
National Grid USA and The Narragansett Electric Company
Division 1-36

Request:

Please provide all Documents, including all reports, assessments, and analyses, in the possession of or prepared by or for PPL or PPL RI (including those provided by National Grid) related to the condition of the Narragansett gas and electric systems.

Response:

On June 15, 2021, counsel for PPL Corporation, PPL Rhode Island Holdings, LLC, National Grid USA, and The Narragansett Electric Company ("Narragansett" and collectively, the "Applicants"), and the Rhode Island Division of Public Utilities and Carriers' Advocacy Section ("Advocacy Section") met to discuss various discovery issues, which included, in particular, the scope of certain data requests, such as Data Request Division 1-36. On June 22, 2021, the Advocacy Section provided guidance to the Applicants relating to the scope of data requests, generally, and agreed that the Applicants may use their sound judgment and the rule of reason in crafting responses to data requests and providing responsive documents, taking into account the Advocacy Section's goal of protecting customers when determining scope and relevancy.

Based on this guidance, National Grid USA and Narragansett are providing the following documents relating to the condition of the Narragansett gas and electric systems, which it provided to PPL in response to questions from PPL during the due diligence process. For ease of reference, each document is identified by a corresponding file number.

- Attachment NG-DIV 1-36-1 – RI Underground Cable Replacement Strategy Study Report, December 2017, identified as "File 1.6.1.11"
- Attachment NG-DIV 1-36-2 – 3VO Program Rhode Island, identified as "File 1.6.1.12"
- Attachment NG-DIV 1-36-3 CONFIDENTIAL – Central Rhode Island East Area Study, September 2017, identified as "File 1.6.1.13"
- Attachment NG-DIV 1-36-4 CONFIDENTIAL – East Bay Area Study, 2015, identified as "File 1.6.1.14"
- Attachment NG-DIV 1-36-5 – Form 3A Recloser Replacement Study NE, identified as "File 1.6.1.15"
- Attachment NG-DIV 1-36-6 – Planning Review Process, identified as "File 1.6.1.16"

Prepared by or under the supervision of: Richard Burlingame and Legal Department

- Attachment NG-DIV 1-36-7 CONFIDENTIAL – Providence Area Study Implementation Plan 2016 – 2030, September 2017, identified as "File 1.6.1.17"

- Attachment NG-DIV 1-36-8 – Rhode Island Study Areas, July 6, 2020, identified as "File 1.6.1.18"

- Attachment NG-DIV 1-36-9 CONFIDENTIAL –South County East Area Study, March 2018, identified as "File 1.6.1.19"

- Attachment NG-DIV 1-36-10 – Asset Age, identified as "File 1.6.1.3"

- Attachment NG-DIV 1-36-11 – Gas Asset Age, identified as "File 1.6.1.4"

- Attachment NG-DIV 1-36-12 – Question ID 1070052 FY 21-25 CAPEX Complex Project Sponsorship, identified as "File 1.6.1.61"

- Attachment NG-DIV 1-36-13 – Responses to Asset Age and Condition Questions, June 15, 2021

- Attachment NG-DIV 1-36-14 – CY19 - CY20 Gas O&M, identified as "File 1.1.2.147 Q85000351 Att. 1"

- Attachment NG-DIV 1-36-15 – New or Revised Gas Material Acceptance, identified as "File 1.1.2.148 Q85000351 Att. 2"

- Attachment NG-DIV 1-36-16 – Response to Question ID. 85000351, identified as "File 1.1.2.149"

- Attachment NG-DIV 1-36-17 – Electric Transmission and Distribution Asset Management, identified as "File 1.1.2.152"

- Attachment NG-DIV 1-36-18 CONFIDENTIAL – Response to Question ID. 85000191, identified as "File 1.6.1.202"

- Attachments NG-DIV 1-36-19-1 through 1-36-19-5 CONFIDENTIAL – Cumberland Documents, identified as "File 1.6.1.203 Att.8500191"

- Attachments NG-DIV 1-36-20-1 through 1-36-20-5 CONFIDENTIAL – Exeter Documents, identified as "File 1.6.1.203 Att. 85000191"

Prepared by or under the supervision of: Richard Burlingame and Legal Department

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- Attachment NG-DIV 1-36-21 – Response to Question ID. 85000190, identified as "File 1.6.1.204"

- Attachment NG-DIV 1-36-22 – Responses to Asset Age & Condition Questions, June 15, 2021

Attachments NG-DIV 1-36-3, NG-DIV 1-36-4, NG-DIV 1-36-7, NG-DIV 1-36-9, NG-DIV 1-36-18, NG-DIV 1-36-19-1, and NG-DIV 1-36-20-2 contain confidential critical energy infrastructure information ("CEII"). Accordingly, National Grid USA and Narragansett are providing the confidential versions of these attachments pursuant to a Motion for Protective Treatment of Confidential Information and are providing redacted versions for the public filing.

nationalgrid

Underground Cable Replacement Program – Study Report
Rhode Island

Jeffrey H. Smith

December 14, 2017

Reviewed by: Elton Prifti Date: 04/17/18
Elton Prifti, Manager
Distribution Planning & Asset Management, NE
Electric Process and Engineering

Approved by: R Ct Date: 4/17/18
Ryan Constable, Director
Distribution Planning & Asset Management, NE Electric
Process and Engineering

Underground Cable Replacement Program
Rhode Island

Jeffrey H. Smith

December 14, 2017

Amendments Record

Issue	Date	Summary of Changes	Author(s)	Approved By (Inc. Job Title)
2	12/14/2017	Updated data, documented data sources, changed scope to main line only cable replacement and updated miles/year figures	Jeffrey H. Smith Distribution Planning & Asset Management	
1	09/29/2014	Initial Issue	Sahir Shakir Distribution Planning & Asset Management	

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Executive Summary

National Grid's underground electric infrastructure (principally electric cables and manhole and duct systems) is extensive. Such infrastructure is most common in the urban centers within the Company's service territory. Asset age and condition varies and certain vintages of cable insulation have demonstrated less reliable performance than others. When they occur, underground asset failures can (and have) resulted in manhole cover dislodgements. Such events are often visible to the public and raise understandable concern with regulators, the community, and public safety officials. Although such contingency events and possible outcomes cannot be completely eliminated, it is the Company's opinion that the frequency with which such events occur can be reduced with programmatic cable replacements.

The program documented with this study report will proactively replace underground cable on sub-transmission, distribution primary, and distribution secondary cable systems in the Rhode Island service territory. These replacements will result from the execution of both specific and programmatic projects.

A list of candidate sub-transmission and distribution primary cable replacement projects was developed and prioritized using a Criticality Scoring Model (CSM) that weighed factors such as asset age, past performance, customers served, proximity to assets experiencing prior failures and cable insulation type, among others. This CMS score was combined with a probability of failure, based on exposure, to create a ranked list of candidate projects. This candidate project list allows for long range program budgeting and resource planning and provides a starting point for further engineering review and the development of specific project proposals. The operating characteristics and availability of data on secondary cable systems does not currently allow for the application of a CSM for candidate project selection. As such, the program will identify and prioritize specific geographic areas within which secondary cable assets would first undergo inspection followed by targeted asset replacement and/or consolidation.

The sub-transmission and distribution primary cable replacement candidate project list was reviewed in detail by a cross functional team of Company representatives having local knowledge and experience with the Rhode Island underground system infrastructure. Functions represented included:

- Distribution Planning & Asset Management engineers
- Operations
- Community and Customer Management
- Resource Planning

It is presently expected that under this program the following costs will be incurred throughout FY19-21:

- Sub-Transmission cable replacements (approximately 10.0 miles) - $7.1M
- Distribution Primary cable replacements (approximately 4.9 miles) - $3.3M
- Distribution Secondary cable replacements (approximately 4.2 miles) - $5.1M

Over a ten year horizon, it is expected that a total of approximately 64 miles of underground cable replacements will be directed by this program at a total estimated cost of $52M.

Additionally, the current splice log application should be updated to improve its usability. Information from this application is a fundamental part of the CSM. Upgrading the program will better support the data collection and extraction process and allow users to more easily enter the data needed to support the continuing improvement of the UG cable replacement program.

Program Justification

1.0 Purpose and Scope

National Grid distribution engineers monitor the electrical distribution system's performance and when necessary develop projects to address concerns (reliability, thermal, voltage, etc.) either existing or anticipated. Underground cable replacement projects have been executed in response to acute or chronic service reliability concerns or have been undertaken based on asset physical condition, deterioration, or age. The Company is now putting forth this program to proactively replace underground cable. The program evaluates the underground cable assets using a Criticality Scoring Model (CSM) which considers multiple factors contributing to asset deterioration and "end of life" and a probability of failure based on the length of the feeder. These two factors are combined to create an overall risk score used to select feeders for cable replacement.

All main line underground cable is included in the analysis; however the program focuses on the conventional underground systems generally found in more urban areas of the service territory. These cables are predominantly installed in manhole and duct systems, yet some may be direct-buried. Underground cables in Underground Residential Developments (URD) and Underground Commercial Developments (UCD) are not a subject of this program. Aerial cable is also outside the scope of this program.

2.0 Program Description

2.1 Background

2.1.1 System Description

National Grid's underground electric infrastructure, principally electric cables and manhole and duct systems, is extensive (approximately 320 circuit miles of main line primary on 420 feeders). Cable operating voltages and functionalities vary. Operating voltages and usages include:

- Sub-transmission from 11 – 34.5 kilovolts (kV)
- Distribution Primary from 4 – 34.5 kV
- Secondary from 0 – 600 volts (V)

At all operating voltages listed above, portions of the distribution system are either operated in a radial or networked fashion.

The age of the underground system varies considerably. As such, underground cables with various vintages of insulation exist. Predominant insulation types include:

- Cross Linked Polyethylene (XLPE)
- Ethylene Propylene Rubber (EPR)
- Paper Insulated Lead Covered (PILC)

Generally, National Grid's underground systems perform very reliably and typically have more redundancy (operational flexibility to respond to system contingencies) than overhead systems. As such, the standard and complete response to contingency events has mostly been reactive repair or replacement of failed equipment. When elements of the system have experienced chronic performance concerns (ex. multiple cable failures), targeted projects have been executed to resolve the situation. National Grid has observed variability in the performance of the various types of cable insulation with certain vintages of XLPE being less reliable than others. In addition, given the fact that significant amounts of PILC cable have been in service for more than 60 years, concerns about the need for replacement due to normal deterioration have begun to surface both at National Grid and in the industry as a whole.

Over the last five years there have been several failures in urban areas of the system that have resulted in manhole cover dislodgements and/or smoking manholes. This has caused concern among public safety officials, regulators and the community regarding the performance of the Company's underground systems.

2.1.2 Industry Benchmarking

In 2014 the Company reviewed the cable replacement plans of several utilities including Commonwealth Edison (ComEd) in Chicago, Potomac Electric Power Company (Pepco) in Washington DC, Consolidated Edison (ConEd) in New York City and Indianapolis Power & Light (IPL) in Indianapolis.

Significant findings:

- The volume of planned replacements varied significantly between companies, and any planned replacements were limited to medium voltage class cable.
- No utilities indicated that they have a proactive secondary cable replacement program.
- Primary cable replacement programs varied from none, to limited opportunistic programs (in which projects based on other drivers were marginally expanded to accommodate localized asset replacement), to significant cable replacement programs.
- A significant program at ComEd is targeting the replacement of 526 miles of cable, primarily PILC cable in urban areas. This volume represents approximately 15% of the PILC cable ComEd indicated they have in service in Chicago. ConEd has an ongoing significant effort to replace PILC cable on their system. Both these PILC cable replacement programs appear to have resulted from concerns about future system performance due to normal deterioration that comes with extensive years in service.

2.2 Program

In response to manhole events and in consideration of the Company's industry benchmarking, National Grid has chosen to develop an underground cable replacement program. The Company has moved to an approach where it evaluates its asset replacement programs utilizing a Criticality Scoring Model (CSM) with standardized weighting factors for:

- Safety (20%)
- Customer Impact (20%)
- Asset Condition (40%)
- Reliability (20%)

Criteria used to populate the CSM have been standardized across both distribution and sub-transmission assets. The key criteria, and their relative impact in the CSM for each sub-group of primary cable used in this program's development, are shown in Appendix 1. The main drivers considered in the evaluation are:

- Safety - Recorded manhole events and public accessibility
- Customer Impact - Number of customer served, System Control Center Priority Code and percent feeder loading
- Asset Condition - Cable age and cable insulation type
- Reliability - Number of cable failures and feeder CKAIDI (Circuit Average Interruption Duration Index)
- Five years (2012 – 2016) of historic data was used across all data sources to feed the CSM.

Data is weighted exponentially by level as shown at the top of the table found in Appendix 1, with the most risk assigned to the highest level and score. Each data set within each category receives a weight based on Subject Matter Expert (SME) opinion. In the Excel based scoring tool used for this program, the weighting of each data set and the criteria for each level within the data set can be altered, and are shown in red in the scoring matrix. This allows scoring to be varied depending on the availability of data and the requirements of each jurisdiction.

The Safety component of the criticality score is primarily based on the potential of a manhole event and the public exposure should an event occur. A manhole event can range from smoke emitting from a manhole to an explosion that causes manhole cover dislodgement. An extensive study performed for ConEd found that previous manhole events are an indicator of future manhole events. The data in this study indicated that 20% of the serious manhole events occurred in the 10% of the manholes that were involved in previous manhole events.

At National Grid, manhole events are recorded in the Outage Reporting Protocol (ORP) database. To analyze this CSM category, manhole events were downloaded from ORP and the locations were matched to the GIS ID of the manhole. ESRI ArcGIS was used to score each feeder by counting the number of “event manholes” each feeder passes through. To measure public exposure to a potential manhole event, a third party data source (Walk Score®) was used to provide a consistent measure of pedestrian access in areas served by manhole and duct systems. ESRI ArcGIS was used to determine the percentage of the feeder passing through areas with a Walk Score ≥ 90 (Walk Scores range from 0 to 100). In the CSM, safety related risks were the only categories that can achieve Level 5 scoring.

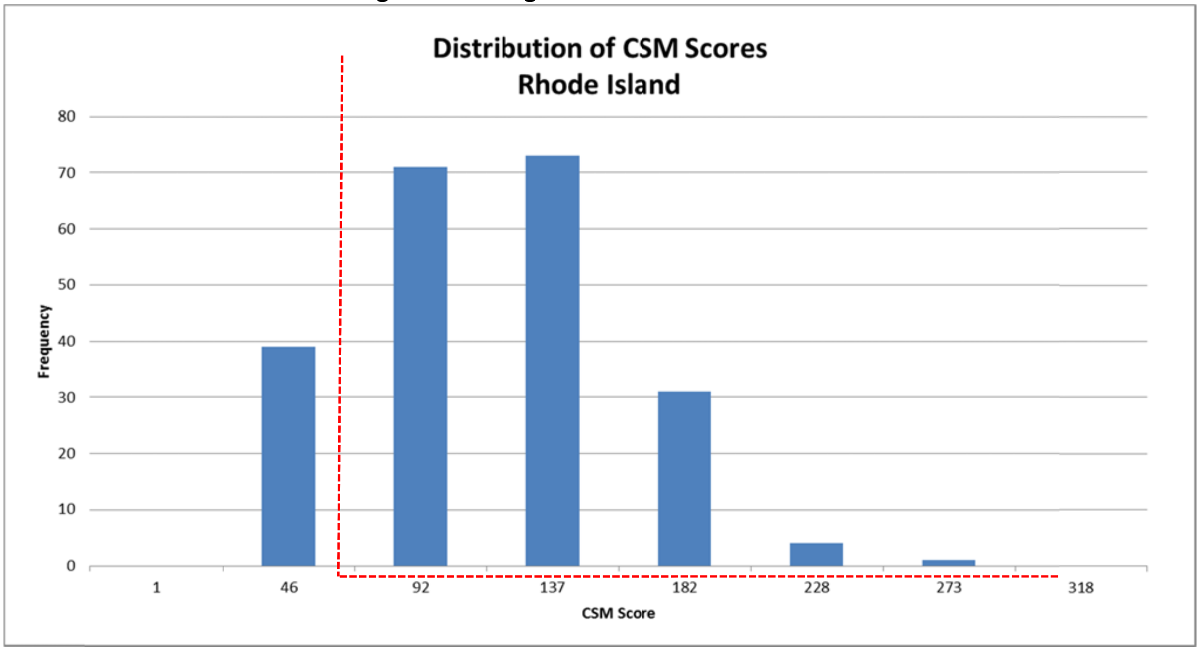
The Customer Impact component of the criticality score is based on the number of customers served by the feeder, the feeder System Control Center (SCC) Priority Code and the percent feeder loading. The number of customers served and the SCC Priority Codes are only available for feeders serving customers directly. Due to this, some of the sub-transmission circuits do not have values for these categories. All feeders have a percent loading value so this category is given more weight in the Customer Impact criticality score.

The Asset Condition component of the criticality score is primarily based on cable age and insulation type. While age alone is not indicative of cable performance, the longer cable is in service the greater normal deterioration it has potentially experienced. In older urban areas, a significant proportion of cables have been in service for well over 50 years, some for over 80 years. Age varies from cable segment to cable segment due to upgrades/repairs over time. The age and insulation type (see Appendix 2 for insulation type weights) data used for scoring was extracted from GIS and split into ranges. This data was reviewed with SME’s to provide a high level check of the GIS information. The GIS data quality for both the cable age and insulation type is inconsistent. As the GIS data matures, the expectation is that the data will become more reliable as new assets are added to the system.

The Reliability component of the criticality score is based on the number of previous failure-related splices (stored in the splice log) and Interruption and Disturbance System (IDS) data. The splice log data captures outages to feeders that don’t necessarily supply customers directly. These outage types do not have IDS data because no customers were interrupted. The splice log is critical for tracking failures on feeders that supply customers indirectly, such as sub-transmission and distribution cables supplying secondary network systems. IDS data was used for the distribution primary cables. More consistent usage of National Grid’s online splice log will enhance future evaluations. A recent review of UG Electric Operating Procedure (EOP) 009 identified a need to improve splice log use and to enhance the splice log application.

The following histogram shows the grouping of the CSM scores:

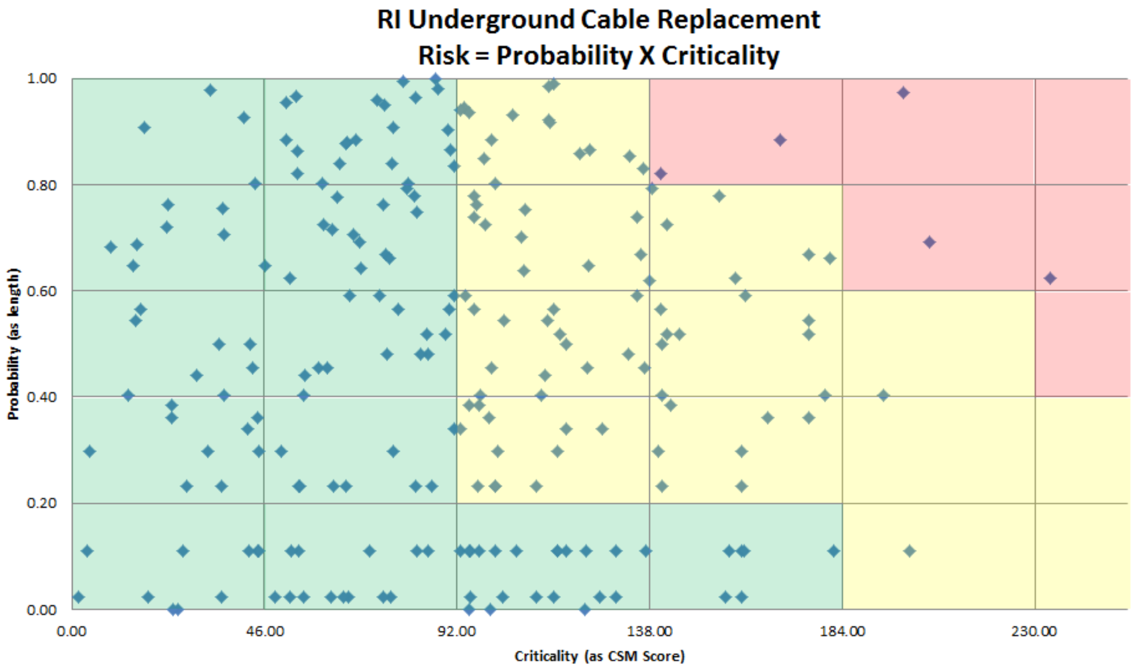
Figure 1 - Histogram of CSM Scores



CSM scores ≥ the average CSM score, 92, have been targeted for potential replacement in the strategy. This represents approximately 50% of the population or 109 of 219 feeders.

The last component of the CSM scoring is the addition of a probability of failure to the analysis. This was accomplished by adding in an exposure component (feeder length) to the analysis. Assuming the failure rate (failures/mile) is consistent, the longer the feeder the more likely it is to experience a failure. A consistent failure rate was used due to a lack of any data to support different failure rates for different cable types. The feeder circuit miles were given a percentile rank to provide consistent scale. The results of combining the CSM score (criticality) with the probability of failure results in the matrix below:

Figure 2 - Risk Matrix for RI Underground Primary Cables



Each blue dot represents a cable, the cables in the green areas represent cables with a risk score that will be tolerated, and cables in the yellow and red areas are addressed in the strategy in order of risk score followed by CSM score. The green area was selected based on CSM scores below the average CSM score (refer to Figure 1) and cables with little exposure and a low to moderate CSM score.

The CSM uses information from available data sources to identify candidate cables for planned replacement by feeder. This candidate list will be provided to local area SME's for cross functional review. Following this review, specific cable replacement projects will be selected. These feeders will be forwarded to local engineering departments for detailed scope and project grade estimate development. In developing the specific scope of planned cable replacement projects, all underground segments of targeted circuits will be evaluated, including laterals and cable to/from sectionalizing riser poles serving backyard distribution.

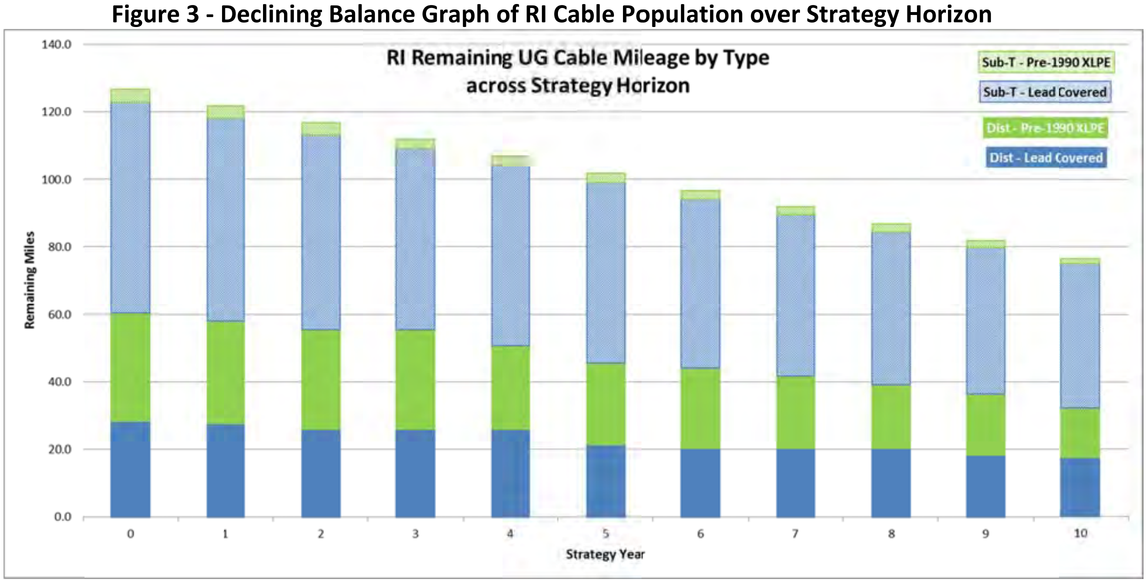
The availability of secondary system data does not presently allow for population and application of a similar CSM for secondary cable. As such, secondary cable replacement scoping and prioritization will focus on geographic areas and will be developed by employee experts with considering of underground system density, past performance, pedestrian activities, etc.

Using the CSM Risk model, this program results in an average annual replacement rate of 8 percent of the total targeted mainline primary cable located within the Rhode Island service territory. The projects already budgeted and the planned annual replacement rate is shown in Table 1 and a graph displaying the declining population of targeted cable is shown in Figure 3. This program is intended to be continuous, with a ten year horizon, to address the continued deterioration of these assets over time. It is expected that the planned mileage in need of replacement will become smaller as the backlog of high risk cable is addressed.

Table 1 - Program Based Cable Replacement Levels

System Wide Goals – Miles Replaced by Fiscal Year						
Asset Group	**FY16-FY18***	**FY19**	**FY20**	**FY21**	**FY22-28**	**Total**
Sub-Transmission	4.0	2.6	2.4	5.0	11.9	**21.9**
Distribution	8.4	2.4	2.5	0.0	23.2	**28.1**
Secondary	3.9	1.4	1.4	1.4	9.8	**14.0**
Total	**16.3**	**6.4**	**6.3**	**6.4**	**44.9**	**64.0**
*Previous years projects already budgeted, not included in Totals						

Figure 3 - Declining Balance Graph of RI Cable Population over Strategy Horizon



Separate program funding streams are established for distribution/ sub-transmission and secondary replacement. The output of the CSM risk tool will be used for budgeting, resource planning and to identify candidate cable replacement projects. Distribution and sub-transmission cable replacement projects will be on a feeder basis, with each project justified, engineered, scoped and approved individually. To reserve funding for future year spending on distribution and sub-transmission cable replacement, specific project placeholders are being used. Secondary cable replacement funding will be accounted for on a program basis, with work performed against a jurisdiction funding project with annually approved funding levels.

Secondary network supply cable replacements will be managed using specific projects resulting from a network study/review. Many of the existing secondary network systems across the New England service territory are being reviewed. Any cable replacements should be coordinated through an overall review of the system.

The intent of the scoring methodology is to take advantage of existing information to identify cable replacement opportunities and to leverage new information as it becomes available. When that information becomes available, the scoring matrix will be reevaluated. In addition to annually reviewing funding levels, program weighting will be evaluated on an as needed basis to leverage lessons learned and as data quality improves. The quality of the data evaluated in the model varied across the system and is expected to improve over time. As such, this program's CSM will be refreshed biannually to properly reflect recent system performance and improved data availability.

Over a ten year horizon, it is expected that approximately 64 circuit miles of underground cable will be replaced as part of this program at a total estimated cost of $52M (CAPEX).

3.0 Benefits

3.1 Safety and Environmental

Much of the cable to be replaced through this program will be PILC cable. There is an environmental benefit to removing PILC cable because this will reduce the amount of lead on the system.

Underground asset failures can (and have) resulted in manhole cover dislodgements. Such events are often visible to the public and raise understandable concern with regulators, the community and public safety officials. Although the consequence of a manhole event can be severe, the likelihood of a manhole event remains low. This program is expected to further reduce the likelihood of manhole events by proactively replacing cable based on its condition and past performance.

The impact of a cable failure on manhole dislodgement may be affected by the type of manhole cover installed. In addition to proactive cable replacement, National Grid is piloting the installation of vented manhole covers.

3.2 Customer/Regulatory

Underground cable systems typically supply urban areas, including critical loads such as police, fire and hospitals. Outages on the underground system typically take longer to isolate and repair. This program intends to mitigate the length of long-term sustained customer interruptions occurring in these urban areas by updating the design to current standards. Inclusion of the SCC Priority Code in the CSM will improve the ability of the model to prioritize critical feeders.

3.3 Reliability

The time to locate and respond to cable failures is typically longer than on the overhead system. Therefore, many cable systems are often designed with an emergency plan and greater redundancy to limit the impact on customer reliability. However, if cable performance deteriorates significantly, the likelihood of concurrent failures increases. The consequences of multiple secondary network failures or multiple sub-transmission failures would be significant. Cable failures can result in increased operations and loading on parallel equipment, further increasing the risk of failure on the rest of the system. Proactive replacement of targeted cable and improved design criteria in these systems is expected to reduce the risk of concurrent failures and the potential for large scale customer interruptions.

3.4 Efficiency

Addressing the cable in a prioritized fashion and re-evaluating the CSM on a regular basis will support the creation of the most cost efficient plan and permit lessons learned from recently completed projects to be applied to subsequent projects. A proactive approach should mitigate premiums paid for emergency replacements and allow for efficient material procurement. Coordinating planned work with the list of replacement feeders and circuits should foster project development and delivery efficiencies in investigation (engineering and manhole survey), mobilization and civil construction costs.

4.0 Estimated Costs

The selection of candidate projects to pursue should consider the cost/benefit of each project. The cable targeted for replacement includes all varnished cambric (VC), PILC cable and some of XLPE cables installed prior to 1990. The selection of the XLPE cable to be replaced will be determined as part of the detailed engineering/design.

1970's vintage XLPE cable has known defects that support replacement as well as other pre-1990's XLPE cables with possible strand shield damage due to repeated faults. For the purposes of this strategy all pre-1990 XLPE cable has been included in the replacement mileage and estimated cost.

