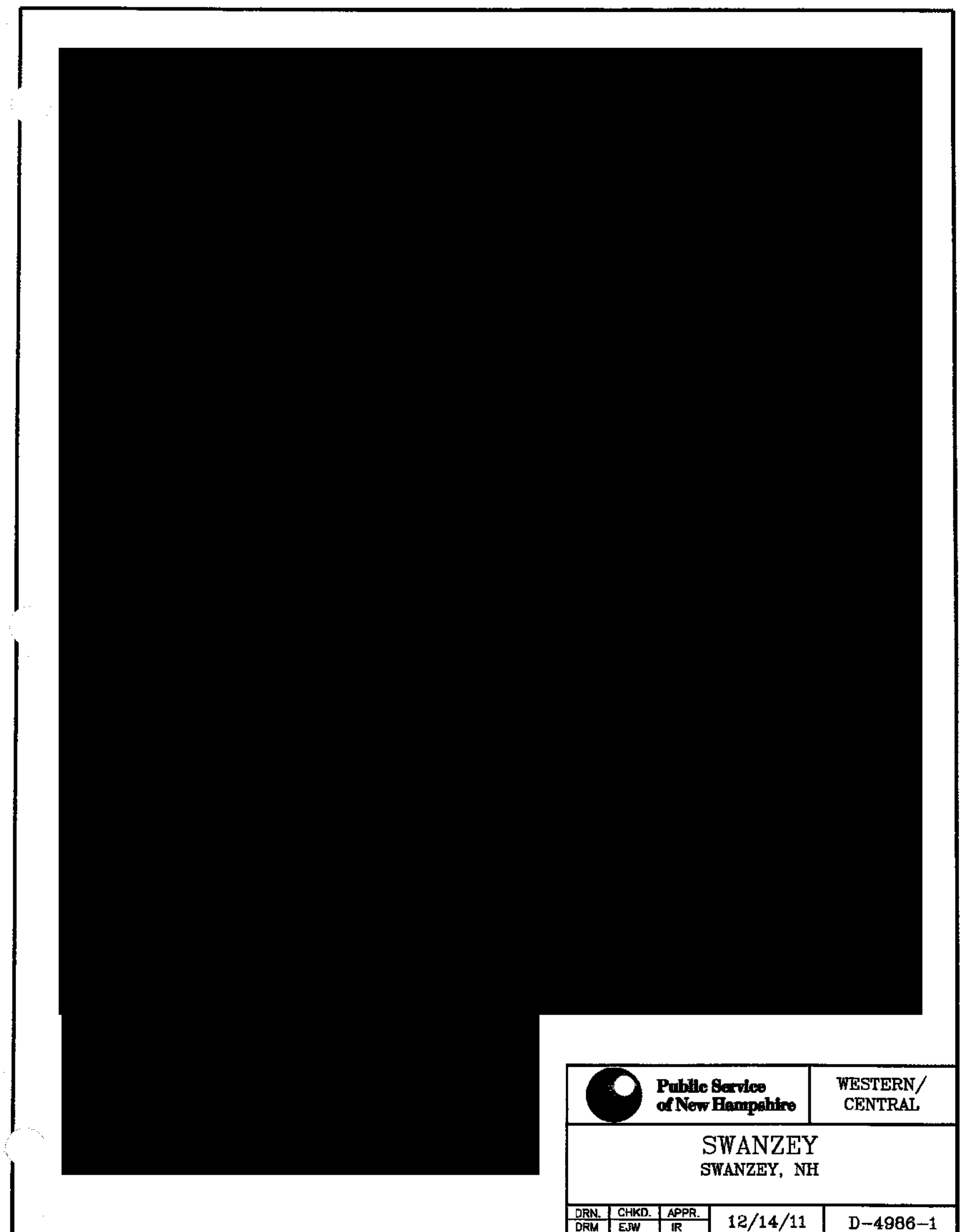
[ONE-LINE DIAGRAM REDACTED]



[redacted]