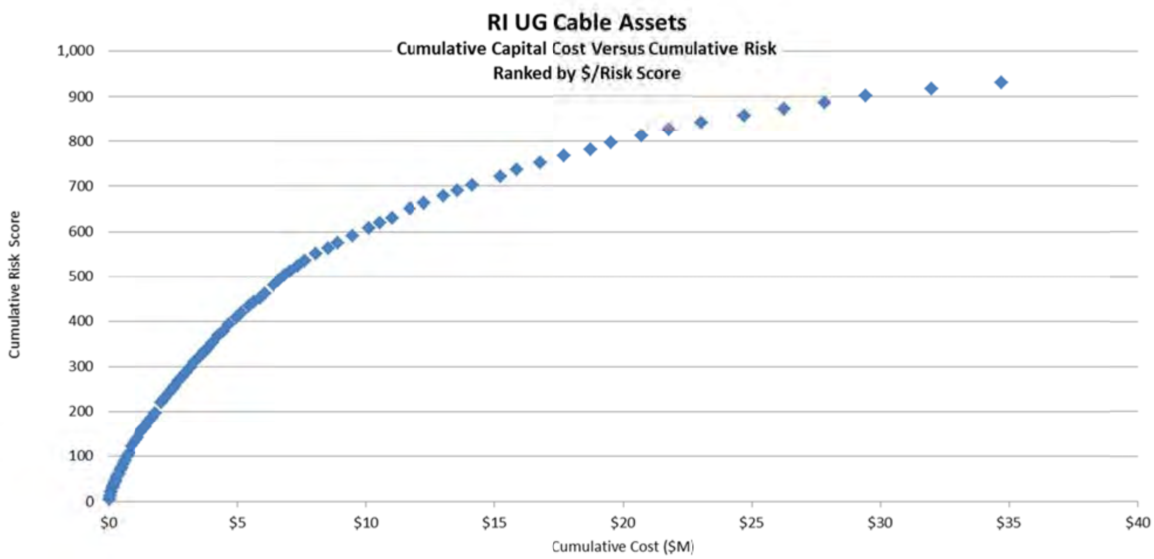
The budgetary cost estimates are based on the installation of 3-1/C 500 Cu EPR cable in conduit with 15% conduit system replacement. The conduit system replacement was added to account for locations with direct buried cable and where existing duct banks no longer have capacity. 15 kV class cable will be installed for all cable replacement at 15 kV and below. This will support any future conversions of 4kV feeders to higher voltages.

Table 2 - Estimated Costs used in the Program

Budgetary Estimates For 1000 circuit feet of construction				
Cable Voltage	**CAPEX (K$)**	**OPEX (K$)**	**Cost of Removal (K$)**	**Total (K$)**
≤ 15 kV	$ 130	$ 2.5	$ 5	$ 137.5
> 15 kV	$ 150	$ 2.5	$ 5	$ 157.5
600 V	$ 240	$ 2.5	$ 5	$ 247.5

Figure 4 shows the cumulative risk, as determined by the scoring methodology, mitigated by a cumulative program cost for replacing each primary feeder cables. Candidate feeders were ranked by efficiency (risk score mitigated per feeder project cost). Only feeders with in the yellow and red areas of the CSM risk matrix, see Figure 2, are included in the analysis.

Figure 4 - Cumulative Risk Mitigation for Replacement of Distribution and Sub-Transmission Primary Cable



Secondary (radial and network) cable replacement projects will be geographically based. Work will be performed against a program project until preset funding levels are approached. After ramp up, a cash flow of $1.5M per year is expected with an annual goal of 1.2 miles per year.

Table 3 represents an investment grade cash flow for capital program costs over a ten year horizon. This cost includes duct bank upgrade or replacement that may be necessary to facilitate cable replacement, which will vary project to project. Estimated program spending has been developed considering both resource requirements and the need to address cable assets of highest risk at a reasonable pace. The costs do not include cable replacement performed due to other drivers (ex. Capacity).

Table 3 - Investment Grade Cash Flow

Budgeted CAPEX Spend Per Fiscal Year ($M)						
Asset Group	**FY16-FY18***	**FY19**	**FY20**	**FY21**	**FY22-28**	**Total**
Sub-Transmission	$ 1.7	$ 1.8	$ 1.7	$ 3.6	$ 8.3	**$ 15.4**
Distribution	$ 2.8	$ 1.6	$ 1.7	$ 0.0	$ 16.0	**$ 19.3**
Secondary	$ 2.8	$ 1.7	$ 1.7	$ 1.7	$ 11.9	**$ 17.0**
Total	**$ 7.3**	**$ 5.1**	**$ 5.1**	**$ 5.3**	**$ 36.2**	**$ 51.7**
*Previous years projects already budgeted, not included in Totals						

Over a ten year horizon, it is expected that approximately 64 circuit miles of underground cable will be replaced as part of this program at a total estimated cost of $52M (CAPEX).

5.0 Implementation

Pursuing projects simply by their cost/benefit rank, as illustrated in Figure 4, would tend to focus activities on the shortest and therefore least costly circuits to replace, leaving some of the poorest performing but most costly projects in service for longer periods of time. That is why the CSM risk matrix was developed to address the cables with the highest estimated risk first. Additionally, the primary cable replacement candidate project list will be reviewed in detail by a cross functional team of Company SME's having local knowledge and experience with the Rhode Island distribution system infrastructure. This review will include data used in the CSM risk tool, consideration of active and currently budgeted projects, upgrades resulting from ongoing planning studies, etc.

The specific list of future projects will be selected based on the budgets established within this underground cable strategy document. The current project list is attached as Appendix 5. A ranked list of the candidate projects, identified by the CSM, is included in Appendix 4. The top ten distribution and sub-transmission feeders are listed for each district.

Each project will be approved individually with a scope, schedule, and cash flow. Distribution Planning & Asset Management (DPAM) Regional Engineering will perform an engineering review and initiate the individual projects. Individual projects will be managed by Program Management or Project Management depending on project complexity. Program Management will track replacement mileage. The overall program will be evaluated annually by DPAM.

DPAM Engineers will work with Operations, Customer Community Management, and Resource Planning to develop geographical areas and projects for secondary cable replacement in the City of Providence. Some of these areas are:

- Jewelry District
- College Hill
- Wayland
- Olneyville

The Company has also made a decision to pilot the application of vented manhole covers and will implement this pilot in conjunction with the secondary replacement program.

The secondary cable replacement program will define the circuit miles to be replaced in jurisdictions each fiscal year. The estimated state-wide replacement goal will be 1.2 miles per year. DPAM Regional Engineering will define projects or geographic areas for secondary cable replacement. Operations will perform the necessary field inspections, replace the cable and document replacements through designed work against program funding projects approved annually by DPAM. Program Management will track the program and limit the scope to keep within approved spending levels and goals.

6.0 Project Execution Considerations

In general, risks to cable removal efforts will be mitigated by applying lessons learned from earlier projects to subsequent projects.

6.1 Safety & Environmental

Individual project costs can be impacted by local environmental issues affecting any needed civil construction. Program costs do not assume significant environmental mitigation.

6.2 Customer/Regulatory

Some projects will require additional manhole and duct bank construction. There is a risk that local jurisdictions will refuse to issue licensing and permitting for the proposed work, or that process delays will impact project schedule. Community outreach in major urban areas should be performed prior to secondary cable replacement program kickoff, and for each individually scoped and approved distribution and sub-transmission cable replacement projects.

There is a risk that licensing will be delayed where roads have recently been repaved which will increase cost. This risk can be partially mitigated with a community outreach to obtain proposed paving schedules for urban communities. The information should be geographically mapped against identified feeder and circuit replacement projects so that the information is available during engineering review.

Some projects may require customer easements to locate equipment above ground as required by current standards. For example, sectionalizing riser poles currently used for backyard construction may require an easement to locate a padmounted switch on private property.

6.3 Reliability

Construction related outages, especially on sub-transmission cable projects, will increase load and customer reliability risks on parallel circuits. Construction related outage risks can be partially mitigated by having all materials on hand prior to starting replacement construction and analyzing outage requirements as part of preliminary engineering.

6.4 Resources

The volume of cable replacement proposed in this program represents an increase in underground work. Additional resources (either internal or contractor) for engineering, program management and data management as well as civil and cable craft workers are expected to be necessary.

7.0 Data Requirements

The Access-based database and Excel-based tool used for this program will be stored on a shared drive. This report identifies how scoring was applied to available information, and makes recommendations for improvements (See Appendix 1).

8.0 Factors Influencing Future Study

Long range studies presently underway may affect the timing of replacing some of the cables this program may identify. Future year candidates will be evaluated after creation of implementation plans associated with individual distribution studies.

The intent of the scoring methodology is to take advantage of existing information to identify cable replacement opportunities and to leverage new information as it becomes available. When that information becomes available, the scoring matrix will be reevaluated. Subsequent engineering review may result in deferral or elimination of candidate projects. In addition to annually reviewing funding levels, program weighting will be evaluated every two years based on lessons learned and as data quality improves.

9.0 <u>Conclusion</u>

The proactive replacement of underground cables on the sub-transmission, distribution primary and distribution secondary systems in the Rhode Island service territory is recommended to minimize faults and the occurrence of manhole events. It is recommended that over the next ten years National Grid spend:

- Sub-Transmission cable replacements (approximately 21.9 miles) - $15.4M CAPEX
- Distribution primary cable replacements (approximately 28.1 miles) - $19.3M CAPEX
- Distribution secondary cable replacements (approximately 14.0 miles) - $17.0M CAPEX

The total capital spend over the ten year horizon is $52M replacing approximately 64 miles of underground cable.

Appendix 1 – Criticality Scoring Model for Identifying UG Cable Replacement

The drivers used in the analysis are each described below. The same scoring categories are used for both distribution and sub-transmission cable assets. This was done to create a common basis for the analysis. As the data quality improves, the small bias created by this common approach should be minimized. All data is taken from the five most recent complete calendar years, 2012 through 2016. The data is converted into either a percentage or per mile form to improve scoring consistency within cable sub-groups. The data is stored and combined within an Access DB to compile the data for each scoring area then exported to Excel for final scoring and to make the results more user-friendly.

List of Data Sources:

GIS – GIS data is extracted from the Business Objects Asset Data Warehouse via the Feeder Reference Model (FRM) and direct underground cable and OFC related queries. The queries focus on the extraction of information related to only main line underground cable as defined in the Smallworld GIS.

FeedPro and Annual Plan Spreadsheets – Feeder loading and rating information

IDS, Interruption and Disturbance System – Five year average (2012 – 2016) feeder level main line reliability data for faults related to underground assets and most recent (2016) customer served counts.

ORP, Outage Reporting Protocol – Manhole event data

UG Splice Log – Cable splice failure data

List of Network Cables – Dan Mungovan, Table updated 2/4/2016

Walk Score® – Third party data source used to provide a consistent measure of pedestrian access in areas served by manhole and duct systems.

Local SME's by district – Meetings were held with each district to get feedback on the accuracy of the GIS cable data to verify/correct approximate age and insulation type of cable. Significant differences between GIS and the assets in the field were identified in most districts, specifically around direct buried versus in conduit construction and the age of XLPE cable in the system.

Safety	
Previous Manhole Events	Manhole event data collected in the ORP DB, manhole event tagged with GIS ID and spatial query is run in ArcGIS to generate a list of cables potentially impacted by the manhole event (cables running through the same manhole). Data is converted into a percentile rank for scoring on an event/mile basis.
OFC Counts	Count of OFC's per feeder extracted from GIS via the FRM. Data is converted into a percentile rank for scoring.
Public Accessibility	The service territory was broken down by census tract and each tract was given a Walk Score based on the geometric center of the underground assets in the tract. Census Tracts with walk scores >= to 90 were considered potentially high pedestrian traffic areas. Feeders are scored based on the percentage of feeder in these areas.
Customer	
Number of Customers Served	Extracted from IDS via the FRM. Most recent calendar year data used (2016). Data is converted into a percentile rank for scoring.
SCC Priority Score	Feeder priority score from 2017 System Control Center Load Shed Plan
% Feeder Loading	FeedPro via FRM and Annual Planning Spreadsheets used to collect most recent summer peak (2016) load and rating data to calculate % SN rating. Data is converted into a percentile rank for scoring.
Asset Condition	
Age	GIS and Local SME's feedback used to score each feeder by cable insulation/construction type for approximate age. Entire feeder is scored based on the age group of the insulation type with the largest %.

Weighted Average Insulation Type	GIS and Local SME's feedback used to determine the cable insulation type for each feeder. Scoring based on the weighted average on the cable insulation scores.
Manhole Crowding	GIS data is used within ArcGIS to create a spatial query counting the number of primary cables running through each manhole. Each feeder is then scored on the average number of cables/manhole on a percentile rank basis.
Direct Buried Percentage	GIS and Local SME's feedback used to score each feeder by cable construction type. This data is used to calculate a direct buried % used to score the feeder.
Reliability	
Splice Log	Data extracted from UG Splice Log to calculate splice failure rates for feeders on an event/mile basis.
Feeder CKAIDI	IDS Data is extracted via FRM to calculate the CKAIDI for main line underground cable interruptions. Data is converted into a percentile rank for scoring.

The categories used in the analysis are shown in green shading. Red lettering indicates weighting that can be changed within the scoring tool to evaluate the effect of different weighting factors. Minimum weighting factors set at 5% per category.

Table 1 – Distribution/Sub-Transmission Feeder Criticality Scoring Model

Rhode Island Feeder/Circuit Scoring Matrix

Category	Data Source	Weight	Level 1	Level 2	Level 3	Level 4	Level 5
			1	20	100	400	1000
Safety		**20%**					
Previous Manhole Events	2012-2016 from I&M Group (ORP DB) - All cables in MH scored Events/Mile	12%	10%	25%	50%	75%	90%
OFC Count	FRM - % Rank Basis	0%	N/A	N/A	N/A	N/A	N/A
Public Accessibility: Percent of Feeder Passing Through High Pedestrian Traffic Area	Walk Score % of feeder in area with Walk Score >=90	8%	10%	25%	50%	75%	90%
Customer		**20%**					
Number of Customers Served	FRM - % Rank Basis	5%	10%	25%	50%	75%	N/A
SCC Priority Code	SCC Load Shed Plan - 2017	5%	10%	25%	50%	75%	N/A
% Feeder Loading	FRM/Annual Planning Spreadsheets % Rank Basis	10%	10%	25%	50%	75%	N/A
Asset Condition		**40%**					
Age	Local Engineering to designate by feeder Entire feeder scored based on largest %	15%	N/A	N/A	26 to 49 Years	50+ Years	N/A
Weighted Average Insulation Type	GIS	15%	Use the weighted average scored for insulation type				
Crowding in Manholes Feeder Passes Through	Custom ESRI GIS Query Count cables passing through each manhole and score on average for feeder % Rank Basis	5%	N/A	25%	50%	75%	N/A
Direct Buried Percentage	GIS DB UG/Total UG	5%	N/A	25%	50%	75%	N/A
Reliability		**20%**					
Splice Log	2012 - 2016 from UG Ops Splice Log Events/Mile % Rank Basis	10%	N/A	25%	50%	75%	N/A
Feeder CKAIDI	ML UG IDS 2012-2016 - % Rank Basis	10%	N/A	25%	50%	75%	N/A

Notes:

- Revised strategy uses the same CSM for all assets, the distribution and sub-transmission cables are no longer analyzed separately.
- Number of Customers Served and SCC Priority Code categories would potentially favor distribution feeders. This is because many Sub-T circuits do not directly serve customers and the IT systems do not currently link substation customer counts to the Sub-T lines supplying them.
- The Splice Log in not used consistently across New England so this will favor areas that use the application.
- Many Sub-T cable outages don't result in permanent customer interruptions so the Feeder CKAIDI category will favor distribution feeders because the Sub-T outages do not get recorded in IDS.

Areas in need of improvement for future strategy updates:

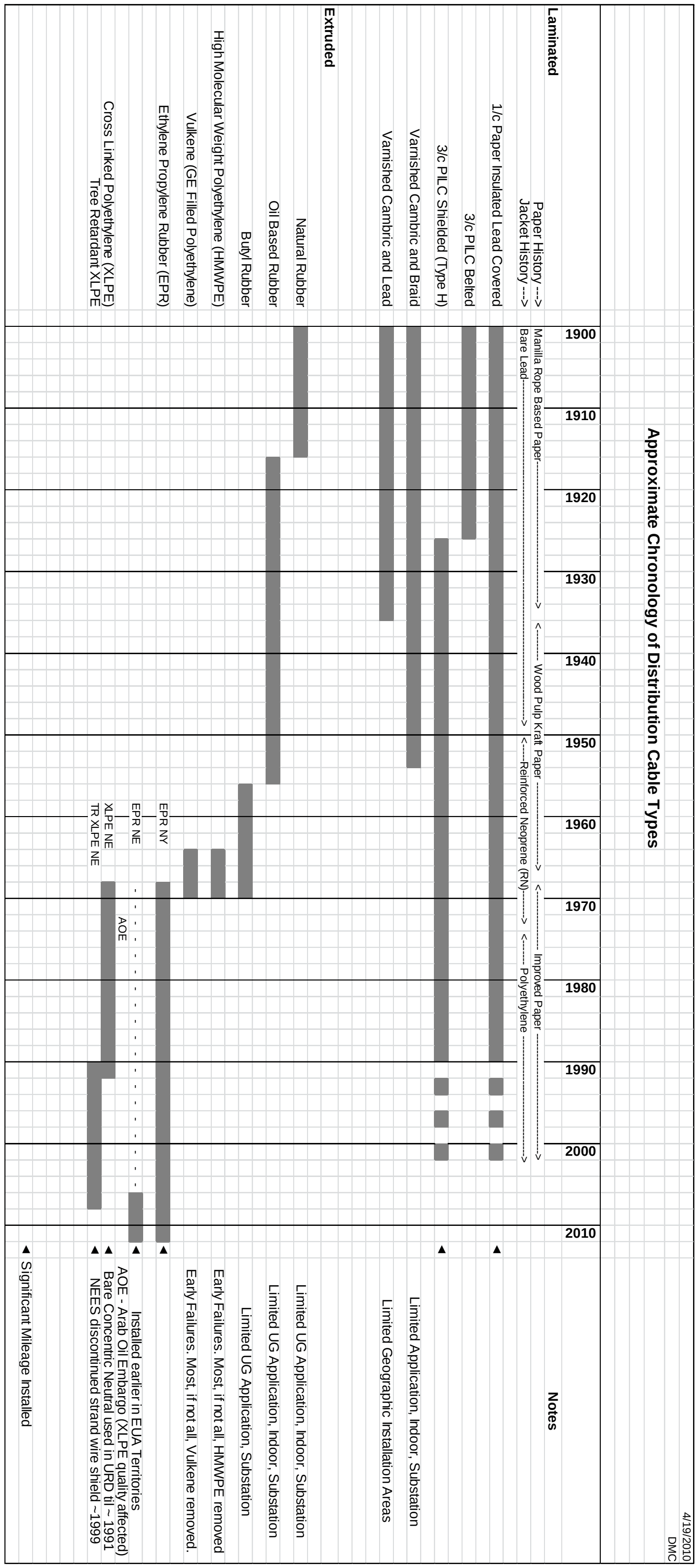
GIS – no reliable age data before 2000, incorrect cable sizes, insulation types and construction types, main line tag not always correct
Feeder Rating and Loading – Inconsistent information in FeedPro and Annual Planning Spreadsheets
IDS – currently being reviewed for update
Splice Log – Not being used consistently, difficult to enter data and extract data. Recommend program update.

The Excel spreadsheet attached contains the data used in the CSM scoring matrix as well as the ranked list of all candidate projects.

Appendix 2 – Cable Insulation Type Weighting

INSULATION CODES IN GIS	Assumed Code Definition	Awarded Points
EPR	EPR	0
KDPS Lead	Kerite Double Permashield Lead Covered	100
KER	Kerite	0
LC	Lead Covered	100
P & L	Paper and Lead	100
PE combined with Age over 26 years	Polyethelene	400
PE combined with Age under 25 years	Tree Retardant Cross Linked Polyethylene	0
R	Rubber	20
R & L	Rubber Covered Lead	100
SUBL	Submarine Cable Lead	100
SUBR	Submarine Cable Rubber	20
VC	Varnished Cambric	1000
VC & L	Varnished Cambric and Lead	1000
XLPE combined with Age over 26 years	Cross Linked Polyethylene	400
XLPE combined with Age under 25 years	Tree Retardant Cross Linked Polyethylene	0

Appendix 3 – Approximate Chronology of Distribution Cable Types



Appendix 4 – Top 10 Distribution and Sub-Transmission Primary Feeder Cable Replacement Candidate Projects/District

District/Feeder	Risk Score	CSM Score	Circuit KFt to be Replaced	Budgetary CAPEX (K$)
Capital	**276**	**3192.9**	**77.4**	**10085.0**
Distribution	**128**	**1850.9**	**11.5**	**1486.0**
49_53_6J6	24	233.8	1.8	237.0
49_53_13F3	20	205.0	2.8	363.0
49_53_6J7	16	181.2	2.2	290.0
49_53_37J5	15	194.0	0.8	109.0
49_53_107W84	12	180.0	0.8	98.0
49_53_48F6	12	161.0	1.6	202.0
49_53_13F4	8	176.0	0.6	79.0
49_53_21F1	8	160.0	0.4	51.0
49_53_69F3	8	160.0	0.3	34.0
49_53_5F4	5	200.0	0.2	23.0
Sub Transmission	**148**	**1342.0**	**65.9**	**8599.0**
49_53_1171	20	169.1	8.1	1057.0
49_53_1144	20	140.6	5.4	699.0
49_53_1142	15	136.6	5.7	741.0
49_53_1151	15	133.2	7.0	916.0
49_53_1137	15	123.8	7.7	1001.0
49_53_1114	15	121.4	7.5	970.0
49_53_1132	15	113.8	19.5	2540.0
49_53_1160	12	145.0	1.3	171.0
49_53_1166	12	123.4	2.1	268.0
49_53_2235	9	135.0	1.6	236.0
Coastal	**124**	**1604.6**	**18.9**	**2460.0**
Distribution	**118**	**1509.6**	**18.2**	**2359.0**
49_56_33F3	16	176.0	2.3	297.0
49_56_154J14	16	142.1	3.4	439.0
49_56_33F2	12	176.0	1.4	181.0
49_56_33F4	12	176.0	1.3	167.0
49_56_51J12	12	142.1	1.3	173.0
49_56_57J1	12	136.1	2.3	301.0
49_56_45J3	12	135.2	3.6	464.0
49_56_14F3	9	136.9	1.0	133.0
49_56_33F1	9	123.0	1.0	124.0
49_56_64F2	8	166.3	0.6	80.0
Sub Transmission	**6**	**95.0**	**0.7**	**101.0**
49_56_2233	6	95.0	0.7	101.0
Grand Total	**400**	**4797.5**	**96.3**	**12545.0**

Appendix 5 – List of Currently Active and Budgeted Cable Replacement Projects

Primary or Sub-T	Project #	Project Description	Budget Year	Ckt Miles
Primary	C055357	RI UG CABLE REPL PROGRAM - FDR 1111	FY16	1.8
Primary	C055359	RI UG CABLE REPL PROGRAM - FDR 79F1	FY16	0.4
Primary	C071307	RI UG CABLE REPL PROG- FDRS 79F1&F2	FY17	1.7
Primary	C074307	RI UG 79F1 DUCT CHARLES & ORMS STS	FY17	-
Primary	C055364	RI UG CABLE REPL PROGRAM - FDR 13F6	FY17	0.5
Primary	C055360	RI UG CABLE REPL PROGRAM - FDR 2J8	FY17	1.9
Primary	C055362	RI UG CABLE REPL PROGRAM - FDR 1105	FY18	1.0
Primary	C055361	RI UG CABLE REPL PROGRAM - FDR 1107	FY18	0.7
Primary	C055363	RI UG CABLE REPL PROGRAM - FDR 1127	FY18	-
SubT	C055367	RI UG CABLE REPL PROGRAM FDR 54K21	FY16	1.4
SubT	C055369	RI UG CABLE REPL PROGRAM FDR 54K23	FY16	1.5
SubT	C072807	RI UG CABLE REPL PROGRAM - FDR 1102	FY17	0.4
SubT	C072826	RI UG CABLE REPL PROGRAM - FDR 1104	FY17	0.4
SubT	C072847	RI UG CABLE REPL PROGRAM - FDR 1106	FY17	0.4

3V0 Program RI

Souresh Mukherjee

January, 2018

Reviewed by ________________________________

Approved by ________________________________

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1. Executive Summary

The addition of distributed generators (DG) to distribution feeders can result in the flow of power in the reverse direction on feeders and, at times, through the substation transformer onto the high voltage transmission system. For certain transmission faults, additional transmission protection, zero sequence overvoltage or "3V0" protection, is required to prevent the DG from contributing to fault overvoltage conditions. As DG penetration levels continue to increase, the need for 3V0 is more frequent. In existing stations, this work can be complex sometimes requiring high voltage yard rearrangement of an extensive duration. Although the cost is factor, the duration of the 3V0 work can create unexpected financial impact to the DG development community. Recent legislation in the state of Rhode Island (RI) with required interconnection timelines also presents execution challenges for the Company. In response to this societal, regulatory, and developmental need, National Grid is developing a proactive 3V0 program.

In order to implement the program a simple ranking methodology was developed by comparing maximum generation of a station to its minimum load. Aggregate DG approaching more than 50% of the station transformer's minimum load provides an indication of a need for potential 3V0 protection. Therefore the 50% DG to minimum load criteria was determined to be appropriate for a proactive 3V0 installation effort. Substations meeting this criterion were considered for 3V0 implementation. For stations with multiple transformers, if the requirement for 3V0 was identified for one transformer, the entire substation was considered for 3V0 modifications. This program has identified a list of 12 RI substations in need of 3V0 implementation. This list is not exhaustive. Depending on future DG interconnections to other RI substations the list will be expanded to include stations that exceed the DG to minimum load ratio threshold of 50%. This list will be reviewed on an annual basis.

The cost estimates for the program were developed from historical costs based on previous Conceptual Engineering Reports at similar stations and high level review of the existing protection schemes of the individual stations on the selected list. The costs were distributed over a 5 year period. The total program costs for the selected stations are $5.605M, broken down into $5.295M Capex and $0.310M Opex. There is no removal costs typically associated with this work. The estimated spending forecast is shown in Table 1 below, which will be reviewed after the first year for any forecast changes.

Table 1: Total Estimated Forecasted Spending

	FY19	FY20	FY21	FY22	FY23	Total
Capex	$1,407,500	$906,250	$1,303,750	$710,000	$967,500	**$5,295,000**
Opex	$93,750	$50,000	$76,250	$33,750	$56,250	**$310,000**
Removal	-	-	-	-	-	-
Total	$1,501,250	$956,250	$1,380,000	$743,750	$1,023,750	**$5,605,000**

2. Introduction

2.1. Purpose

The addition of distributed energy sources (DER) to distribution feeders can result in the flow of power in the reverse direction on feeders and, at times, the substation transformer, effectively turning a station transformer (designed to step transmission voltage down to distribution voltage for serving load) into a generation step-up transformer pushing excess power onto the transmission system. Protection of a transmission side ground fault overvoltage on power transformer equipment from any source on the secondary side is a National Grid standard practice. Substation step down transformers commonly have a Delta connection on the transmission side and Wye-grounded connection on the distribution side. With a Delta or an ungrounded-Wye connection on the transmission side, distributed generation cannot contribute zero sequence ground fault current during transmission single line to ground faults. In effect the distributed generation cannot "see" the fault, can remain islanded for a short period of time, and contribute to overvoltage conditions. Therefore in order to protect against ground faults with secondary source connections, zero sequence overvoltage ("3V0") protection equipment is required.

This program focuses on developing a list of Rhode Island substations in the need of 3V0 protection based on total aggregate distribution generation connected on a transformer that has a delta or an ungrounded-wye connection on the transmission side.

2.2. Problem

Significant amount of solar and wind power capacity are being installed at the distribution level in Rhode Island, and is expected to increase more to meet renewable energy mandates. As the aggregation of DG saturate distribution circuits to a level of concern, depending on the protection schemes in place at the given substation, zero sequence overvoltage ("3V0") protection equipment is required.

DERs on Delta-Wye (or Ungrounded Wye-Wye) connected transformers cannot contribute zero sequence ground fault current during single line to ground faults on a transmission line, resulting in the voltages on the unfaulted phases to rise significantly and rapidly. These overvoltages have the potential to exceed insulation levels of the substation and transmission line equipment, and maximum continuous operating voltage of surge arresters. In order to detect these overvoltage conditions, 3V0 protection on the primary side of the transformer is a standard method employed by National Grid. This 3V0 protection will open all feeder protective devices in order to disconnect all possible DER sources from the substation bus, thereby stopping the DER from contributing to the transmission-side fault condition.

2.3. Scope

This program will cover the installation of 3V0 protective devices in Rhode Island substations over a 5 year period.

3. Background

In today's evolving electric grid where there is an influx of distributed energy resources located on the customer side, National Grid's distribution systems must work with a variety of non-utility generation sources. The widespread application of renewable energy sources such as photovoltaic and wind technologies have caused a dramatic increase in the use of inverter-based systems. In addition, typical synchronous systems such as small hydro, diesel, methane, and natural gas powered generator systems are still being installed. Multiple generation sources and the resulting bi-directional power flow bring significant benefits and challenges for the existing and emerging power grids. In particular, the effect of distributed generation on protection concepts and approaches needs to be understood, and accounted for.

National Grid implements standard equipment and installation methods in its substations for 3V0 protection equipment as good utility practice. Installation of 3V0 equipment typically requires a significant engineering and construction effort by National Grid, which presently spans 18-24 months. From the industry perspective, developers are continually seeking to interconnect in the most time efficient fashion. As such, the development community has a strong desire in shortening construction timelines wherever possible. Recent legislation in the state of Rhode Island with required interconnection timelines also presents execution challenges for the Company. In response to this societal, regulatory, and developmental need, it is important to develop a program that will proactively make National Grid substation's in RI 3V0 ready.

Aggregate DG approaching more than 50% of the station transformer's minimum load provides an indication of an approaching need for potential 3V0 protection. In accordance with National Grid guideline document GL 309B.0917, DGs that exceeds a 67% DG to minimum load ratio trigger the need for 3V0 installation at the substation. The intent of this program is to proactively install 3V0 at substations that are approaching that threshold. Therefore a 50% DG to minimum load ratio was determined to be appropriate for the purposes of this program. The strategy results in an effective approach that promotes deployment prior to 3V0 policy/criteria.

4. Program Description

4.1. Methodology

In order to implement the program a simple ranking methodology was developed by comparing maximum generation of a station to its minimum load. An initial review of all the transmission and distribution substations in Rhode Island was done to identify ongoing project work, rebuild work or projected retirement work. 3V0 protection was added to the scope of ongoing project work where possible. The stations that were projected to be retired in the upcoming years were excluded from consideration for 3V0 implementation. The following steps were followed while developing a list of substations:

- The high side transformer configuration was identified for each station. Stations with a high side Wye-ground transformer configuration were excluded.
- The stations were investigated for existing 3V0 protection. Substations equipped with high side protection scheme capable of detecting line to ground faults and tripping the low side breaker were excluded from consideration.
- The substations were selected on the basis of DG to minimum load ratio. If the ratio of the maximum distributed generation of a station to the minimum load exceeded 50%, the station was considered for 3V0 implementation.

4.2. Identification

This program has identified 12 substations in need of 3V0 implementation. Table 1 below shows the following substations.

Table 2: Substation List for 3V0 Implementation

No.	Substation	Total DG (kW)	Total Minimum Load (KW)	Station Voltage (kV)	Station Class	High Level 3V0 Scope
1	Tiverton	7500	4800	115/12.47	T	3V0 on T1 & T2, 2 sets of 115 kV CCVTs, 2 - 59N Relay, No Revenue Metering
2	Kilvert Street	9800	10400	115/12.47	T	3V0 on T1 Only, 1 set of 115 kV CCVT, 1 - 59N Relay, No Revenue Metering
3	Old Baptist Road	3300	4400	115/12.47	T	3V0 on T1 Only, 1 set of 115 kV CCVT, 1 - 59N Relay, No Revenue Metering
4	Davisville	13200	17500	115/34.5	T	3V0 on T1 & T2 , 2 sets of 115 kV CCVTs, 2 - 59N Relay, No Revenue Metering
5	Wolf Hill	8000	8900	115/23	T	3V0 on T1, 1 set of 115 kV CCVT, 1 - 59N Relay, No Revenue Metering
6	Pontiac	3400	5000	115-12.47	T	3V0 on T1 & T2, 2 sets of 115 kV CCVTs, 2 - 59N Relay , No Revenue Metering
7	Riverside	7100	5000	115/13.8	T	3V0 on 81T & 82T by implementing 115 kV bus differential protection by installing 2 relays SEL587 & B-PRO, No Revenue Metering, 2 - Transformer LTC Control Upgrades
8	Quonset	7200	4900	34.5/12.47	D	3V0 on T1 & T2, 2 sets of 34.5kV VTs, 2 - 59N Relay, No Revenue Metering
9	Peacedale	4800	14800	34.5/12.47	D	3V0 on T1 & T2, 2 sets of 34 kV VTs, 2 - 59N Relay, No Revenue Metering
10	Warwick Mall	800	1300	23/12.47	D	3V0 on T1 & T2, 2 sets of 23 kV VTs, 2 - 59N Relay, No Revenue Metering
11	Staples	7200	6600	115/13.8	T	3V0 on T1, Existing CCVT (might need 2 single phase CCVTs), 1 - 59N Relay, No Revenue Metering
12	Point Street	5400	20400	115/12.47	T	3V0 on T1 & T2, 2 sets of 115 kV CCVTs, 2 - 59N Relay, No Revenue Metering

The substations were selected on the basis of distributed generation to minimum load ratio. The total connected and in-queue DG capacity (in Kilowatts, kW) was determined for each station transformer by adding up the distributed generation on each individual feeder for that particular transformer. The DG "Nameplate Rating" in kW was obtained from the September 2017 version of the "DG_on_Feeder" list stored on the Retail Connections Engineering department's shared drive. The minimum load for the station transformer was determined using FeedPro or PI. If FeedPro/PI data was insufficient to determine minimum loading, 25% of the peak transformer loading was assumed to be the minimum load (a National Grid typical value determined by analysis of actual peak loads across our systems). If the ratio of the total distributed generation of a station transformer to the minimum load exceeded 50%, the station was considered for 3V0 implementation. For stations with multiple transformers, if the requirement for 3V0 was identified for one transformer, the entire substation was considered for 3V0 modifications.

This list is not exhaustive. It is recognized that DG can change in future years. Depending on future DG interconnections to other RI substations the list will be expanded to include stations that exceed the DG to minimum load ratio threshold of 50%. This list will be reviewed on an annual basis.

4.3. Resource Considerations

The volume of work proposed in this program may require additional resources from Engineering, Program Management, and Operations. These additional resources could be obtained through Master Services Agreements (MSA) with existing consultants and contractors.

5. Costs

The 3V0 implementation program in RI will be scheduled over a 5 year period. Table 3 shows the Capital and O&M cost for each station on the priority list. The costs have been divided into transmission (T-Sub) and distribution (D-Sub) spending categories. There is no removal costs typically associated with this work.

Table 3: Cost Estimates

Number	Substation	Station Voltage (kV)	Spend Type	Estimates			
				Capital	O&M	Removal	Total
1	Tiverton	115/12.47	T-Sub	$525,000	$25,000	-	**$550,000**
			D-Sub	$60,000	$10,000	-	**$70,000**
2	Kilvert Street	115/12.47	T-Sub	$285,000	$15,000	-	**$300,000**
			D-Sub	$40,000	$10,000	-	**$50,000**
3	Old Baptist Road	115/12.47	T-Sub	$285,000	$15,000	-	**$300,000**
			D-Sub	$40,000	$10,000	-	**$50,000**
4	Davisville	115/34.5	T-Sub	$525,000	$25,000	-	**$550,000**
			D-Sub	$60,000	$10,000	-	**$70,000**
5	Wolf Hill	115/23	T-Sub	$340,000	$10,000	-	**$350,000**
			D-Sub	$40,000	$10,000	-	**$50,000**
6	Pontiac	115/12.47	T-Sub	$525,000	$25,000	-	**$550,000**
			D-Sub	$60,000	$10,000	-	**$70,000**
7	Riverside	115/13.8	T-Sub	$240,000	$10,000	-	**$250,000**
			D-Sub	$40,000	$10,000	-	**$50,000**
8	Quonset	34.5/12.47	D-Sub	$430,000	$20,000	-	**$450,000**
9	Peacedale	34.5/12.47	D-Sub	$430,000	$20,000	-	**$450,000**
10	Staples	115/13.8	T-Sub	$315,000	$10,000	-	**$325,000**
			D-Sub	$40,000	$10,000	-	**$50,000**
11	Warwick Mall	23/12.47	D-Sub	$430,000	$20,000	-	**$450,000**
12	Point Street	115/12.47	T-Sub	$525,000	$25,000	-	**$550,000**
			D-Sub	$60,000	$10,000	-	**$70,000**
Total Costs				**$5,295,000**	**$310,000**		**$5,605,000**

The above cost estimates were based on the following:

- Historical costs from previous Conceptual Engineering Reports (CER) at similar stations
- High level review of the existing protection schemes and the work scopes of the individual stations on the list
    - Need for coupling capacitor voltage transformers (CCVT)
    - Number of transformers in the station requiring 3V0 protective equipment

These cost estimates were distributed over a 5 year period to show the 3V0 implementation of the stations listed in section 4.2. The total program costs for the selected stations are $5.605M, broken down into $5.295M Capex and $0.310M Opex. Individual T-Sub and D-Sub funding projects have been initiated for each substation location. These costs are initial estimates to start the program. Depending on future DG interconnections to other RI substations the list will be expanded to include those stations and the resulting work scope and subsequent annual costs will change.

The estimated Capital spending forecast for T&D spend is shown in Table 4 below.

Table 4: Estimated Yearly Capital Expenditure

Number	Substation	Station Voltage (kV)	Spend Type	Estimates					
				FY19	FY20	FY21	FY22	FY23	Total
1	Tiverton	115/12.47	T-Sub	$525,000					**$525,000**
			D-Sub	$60,000					**$60,000**
2	Kilvert Street	115/12.47	T-Sub	$285,000					**$285,000**
			D-Sub	$40,000					**$40,000**
3	Old Baptist Road	115/12.47	T-Sub	$285,000					**$285,000**
			D-Sub	$40,000					**$40,000**
4	Davisville	115/34.5	T-Sub	$150,000	$375,000				**$525,000**
			D-Sub	$22,500	$37,500				**$60,000**
5	Wolf Hill	115/23	T-Sub		$96,250	$243,750			**$340,000**
			D-Sub		$17,500	$22,500			**$40,000**
6	Pontiac	115/12.47	T-Sub		$150,000	$375,000			**$525,000**
			D-Sub		$22,500	$37,500			**$60,000**
7	Riverside	115/13.8	T-Sub		$67,500	$172,500			**$240,000**
			D-Sub		$17,500	$22,500			**$40,000**
8	Quonset	34.5/12.47	D-Sub		$122,500	$307,500			**$430,000**
9	Peacedale	34.5/12.47	D-Sub			$122,500	$307,500		**$430,000**
10	Staples	115/13.8	T-Sub				$90,000	$225,000	**$315,000**
			D-Sub				$17,500	$22,500	**$40,000**
11	Warwick Mall	23/12.47	D-Sub				$122,500	$307,500	**$430,000**
12	Point Street	115/12.47	T-Sub				$150,000	$375,000	**$525,000**
			D-Sub				$22,500	$37,500	**$60,000**
T-Sub Total				$1,245,000	$688,750	$791,250	$240,000	$600,000	**$3,565,000**
D-Sub Total				$162,500	$217,500	$512,500	$470,000	$367,500	**$1,730,000**

6. Conclusions and Recommendations

This paper recommends a five year program that will install 3V0 protective equipment at several Rhode Island substations. The estimated cost of the project is approximately $5.605M. Spending will begin in FY19. The program will be reviewed on an annual basis to include substations where DG related projects have triggered the need for 3V0 protection. Individual work orders created under each project will be managed according to complexity and a Project Manager will track the progress.

The average cost of the 3V0 upgrades will be assessed at the end of the first construction year to refine existing estimates. Distribution Planning will review the optimal amount of yearly spend with the Resource Planning Department every year through the re-sanctioning process. As with any program, actual implementation will be coordinated with Resource Planning and Investment Planning. Spending levels may slightly decrease or increase the actual duration of this proposed five year construction program.

nationalgrid

Central Rhode Island East Area Study

Jack P. Vaz, PE

September 2017

Reviewed by: ______________________________ Date: ____________________
Elton Prifti, Distribution Planning & Asset Manager – NE, Network Strategy

Approved by: ______________________________ Date: ____________________
Ryan Constable, Acting Director, Distribution Planning and Asset Management, NE, Network Strategy

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LEGEND	
Al	Aluminum wire or cable
ARP	Asset Replacement Program
Cal/cm^2	Calories/square centimeter
Capex	Capital expenditure (budget expenditure type)
CKAIFI	Circuit Average Interruption Frequency Index
CKAIDI	Circuit Average Interruption Duration Index
Cu	Copper wire or cable
DPG	Distribution Planning Guide rev 1, dated February 2011
EMS	Energy Management System
GIS	Geographic Information System
ISO	Independent System Operator
kV	Kilovolts
LTC	Load Tap Changer
MVA	Megavolt Ampere
MVAR	Megavolt Ampere Reactive
MW	Megawatts
MWh	Megawatt hour
MOV	Metal-Oxide Varistor
NE	New England
Opex	Operations/Maintenance expenditure (budget expenditure type)
PEX	Process Excellence
PT	Potential Transformer
RAPR	Remote Access Pulse Recorder
RI	Rhode Island
PUC	Public Utility Commission
SN	Summer Normal Rating of Equipment
SE	Summer Emergency Rating of Equipment

1. Executive Summary

A comprehensive study of the Central Rhode Island East area was performed to identify existing and potential future distribution system performance concerns. System evaluation included comparison of equipment loading to thermal limits, contingency response capability, voltage performance, breaker operating capability, arc flash, reactive compensation performance, asset condition, and safety and environmental issues. The recommendations provide a comprehensive solution to address all the known system performance concerns in the study area thru 2030. As a result of potential overlap, this study was performed in collaboration with the Providence Study to develop a solution to address the needs of both areas.

This study was conducted using the latest methods resulting from a Process Excellence ("PEX") review of project sponsorship. Engineering, Design, Project Estimating, Operations, Resource Planning, Project Management, Permitting, Licensing, Community and Customer Management, Transmission Planning, and other internal departments were consulted during initial study scoping as well as throughout problem identification and solution development. Such consultation was gathered at an investment grade or high level to explore feasibility of the alternatives and gather economic data sufficient to make investment decisions.

The major components of items common to all plans are to:

- Modify the Drumrock 23 kV station to operate with normally open tie breakers. It currently operates with normally closed tie breakers. This change will reduce the fault current below the interrupting capabilities of the breakers and reduces the stress on the line conductors and other equipment in the event of a fault.
- Apponaug Short-Term: Retire the 23 kV station and remove all 23 kV equipment. Install relayed reclosers for protection of the No 3 and No 4 transformers. Upgrade the 2262 and 2264 line protection at Drumrock and remove the line differential scheme. Remove the abandoned 3 MVAR station capacitor bank.
- Apponaug Long-Term: Rebuild the station with two new 23/12.47 kV modular feeders utilizing standard open air modular feeder construction. Remove all existing equipment. This long-term plan addresses all the remaining concerns at this station.

The major components of the recommended plan, which were co-studied in the Providence Study, are to:

- Build a new 115/12.47 kV substation, open air low profile with a breaker-and-one-half design, at the existing Auburn substation site with two 115/12.47 kV 33/44/55 MVA transformers, eight feeder positions, and two 7.2 MVAr station capacitor banks.
- Extend two 115 kV transmission lines, I-187 and J-188, from Sockanosset substation approximately 1.10 miles north to the proposed Auburn substation. This proposed transmission line extension will be located within the existing 23 kV sub-transmission right-of-way and no new rights are anticipated to be required.
- Modify the area distribution due to the eight new feeders from Auburn substation. Retire the Auburn 23/4.16 kV station, the Lakewood 23/4.16 kV station, and the Sockanosset 115/23 kV station.

Table 1.1 shows the estimated capital spending per project with Common Items and Plan 1 subtotals. Bolded and shaded Plan 1 costs are duplicated, and not in addition to, the costs for the same scope shown in the Providence Study.

Table 1.1 – Estimated Capital Spending By Project ($M)

Description	Rationale	TOTAL	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28
Common Items												
Drumrock Modifications (T-Sub)	Protection System	$0.27	0.05	0.16	0.05							
Apponaug Short-Term (D-Sub)	Asset Condition	$0.76	0.15	0.46	0.15							
Apponaug Short-Term (D-Line)	Asset Condition	$0.17	0.03	0.10	0.03							
Apponaug Long-Term (D-Sub)	Asset Condition	$3.80					0.38	0.76	1.90	0.76		
Apponaug Long-Term (D-Line)	Asset Condition	$0.76					0.08	0.15	0.38	0.15		
Common Items Total		$5.76	$0.24	$0.72	$0.24		$0.46	$0.91	$2.28	$0.91		
Plan 1 Items												
Auburn Substation (T-Sub)	Asset Condition	**$0.50**							**0.05**	**0.10**	**0.30**	**0.05**
Auburn Substation (T-Line)	Asset Condition	**$6.00**						**0.15**	**0.45**	**2.85**	**2.55**	
Auburn Substation (D-Sub)	Asset Condition	**$8.32**							**0.83**	**1.66**	**4.99**	**0.83**
Auburn Substation (D-Line)	Asset Condition	**$11.98**					**2.04**	**4.07**	**4.43**	**0.72**	**0.72**	
Sockanosset Retirement (D-Sub)	Asset Condition	$0.00										
Lakewood Retirement (D-Sub)	Asset Condition	$0.00										
Lakewood Retirement (D-Line)	Asset Condition	$4.09					0.04	0.20	0.82	1.23	1.23	0.57
Plan 1 Total		30.89					2.08	4.43	6.58	6.56	9.79	1.45
TOTAL (T-Spend)		$6.77	$0.05	$0.16	$0.05			$0.15	$0.50	$2.95	$2.85	$0.05
TOTAL (D-Spend)		$29.88	$0.19	$0.56	$0.19		$2.53	$5.19	$8.36	$4.52	$6.94	$1.40
GRAND TOTAL		$36.65	$0.24	$0.72	$0.24		$2.53	$5.34	$8.86	$7.47	$9.79	$1.45

The complete study costs including the recommended plan and all common items are $47.50M, broken down into $36.65M Capex, $1.91M Opex, and $8.94M Removal. The estimated spending forecast is shown in Table 1.2 below.

Table 1.2 – Estimated Forecasted Spending – Recommended Plan & Common Items ($M)

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Capex	0.24	0.72	0.24		2.53	5.34	8.86	7.47	9.79	1.45		36.65
Opex	0.01	0.02	0.01		0.14	0.29	0.49	0.31	0.54	0.10		1.91
Removal	0.06	0.18	0.06		0.66	1.36	2.10	1.29	1.14	1.14	0.94	8.94
Total	0.31	0.92	0.31		3.34	7.00	11.46	9.07	11.46	2.70	0.94	47.50

The recommended plan provides a comprehensive solution to address all the known system concerns existing and anticipated in the study area thru 2030.

2. Introduction

2.1 Purpose

A comprehensive study of the Central Rhode Island East area was performed to identify existing and potential future distribution system performance concerns. System evaluation included comparison of equipment loading to thermal limits, contingency response capability, voltage performance, breaker operating capability, arc flash, reactive compensation performance, asset condition, and safety and environmental issues. The recommendations provide a comprehensive solution to address all the known system performance concerns in the study area thru 2030.

2.2 Problem

The Providence Study identified a need for new distribution capacity in the northern section of the Central Rhode Island East study area to address projected thermal overloads and other distribution planning criteria violations in the Providence area. This study was performed in collaboration with the Providence Study to develop a comprehensive solution to address the needs of both areas.

Formal and informal asset condition reviews and inspection results indicate there may be growing asset condition and reliability concerns in this area. This study is being performed to recommend prudent and comprehensive solutions to provide adequate, reliable and economic service to the customers in this area.

Sockanosset substation is a major supply station in the area. Its location abuts the Pawtuxet River and is within the flood plain. In March of 2010, flooding at this station damaged nearly all the substation equipment. Although repairs were made to return the station to service, the station remains within the flood plain. This study is being performed to develop a comprehensive solution that addresses these flooding concerns.

3. Background

3.1 Scope

3.1.1 Geographic Scope

The Central Rhode Island East study area consists of the eastern sections of the Cities of Cranston and Warwick. The study area is bounded by the City of Providence to the north, Interstate 295 to the west and Narragansett Bay to the east and south. The study area is shown geographically in Appendix 9.1.

3.1.2 Electrical Scope

The customer load in this area is mostly supplied from the Drumrock 115 kV station. Two 115kV transmission lines, I-187 and J-188, combined with the Drumrock 12.47 kV station supply nearly all the load in the study area. A small portion of the load is supplied from a 11.5 kV system at Franklin Square and South Street substations. This area has an extensive sub-transmission system consisting of seven 23kV lines (2213, 2222, 2224, 2233, 2235, 2262 and 2264). One line diagrams are shown in Appendix 9.2.

Four 115/12.47 kV substations consisting of Drumrock, Kilvert Street, Lincoln Avenue, and Pontiac supply 170 MW of area load. The 23 kV sub-transmission system from Drumrock and Sockanosset substations supplies 79 MW of load. The remainder of the load, or 10 MW, is supplied from the 11.5 kV system at Franklin Square and South Street substations.

The area has two pockets of 4.16 kV load. The first pocket, approximately 7.7 MW, is supplied from Lakewood substation located in the City of Warwick. The second pocket, approximately 9.3 MW, is supplied from Auburn substation located in the City of Cranston. Both 4.16 kV load pockets are self-contained with no ties to any other station or to each other.

The area has approximately fifteen industrial customers with approximately 10 MW of load supplied directly from an unregulated 23 kV sub-transmission system. These customers are supplied from Drumrock, Sockanosset, and Elmwood substations.

3.2 Area Load and Load Forecast

The study area has approximately 55,500 customers with a peak electrical demand of 243 MW. The study area is summer peaking and summer limited. This study used the most recent forecast developed by National Grid, the "2016 New England Electric Peak Forecast". It utilized the 95/5 extreme weather scenario case. Table 3.2.1 shows the forecasted load growth rate for the study area from 2016 to 2030.

TABLE 3.2.1 – Forecasted Load Growth Rate from 2016 to 2030 for Study Area

Forecasted Growth – Central Rhode Island East					AVG	AVG
2016	2017	2018	2019	2020	'21 to '25	'26 to '30
-0.3%	0.3%	0.2%	0.1%	0.2%	0.6%	0.8%

The projected peak electrical demand by year 2030, or the end of the study horizon period, is approximately 262 MW. This projected demand was adjusted to reflect a transfer of 6 MW to the Central Rhode Island West Study Area as a result of the proposed New London Ave substation currently in construction.

3.3 Active Projects

A new 115/12.47 kV substation is being built on New London Avenue in the City of Warwick with a projected in-service date of November 2018. New London Ave feeders will provide relief to two heavily loaded Drumrock feeders. This will transfer approximately 6 MW of Central Rhode Island East area load to the Central Rhode Island West area.

Two new 12.47 kV feeders, 87F5 and 87F6, are in construction at Kilvert Street substation in the City of Warwick. These circuits are near completion and are assumed to be in-service prior to summer 2017.

3.4 Limitations on Infrastructure Development

Several physical barriers divide the study area. These barriers include Interstate 95, the Pawtuxet River, Amtrak northeast rail corridor and T. F. Green airport. Interstate 95, the Pawtuxet River and the Amtrak rail corridor limit distribution ties between the east and west sections of the study area while T. F. Green airport limits the number of overhead supply and distribution ties to eastern sections of Warwick.

3.5 Assumptions & Guidelines

The current Distribution Planning Guide rev 1, February 2011 ("DPG") was used in performing this study. The guide describes the normal and contingency analysis, as well as considerations for safety, the environment, reliability, reactive compensation, load balance, voltage, and efficiency, used in National Grid's distribution planning studies. Appendix 9.15 shows the DPG document.

The Distribution Planning & Asset Management department uses the Siemens PTI PSS/e loadflow program to analyze the transmission and sub-transmission system which is the same program used by ISO NE and the National Grid Transmission Planning department.

The CYMdist program was used to analyze radial three-phase unbalanced systems (distribution feeders). Databases were extracted from the GE-SmallWorld GIS System into a Microsoft Access format. The arc flash module of this program was used for relevant arc flash analysis.

The ASPEN OneLiner program was used to determine short circuit duty values at all substations. This is the same program used by National Grid Protection Engineering for all short circuit and relay coordination studies.

4. Problem Identification

4.1 Thermal Loading

4.1.1 Normal Configuration - Thermal Loading

Feeders: Loading on distribution line sections of each feeder was analyzed using the CYMdist software. The Pontiac 27F4 feeder and sections of the Apponaug 3F1 feeder are projected to be loaded above summer normal limits during the study horizon period. A loading table is shown in Table 4.1.1.1 and the CYME analysis is shown in Appendix 9.4.

TABLE 4.1.1.1 – Feeder Loading

Substation	kV	Feeder	2018		2022		2026		2030	
			Amps	%SN	Amps	%SN	Amps	%SN	Amps	%SN
APPONAUG	12.47	3F1	376	71%	382	73%	392	74%	404	77%
APPONAUG	12.47	3F2	380	74%	386	75%	396	77%	409	79%
DRUMROCK	12.47	14F1	312	59%	317	60%	325	61%	336	63%
DRUMROCK	12.47	14F2	386	73%	392	74%	402	76%	415	78%
DRUMROCK	12.47	14F3	319	62%	324	63%	333	65%	343	67%
DRUMROCK	12.47	14F4	267	52%	271	53%	278	54%	287	56%
KILVERT STREET	12.47	87F1	412	78%	419	79%	429	81%	443	84%
KILVERT STREET	12.47	87F2	351	62%	356	62%	366	64%	377	66%
KILVERT STREET	12.47	87F3	328	62%	333	63%	342	65%	353	67%
KILVERT STREET	12.47	87F4	315	59%	320	60%	328	62%	339	64%
KILVERT STREET	12.47	87F5	336	63%	341	64%	350	66%	361	68%
KILVERT STREET	12.47	87F6	310	59%	315	59%	323	61%	334	63%
LINCOLN AVENUE	12.47	72F1	273	52%	277	52%	285	54%	294	55%
LINCOLN AVENUE	12.47	72F2	364	69%	369	70%	379	72%	391	74%
LINCOLN AVENUE	12.47	72F3	447	84%	454	86%	466	88%	481	91%
LINCOLN AVENUE	12.47	72F4	375	71%	380	72%	390	74%	403	76%
LINCOLN AVENUE	12.47	72F5	400	78%	407	79%	417	81%	431	84%
LINCOLN AVENUE	12.47	72F6	461	81%	468	82%	480	85%	495	87%
PONTIAC	12.47	27F1	378	71%	384	72%	394	74%	407	77%
PONTIAC	12.47	27F2	431	81%	438	83%	449	85%	464	88%
PONTIAC	12.47	27F3	169	37%	172	37%	176	38%	182	40%
PONTIAC	12.47	27F4	467	102%	474	103%	487	106%	502	109%
PONTIAC	12.47	27F5	424	80%	430	81%	442	83%	456	86%
PONTIAC	12.47	27F6	247	47%	251	47%	257	49%	266	50%
WARWICK	12.47	52F1	239	49%	243	50%	249	51%	257	53%
WARWICK	12.47	52F2	111	23%	113	23%	116	24%	120	25%
WARWICK	12.47	52F3	377	72%	383	73%	393	75%	406	77%
AUBURN	4.16	73J1	145	39%	147	40%	151	41%	156	42%
AUBURN	4.16	73J2	139	36%	141	37%	145	38%	150	39%
AUBURN	4.16	73J3	316	82%	320	83%	329	85%	339	88%
AUBURN	4.16	73J4	176	46%	179	47%	184	48%	190	49%
AUBURN	4.16	73J5	316	77%	320	79%	329	81%	339	83%
AUBURN	4.16	73J6	209	55%	212	56%	218	57%	225	59%
LAKEWOOD	4.16	57J1	158	43%	160	43%	164	45%	170	46%
LAKEWOOD	4.16	57J2	290	64%	294	65%	302	67%	312	69%
LAKEWOOD	4.16	57J3	350	86%	356	87%	365	89%	377	92%
LAKEWOOD	4.16	57J5	325	66%	330	67%	338	69%	349	71%

Transformers: There are no projected transformer normal configuration overloads within the study period. Table 4.1.1.2 shows the summer normal loading on the study area transformers.

TABLE 4.1.1.2 – Transformer Loading (Normal)

Substation	Tranf. ID	System Voltage (kV)		Rating (MVA)	Peak Load							
					2018		2022		2026		2030	
		From	To	SN	MVA	% SN	MVA	% SN	MVA	% SN	MVA	% SN
APPONAUG	3	23	12.47	15.50	8.1	52%	8.2	53%	8.5	55%	8.7	56%
APPONAUG	4	23	12.47	11.90	8.2	69%	8.3	70%	8.5	72%	8.8	74%
KILVERT STREET	1	115	12.47	72.00	23.3	32%	23.6	33%	24.2	34%	25.0	35%
KILVERT STREET	2	115	12.47	70.00	21.1	30%	21.4	31%	22.0	31%	22.7	32%
LINCOLN AVENUE	1	115	12.47	52.07	24.2	47%	24.6	47%	25.2	48%	26.0	50%
LINCOLN AVENUE	2	115	12.47	52.07	25.4	49%	25.8	49%	26.4	51%	27.3	52%
PONTIAC	1	115	12.47	50.67	20.6	41%	20.9	41%	21.4	42%	22.1	44%
PONTIAC	2	115	12.47	46.49	23.8	51%	24.1	52%	24.7	53%	25.5	55%
WARWICK	1	23	12.47	11.60	7.6	65%	7.7	66%	7.9	68%	8.1	70%
WARWICK	4	23	12.47	12.00	8.1	68%	8.3	69%	8.5	71%	8.8	73%
AUBURN	1	23	4.16	10.56	5.6	53%	5.7	54%	5.8	55%	6.0	57%
AUBURN	2	23	4.16	9.66	3.8	39%	3.8	40%	3.9	41%	4.1	42%
LAKEWOOD	1	23	4.16	10.09	4.7	47%	4.8	47%	4.9	49%	5.1	50%
LAKEWOOD	2	23	4.16	10.15	3.1	31%	3.2	31%	3.3	32%	3.4	33%
DRUMROCK	[redacted]											
DRUMROCK												
DRUMROCK												
SOCKANOSSET	1	115	23	50.29	23.2	46%	23.5	47%	24.1	48%	24.9	50%
SOCKANOSSET	2	115	23	50.37	23.0	46%	23.3	46%	23.9	47%	24.7	49%

Supply Lines: There are no projected supply line normal configuration overloads within the study area for the analysis period. The 2235 line, in the Providence Study area, supplies the Elmwood 12.47 kV substation and a number of industrial customers. This line is projected to be loaded above summer normal limits as described within that study.