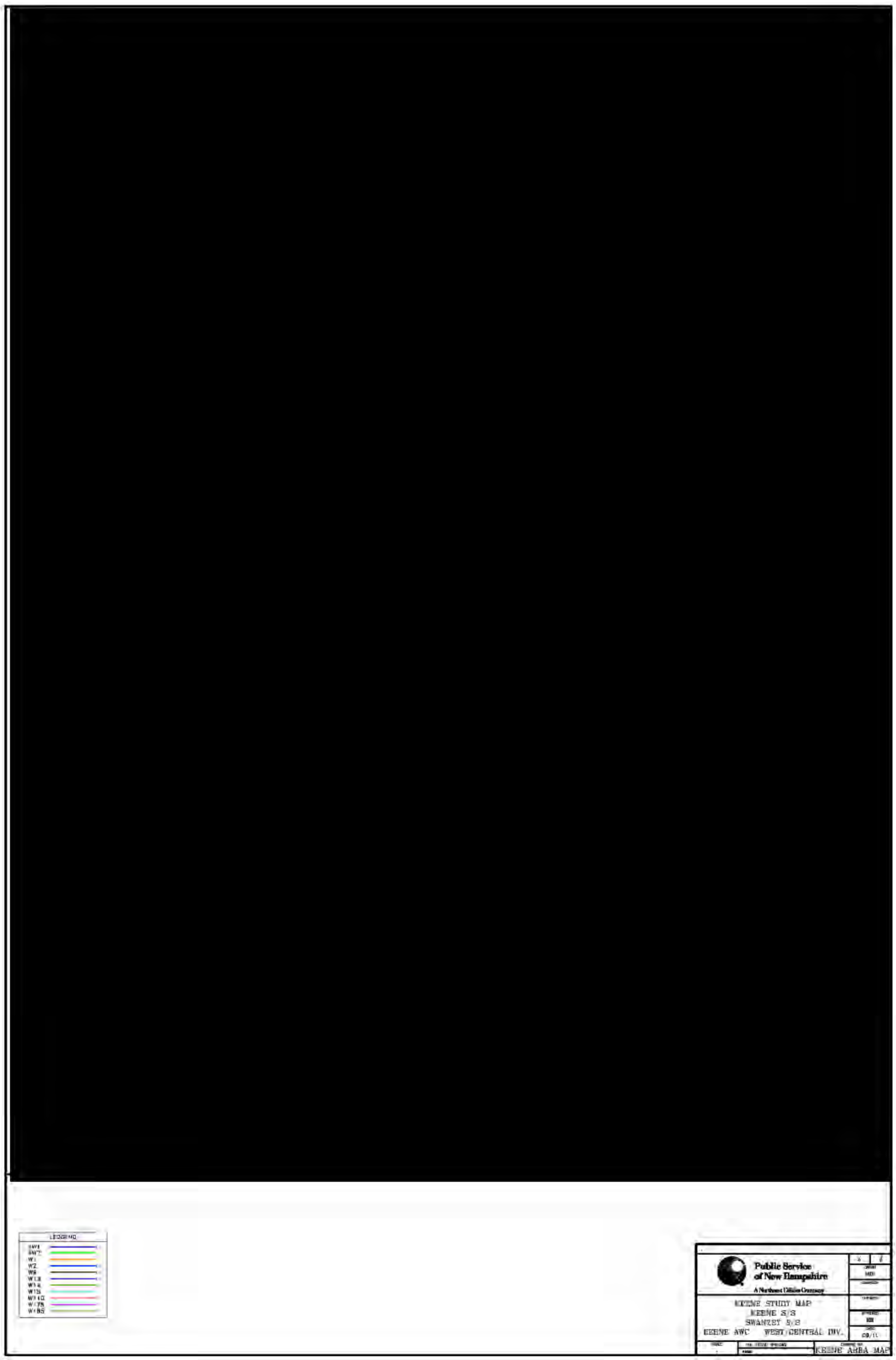
Appendix F Swanzey Substation One-Line Diagram

[ONE-LINE DIAGRAM REDACTED]