4.1.2 Contingency Configuration - Thermal Loading

Feeders: A contingency analysis was performed for all feeders in the study area. This analysis calculates a megawatt*hour ("MWh") 'exposure' or risk assuming a worst case component failure during summer peak (extreme weather) loading conditions. The assumptions made for this analysis were:

- A one-hour response time before performing the first switching step and 30-minutes to execute each additional switching step.
- Assumes a failed component can be repaired within four hours. Some feeders have underground cable getaways which may require a longer repair time. Because this exposure is small, a cable failure was not assumed in the analysis.
- Some feeders are double circuited on the same pole plant. Because this exposure is small, a failure involving two feeders was not assumed in the analysis.
- The MWh calculations utilize the summer emergency ratings of the feeders.

There were no calculated feeder criteria violations in excess of the DPG.

<u>Transformers:</u> A contingency analysis was performed for all station power transformers in the study area. This analysis calculates a MWh 'exposure' or risk assuming a worst case component failure during summer peak (extreme weather) loading conditions. There were no calculated transformer criteria violations in excess of the DPG. Table 4.1.2 shows the summer contingency loading on the study area transformers.

TABLE 4.1.2 – Transformer Loading (Contingency)

Substation	Tranf. ID	System Voltage (kV)		Rating (MVA)	Peak Load							
					2018		2022		2026		2030	
		From	To	SE	MVA	% SE	MVA	% SE	MVA	% SE	MVA	% SE
APPONAUG	3	23	12.47	19.60								
APPONAUG	4	23	12.47	12.60								
KILVERT STREET	1	115	12.47	82.00	44.3	54%	45.0	55%	46.2	56%	47.7	58%
KILVERT STREET	2	115	12.47	79.00	44.3	56%	45.0	57%	46.2	58%	47.7	60%
LINCOLN AVENUE	1	115	12.47	54.92	49.6	90%	50.3	92%	51.7	94%	53.3	97%
LINCOLN AVENUE	2	115	12.47	54.92	49.6	90%	50.3	92%	51.7	94%	53.3	97%
PONTIAC	1	115	12.47	53.32	44.3	83%	45.0	84%	46.2	87%	47.7	89%
PONTIAC	2	115	12.47	51.88	44.3	85%	45.0	87%	46.2	89%	47.7	92%
WARWICK	1	23	12.47	12.70								
WARWICK	4	23	12.47	12.00								
AUBURN	1	23	4.16	11.81	9.4	79%	9.5	81%	9.8	83%	10.1	85%
AUBURN	2	23	4.16	10.64	9.4	88%	9.5	89%	9.8	92%	10.1	95%
LAKEWOOD	1	23	4.16	10.63	7.9	74%	8.0	75%	8.2	77%	8.4	79%
LAKEWOOD	2	23	4.16	11.46	7.9	68%	8.0	70%	8.2	71%	8.4	74%
DRUMROCK	[redacted]											
DRUMROCK												
DRUMROCK												
SOCKANOSSET	1	115	23	56.81	46.1	81%	46.8	82%	48.0	85%	49.6	87%
SOCKANOSSET	2	115	23	57.03	46.1	81%	46.8	82%	48.0	84%	49.6	87%

<u>Supply Lines:</u> A contingency analysis was performed for all supply lines in the study area. This analysis calculates a MWh 'exposure' or risk assuming a worst case component failure during summer peak loading conditions. There were no calculated supply line criteria violations within the study area.

The loss of the preferred supply to Elmwood 12.47 kV station (2235 line) requires the Elmwood station load to be supplied from Franklin Square and South Street lines (2210, 2216, and 2220). These supply lines have limited capacity and would result in approximately 15 MW of Elmwood 12.47 kV load remaining un-served until repairs can me date to the 2235 line. While this exposure does not exceed guidelines it is noted as risk.

4.2 Voltage Performance

The DPG recommends that customer service voltages be maintained to meet ANSI 84.1 guidelines. ANSI 84.1 requires that service voltages be maintained between 0.95 and 1.05 per unit during normal loading conditions and between 0.90 and 1.05 per unit during contingency loading conditions. The ability to adjust transformer tap settings combined with voltage regulation equipment allows the supply system to vary greater than the required service voltage range. However for study purposes, the supply system was screened for potential issues using the ANSI 84.1 ranges.

The PSS/e load flow program was used to model the electrical system down to the 23 kV sub-transmission level including step-down transformers to the distribution feeder level. No major voltage violations were identified during this PSS/e screening effort. A slight violation was observed on the Warwick 52F3 feeder during an extreme weather event at peak loading, bus voltage is 0.938 PU. However, this slight violation can be mitigated by utilizing the voltage regulators on the feeder. See Appendix 9.3 for loadflow diagrams.

The CYME program models all three phases of each distribution feeder for its entire length starting at the substation. Voltages at all points should be maintained between the range of 0.95 to 1.05 per unit, or from 114 volts to 126 volts on a 120 volt base. Minor violations were identified which can be mitigated by feeder balancing. See Appendix 9.4 for CYME diagrams.

4.3 Asset Condition

The substation O&M services department performed asset condition assessments for each substation in the study area. The following substations have known asset condition concerns:

Apponaug consists of a 23 kV station and two 12.47 kV modular feeders. It supplies 15 MW of peak load. Appendix 9.2 shows a one-line of the station. Appendix 9.14 shows Appanaug asset pictures. The station has a history of operational challenges and asset condition concerns. The major concerns are:

- The short circuit current exceeds the breaker duty on the 23 kV 1-4 breaker. In addition, all the 23 kV breakers are in poor condition and no longer reliable.
- The #4 transformer has signs of increased gassing placing it at an elevated risk of failure.
- The control building needs major repairs and much of the 23 kV control equipment in the building is obsolete. The building contains both asbestos wiring and asbestos panels.
- The 23 kV auto-transfer scheme is obsolete and has a history of mis-operation. This has resulted in customer outages due to its failure to operate.
- The voltage regulators are in poor condition and consist of non-standard installation. This non-standard installation makes it very challenging to replace the regulators.
- The 23 kV disconnect switches are obsolete, unreliable, and often fail to latch close.
- The station has no remote status, control and monitoring of switching devices, transformers, voltage regulation and battery systems (no EMS).

Auburn is a 23/4.16 kV substation supplying 9.4 MW of peak load. Appendix 9.2 shows a one-line of the station. Station supplies a pocket of 4.16 kV with no ties to other stations. It is a 1950's vintage station with a number of concerns:

- The 1950's vintage circuit breakers are obsolete and no longer reliable.
- The 23 kV transfer scheme is installed on non-standard wooden structures.
- The station has no remote status, control and monitoring of switching devices, transformers, voltage regulation and battery systems (no EMS).

Lakewood is a 23/4.16 kV substation supplying 7.8 MW of peak load. Appendix 9.2 shows a one-line of the station. This station supplies a pocket of 4.16 kV with no ties to other stations. It is a 1950's vintage station with a number of concerns:

- The short circuit current exceeds the breaker duty on the 4.16 kV breakers.
- The 23 kV transfer scheme switches and structures are obsolete.
- The #2 transformer shows signs of increased gassing with an elevated risk of failure.
- The station has no remote status, control and monitoring of switching devices, transformers, voltage regulation and battery systems (no EMS).

4.4 Additional Analysis

4.4.1 Flood Mitigation

Sockanosset is a 115/23 kV substation with two 24/32/40 MVA transformers and two 23 kV supply lines (2233 and 2235). It supplies approximately 46MW of peak load. It supplies Auburn, Elmwood and Lakewood substations and supplies a number of industrial customers directly at 23 kV. Appendix 9.2 shows a one-line of the station.

Sockanosset is located near the Pawtuxet River in Cranston and is within the flood plain. On March 31, 2010 flood waters from the Pawtuxet River reached levels of 6 ½ feet in the station yard. Attempts to access the substation by boat were made on April 1st but current from the Pawtuxet River prevented safe access. Finally, on April 2nd crews were able to gain access to the station using a "Trac" vehicle.

A condition assessment of the station was performed on April 2nd and it noted that flood waters from the river were brackish, contained raw sewage and other contaminants such as oil and gasoline. These contaminants were a hazard to the safety of personnel and detrimental to the mechanical equipment components such as circuit breaker operating mechanisms, electromechanical relays, circuit switcher operators, microprocessor and solid state printed circuit boards, and other equipment.

The substation fence collapsed in its entirety pulling the fence mesh from its support posts, snapping support posts, and undermining fence posts due to the forces of the current from the river. The transformer cabinets were submerged and covered with silt from the water as were the motors of the cooling fans. The damage to equipment within the control house and equipment in the switchyard was extensive due to the height of the water, length of time equipment was submerged, and forces of the current due to proximity to the river.

An environmental contractor was hired to provide remediation and disinfecting services of equipment exposed to the flood waters. Once remediation was complete the damaged station equipment was replaced and the station was returned to service on April 16, 2010. All further work at the station is on hold pending the results of this study.

4.4.2 Reliability Performance

A reliability review was conducted to check feeder indices against system targets. For calendar year 2015, the CKAIFI target was 1.05 and CKAIDI target was 71.9 minutes. CKAIFI or "Circuit Average Interruption Frequency Index" means the total number of customer interruptions divided by the total number of customers connected to the circuit, expressed in average number of interruptions per year. CKAIDI or "Circuit Average Interruption Duration Index" is defined as the total minutes of customer interruptions for a circuit divided by the total number of customers connected to the circuit, expressed in minutes per year.

Table 4.4.2 below lists the three year CKAIFI and CKAIDI reliability data for all the feeders in the study area.

TABLE 4.4.2 – Study Area Reliability Indices

FEEDER	2013		2014		2015		AVERAGE	
	CKAIFI	CKAIDI	CKAIFI	CKAIDI	CKAIFI	CKAIDI	CKAIFI	CKAIDI
3F1	0.02	4	0.05	7	1.27	53	0.44	21
3F2	0.38	33	0.61	55	2.53	195	1.18	94
14F1	1.11	56	0.06	6	2.58	155	1.25	72
14F2	0.18	22	0.07	23	2.61	104	0.95	50
52F1	1.07	85	1.03	190	1.60	78	1.23	118
52F2	0.43	64	0.09	7	2.76	131	1.10	67
52F3	1.16	104	0.67	53	1.19	57	1.01	71
72F1	1.13	49	0.11	5	1.08	62	0.77	39
72F2	0.05	22	0.07	6	2.14	37	0.75	22
72F3	1.17	113	0.47	33	2.79	97	1.48	81
72F4	0.04	5	0.27	18	2.21	32	0.84	18
72F5	1.18	68	0.86	114	2.02	85	1.35	89
72F6	1.12	76	1.95	90	1.81	14	1.63	60
87F1	0.75	48	0.69	71	0.96	109	0.80	76
87F2	0.19	176	0.00	0	0.00	0	0.06	59
87F3	1.03	55	0.09	7	1.25	182	0.79	81
87F4	0.75	164	0.00	0	0.01	1	0.25	55
27F1	0.07	13	0.09	7	0.86	42	0.34	20
27F2	0.08	7	0.02	7	0.01	10	0.03	7
27F3	0.00	0	0.00	0	0.00	0	0.00	0
27F4	0.15	16	0.02	2	0.73	42	0.30	20
27F5	0.22	17	1.20	130	0.04	6	0.49	51
27F6	0.00	0	0.00	1	0.00	0	0.00	0
73J1	0.00	0	0.99	28	0.04	116	0.35	48
73J2	0.00	0	0.00	0	0.00	0	0.00	0
73J3	0.00	0	0.00	0	0.01	2	0.00	1
73J4	2.00	715	0.12	20	0.00	0	0.71	245

73J5	0.12	8	0.04	3	0.10	6	0.08	6
73J6	0.06	4	0.01	0	0.03	2	0.03	2
57J1	0.37	48	0.28	14	0.00	0	0.22	21
57J2	0.12	15	0.05	6	0.61	18	0.26	13
57J3	1.02	75	0.01	1	0.01	1	0.35	26
57J5	0.02	2	0.00	0	0.01	1	0.01	1
Feeders below are being reconfigured due to New London Ave Substation								
14F3	2.91	144	0.01	2	1.38	170	1.43	105
14F4	0.30	24	0.32	88	1.03	54	0.55	55

In 2015 the 3F2 feeder experienced a significant increase in frequency and duration. The increase in frequency can be attributed to a number of fused branch outages due to down tree branches and animal contacts. The increased duration can be attributed to a single event that resulted from a failed line insulator that required an extended feeder outage to perform repairs.

In 2015 the 14F1 feeder experienced a significant increase in frequency and duration. The increase in frequency can be attributed to a number of fused branch outages due to down tree branches and animal contacts. The increased duration can be attributed to a single event that began as a disturbance on the J-188 115kV line due to a lightning strike and spread to include the 14F1 breaker being locked open.

In 2015 the 52F2 feeder experienced a significant increase in frequency and duration. The increase in frequency can be attributed to a number of fused branch outages due to down tree branches and animal contacts. The increased duration can be attributed to two events. The first event was a motor vehicle accident that damaged feeder conductors and the second was the intentional opening of a recloser to remove a fallen tree resting on the wires.

4.4.3 Arc Flash

Refer to Appendix 9.5 for the Arc Flash analysis.

4.4.4 Fault Duty/Short Circuit Availability

The ASPEN program was used to calculate single phase to ground and three phase short circuit current values at each area substation. These short circuit current values were compared to the station breaker interrupting capabilities. The available fault current on a number of substations exceeds the interrupting capability of the breakers. The table in Appendix 9.6 summarizes the results of this analysis.

4.4.5 Reactive Compensation

Refer to Appendix 9.12 for the reactive compensation analysis.

4.4.6 Protective Coordination

A variety of devices are used to protect or isolate sections of a feeder during fault conditions. Typical protective devices in use are circuit breakers, circuit reclosers, line reclosers and fuses. In rearranging a distribution system particular care must be given to ensure that the coordination between protective devices is maintained. In some instances line reclosers settings may have to be adjusted or reclosers relocated or added as the feeder configuration changes.

Due to the significant feeder and supply line reconfigurations being recommended in this study and in the Providence study, an existing configuration coordination study is not required.

5. Plan Development

5.1 Consideration of Distributed Generation in Plan Development

The impact of existing and planned distributed generation ("DG") installations was considered in the plan formation. There are no existing or planned installations of significant size (greater than 1MW) on any feeder or sub-transmission line. Appendix 9.11 lists the existing and proposed DG within the study area.

Nearly all the issues in the study area are asset condition and flood mitigation driven. The existing and proposed DG does not address or avoid necessary asset condition and flood mitigation issues and is not significant or dependable in load levels to mitigate capacity issues. As a result, the comprehensive plans are unaffected by the existing or proposed distributed generation in this area.

5.2 Common Items

Drumrock 23kV Station:

The fault current on the Drumrock 23 kV station exceeds the interrupting capabilities of the circuit breakers. The station tie breakers operate normally closed resulting in fault current contribution from the No. 3, No. 4, and No. 5 transformers. The high fault current also places undue stress on the sub-transmission line conductors and other equipment resulting in the potential damage to these conductors and equipment.

To mitigate the fault current concerns at this station the recommended plan is to operate the 23 kV station tie breakers "normally open". This is the most economical approach and has a minimal impact on the reliability of this system. A one-line of the proposed Drumrock substation modifications is shown on Appendix 9.7 along with projected post-project fault duty.

Apponaug Substation:

The recommended short-term plan is to retire the 23 kV station, remove all 23 kV equipment, and install relayed reclosers for transformer protection. The removal of the 23 kV station requires the 2262 and 2264 line protection to be upgraded at Drumrock. The abandoned 3MVAR station capacitor bank will also be removed. The removal of the 23 kV station eliminates the need for the control house which can be retired in place. A one line of the proposed removals and the proposed short-term plan is shown in Appendix 9.7. This short-term plan addresses the immediate concerns at this station.

The recommended long-term plan is to rebuild the station with two 23/12.47 kV modular feeders. This investment addresses all the remaining asset concerns at the station. Two options were estimated for modular feeder construction. Option 1 consists of standard open air modular feeder construction with an estimate cost of $5.300M. Option 2 consists of utilizing a Modular Integrated Transportable Substation (MITS) design with an estimated cost of $9.900M. Option 1 is recommended for implementation because it is the most economical option while addressing all the concerns at this station.

Although the recommended short-term plan for Apponaug eliminates the need for the control building it is unlikely the building can be demolished. The building is located within a historic district and although the building itself does not appear on the historic register, it may still be considered a historic building. In 2010, the company was denied a demolition permit from the City of Warwick to demolish this building. Furthermore, the City of Warwick has interest in acquiring this building from the company and has approached the company about this potential acquisition.

Investments and expenses for the common items:

The investments and expenses for the common items are shown in Table 5.2 below:

TABLE 5.2 - Estimated Cost of Common Items ($M)

Component	Capex	Opex	Removal	Total
Drumrock Modifications (T-Sub)	$0.270	$0.020	$0.080	$0.370
Apponaug Short-Term (D-Sub)	$0.760	$0.010	$0.200	$0.970
Apponaug Short-Term (D-Line)	$0.170	$0.010	$0.020	$0.200
Apponaug Long-Term (D-Sub)	$3.800	$0.200	$1.300	$5.300
Apponaug Long-Term (D-Line)	$0.760	$0.050	$0.150	$0.960
TOTAL (Common Items)	$5.760	$0.290	$1.750	$7.800

5.3 Plan – 1

The recommended plan is to build a new 115/12.47 kV substation at the existing Auburn substation site with two 115/12.47 kV 33/44/55 MVA transformers, eight regulated feeder positions, and two 7.2 MVAr station capacitor banks each consisting of two 3.6 MVAr stages. The preferred arrangement of the station is open air low profile with a breaker-and-one-half design. The proposed one line for this station is shown in Appendix 9.8.

Extend the 115 kV transmission circuits, I-187 and J-188, from Sockanosset substation to the Auburn substation along an existing right-of-way. Utilize 795 kcmil ACSR conductor for the 115 kV transmission circuits. Remove the 23 kV circuit, 2235, from the right-of-way.

As documented in the Providence Study, one of the transmission lines will be initially energized at 23 kV to maintain the supply to Elmwood 23/12.47 kV substation from Sockanosset. The second line will be energized at 115 kV to supply Auburn substation initially with a single transformer. The second transmission line would then be disconnected from the 2235 and energized at 115 kV to supply the second 115 kV transformer at Auburn after the Elmwood 23/12.47 kV station is retired.

Remove the existing Auburn 23/4.16 kV station to make room for the new station. New Auburn feeders will follow the route of the existing 4.16 kV feeders and will supply the existing Auburn load, load converted within Huntington Park on the 23 kV and 4.16 kV circuits, a portion of the Knightsville load, a portion of the Sprague Street load, a portion of the Elmwood 23 kV and 12.47 kV load, and provide relief to heavily loaded 12.47 kV feeders from Point Street and Pontiac substations.

A new Auburn feeder will be used to retire Lakewood substation. The retirement of Lakewood eliminates a pocket of 4.16 kV and creates new 12.47 kV feeder ties to improve reliability in the area. The retirement of Lakewood also eliminates the overdutied station breakers, the need to replace the gassing transformer, and the obsolete auto-transfer scheme.

The retirement of Lakewood and Auburn substations eliminates the need for Sockanosset substation. The retirement of Sockanosset addresses the flood concerns at least cost. It eliminates a large portion of the 23 kV supply system installed in a difficult to access right-of-way and double circuited on City streets putting it at risk of motor vehicle accidents and tree related outages.

The projected transformer loading (normal and contingency) tables and the proposed mainline distribution for Plan 1 are shown in Appendix 9.8. The investments and expenses for Plan 1 are detailed in Table 5.3 below.

TABLE 5.3 - Estimated Investments and Expenses for Plan 1

Component ($M)	Capex	Opex	Removal	Total
Auburn Substation (T-Sub)	$0.500	$0.000	$0.000	$0.500
Auburn Substation (T-Line)	$6.000	$0.024	$0.308	$6.332
Auburn Substation (D-Sub)	$8.315	$0.700	$0.350	$9.365
Auburn Substation (D-Line)	$11.983	$0.684	$2.981	$15.648
Lakewood Retirement (D-Sub)	$0.000	$0.000	$0.850	$0.850
Lakewood Retirement (D-Line)	$4.094	$0.208	$1.199	$5.500
Sockanosset Retirement (D-Sub)	$0.000	$0.000	$1.500	$1.500
Total Cost ($M)	$30.892	$1.616	$7.188	$39.695

T-Spend	$6.500	$0.024	$0.308	$6.832
D-Spend	$24.392	$1.592	$6.880	$32.863

5.4 Alternate Plans

5.4.1 Plan – 2

This plan recommends new distribution capacity supplied from an expanded and upgraded 23 kV sub-transmission system and minimal 115 kV transmission system expansion. The major modifications are a new 115/23 kV substation at Sockanosset, a new 23/12.47 kV substation at Auburn, and an expanded Elmwood 12.47 kV substation. The estimated investments and expenses for Plan 2 are $51.273M. Appendix 9.9 has a comprehensive analysis of Plan 2.

5.4.2 Plan – 3

This plan recommends new distribution capacity supplied from a new 34.5 kV sub-transmission system and minimal 115 kV transmission system expansion. The major modifications are a new 115/34.5 kV substation at Sockanosset, a new 34.5/12.47 kV substation at Auburn, and an expanded Elmwood 12.47 kV substation. The estimated investments and expenses for Plan 3 are $52.660M. Appendix 9.10 has a comprehensive analysis of Plan 3.

5.4.3 Do Nothing

Taking no action would leave all the problems mentioned in Section 4 unaddressed. Violations of the Distribution Planning Criteria would continue to exist and worsen as time goes by, adversely affecting customer service and reliability performance. Sockanosset substation would remain in the flood plain exposing customers to extended outages in case of area flooding.

6. Plan Considerations and Comparisons

6.1 Economic, Schedule, and Technical Comparisons

The estimated investments and expenses for the three Plans are shown in Table 6.1 below. The economic comparisons exclude the cost of common items.

TABLE 6.1 – Estimated Investments and Expenses for Plan 1, Plan 2, and Plan 3

	Plan 1	Plan 2	Plan 3
Capex	$30.892	$42.278	$43.695
Opex	$1.616	$2.029	$2.028
Removal	$7.188	$6.966	$6.937
TOTAL	$39.695	$51.273	$52.660

T-Spend	$6.832	$0.000	$0.000
D-Spend	$32.863	$51.273	$52.660

Plan 1 is the most economical plan, is the most reliable, and has the lowest losses. It eliminates a large portion of the 23 kV supply system installed in difficult to access right-of-way and along highly congested roadways with significant exposure to motor vehicle accidents and tree related outages. It adds new distribution capacity supplied from a more reliable 115 kV system with minimal exposure to motor vehicle accidents and the tree related outages.

Plan 2 has no economic or reliability benefits over Plan 1 and has higher losses. It upgrades and expands the 23 kV system to supply 23/12.47 kV stations. These supply upgrades would consist of a mixture of right-of-way construction and construction along highly congested roadways. This supply system would have exposure to motor vehicle accidents and tree related outages due to the extensive roadway construction.

Plan 3 offers no economic or reliability benefits over Plan 1 and has higher losses. It replaces the existing 23 kV supply system with a new 34.5 kV system that will supply 34.5/12.47 kV stations. These supply upgrades would consist of a mixture of right-of-way construction and construction along highly congested roadways. This supply system would have exposure to motor vehicle accidents and tree related outages due to the extensive roadway construction.

Both Plan 2 and Plan 3 would rebuild Sockanosset substation within the flood plain. Although the station would be built on an elevated platform, the site could still remain un-accessible during an extreme flooding event. In the March 2010 flooding, this substation site was un-accessible to company vehicles for three days.

A summary of key factors used in plan selection are shown in the Plan Comparison Matrix below.

Plan Comparison Matrix

KEY FACTOR	PLAN 1	PLAN 2	PLAN 3
Initial Cost	√	×	×
Reliability	√	×	×
Losses	√	×	×
Maintenance Costs	√	×	×
Climate Resiliency	√	×	×
Future Expansion Flexibility	√	×	×

6.2 Non-Wires Alternatives Considerations

Where an issue has been identified, a Non-Wires Alternative may be considered as an option to defer a transmission, sub-transmission, or distribution wires solution for a period of time. Considering Non-Wires Alternatives to every wires solution is not practical given the low cost of a large volume of potential wires solutions, the magnitude of load relief required in certain situations, the time to acquire Non-Wires Alternatives (and verify their availability) or instances where the issue is poor operating condition of the asset. As a result, Non-wires Alternatives are screened against the following four guidelines:

- A wires solution will likely be more than $1M.
- If load reduction is necessary, it should be less than 20 percent of the total load in the area of the defined need.
- Start of construction is at least 36 months in the future.
- The need is not based on Asset Condition.

Although the plans developed for this study will exceed $1M and the start of construction for the majority of the work will be at least 36 months in the future, there are significant asset condition issues and the need for flood mitigation measures within the study area as described in Section 4.3. Therefore Non-Wires Alternatives are not considered feasible to provide a comprehensive study area solution.

6.3 Permitting, Licensing, Real Estate, and Environmental Considerations

Refer to Appendix 9.13.

6.4 Planned Outage Considerations

All three plans involve work on 115kV supplied stations. Plan 1 requires tapping 115 kV transmission lines and extending them to Auburn substation site. Any required 115kV line outages will have to be coordinated with ISO-NE. Plan 2 and Plan 3 require rebuilding Sockanosset substation while the existing station remains in service. Any required 115kV line outages will have to be coordinated with ISO-NE. All three plans required conversion of 4.16 kV circuits to 12.47 kV. Coordination will be required during the actual conversion process.

6.5 Asset Physical Security Considerations

National Grid Security department will be consulted during the design process for the new substations. Recommendations for improved security at existing area substations will also be solicited and incorporated.

6.6 Climate Resiliency

Plan 2 and Plan 3 rebuild Sockanosset in the flood plain. Although the substation will be built on a raised platform approximately eight feet above the finished grade, significant flooding may limit access to the substation and still place customers at risk of extended outages. The recommended plan removes facilities from the flood plain and it is anticipated to be the most reliable of the three plans.

6.7 Grid Modernization

All recommended equipment will be installed with the latest standard control and communication equipment or with provisions for pending control and communication standards. New substations will be built with facilities to accommodate the possible future installation of feeder distributed generation such as CCVTs, bi-directional regulators, protective relaying, conduits, etc.

All recommended distribution line reclosers and capacitors will be installed with the latest sensors, controls and communication capabilities per standards:

12-338 – 15kV loop scheme recloser with PTs
12-340 – 15kV loop scheme wiring
15-335 – 15kV advanced capacitor with 3 phase sensing and antennae
15-336 – 35kV (23kV) advanced capacitor with single phase sensing and no antennae

6.8 System Loss Analysis

The recommended plan installs new distribution capacity supplied directly from the 115 kV transmission system. The voltage is stepped down from 115 kV to 12.47 kV thru a single level of transformation. This approach results in the lowest losses.

Plan 2 requires two levels of transformation. First, the voltage would be stepped down from 115 kV to 23 kV and then from 23 kV to 12.47 kV. Furthermore, plan 2 would utilize an extensive 23 kV sub-transmission system to supply the 12.47 kV distribution stations. Plan 2 has the highest losses.

Plan 3 requires two levels of transformation. First, the voltage would be stepped down from 115 kV to 34.5 kV and then from 34.5 kV to 12.47 kV. Furthermore, plan 3 would utilize an extensive 34.5 kV sub-transmission system to supply the 12.47 kV distribution stations. Plan 3 has lower losses than Plan 2 but higher losses than the recommended plan.

6.9 Recommended Plan Spending Forecast

The following spending forecast tables were developed in coordination with the Providence study, long term resource planning, and relevant subject matter experts. Tables 6.9.1, 6.9.2, and 6.9.3 show the recommended plan capital, expense and removal spending forecasts including all common items.

TABLE 6.9.1 – Capital Spending Forecast

Description	TOTAL	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28
Auburn Substation (T-Sub)	0.50							0.05	0.10	0.30	0.05
Auburn Substation (T-Line)	6.00						0.15	0.45	2.85	2.55	
Auburn Substation (D-Sub)	8.32							0.83	1.66	4.99	0.83
Auburn Substation (D-Line)	11.98					2.04	4.07	4.43	0.72	0.72	
Lakewood Retirement (D-Sub)											
Lakewood Retirement (D-Line)	4.09					0.04	0.20	0.82	1.23	1.23	0.57
Sockanosset Retirement (D-Sub)											
Drumrock Modifications (T-Sub)	0.27	0.05	0.16	0.05							
Apponaug Short-Term (D-Sub)	0.76	0.15	0.46	0.15							
Apponaug Short-Term (D-Line)	0.17	0.03	0.10	0.03							
Apponaug Long-Term (D-Sub)	3.80					0.38	0.76	1.90	0.76		
Apponaug Long-Term (D-Line)	0.76					0.08	0.15	0.38	0.15		
T-Spend	6.77	0.05	0.16	0.05			0.15	0.50	2.95	2.85	0.05
D-Spend	29.88	0.19	0.56	0.19		2.53	5.19	8.36	4.52	6.94	1.40

TABLE 6.9.2 – Expense Spending Forecast

Description	TOTAL	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28
Auburn Substation (T-Sub)											
Auburn Substation (T-Line)	0.02								0.01	0.01	
Auburn Substation (D-Sub)	0.70							0.07	0.14	0.42	0.07
Auburn Substation (D-Line)	0.68					0.12	0.23	0.25	0.04	0.04	
Lakewood Retirement (D-Sub)											
Lakewood Retirement (D-Line)	0.21					0.00	0.01	0.04	0.06	0.06	0.03
Sockanosset Retirement (D-Sub)											
Drumrock Modifications (T-Sub)	0.02	0.00	0.01	0.00							
Apponaug Short-Term (D-Sub)	0.01	0.00	0.01	0.00							
Apponaug Short-Term (D-Line)	0.01	0.00	0.01	0.00							
Apponaug Long-Term (D-Sub)	0.20					0.02	0.04	0.10	0.04		
Apponaug Long-Term (D-Line)	0.05					0.01	0.01	0.03	0.01		
T-Spend	0.04	0.00	0.01	0.00					0.01	0.01	
D-Spend	1.86	0.00	0.01	0.00		0.14	0.29	0.49	0.29	0.52	0.10

TABLE 6.9.3 – Removals Spending Forecast

Description	TOTAL	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Auburn Substation (T-Sub)												
Auburn Substation (T-Line)	0.31								0.15	0.15		
Auburn Substation (D-Sub)	0.35							0.04	0.07	0.21	0.04	
Auburn Substation (D-Line)	2.98					0.51	1.01	1.10	0.18	0.18		
Lakewood Retirement (D-Sub)	0.85								0.09	0.09	0.34	0.34
Lakewood Retirement (D-Line)	1.20					0.01	0.06	0.24	0.36	0.36	0.17	
Sockanosset Retirement (D-Sub)	1.50								0.15	0.15	0.60	0.60
Drumrock Modifications (T-Sub)	0.08	0.02	0.05	0.02								
Apponaug Short-Term (D-Sub)	0.20	0.04	0.12	0.04								
Apponaug Short-Term (D-Line)	0.02	0.00	0.01	0.00								
Apponaug Long-Term (D-Sub)	1.30					0.13	0.26	0.65	0.26			
Apponaug Long-Term (D-Line)	0.15					0.02	0.03	0.08	0.03			
T-Spend	0.39	0.02	0.05	0.02					0.15	0.15		
D-Spend	8.55	0.04	0.13	0.04		0.66	1.36	2.10	1.13	0.98	1.14	0.94

7. Conclusions and Recommendations

The three plans provide a comprehensive solution for the area and address all asset condition, safety, reliability, and flooding concerns. The plans address thermal loading concerns, provide capacity to supply new load growth, and addresses distribution planning criteria violations thru the study horizon period of 2030.

Plan 1 is recommended for implementation. Plan 1 provides a comprehensive solution to address all the concerns in the study area at least cost. The total cost of plan 1 is $39.70M which is $11.58M lower in cost then Plan 2 and $12.97M lower in cost than Plan 3.

Plan 1 builds new distribution capacity supplied from a 115 kV system with minimal exposure to motor vehicle accidents and tree related outages. It eliminates the 23 kV supply system from Sockannosset which has significant roadway construction and exposure to motor vehicle accidents and tree related outages. Moreover, it eliminates the need to rebuild Sockanosset substation in the flood plain.

8. Factors Influencing Futures Studies

Unexpected significant load growth is one factor that could affect future studies. The recommended plan will supply significant load in the Providence area. If required, additional investments could be made in the Providence area to free up Auburn substation capacity to supply the Central Rhode Island East area.

9. Appendix

9.1 Area Maps

FIGURE 9.1.1 – STUDY AREA

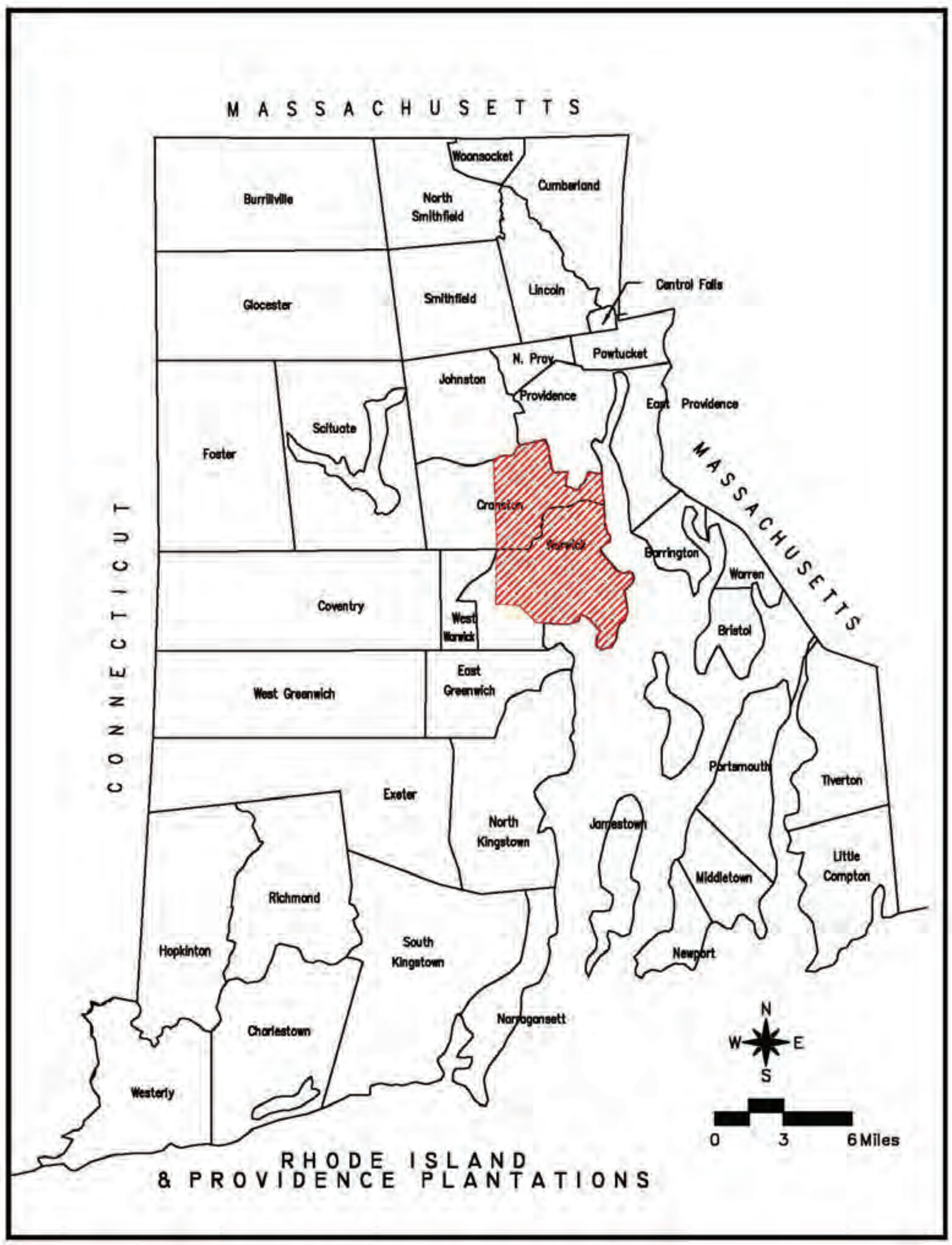


FIGURE 9.1.2 – STUDY AREA SUBSTATIONS

FIGURE 9.1.3 – STUDY AREA LOAD

System Voltage	Transformer	2016 MVA	Total Load
115/12.47kV SUPPLIED AREA LOAD	KILVERT STREET T1	15.4	170
	KILVERT STREET T2	15.2	
	LINCOLN AVENUE T1	28	
	LINCOLN AVENUE T2	26.5	
	PONTIAC T1	20.5	
	PONTIAC T2	25.7	
	DRUMROCK T3 (12.47 kV)	18.2	
	DRUMROCK T5 (12.47 kV)	20.1	
DRUMROCK 23kV SUPPLIED AREA LOAD	APPONAUG T3	8.1	33
	APPONAUG T4	6.9	
	WARWICK T1	9.9	
	WARWICK T4	8.1	
SOCKANOSSET 23kV SUPPLIED LOAD	SOCKANOSSET T1	23.1	46
	SOCKANOSSET T2	22.8	
TOTAL AREA LOAD			**249**
Transfer to New London Ave substation (Central RI West Study Area)		-6	**243**

9.2 One Line Diagrams

FIGURE 9.2.1 – 115 KV SUPPLY SYSTEM ONE-LINE DIAGRAM

[redacted]

FIGURE 9.2.2 – 23kV SUPPLY SYSTEM ONE-LINE DIAGRAM (NORTH)

[redacted]

FIGURE 9.2.3 – 23kV SUPPLY SYSTEM ONE-LINE DIAGRAM (SOUTH)

[redacted]

FIGURE 9.2.4 – APPONAUG SUBSTATION ONE-LINE DIAGRAM

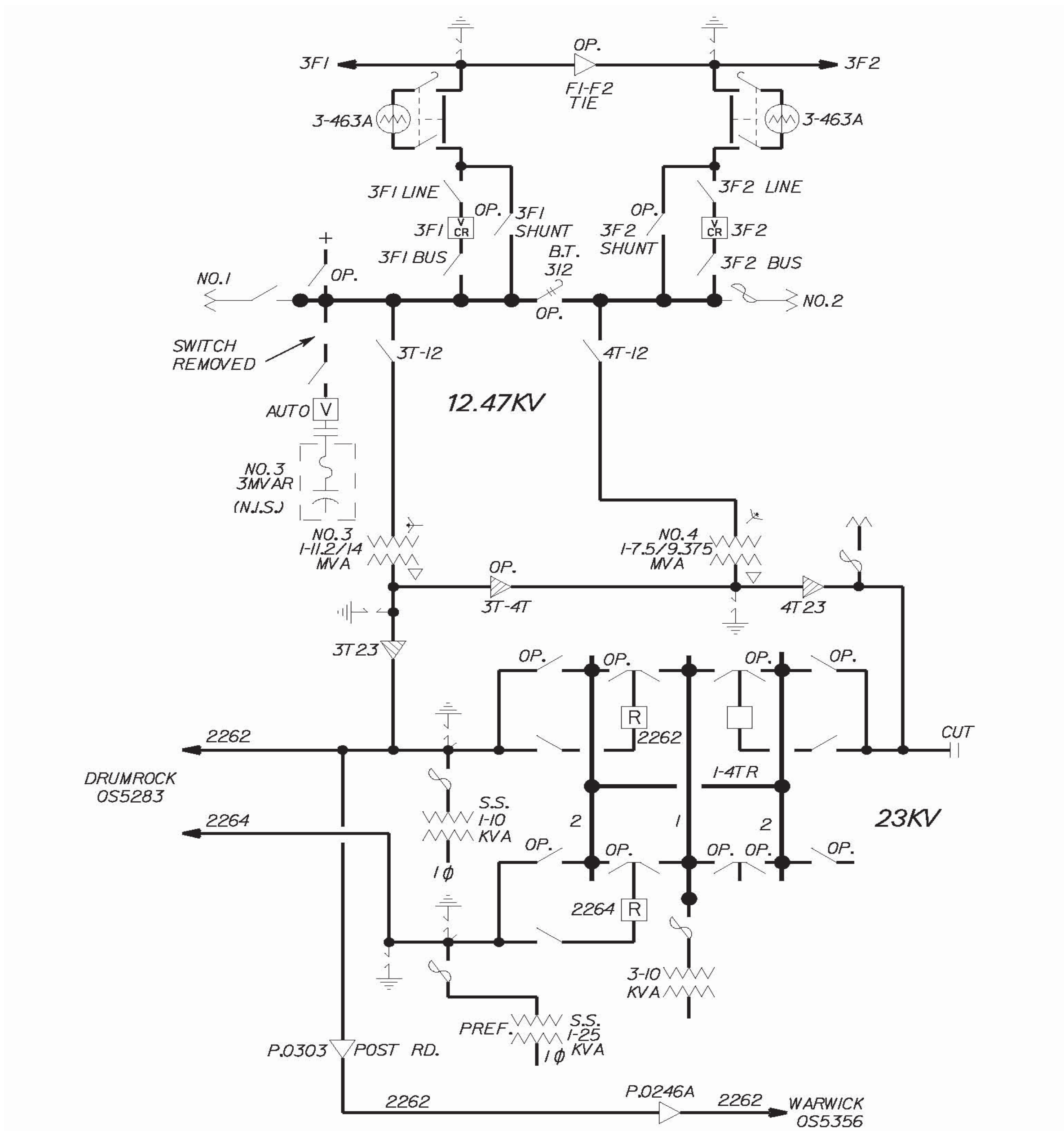


FIGURE 9.2.5 – AUBURN SUBSTATION ONE-LINE DIAGRAM

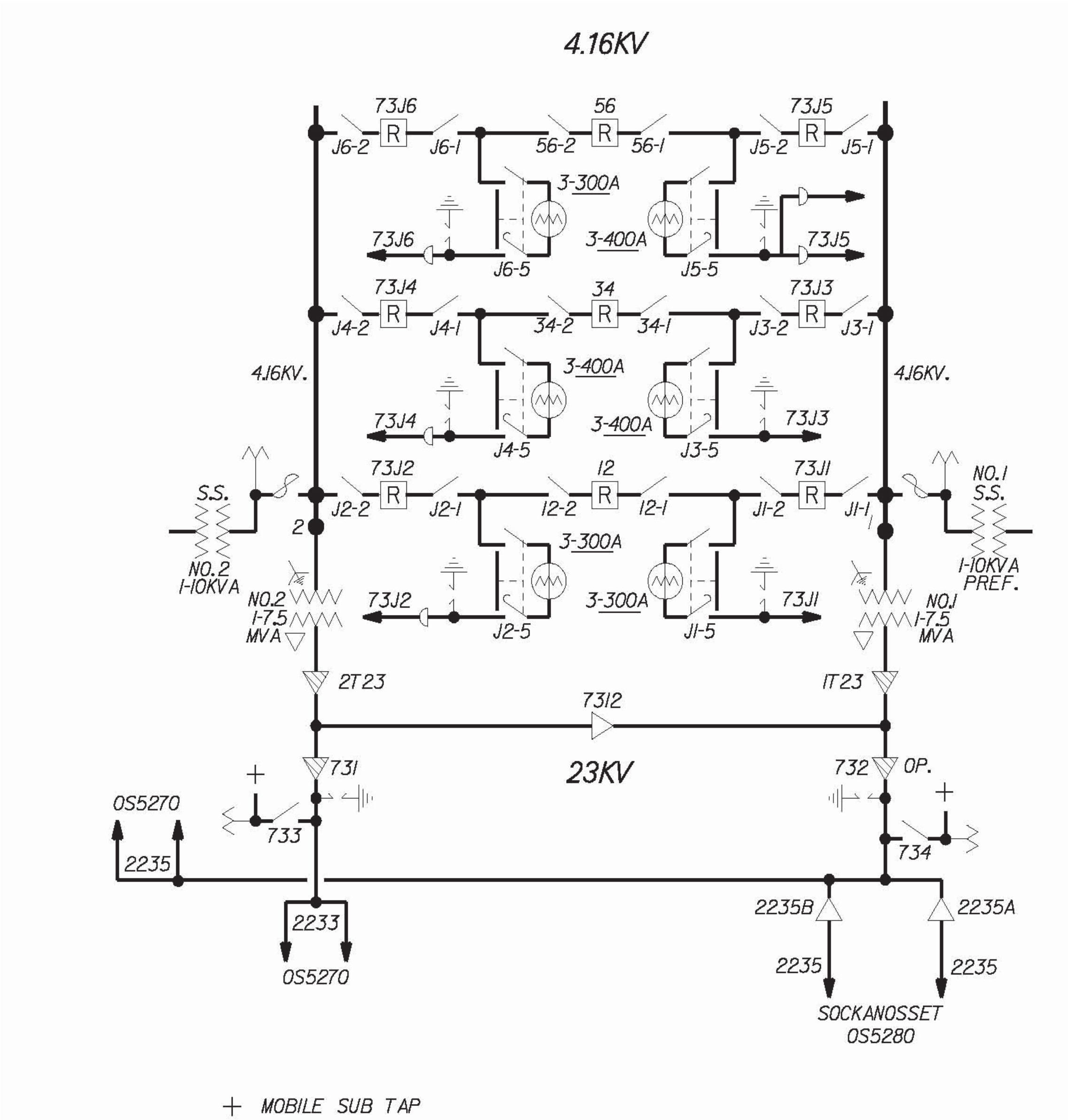


FIGURE 9.2.6 – DRUMROCK SUBSTATION ONE-LINE DIAGRAM

[redacted]