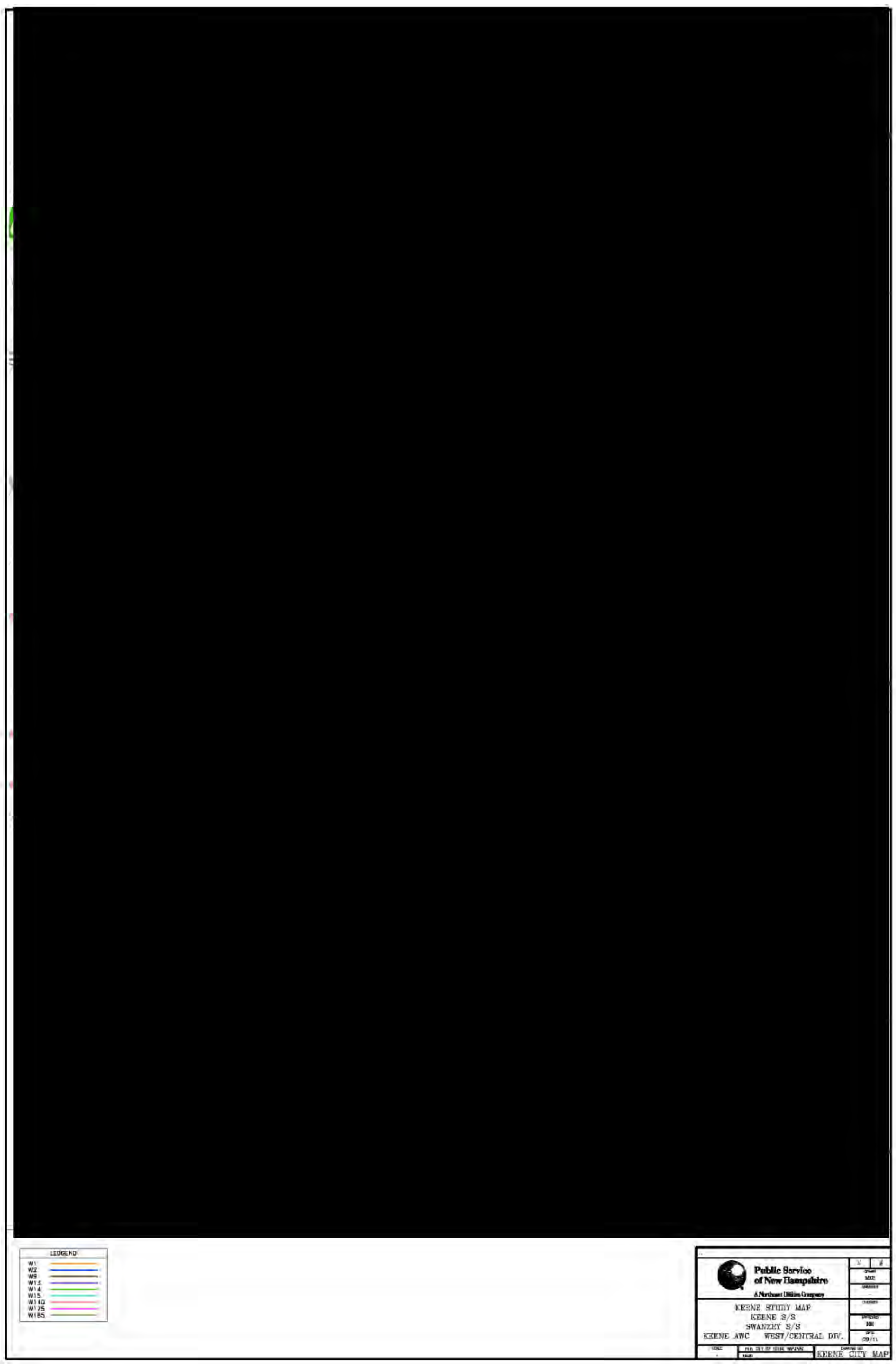
Appendix G Keene Area 12.47 kV Circuit Diagram

[ONE-LINE DIAGRAM REDACTED]



Appendix H — City of Keene Circuit Diagram

[ONE-LINE DIAGRAM REDACTED]



Appendix I Cost and Net Present Value Summary

K:\Deptdata\Energy Delivery\System Plan&Strategy\Comprehensive Studies\Keene Area Study\Report\Options Costs T and D.xlsx