FIGURE 9.2.7 – ELMWOOD SUBSTATION ONE-LINE DIAGRAM

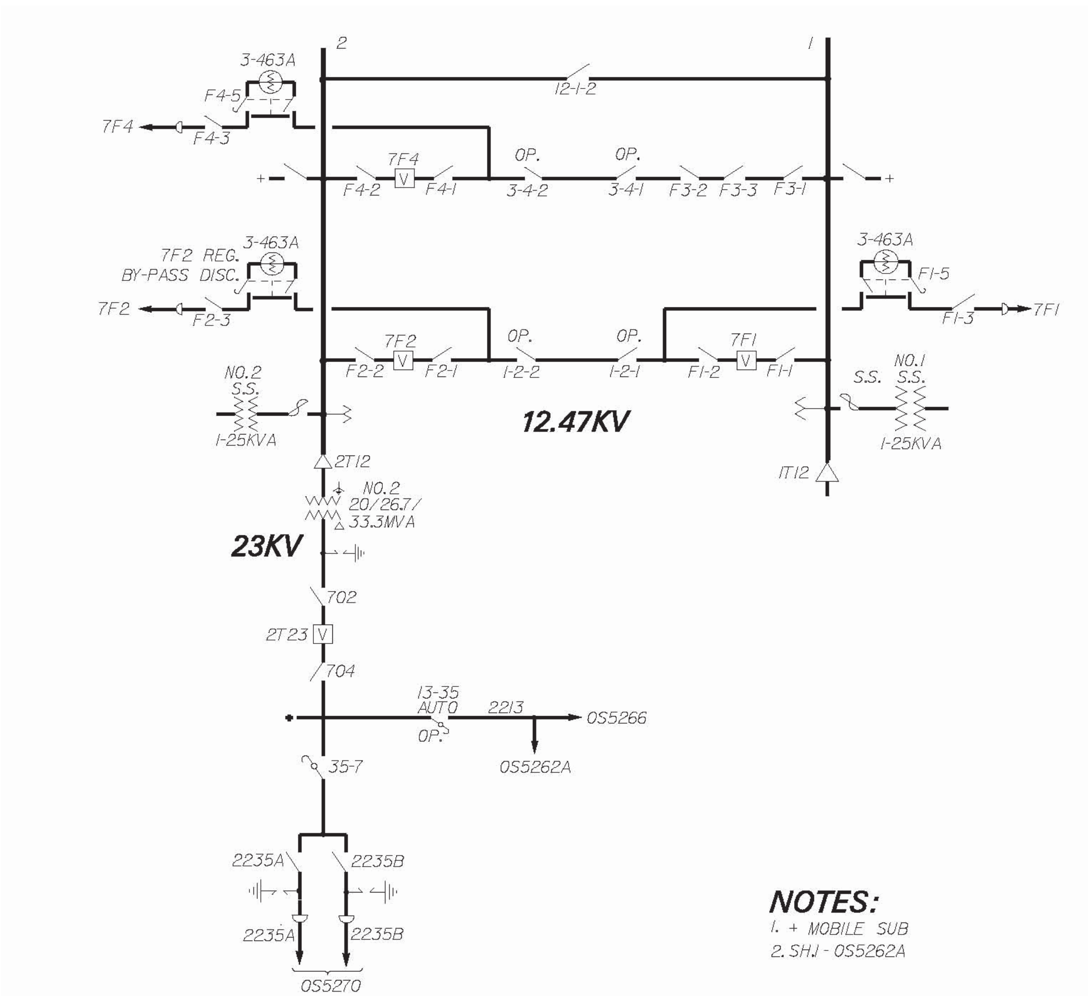


FIGURE 9.2.8 – KILVERT ST SUBSTATION ONE-LINE DIAGRAM

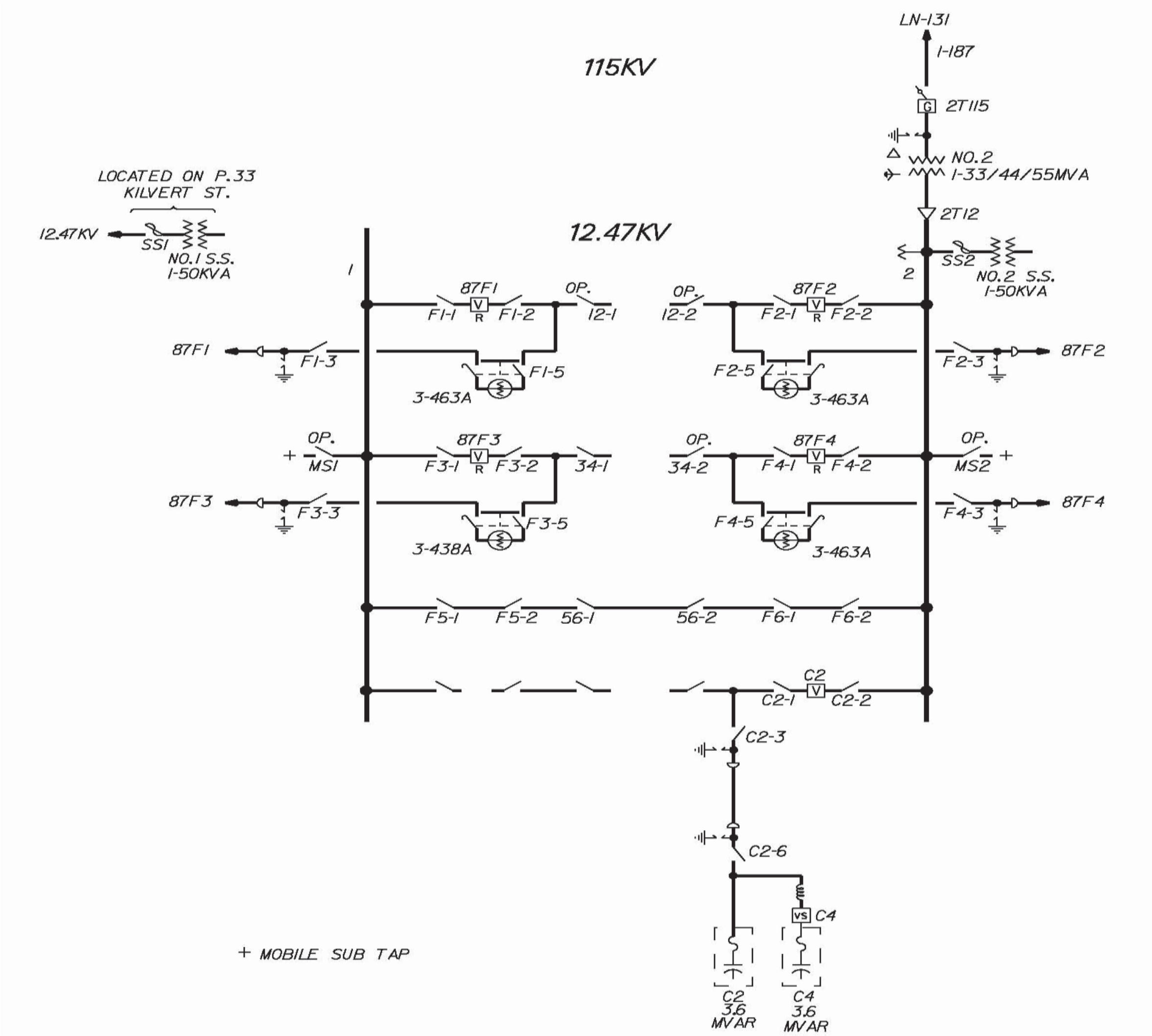


FIGURE 9.2.9 – LAKEWOOD SUBSTATION ONE-LINE DIAGRAM

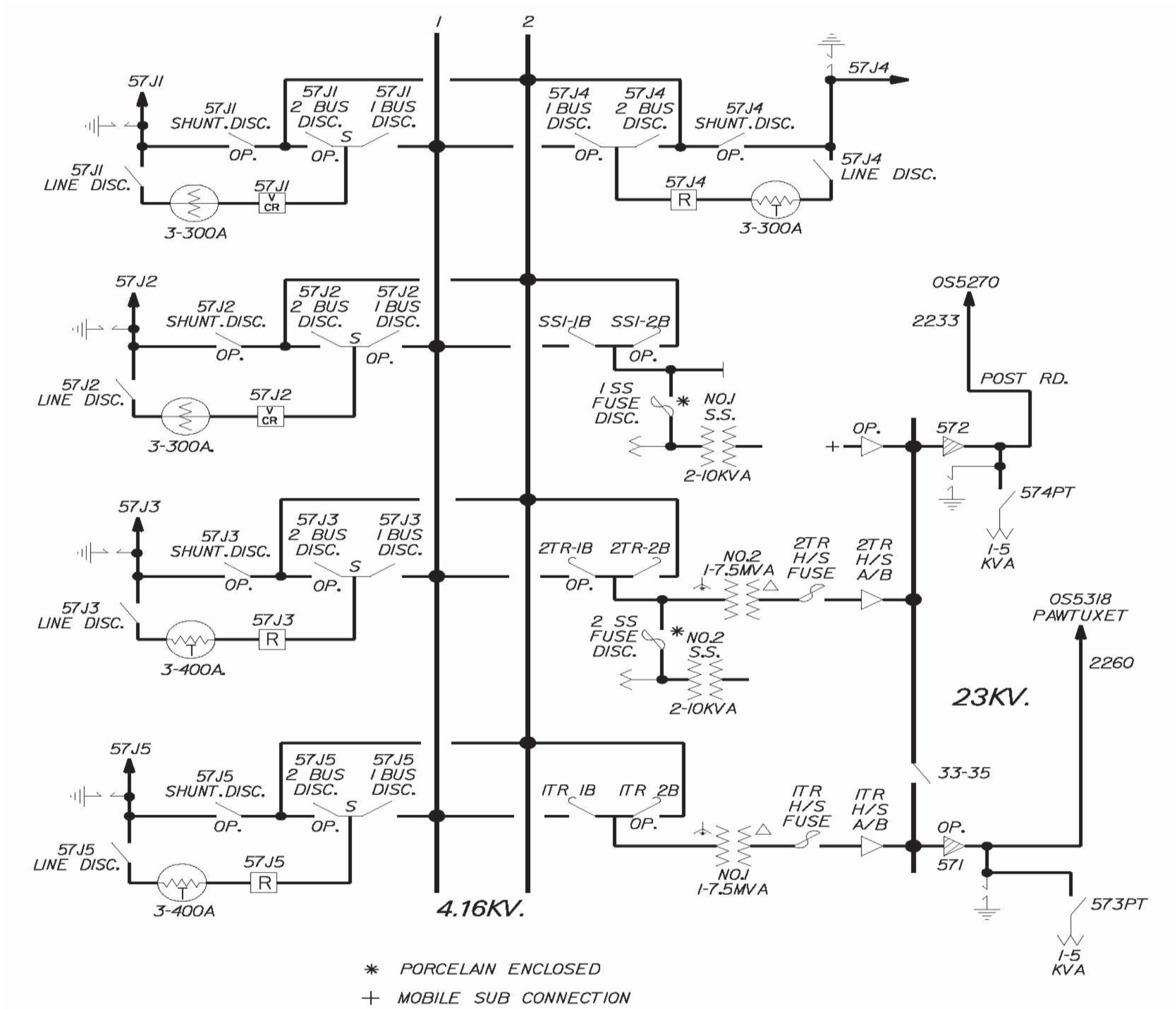


FIGURE 9.2.10 – LINCOLN AVE SUBSTATION ONE-LINE DIAGRAM

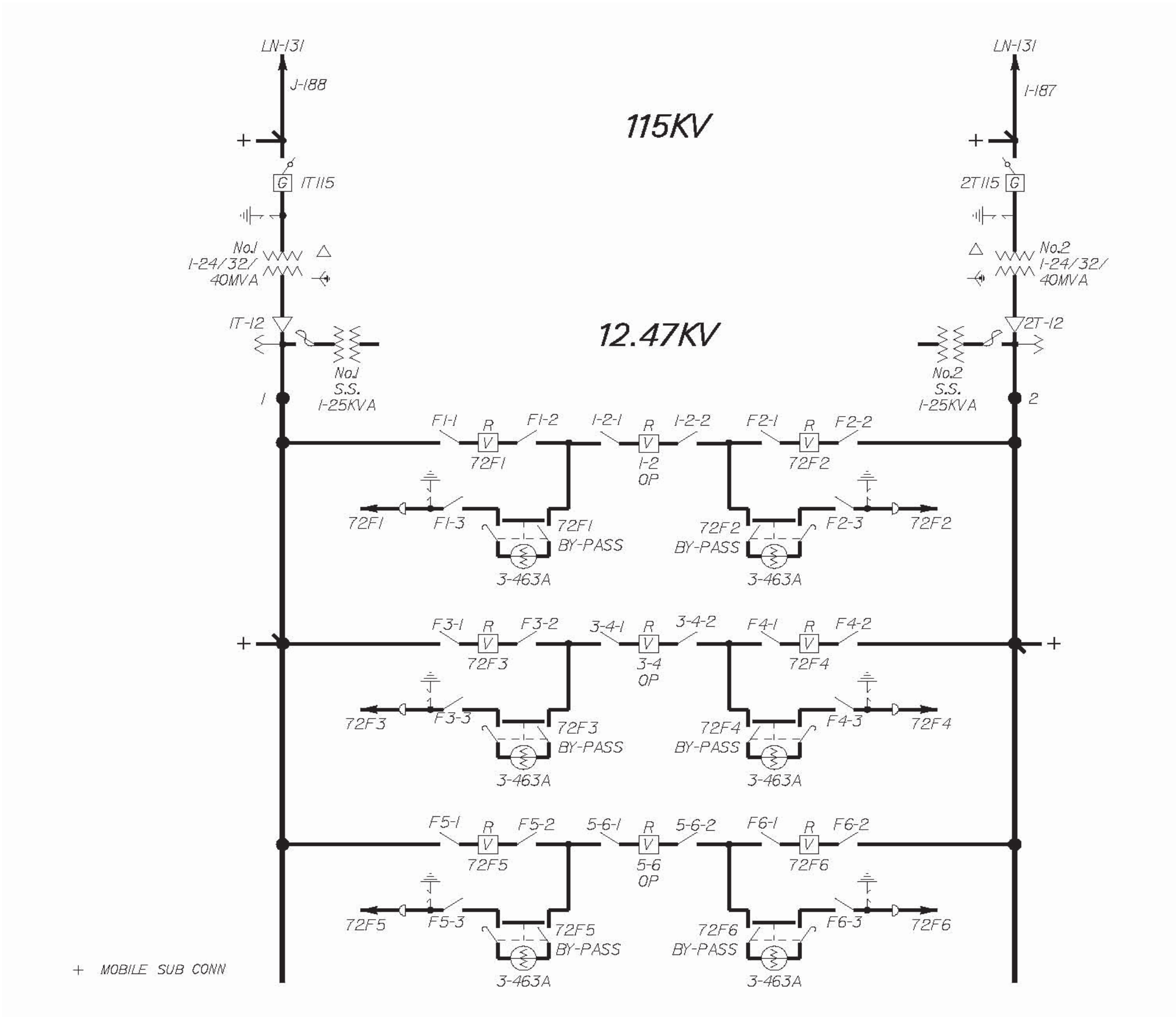


FIGURE 9.2.11 - PONTIAC SUBSTATION ONE-LINE DIAGRAM

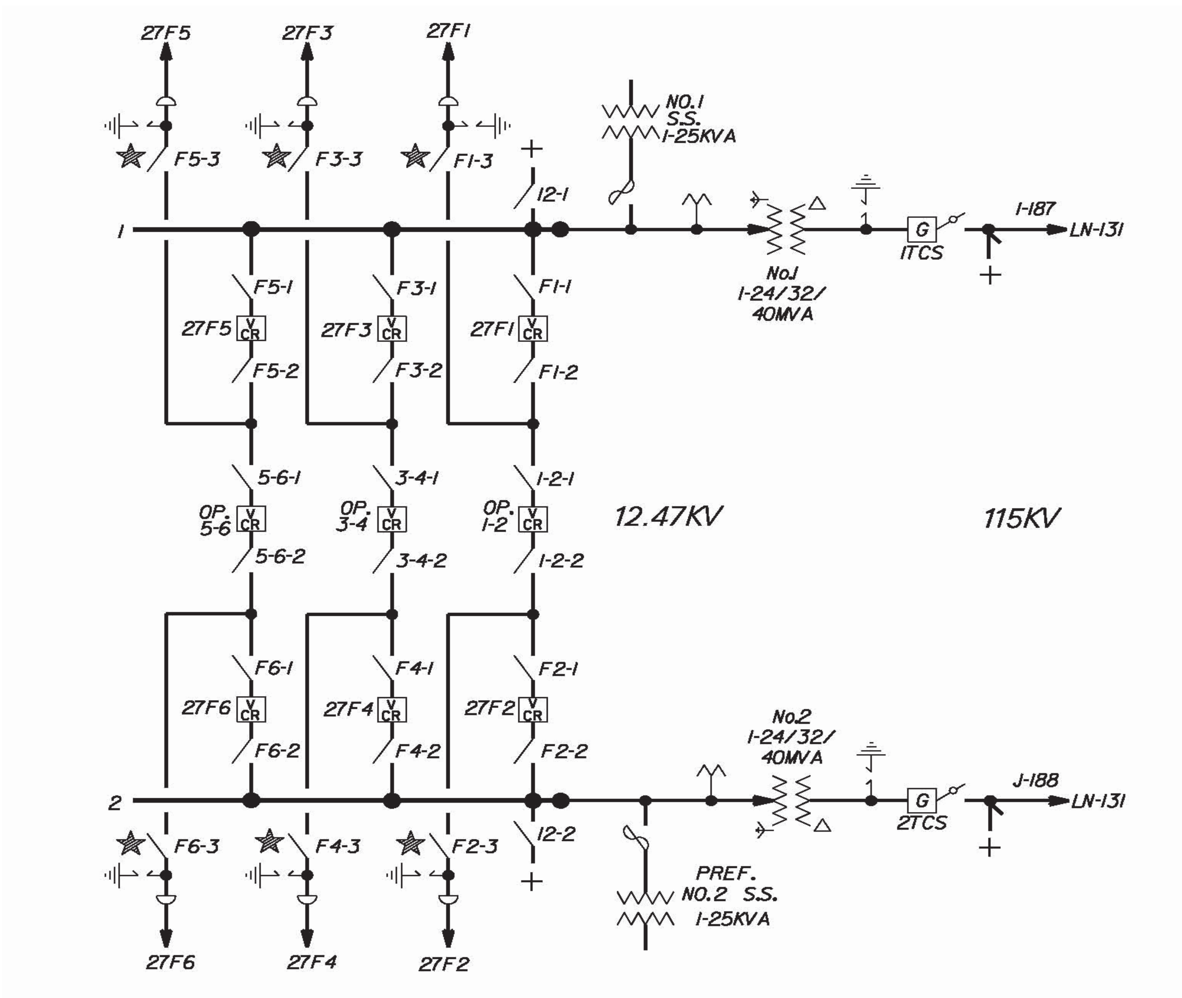


FIGURE 9.2.12 - SOCKANOSSET SUBSTATION ONE-LINE DIAGRAM

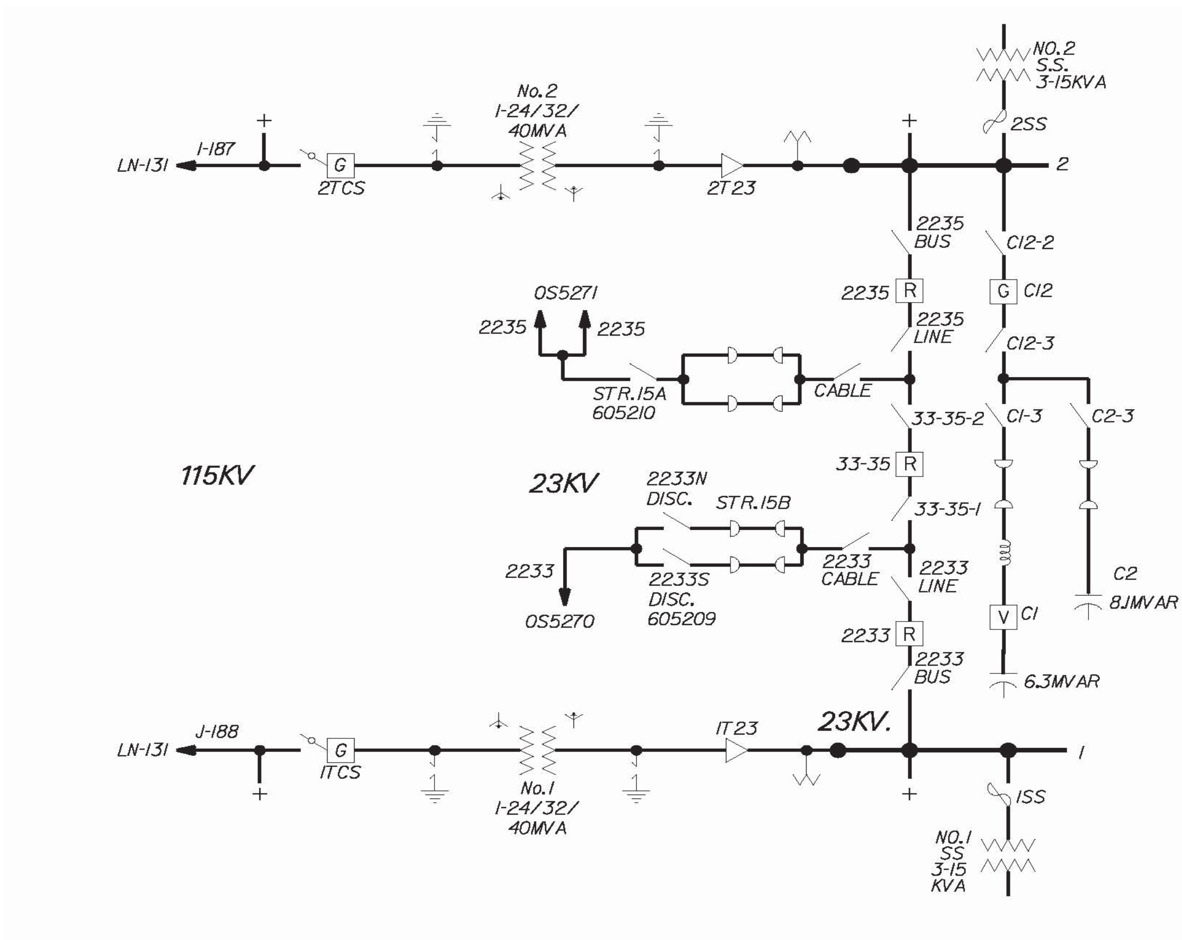
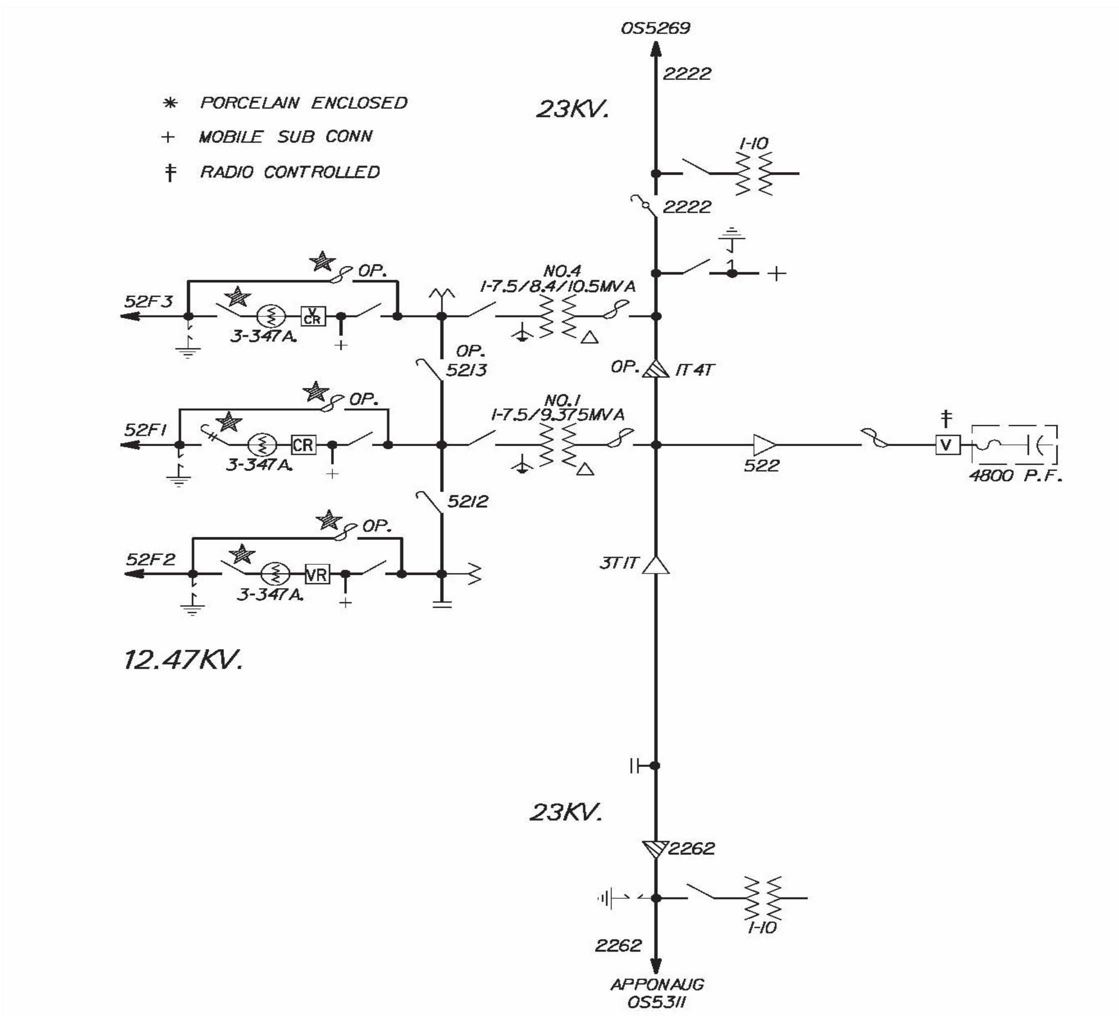


FIGURE 9.2.13 - WARWICK SUBSTATION ONE-LINE DIAGRAM



9.3 Loadflow Diagrams

Figure 9.3.1 – Existing System – Normal Configuration Power Flow (Sockanosset Supply)

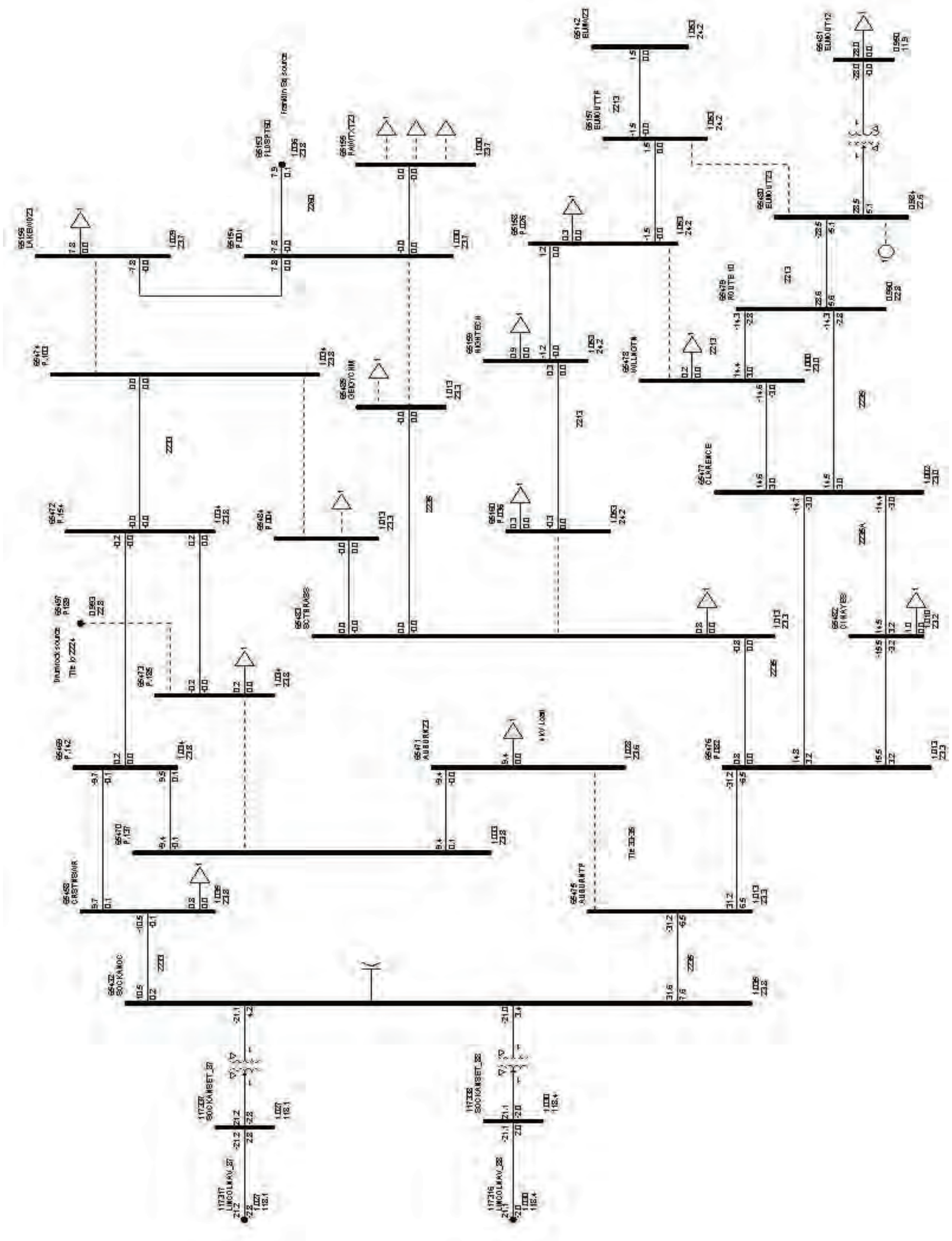


Figure 9.3.2 – Existing System – Normal Configuration Power Flow (Drumrock Supply)

[redacted]

Figure 9.3.4 – Plan 1 – Normal Configuration Percent Loading, 2026 Projected Loads

(See Providence Study)[1]

[1] This study is being performed in collaboration with the Providence Study. The Providence Study recommended a new substation at Auburn and will perform all the required PSSe analysis. Refer to the Providence Study for additional information regarding the Auburn substation.

9.4 CYME Radial Distribution Analysis Diagrams

Figure 9.4.1 – CYME Existing Configuration – Circuit Arrangement Capital Area

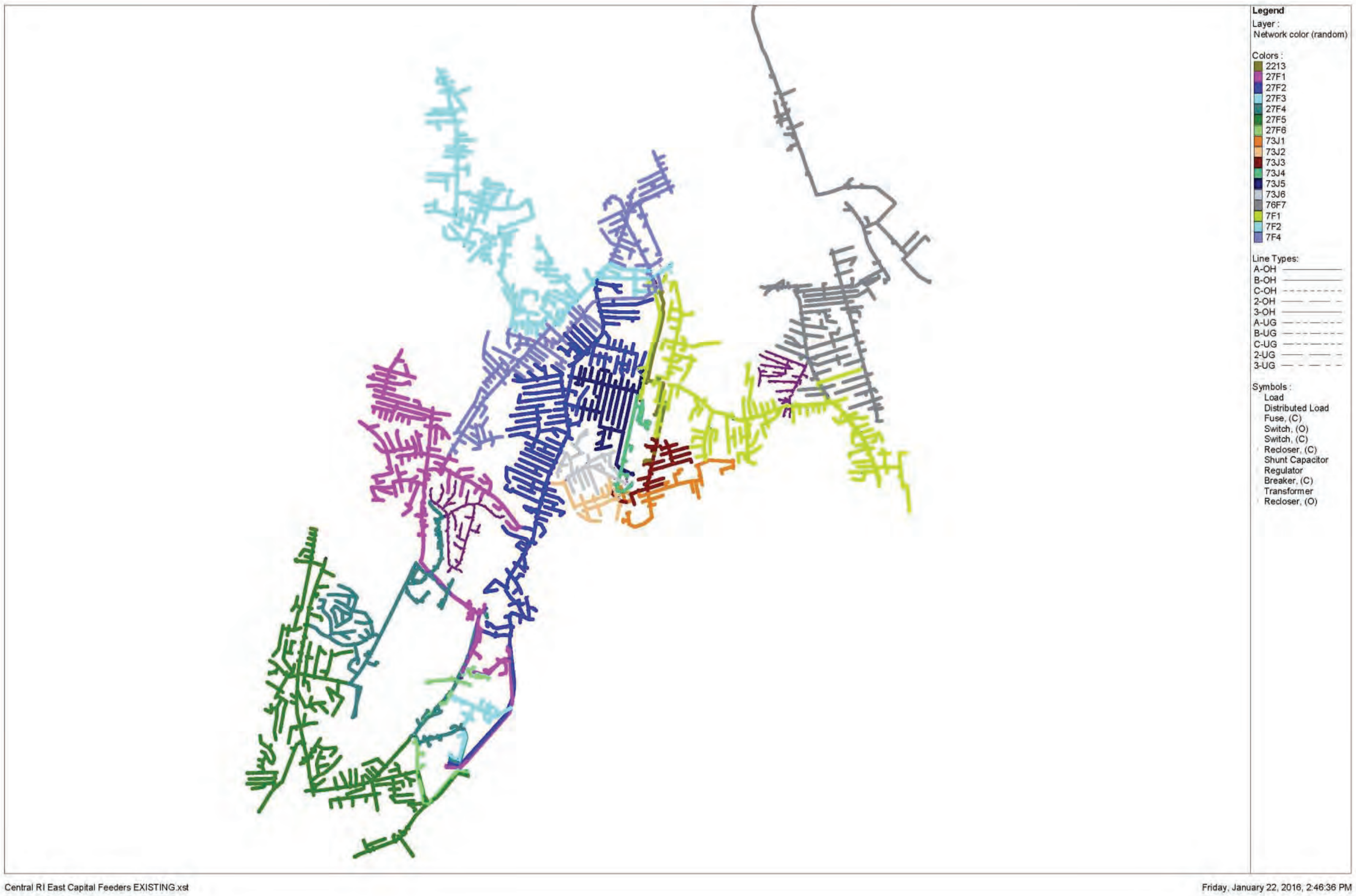


Figure 9.4.2 – CYME Existing Configuration – Circuit Arrangement Coastal Area

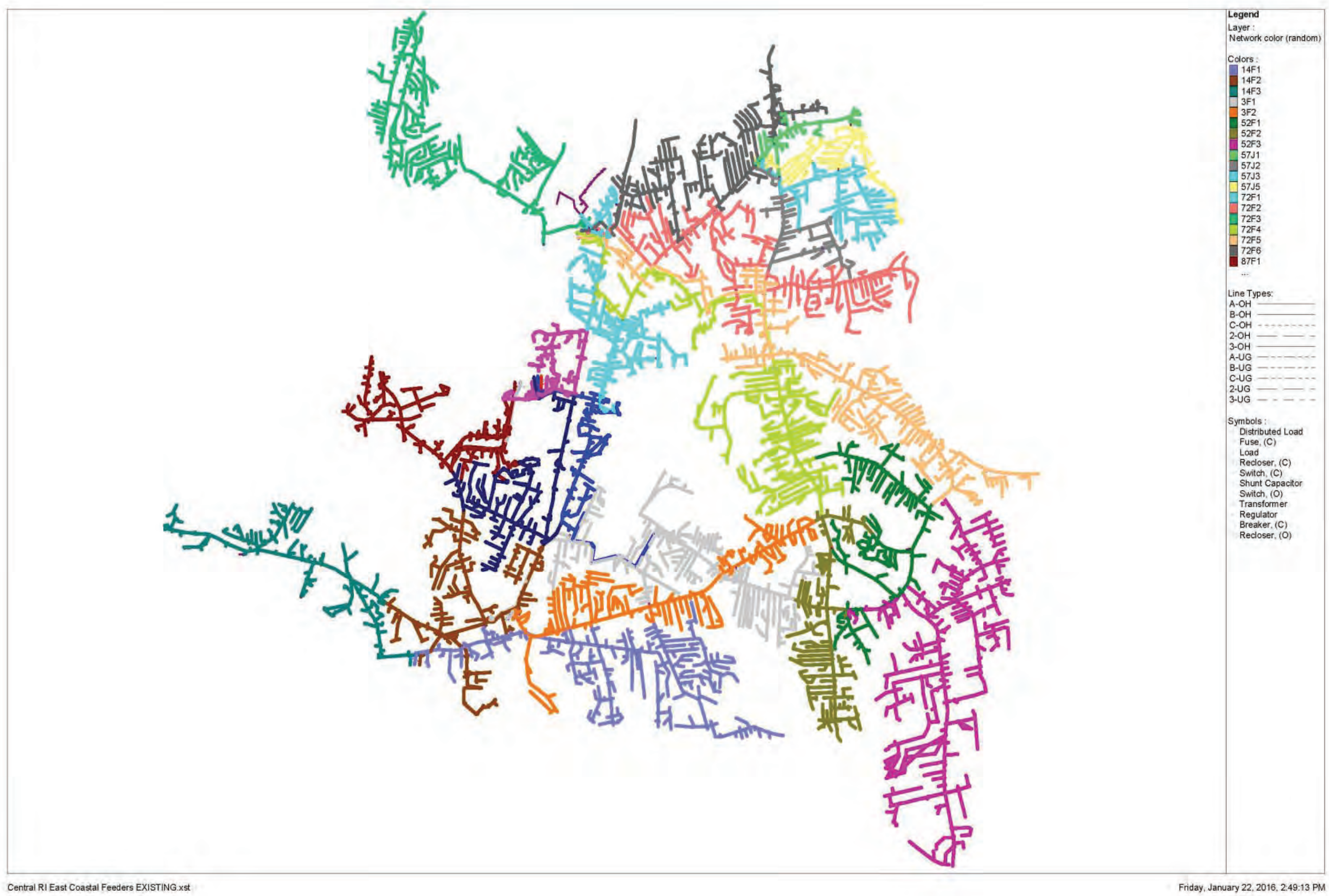


Figure 9.4.3 – CYME Existing Configuration – Loading Analysis Capital Area

Figure 9.4.4 – CYME Existing Configuration – Loading Analysis Coastal Area

Figure 9.4.5 – CYME Existing Configuration – Voltage Analysis Capital Area

Figure 9.4.6 – CYME Existing Configuration – Voltage Analysis Coastal Area

Figure 9.4.7 – CYME Plan 1 Configuration – Circuit Arrangement Capital Area

(See Providence Study)[2]

[2] This study is being performed in collaboration with the Providence Study. The Providence Study recommended a new substation at Auburn and will perform all the required CYMe analysis. Refer to the Providence Study for additional information regarding the Auburn substation.

Figure 9.4.8 – CYME Plan 1 Configuration – Circuit Arrangement Coastal Area

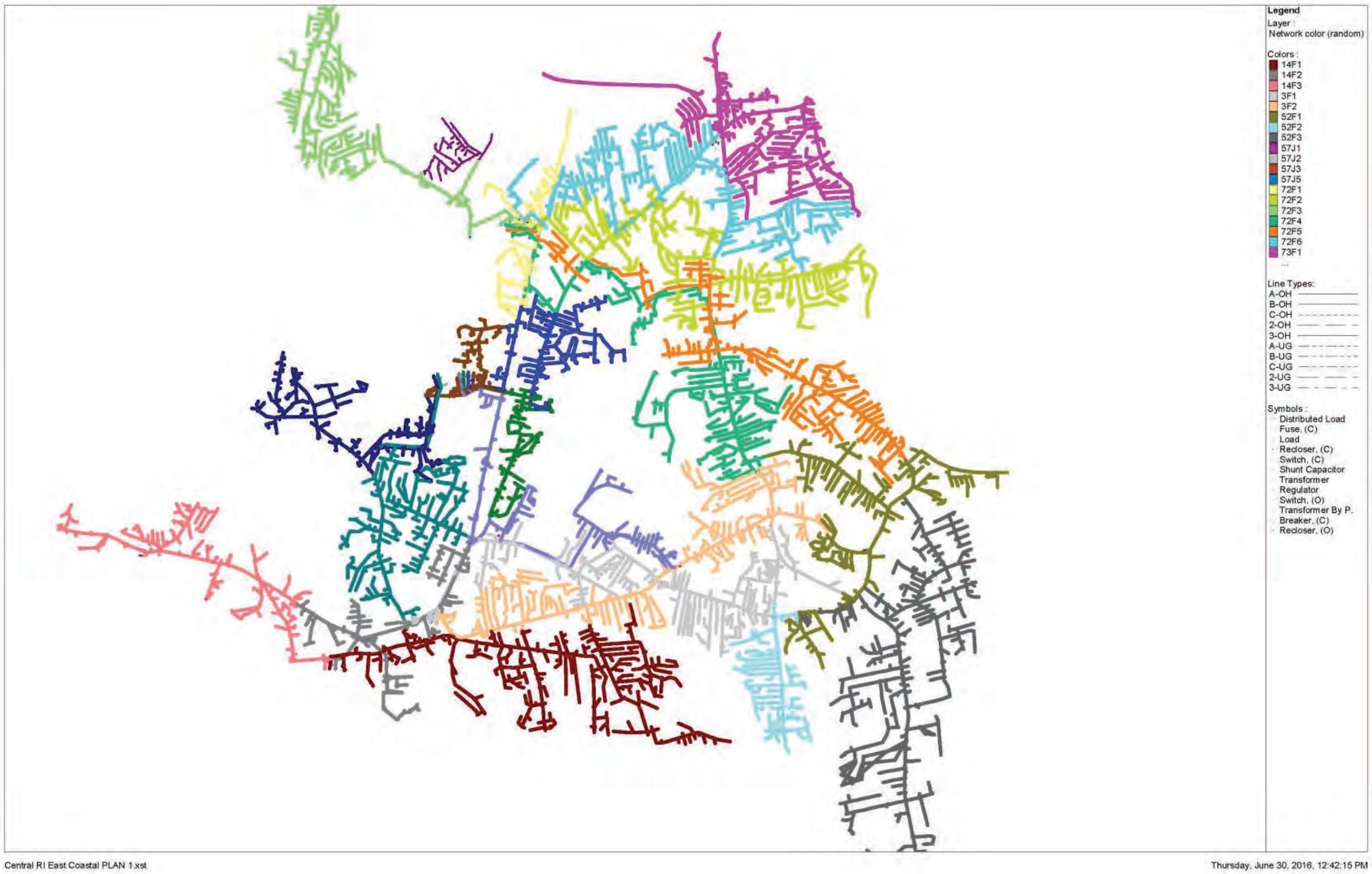


Figure 9.4.9 – CYME Plan 1 Configuration – Loading Analysis Capital Area

(See Providence Study)[3]

[3] This study is being performed in collaboration with the Providence Study. The Providence Study recommended a new substation at Auburn and will perform all the required CYMe analysis. Refer to the Providence Study for additional information regarding the Auburn substation.

Figure 9.4.10 – CYME Plan 1 Configuration – Loading Analysis Coastal Area

Figure 9.4.11 – CYME Plan 1 Configuration – Voltage Analysis Capital Area

(See Providence Study)[4]

[4] This study is being performed in collaboration with the Providence Study. The Providence Study recommended a new substation at Auburn and will perform all the required CYMe analysis. Refer to the Providence Study for additional information regarding the Auburn substation.

Figure 9.4.12 – CYME Plan 1 Configuration – Voltage Analysis Coastal Area

9.5 Arc Flash Analysis

On April 1, 2014, the United States Department of Labor's Occupational Safety and Health Administration ("OSHA") issued final rule 1910.269 requiring the employer to assess the workplace to identify employees exposed to hazards from flames or electric arcs. Rule 1910.269 proposed compliance dates of January 1, 2015 and April 1, 2015 for completion of the hazard assessment and implementation of the assessment results respectively. As the industry adjusted to these new requirements and calculation methods, the dates were adjusted to March 31, 2015 and August 31, 2015.

A review using CYME fault current analysis and protection coordination values with ArcPro incident energy calculations provided an analysis in compliance with OSHA requirements. The table below shows results of this analysis with no study area feeders indicating incident energies above 8 calories per centimeter squared (cal/cm^2).

Substation	Feeder	Line-Line Voltage (kV)	Overhead Incident Energy (cal/cm2)	Underground Incident Energy (cal/cm2)
AUBURN 73	49_53_73J1	4.16	0.72	0.68
AUBURN 73	49_53_73J2	4.16	0.73	0.70
AUBURN 73	49_53_73J3	4.16	0.81	0.78
AUBURN 73	49_53_73J4	4.16	0.70	0.65
AUBURN 73	49_53_73J5	4.16	0.60	0.48
AUBURN 73	49_53_73J6	4.16	0.60	0.46
PONTIAC 27	49_53_27F1	12.47	1.71	1.35
PONTIAC 27	49_53_27F2	12.47	1.71	1.35
PONTIAC 27	49_53_27F3	12.47	5.75	4.45
PONTIAC 27	49_53_27F4	12.47	1.11	0.86
PONTIAC 27	49_53_27F5	12.47	1.81	1.43
PONTIAC 27	49_53_27F6	12.47	1.99	1.58
ELMWOOD 7 - OUTDOOR	49_53_7F1	12.47	3.76	6.66
ELMWOOD 7 - OUTDOOR	49_53_7F2	12.47	4.18	7.41
ELMWOOD 7 - OUTDOOR	49_53_7F4	12.47	3.29	5.83
APPONAUG 3	49_56_3F1	12.47	1.81	1.23
APPONAUG 3	49_56_3F2	12.47	1.97	1.36
DRUMROCK 14	49_56_14F3	12.47	2.01	1.13
DRUMROCK 14	49_56_14F4	12.47	2.80	1.57
DRUMROCK 14	49_56_14F1	12.47	2.24	1.17
DRUMROCK 14	49_56_14F2	12.47	2.04	1.06
KILVERT STREET 87	49_56_87F1	12.47	6.25	4.82
KILVERT STREET 87	49_56_87F2	12.47	5.50	4.51
KILVERT STREET 87	49_56_87F3	12.47	3.44	2.73
KILVERT STREET 87	49_56_87F4	12.47	7.04	5.77
LAKEWOOD 57	49_56_57J1	4.16	2.06	1.79
LAKEWOOD 57	49_56_57J2	4.16	2.17	1.87

LAKEWOOD 57	49_56_57J3	4.16	2.79	2.43
LAKEWOOD 57	49_56_57J5	4.16	3.15	2.73
LINCOLN AVENUE 72	49_56_72F1	12.47	2.90	2.10
LINCOLN AVENUE 72	49_56_72F2	12.47	2.73	1.95
LINCOLN AVENUE 72	49_56_72F3	12.47	3.07	2.22
LINCOLN AVENUE 72	49_56_72F4	12.47	2.86	2.04
LINCOLN AVENUE 72	49_56_72F5	12.47	2.87	2.05
LINCOLN AVENUE 72	49_56_72F6	12.47	3.38	2.42
WARWICK 52	49_56_52F1	12.47	1.22	0.77
WARWICK 52	49_56_52F2	12.47	1.22	0.77
WARWICK 52	49_56_52F3	12.47	1.72	1.03

9.6 Fault Duty Analysis

Figure 9.6.1 – Breaker Duty Analysis

Location	Position	Class	Rated IC (A)	3-Phase Fault (A)	1-Phase Fault (A)
Apponaug	1-4 OCB	25kV	12,400	19,908	10,244
Apponaug	2262 OCB	25kV	35,200	19,908	10,244
Apponaug	2264 OCB	25kV	20,000	19,908	10,244
Drumrock	2222 OCB	25kV	35,200	43,205	30,545
Drumrock	2224 OCB	25kV	25,000	43,205	30,545
Drumrock	2230 GCB	25kV	40,000	43,205	30,545
Drumrock	2231 OCB	25kV	35,200	43,205	30,545
Drumrock	2232 GCB	25kV	40,000	43,205	30,545
Drumrock	2262 OCB	25kV	35,200	43,205	30,545
Drumrock	2264 OCB	25kV	35,200	43,205	30,545
Drumrock	2266 GCB	25kV	40,000	43,205	30,545
Drumrock	30-24 OCB	25kV	35,200	43,205	30,545
Drumrock	31-64 GCB	25kV	40,000	43,205	30,545
Drumrock	32-22 TIE GCB	25kV	40,000	43,205	30,545
Drumrock	62-66 OCB	25kV	35,200	43,205	30,545
Drumrock	C34 GCB	25kV	40,000	43,205	30,545
Drumrock	C56 GCB	25kV	40,000	43,205	30,545
Sockanosset	2233 VCB	25kV	25,000	13,071	11,833
Sockanosset	2235 VCB	25kV	25,000	13,071	11,833
Sockanosset	33-35 VCB	25kV	25,000	13,071	11,833
Sockanosset	C12 VCB	25kV	25,000	13,071	11,833
Apponaug	3F1 VCR	15kV	12,000	5,511	5,800
Apponaug	3F2 VCR	15kV	12,000	5,741	6,056
Drumrock	1-4 VCB	15kV	?	7,558	2,279
Drumrock	2-3 OCB	15kV	10,000	7,558	2,279
Drumrock	14F1 OCB	15kV	20,000	5,214	2,805
Drumrock	14F2 VCB	15kV	20,000	7,558	2,279
Drumrock	14F3 OCB	15kV	18,000	5,214	2,805
Drumrock	14F4 OCB	15kV	18,000	7,558	2,279
Kilvert St	87F1 VCB	15kV	20,000	10,765	10,650
Kilvert St	87F2 VCB	15kV	20,000	10,765	10,650
Kilvert St	87F3 VCB	15kV	20,000	10,765	10,650
Kilvert St	87F4 VCB	15kV	20,000	10,765	10,650
Kilvert St	C2 VCB	15kV	20,000	10,765	10,650
Pontiac	1-2 VCR	15kV	12,000	9,446	9,679
Pontiac	27F1 VCR	15kV	20,000	9,446	9,679
Pontiac	27F2 VCR	15kV	20,000	8,255	8,475
Pontiac	27F3 VCR	15kV	12,000	9,446	9,679
Pontiac	27F4 VCR	15kV	12,000	8,255	8,475
Pontiac	27F5 VCB	15kV	20,000	9,446	9,679

Pontiac	27F6 VCB	15kV	20,000	8,255	8,475
Pontiac	3-4 VCR	15kV	12,000	9,446	9,679
Pontiac	5-6 VCB	15kV	20,000	9,446	9,679
Warwick	52F1 CR	15kV	8,000	3,613	4,254
Warwick	52F2 VCR	15kV	12,000	3,613	4,254
Warwick	52F3 VCR	15kV	12,000	2,817	3,467
Lincoln Avenue	1-2 TIE VCB	15kV	20,000	7,033	7,152
Lincoln Avenue	3-4 TIE VCB	15kV	20,000	7,033	7,152
Lincoln Avenue	5-6 TIE VCB	15kV	20,000	7,033	7,152
Lincoln Avenue	72F1 VCB	15kV	20,000	6,973	7,117
Lincoln Avenue	72F2 VCB	15kV	20,000	7,033	7,152
Lincoln Avenue	72F3 VCB	15kV	20,000	6,973	7,117
Lincoln Avenue	72F4 VCB	15kV	20,000	7,033	7,152
Lincoln Avenue	72F5 VCB	15kV	20,000	6,973	7,117
Lincoln Avenue	72F6 VCB	15kV	20,000	7,033	7,152
Auburn	1-2 OCB	5kV	16,000	14,281	15,642
Auburn	3-4 OCB	5kV	16,000	14,281	15,642
Auburn	5-6 OCB	5kV	16,000	14,281	15,642
Auburn	73J1 OCB	5kV	16,000	14,281	15,642
Auburn	73J2 OCB	5kV	16,000	14,281	15,642
Auburn	73J3 OCB	5kV	16,000	14,281	15,642
Auburn	73J4 OCB	5kV	16,000	14,281	15,642
Auburn	73J5 OCB	5kV	16,000	14,281	15,642
Auburn	73J6 OCB	5kV	16,000	14,281	15,642
Lakewood	57J1 VCR	5kV	12,000	11,211	13,054
Lakewood	57J2 VCR	15kV	12,000	11,318	13,199
Lakewood	57J3 OCB	5kV	12,000	11,211	13,054
Lakewood	57J4 OCB	5kV	10,000	11,318	13,199
Lakewood	57J5 OCB	5kV	16,000	11,211	13,054

Figure 9.6.2 – Voltage Regulator Duty Analysis

Location	Position	Type	kV	Rated IC (A)	3-Phase Fault (A)	1-Phase Fault (A)
Apponaug	3F1 REG A	STEP	12.4	16,000	5,511	5,800
Apponaug	3F1 REG B	STEP	12.4	16,000	5,741	6,056
Apponaug	3F1 REG C	STEP	12.4	16,000	5,741	6,056
Apponaug	3F2 REG A	STEP	12.4	16,000	5,741	6,056
Apponaug	3F2 REG B	STEP	12.4	16,000	5,741	6,056
Apponaug	3F2 REG C	STEP	12.4	16,000	5,741	6,056
Auburn	73J1 REG A	STEP	4.16	16,000	14,281	15,642
Auburn	73J1 REG B	STEP	4.16	16,000	14,281	15,642
Auburn	73J1 REG C	STEP	4.16	16,000	14,281	15,642
Auburn	73J2 REG A	STEP	4.16	16,000	14,281	15,642
Auburn	73J2 REG B	STEP	4.16	16,000	14,281	15,642
Auburn	73J2 REG C	STEP	4.16	16,000	14,281	15,642
Auburn	73J3 REG A	STEP	4.16	16,000	14,281	15,642
Auburn	73J3 REG B	STEP	4.16	16,000	14,281	15,642
Auburn	73J3 REG C	STEP	4.16	16,000	14,281	15,642
Auburn	73J4 REG A	STEP	4.16	16,000	14,281	15,642
Auburn	73J4 REG B	STEP	4.16	16,000	14,281	15,642
Auburn	73J4 REG C	STEP	4.16	16,000	14,281	15,642
Auburn	73J5 REG A	STEP	4.16	16,000	14,281	15,642
Auburn	73J5 REG B	STEP	4.16	16,000	14,281	15,642
Auburn	73J5 REG C	STEP	4.16	16,000	14,281	15,642
Auburn	73J6 REG A	STEP	4.16	16,000	14,281	15,642
Auburn	73J6 REG B	STEP	4.16	16,000	14,281	15,642
Auburn	73J6 REG C	STEP	4.16	16,000	14,281	15,642
Drumrock	14F1 REG A	STEP	12.4	16,000	5,214	2,805
Drumrock	14F1 REG B	STEP	12.4	16,000	5,214	2,805
Drumrock	14F1 REG C	STEP	12.4	16,000	5,214	2,805
Drumrock	14F2 REG A	STEP	12.4	16,000	7,558	2,279
Drumrock	14F2 REG B	STEP	12.4	16,000	7,558	2,279
Drumrock	14F2 REG C	STEP	12.4	16,000	7,558	2,279
Drumrock	14F3 REG A	STEP	12.4	16,000	5,214	2,805
Drumrock	14F3 REG B	STEP	12.4	16,000	5,214	2,805
Drumrock	14F3 REG C	STEP	12.4	16,000	5,214	2,805
Drumrock	14F4 REG A	STEP	12.4	16,000	7,558	2,279
Drumrock	14F4 REG B	STEP	12.4	16,000	7,558	2,279
Drumrock	14F4 REG C	STEP	12.4	16,000	7,558	2,279
Kilvert St.	87F1 REG A	STEP	12.47	16,000	10,765	10,650
Kilvert St.	87F1 REG B	STEP	12.47	16,000	10,765	10,650
Kilvert St.	87F1 REG C	STEP	12.47	16,000	10,765	10,650
Kilvert St.	87F2 REG A	STEP	12.47	16,000	10,765	10,650
Kilvert St.	87F2 REG B	STEP	12.47	16,000	10,765	10,650
Kilvert St.	87F2 REG C	STEP	12.47	16,000	10,765	10,650
Kilvert St.	87F3 REG A	STEP	12.47	16,000	10,765	10,650
Kilvert St.	87F3 REG B	STEP	12.47	16,000	10,765	10,650
Kilvert St.	87F3 REG C	STEP	12.47	16,000	10,765	10,650
Kilvert St.	87F4 REG A	STEP	12.47	16,000	10,765	10,650

Kilvert St.	87F4 REG B	STEP	12.47	16,000	10,765	10,650
Kilvert St.	87F4 REG C	STEP	12.47	16,000	10,765	10,650
Lakewood	57J1 REG A	STEP	4.16	16,000	11,211	13,054
Lakewood	57J1 REG B	STEP	4.16	16,000	11,211	13,054
Lakewood	57J1 REG C	STEP	4.16	16,000	11,211	13,054
Lakewood	57J2 REG A	STEP	4.16	16,000	11,318	13,199
Lakewood	57J2 REG B	STEP	4.16	16,000	11,318	13,199
Lakewood	57J2 REG C	STEP	4.16	16,000	11,318	13,199
Lakewood	57J3 REG A	STEP	4.16	16,000	11,211	13,054
Lakewood	57J3 REG B	STEP	4.16	16,000	11,211	13,054
Lakewood	57J3 REG C	STEP	4.16	16,000	11,211	13,054
Lakewood	57J4 REG A	STEP	4.16	16,000	11,318	13,199
Lakewood	57J4 REG B	STEP	4.16	16,000	11,318	13,199
Lakewood	57J4 REG C	STEP	4.16	16,000	11,318	13,199
Lakewood	57J5 REG A	STEP	4.16	16,000	11,211	13,054
Lakewood	57J5 REG B	STEP	4.16	16,000	11,211	13,054
Lakewood	57J5 REG C	STEP	4.16	16,000	11,211	13,054
Lincoln Ave.	72F1 REG A	STEP	12.4	16,000	7,033	7,152
Lincoln Ave.	72F1 REG B	STEP	12.4	16,000	7,033	7,152
Lincoln Ave.	72F1 REG C	STEP	12.4	16,000	7,033	7,152
Lincoln Ave.	72F2 REG A	STEP	12.4	16,000	6,973	7,117
Lincoln Ave.	72F2 REG B	STEP	12.4	16,000	6,973	7,117
Lincoln Ave.	72F2 REG C	STEP	12.4	16,000	6,973	7,117
Lincoln Ave.	72F3 REG A	STEP	12.4	16,000	7,033	7,152
Lincoln Ave.	72F3 REG B	STEP	12.4	16,000	7,033	7,152
Lincoln Ave.	72F3 REG C	STEP	12.4	16,000	7,033	7,152
Lincoln Ave.	72F4 REG A	STEP	12.4	16,000	6,973	7,117
Lincoln Ave.	72F4 REG B	STEP	12.4	16,000	6,973	7,117
Lincoln Ave.	72F4 REG C	STEP	12.4	16,000	6,973	7,117
Lincoln Ave.	72F5 REG A	STEP	12.4	16,000	7,033	7,152
Lincoln Ave.	72F5 REG B	STEP	12.4	16,000	7,033	7,152
Lincoln Ave.	72F5 REG C	STEP	12.4	16,000	7,033	7,152
Lincoln Ave.	72F6 REG A	STEP	12.4	16,000	6,973	7,117
Lincoln Ave.	72F6 REG B	STEP	12.4	16,000	6,973	7,117
Lincoln Ave.	72F6 REG C	STEP	12.4	16,000	6,973	7,117
Warwick	52F1 REG A	STEP	7.2	16,000	3,613	4,254
Warwick	52F1 REG B	STEP	7.2	16,000	3,613	4,254
Warwick	52F1 REG C	STEP	7.2	16,000	3,613	4,254
Warwick	52F2 REG A	STEP	12.4	16,000	3,613	4,254
Warwick	52F2 REG B	STEP	13.8	16,000	3,613	4,254
Warwick	52F2 REG C	STEP	13.8	16,000	3,613	4,254
Warwick	52F3 REG A	STEP	12.4	16,000	2,817	3,467
Warwick	52F3 REG B	STEP	12.4	16,000	2,817	3,467
Warwick	52F3 REG C	STEP	12.4	16,000	2,817	3,467

9.7 Plan Development – Common Items

FIGURE 9.7.1 – DRUMROCK 23kV SUBSTATION ONE-LINE DIAGRAM

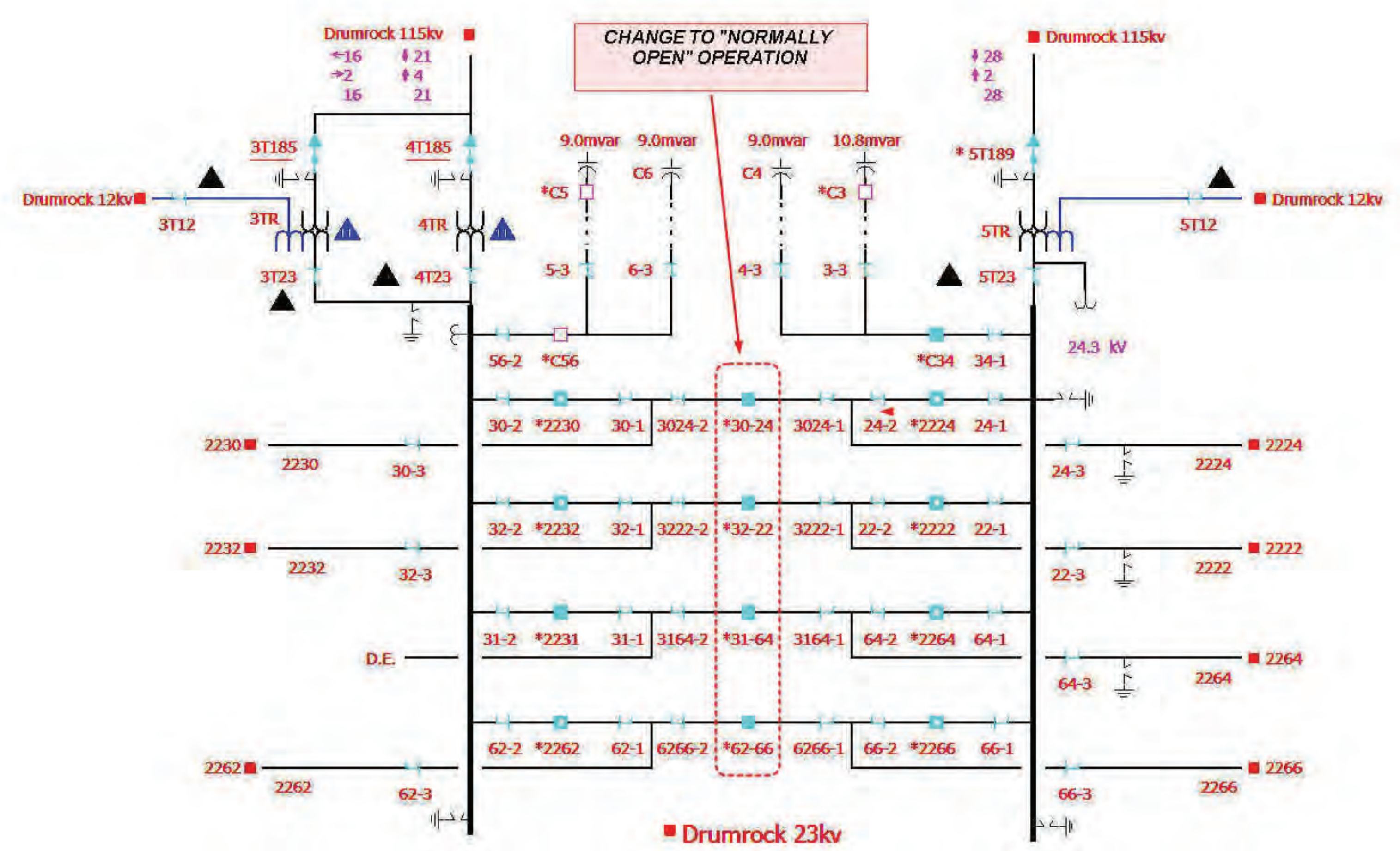


FIGURE 9.7.2 – DRUMROCK 23kV SUBSTATION FAULT DUTY (N.O. TIE BREAKERS)

location	position	type	ferc_type	kV	Rated IC (A)	3-Phase Fault (A)	1-Phase Fault (A)
Drumrock	2222 OCB	OCB	Transmission	23	35,200	23,928	14,261
Drumrock	2224 OCB	VCB	Transmission	23	25,000	23,928	14,261
Drumrock	2230 GCB	GCB	Transmission	23	40,000	26,494	19,107
Drumrock	2231 OCB	OCB	Transmission	23	35,200	26,494	19,107
Drumrock	2232 GCB	GCB	Transmission	23	40,000	26,494	19,107
Drumrock	2262 OCB	OCB	Transmission	23	35,200	26,494	19,107
Drumrock	2264 OCB	OCB	Transmission	23	35,200	23,928	14,261
Drumrock	2266 GCB	GCB	Transmission	23	40,000	23,928	14,261
Drumrock	30-24 OCB	OCB	Transmission	23	35,200	26,494	19,107
Drumrock	31-64 GCB	GCB	Transmission	23	40,000	26,494	19,107
Drumrock	32-22 TIE GCB	GCB	Transmission	23	40,000	26,494	19,107
Drumrock	62-66 OCB	OCB	Transmission	23	35,200	26,494	19,107
Drumrock	C34 GCB	GCB	Transmission	23	40,000	23,928	14,261
Drumrock	C56 GCB	GCB	Transmission	23	40,000	26,494	19,107

FIGURE 9.7.3 – APPONAUG SUBSTATION ONE-LINE DIAGRAM (Short-Term)

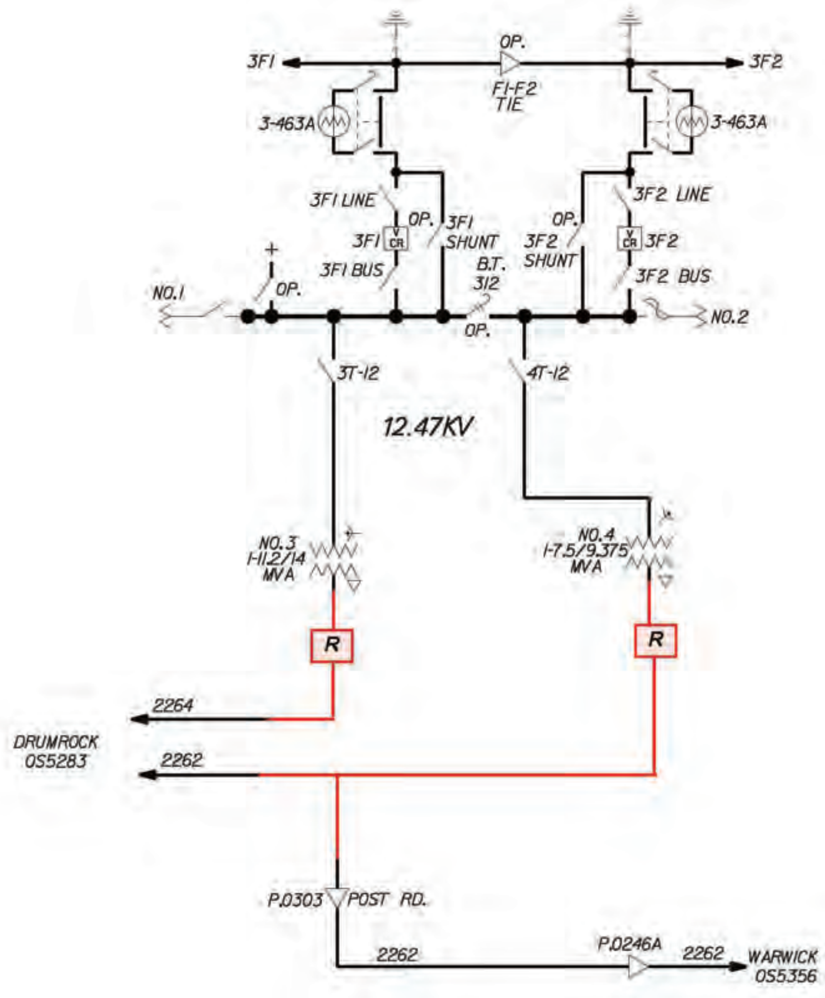
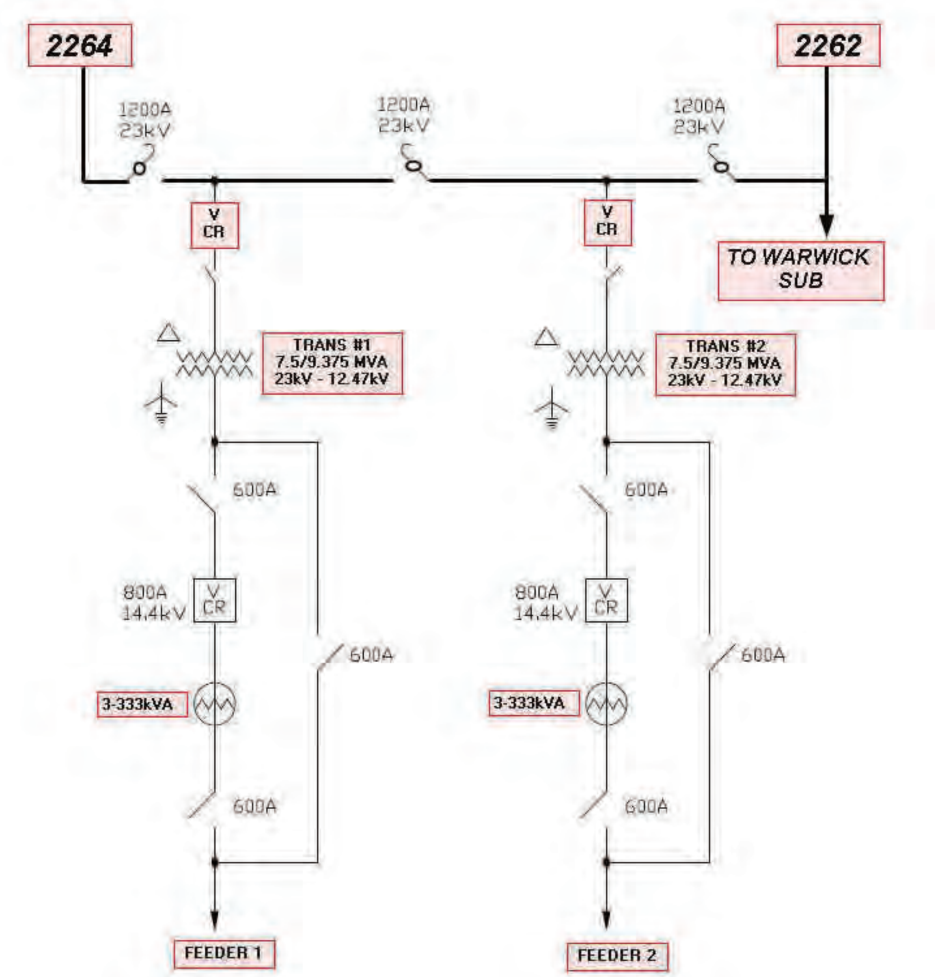


FIGURE 9.7.4 – APPONAUG SUBSTATION ONE-LINE DIAGRAM (Long-Term)