Costs are in $Millions

2012 Dollars	New North Keene S/S	Rebuild Emerald St.	Rebuild Emerald St. w/ two units	New South Keene Site
Options				
Distribution S/S	5.94	7.03	7.97	5.94
Distribution Line	1.20	0.50	0.50	0.70
Transmission S/S	12.42	6.00	6.00	12.42
Total	19.56	13.53	14.47	19.06

	Present Value	
Emerald Only	option 2	26.2
No. Keene	option 3	33.7
So. Keene	option 4	33.2
No. & So. Keene	option 5	39.2

The above present values were developed from the information provided below:

Distribution Substation: (Ingrid Rahaim 2/28/2012)

Please find the high level cost estimates for the Distribution portions of potential Keene area projects. The cost is in 2012 dollars. The estimates are based on ED3064 “Capital Budget Estmating” - DISTRIBUTION SUBSTATION ENGINEERING UNIT COST.

New North Keene S/S: $4.0M - $9.5M
The order of magnitude is conceptual where the scope is similar to a previously completed project and has not been sufficiently defined to make a direct comparison. The expected accuracy ranges from -30% to + 60% and the contingency from 25% to 50% .
Assumptions:
The Distribution cost for one (1) 115 to 12.47 kVtransformer, one capacitor bank and four feeder positions (W1, W13, W14)

Rebuild Emerald Street with two transformers: $6.25M - $12.75M
The order of magnitude is conceptual where the scope is similar to a previously completed project and has not been sufficiently defined to make a direct comparison. The expected accuracy ranges from -30% to + 60% and the contingency from 25% to 50% .
Assumptions:

The 0.97 A property across the street from existing station is large enough accommodate the 115kV terminals
The 0.97 A property does not require extreme environmental mitigation
Two (2) 115 to 12.47 kV, 30 MVA transformer units
Eight (8) 12.47 kV feeder positions (W15, W110, 75W1&2, W185, W1, W13, W14, spare) , two transformer breaker; provisions for two capacitor banks.
TB3 and bus 3 will remain in the station to feed W9 and W2.
The cost to remove and provide a temporary set-up for TB12 or TB 18 is not included.

Rebuild Emerald Street with one transformer: $5.00M - $11.25M
The order of magnitude is conceptual where the scope is similar to a previously completed project and has not been sufficiently defined to make a direct comparison. The expected accuracy ranges from -30% to + 60% and the contingency from 25% to 50% .
Assumptions:
The 0.97 A property across the street from existing station is large enough accommodate the 115kV terminals
The 0.97 A property does not require extreme environmental mitigation
One (1) 115-12.47kV, 30 MVA transformer units
Eight (8) 12.47 kV feeder positions (includes 2-4 future or spare feeders) , one transformer breaker; provisions for one capacitor bank.
TB3 and bus 3 will remain in the station to feed W9 and W2.
The cost to remove and provide a temporary set-up for TB12 or TB 18 is not included.

New South Keene S/S: $4.0M - $9.5M:
The order of magnitude is conceptual where the scope is similar to a previously completed project and has not been sufficiently defined to make a direct comparison. The expected accuracy ranges from -30% to + 60% and the contingency from 25% to 50% .
Assumptions:
The Distribution cost for one (1) 115 to 12.47 kV transformer, one capacitor bank and four feeder positions (W15, W185, W2)

Transmission Substation: (Jim Jiottis 2/27/2012)

The following can be used for budgetary planning. These are high level estimates, once the full scope is defined, new estimates with better detail should be developed.
The costs are in 2015 dollars.

New substation on the north end of Keene
The design would be our standard distribution substation, 2-115 kV breakers with a motor operated switch between the transformers.

The estimate for the transmission only portion of the yard is: **$6.21M - $25.26M**
Order of Magnitude (-50%+200%) estimate:
As the specific location has not been determined, an additional $1.5 mil has been added for land/row costs.

Expansion at Keene
This includes the following assumptions:
Removal of existing 12.47 kV transformers except TB3
Distribution can fit it new facilities on the existing .9 acres currently owned by PSNH
Connections will be underground cable using the former location and facilities of TB 18 and TB12 (approx 500 ft for each transformer)
No 115 kV breakers will be added, assume distribution will be using fully rated circuit switchers at new substation

Underground cables will be included in existing bus protection, distribution will provide sufficient CT's on new transformers for this
Assumes Emerald street can be ended at existing gas facilities and new parcel can be made contiguous with existing land.
Assumes distribution will allow removal of either TB18 or TB12 prior to completion of new substation.

The estimate for the transmission only portion is: **$3M - $12M**

New substation on the south end of Keene:

Same as North Keene estimate:
The estimate for the transmission only portion of the yard is: **$6.21M - $25.26M**
Order of Magnitude (-50%+200%) estimate:
As the specific location has not been determined, an additional $1.5 mil has been added for land/row costs.

Appendix J

Project Benefit Comparison

K:\Deptdata\Energy Delivery\System Plan&Strategy\Comprehensive Studies\Keene Area Study\Report\MATRIX FORM Keene Area Study.xls

Keene Area Study - Matrix for Option Comparison

Project: Construct New 115-12.47 kV Substations in Keene Area with two 30 MVA transformers in 2015. Remove obsolete equipment in Existing Keene Substation.	**Weighting**	**Rating** 4-5 = Superior, 2 -3 = Adequate, 0-1= Inferior					
		Option 1 Expand at 34.5kV to alleviate S/S transformer overloads	**Option 2** Reconstruct 115-12.47 kV Keene S/S with two 30 MVA XFMRs, replacing obsolete equipment at existing Keene S/S.	**Option 3** Construct a 115-12.47 kV North Keene S/S with one 30 MVA XFMR. Replace obsolete equipment at existing Keene S/S with one 30MVA XFMR	**Option 4** Construct a 115-12.47 kV South Keene S/S with one 30 MVA XFMR. Replace obsolete equipment at existing Keene S/S with one 30MVA XFMR	**Option 5** Construct a 115-12.47 kV North Keene S/S with one 30 MVA XFMR. Construct a 115-12.47 kV South Keene S/S with one 30 MVA XFMR. Remove obsolete equipment at existing Keene S/S.	**Option 6** Install Distributed Generation (20MW Combustion Turbine)
Cost			$26.2M	$33.7M	$33.2M	$39.2M	~$45M
Addresses Area Load Growth (Long Term)	8	1	3	5	5	5	1
Improves Reliability: SAIDI	8	1	2	3	3	4	1
Net Present Value (2012) (Appendix A)	7	2	5	4	4	3	2
Feasibility of In-Service Date (ISD)	6	2	2	4	3	3	4
Environmental Impact	5	3	1	2	2	3	1
Contingency Solution	5	1	2	3	3	4	3
Power Quality Improvement (SARFI -70)	4	2	3	3	3	3	2
Operating Cost	3	2	3	3	3	3	2
System Loss Savings (Appendix B)	3	1	1 adds 36.8 kw	4% 3 205.3 kw	2% 2 94.9 kw	6% 4 345.9 kw	4
Total		**79**	**126**	**171**	**162**	**179**	**100**

Public Service Company of New Hampshire d/b/a Eversource Energy
Docket No. DE 22-030

Date Request Received: June 28, 2022 **Date of Response: July 15, 2022**
Data Request No. TS 1-012 **Page 1 of 2**

Request from: Department of Energy

Witness: Renaud, Paul R, Dipaola-Tromba, John P, Dickie, Brian J, Plante, David L

Request:
Reference DOE 1-008, project A14W01, Emerald Street SS Rebuild:

a) (pp 4-5 of SRF) Please explain how 52 drawings needed for AZZ metal-clad switchgear design could have been missed in the detailed engineering design phase of the original work scope.

b) (p 5 of SRF) Please explain how construction costs to cover additional grounding to meet step touch potential safety standards outside of the substation fence could have been missed in the detailed engineering design phase of the original work scope.

c) (p 6 of SRF) Please explain how the need to rent a load bank testing unit for Protection & Control to test current transformer polarity a ratio checks could have been missed in the detailed engineering design phase of the original work scope.

Response:

a) The bid specification for the detailed substation engineering included a requirement that the engineering vendor assist with the preparation of a "general specification for power/control enclosures with metalclad switchgear to issue to equipment suppliers" and also went on to explain that the engineering vendor was responsible for engineering "where not part of the metalclad design". Leidos, in their proposal, attempted to clarify this demarcation or responsibility, taking on engineering drawings they felt were to be done by the engineering vendor and identifying drawings they felt would be done by the switchgear manufacturer. After award of the engineering contract, Eversource decided that preparing these drawings in advance and including with the switchgear specification would provide the Company with the best and most complete bid responses. This resulted in a change order for Leidos to complete these drawings. In theory, this also resulted in better bids for the switchgear, as the vendors did not need to prepare them, and this reduced the number of assumptions that the bidders would need to make in preparing their proposals.

b) The additional construction costs to address the additional grounding is related to the expansion of one side of the fence and installation of a retaining wall. Though the location of the retaining

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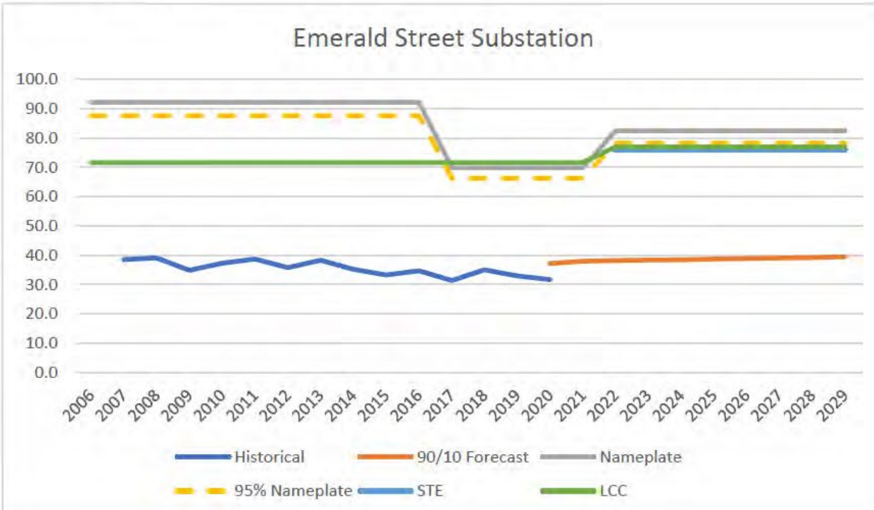
wall and fence expansion was known at the time of the construction contracting, the specific details of the grounding were not yet available as the construction bid was based upon the 70% engineering package and some details were not yet finalized. Therefore, a contingency of $25,000 was included in the construction contract, however the actual total cost was $56,000.

c) Commissioning of protective equipment is accomplished by loading the breaker and associated auxiliaries (CTs, PTs, instrument wiring etc) by closing the associated breaker and picking up customer load. Utilizing customer load for commissioning purposes does put customer load at risk while the commissioning engineers are doing their verifications. Due to the quality control issues encountered with the AZZ switchgear, Protection and Controls engineering recommended the use of the load bank to perform this work. This mitigated any risks to customers while performing the final commissioning work.

Loading and Capacity



Distribution Company	Customers
Eversource Energy	8,723
Total Customers	8,723

Pre-Project	Mfg. Year	Condition Code[1]	Nameplate	LTE	STE[2]	LCC
TB3	2000	1 – Green	22.4	26	33	
TB7	1964	3 – Orange	22.4	27	32	
TB12 - *OOS*	1969	3 – Orange	22.4	N/A	N/A	
TB18	1953	2 - Yellow	12.5	16	18	
TB23	1954	2 - Yellow	12.5	15	18	
Substation			92.2			71.6
Post-Project	**Mfg. Year**	**Condition Code[1]**	**Nameplate**	**LTE**	**STE[3]**	**LCC**
TX3	2000	1 – Green	22.4	27	33	
TX123	2018	N/A	30.0	37	45	
TX136	2018	N/A	30.0	38	45	
Substation			82.4		78	77.0

Note 1: Transformer condition code as of May 2020.

Note 2: Automatic bus restoral scheme, bus tie 1200 auto closes for loss of TB7 or TB12.

Note 3: Automatic bus restoral scheme, BT12 or TB23 auto closes based on seasonal limits.