9.8 Plan Development – Plan 1

TABLE 9.8.1 – Transformer Loading (Normal) with Plan 1 Improvements

Substation	Tranf. ID	System Voltage (kV)		Rating (MVA)	Peak Load							
					2018		2022		2026		2030	
		From	To	SN	MVA	% SN	MVA	% SN	MVA	% SN	MVA	% SN
APPONAUG 3	3	23	12.47	15.50	8.1	52%	8.2	53%	8.5	55%	8.7	56%
APPONAUG 3	4	23	12.47	11.90	8.2	69%	8.3	70%	8.5	72%	8.8	74%
KILVERT STREET 87	1	115	12.47	70.30	23.3	33%	23.6	34%	24.2	34%	25.0	36%
KILVERT STREET 87	2	115	12.47	70.00	21.1	30%	21.4	31%	25.0	36%	25.8	37%
LINCOLN AVENUE 72	1	115	12.47	52.07	24.2	47%	24.6	47%	22.7	44%	23.4	45%
LINCOLN AVENUE 72	2	115	12.47	52.07	25.4	49%	25.8	49%	24.8	48%	25.6	49%
PONTIAC 27	1	115	12.47	50.67	20.6	41%	20.9	41%	19.2	38%	19.8	39%
PONTIAC 27	2	115	12.47	46.49	23.8	51%	24.1	52%	20.0	43%	20.7	44%
WARWICK 52	1	23	12.47	11.60	7.6	65%	7.7	66%	7.9	68%	8.1	70%
WARWICK 52	4	23	12.47	12.00	8.1	68%	8.3	69%	8.5	71%	8.8	73%
AUBURN 73	1	23	4.16	10.56	5.6	53%	5.6	53%	Retired			
AUBURN 73	2	23	4.16	9.66	3.8	39%	2.5	26%	Retired			
LAKEWOOD 57	1	23	4.16	10.09	4.7	47%	4.8	47%	Retired			
LAKEWOOD 57	2	23	4.16	10.15	3.1	31%	3.2	31%	Retired			
DRUMROCK 14	[redacted]											
DRUMROCK 14	[redacted]											
DRUMROCK 14	[redacted]											
SOCKANOSSET 24	1	115	23	50.29	19.3	38%	19.6	39%	Retired			
SOCKANOSSET 24	2	115	23	50.37	20.7	41%	21.0	42%	Retired			
AUBURN 73 (New)	T1	115	12.47	65.00					33.0	51%	34.1	52%
AUBURN 73 (New)	T2	115	12.47	65.00					35.0	54%	36.2	56%

TABLE 9.8.2 – Transformer Loading (Contingency) with Plan 1 Improvements

Substation	Tranf. ID	System Voltage (kV)		Rating (MVA)	Peak Load							
					2018		2022		2026		2030	
		From	To	SE	MVA	% SN	MVA	% SN	MVA	% SN	MVA	% SN
APPONAUG 3	3	23	12.47	19.60								
APPONAUG 3	4	23	12.47	12.60								
KILVERT STREET 87	1	115	12.47	79.30	44.3	56%	45.0	57%	49.3	62%	50.8	64%
KILVERT STREET 87	2	115	12.47	79.00	44.3	56%	45.0	57%	49.3	62%	50.8	64%
LINCOLN AVENUE 72	1	115	12.47	54.92	49.6	90%	50.3	92%	47.5	86%	49.0	89%
LINCOLN AVENUE 72	2	115	12.47	54.92	49.6	90%	50.3	92%	47.5	86%	49.0	89%
PONTIAC 27	1	115	12.47	53.32	44.3	83%	45.0	84%	39.2	74%	40.5	76%
PONTIAC 27	2	115	12.47	51.88	44.3	85%	45.0	87%	39.2	76%	40.5	78%
WARWICK 52	1	23	12.47	12.70								
WARWICK 52	4	23	12.47	12.00								
AUBURN 73	1	23	4.16	11.81	9.4	79%	8.1	69%	Retired			
AUBURN 73	2	23	4.16	10.64	9.4	88%	8.1	76%	Retired			
LAKEWOOD 57	1	23	4.16	10.63	7.9	74%	8.0	75%	Retired			
LAKEWOOD 57	2	23	4.16	11.46	7.9	68%	8.0	70%	Retired			
DRUMROCK 14	[redacted]											
DRUMROCK 14												
DRUMROCK 14												
SOCKANOSSET 24	1	115	23	56.81	40.0	70%	40.6	71%	Retired			
SOCKANOSSET 24	2	115	23	57.03	40.0	70%	40.6	71%	Retired			
AUBURN 73 (New)	T1	115	12.47	80.00					68.1	85%	70.3	88%
AUBURN 73 (New)	T2	115	12.47	80.00					68.1	85%	70.3	88%

FIGURE 9.8.1 – AUBURN SUBSTATION ONE LINE-DIAGRAM (PLAN 1)

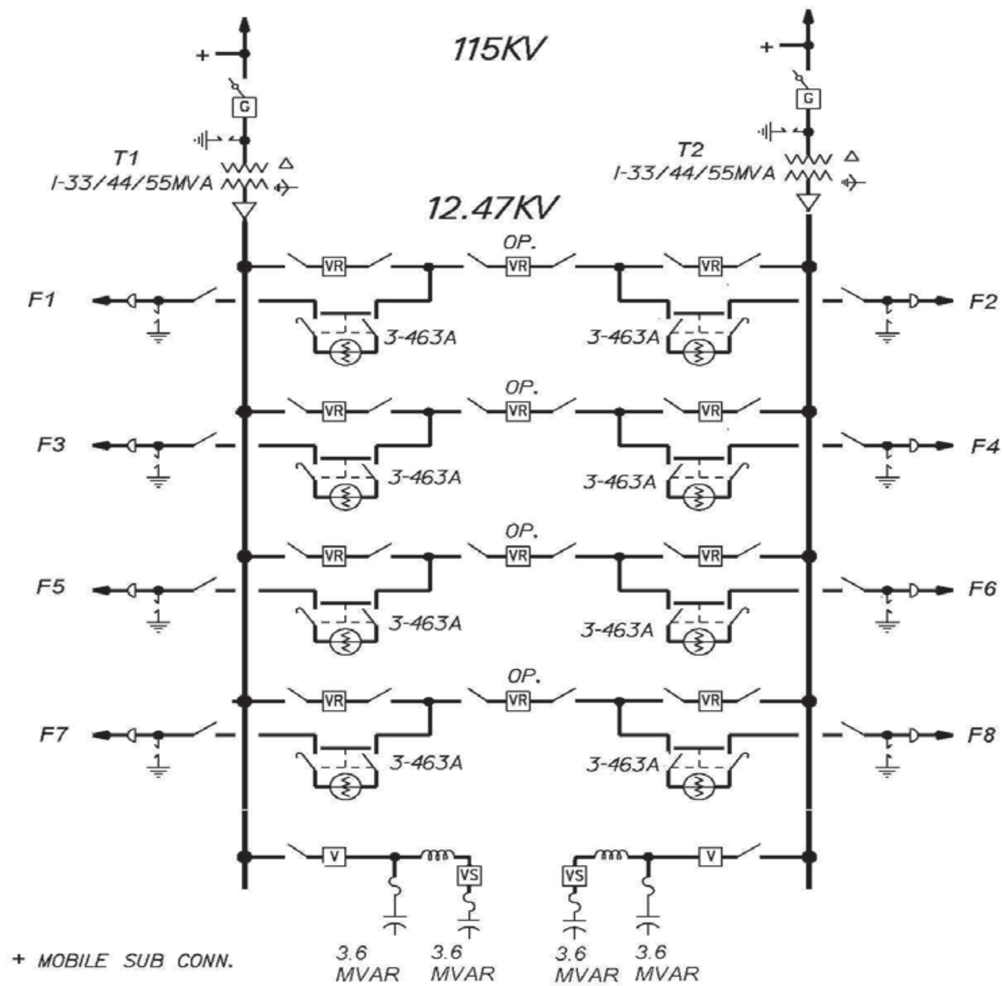


FIGURE 9.8.2 –LAKEWOOD SUBSTATION ONE LINE-DIAGRAM (PLAN 1)

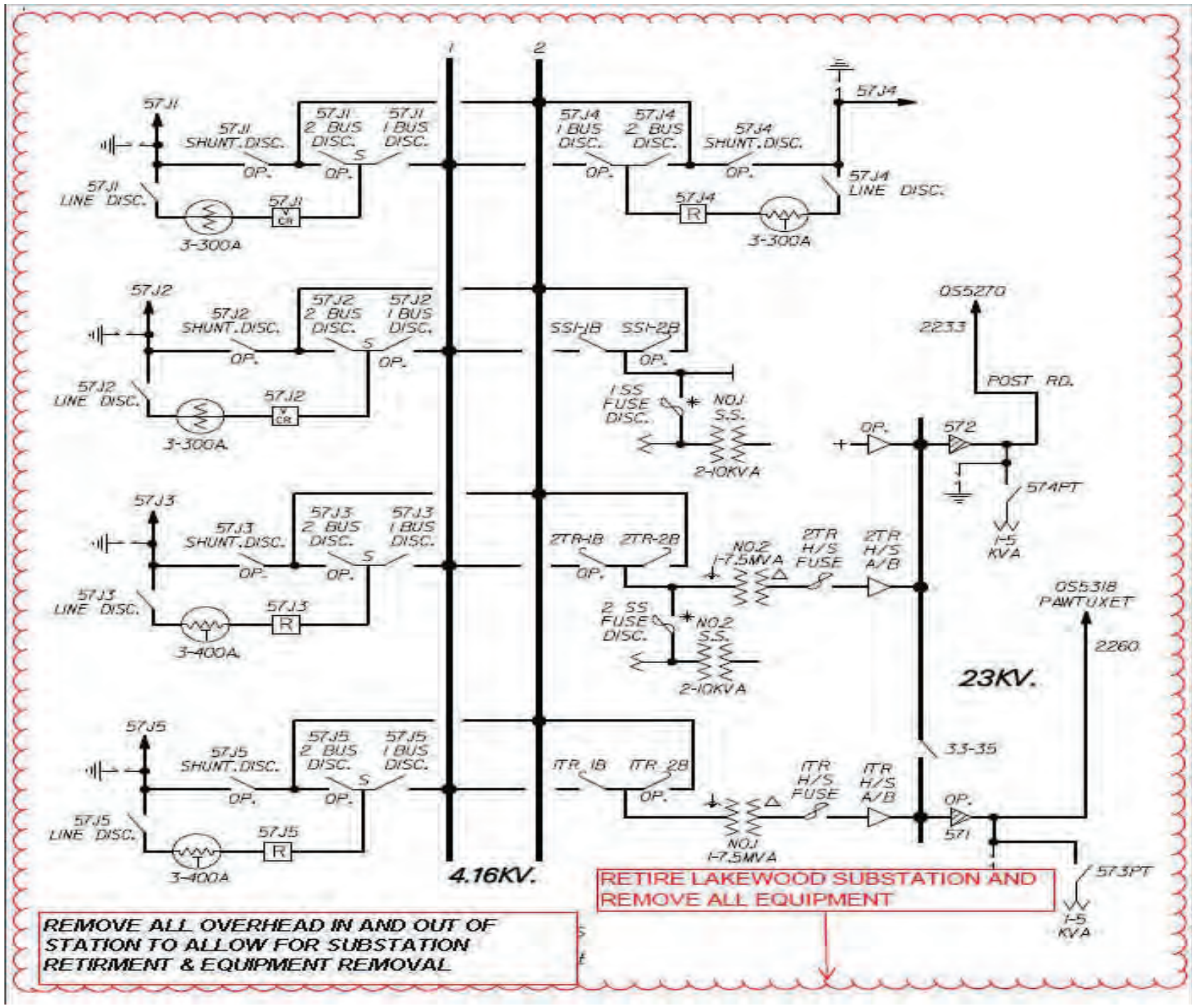


FIGURE 9.8.3 – SOCKANOSSET SUBSTATION ONE LINE-DIAGRAM (PLAN 1)

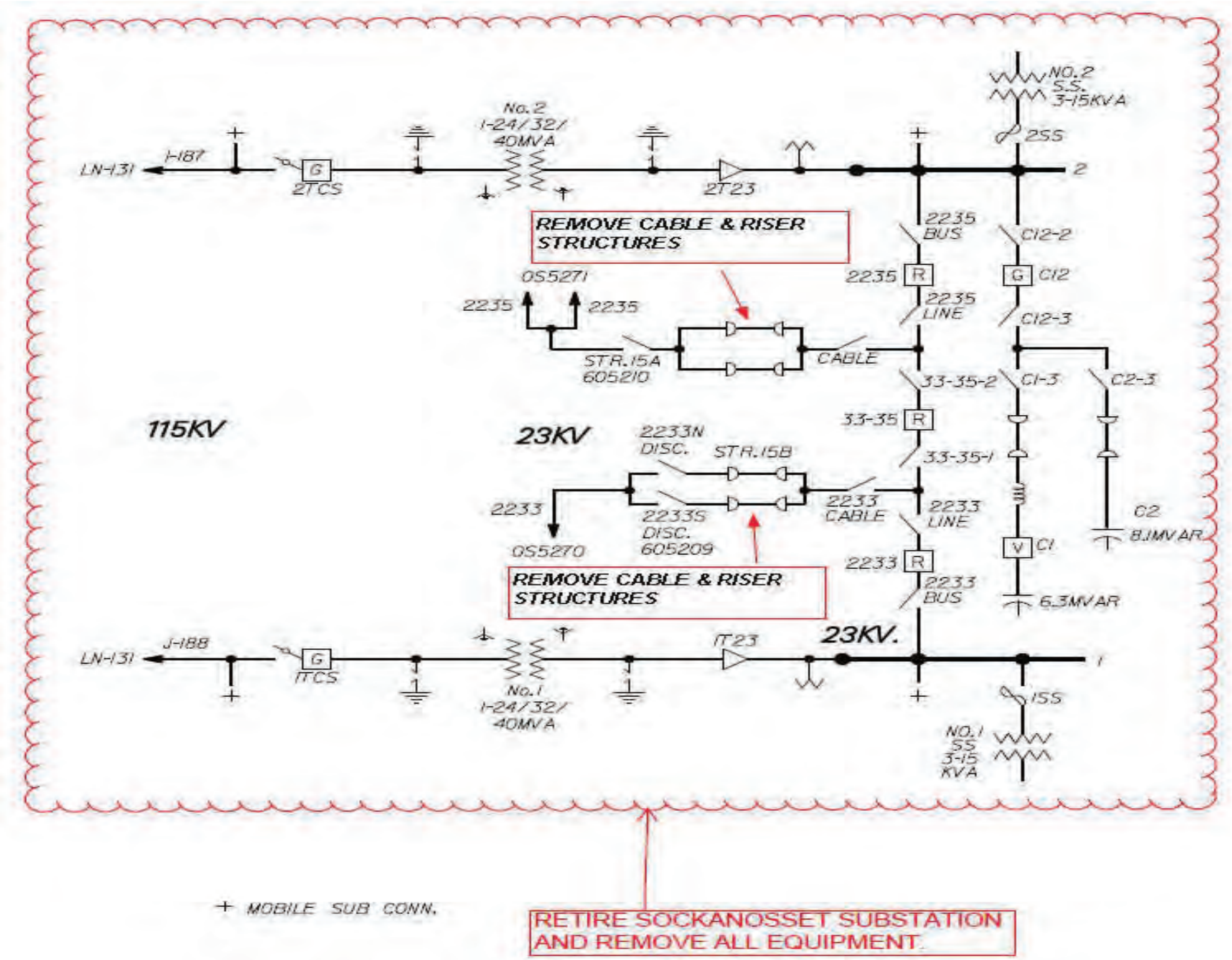


FIGURE 9.8.4 – PROPOSED 115 kV SUPPLY SYSTEM (PLAN 1)

[redacted]

FIGURE 9.8.5 – PROPOSED 23 kV SUPPLY SYSTEM (PLAN 1)

[redacted]

9.9 Plan Development – Plan 2

This plan recommends new distribution capacity supplied from an expanded and upgraded 23 kV sub-transmission system and minimal 115 kV transmission system expansion. The following are the major modifications proposed.

Build a new 115/23 kV Substation at Sockanosset: Build a new metal clad substation at the existing Sockanosset substation site consisting of (2) 115/23 kV 33/44/55 MVA transformers, (4) circuit positions, and (2) 10.4 MVAr station capacitor banks each with (2) 5.2 MVAr stages. The preferred arrangement is a breaker-and-one-half design. The switchgear would be installed at an elevation of approximately eight feet above finish grade utilizing a steel structure to raise the switchgear above the flood plain. The elevated foundation would require a steel ramp, stairway and work platform with rails. Two circuits would supply a new Auburn substation and two circuits would supply an expanded Elmwood substation.

Build a new 23/12.47 kV Substation at Auburn: Build a new substation at the existing Auburn substation site consisting of (2) 23/12.47 kV 24/32/40 MVA transformers, (4) feeder positions, and (2) 7.2 MVAr station capacitor banks each with (2) 3.6 MVAr stages. The preferred arrangement is an open air low profile breaker-and-one-half design. The ultimate build-out of the station would be six feeder positions. The station would be supplied by two dedicated supply lines from the rebuilt Sockanosset substation. The existing 4.16 kV station at Auburn would be retired to provide space for the new station, provide routes for the new feeders, and address the asset condition concerns at the existing station. The four Auburn feeders would follow the route of the existing 4.16 kV feeders.

Expand the Existing Elmwood 12.47 kV Substation: Install a second 20/26.7/33 MVA transformer at Elmwood, a new feeder position (7F3) and tie breakers. The station would be supplied by two dedicated supply lines from the rebuilt Sockanosset substation.

Modify Area Distribution: Four Auburn feeders combined with four Elmwood feeders would provide capacity to supply the existing Auburn 4.16kV load, load converted within Huntington Park on the 23 kV and 4.16 kV circuits, a portion of the Knightsville load, a portion of the Sprague Street load, and provide relief to heavily loaded 12.47 kV feeders from Point Street and Pontiac substations.

A new Auburn feeder will be used to retire Lakewood substation. The retirement of Lakewood eliminates a pocket of 4.16 kV and creates new 12.47 kV feeder ties to improve reliability in the area. The retirement of Lakewood also eliminates the overdutied station breakers, the need to replace the gassing transformer, and the obsolete auto-transfer scheme.

The investments and expenses for Plan 2 are detailed in Table 9.9.1 below.

TABLE 9.9.1 - Estimated Investments and Expenses for Plan 2

Component ($M)	Capex	Opex	Removal	Total
Sockanosset Substation (D-Sub)	$8.550	$0.050	$0.600	$9.200
Sockanosset Substation (D-Line)	$7.086	$0.210	$0.804	$8.100
Auburn Substation (D-Sub)	$8.165	$0.700	$0.335	$9.200
Auburn Substation (D-Line)	$12.033	$0.752	$3.128	$15.913
Elmwood Substation (D-Sub)	$2.200	$0.100	$0.100	$2.400
Elmwood Substation (D-Line)	$0.150	$0.010	$0.000	$0.160
Lakewood Substation Retirement (D-Sub)	$0.000	$0.000	$0.800	$0.800
Lakewood Substation Retirement (D-Line)	$4.094	$0.208	$1.199	$5.500
Total Cost	$42.278	$2.029	$6.966	$51.273

FIGURE 9.9.1 – SOCKANOSSET SUBSTATION ONE-LINE DIAGRAM (PLAN 2)

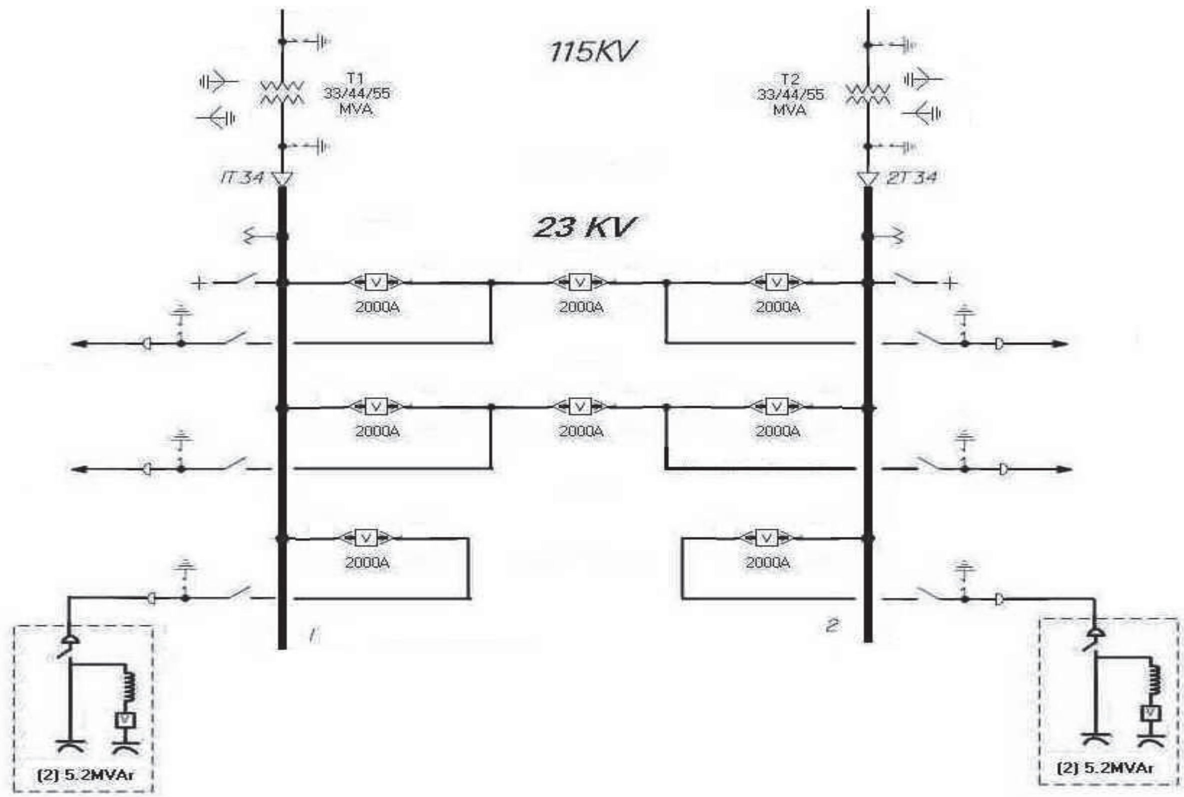


FIGURE 9.9.2 – AUBURN SUBSTATION ONE-LINE DIAGRAM (PLAN 2)

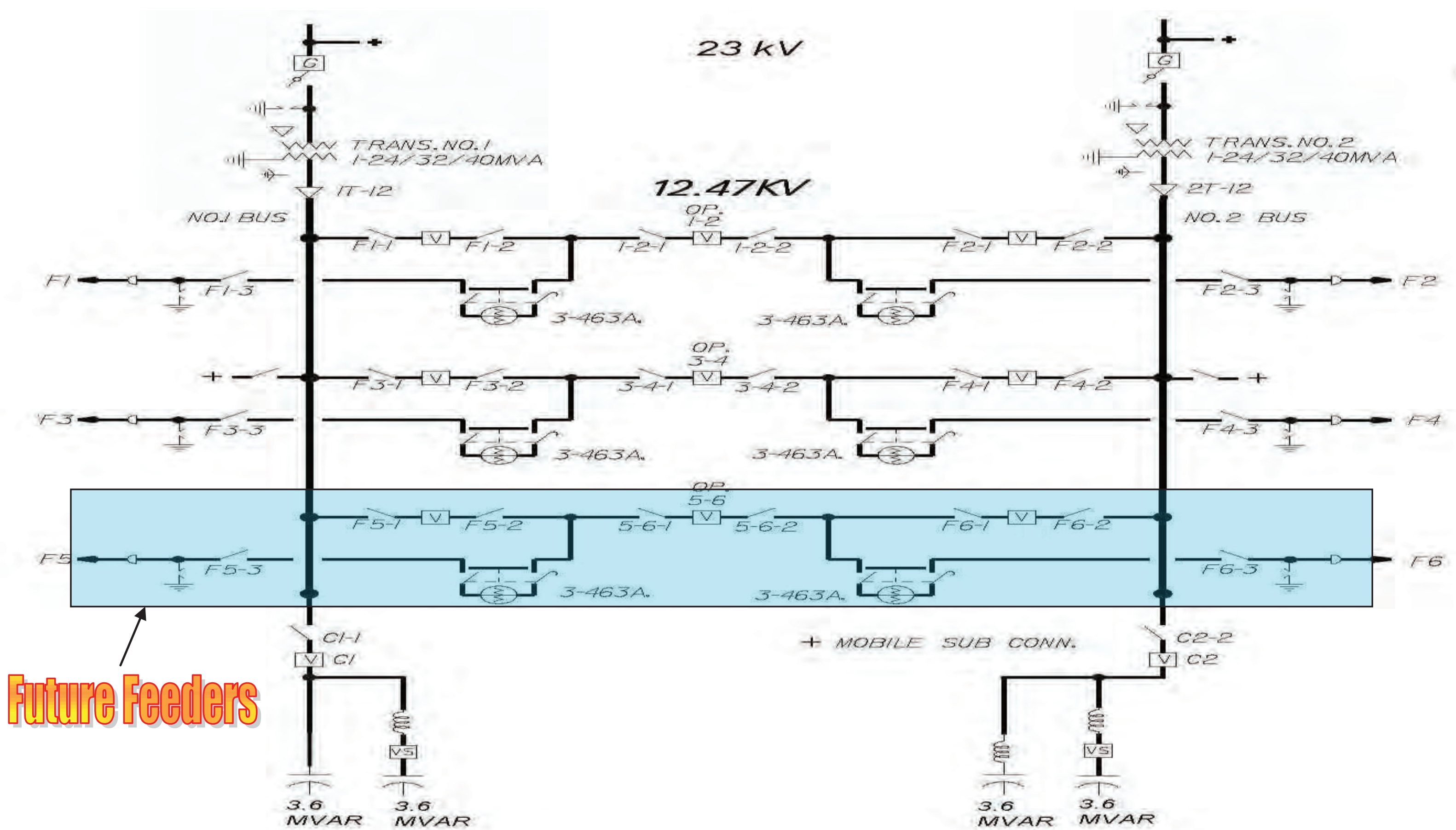


FIGURE 9.9.3 – ELMWOOD SUBSTATION ONE-LINE DIAGRAM (PLAN 2)

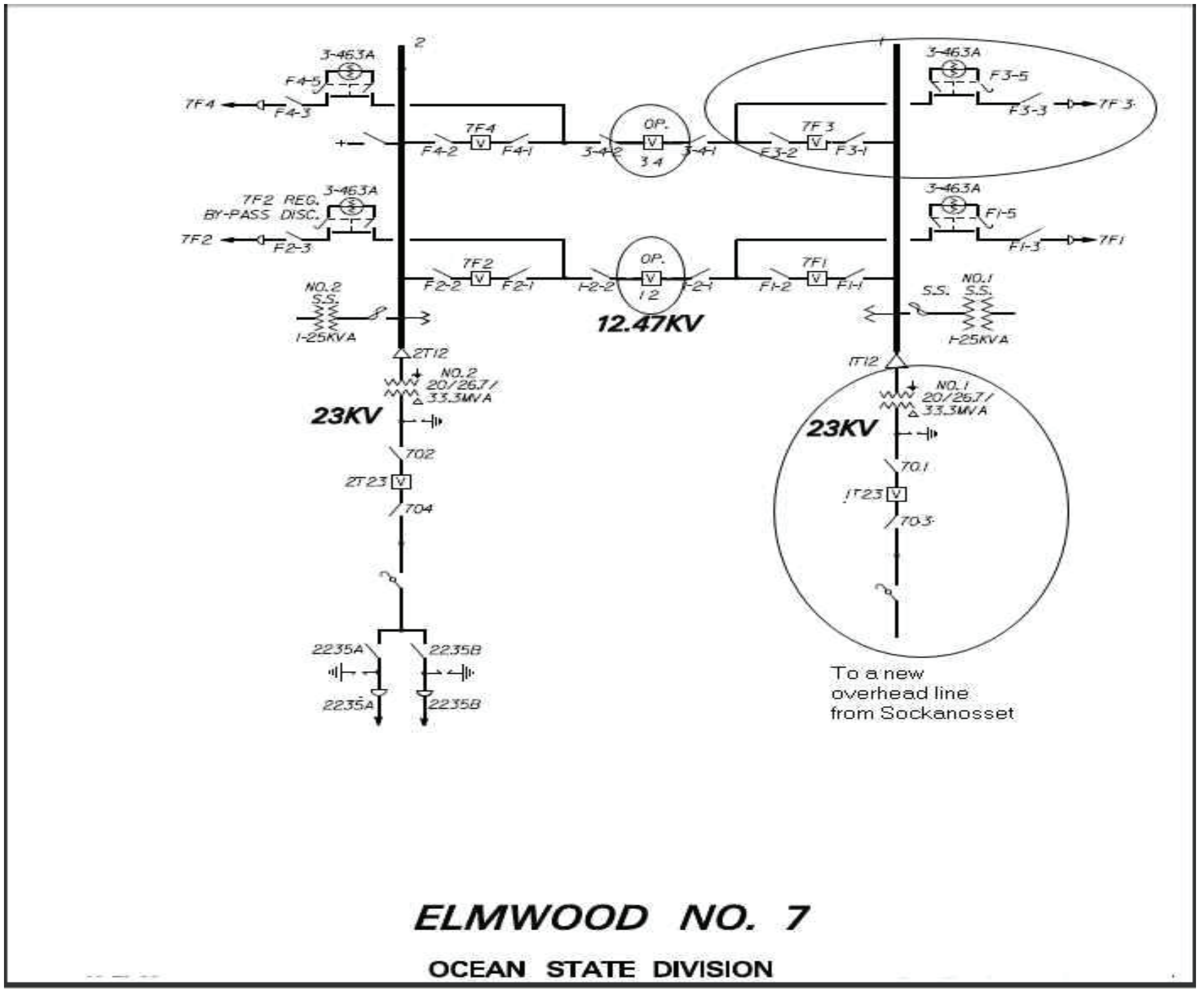


FIGURE 9.9.4 – LAKEWOOD SUBSTATION ONE LINE-DIAGRAM (PLAN 2)

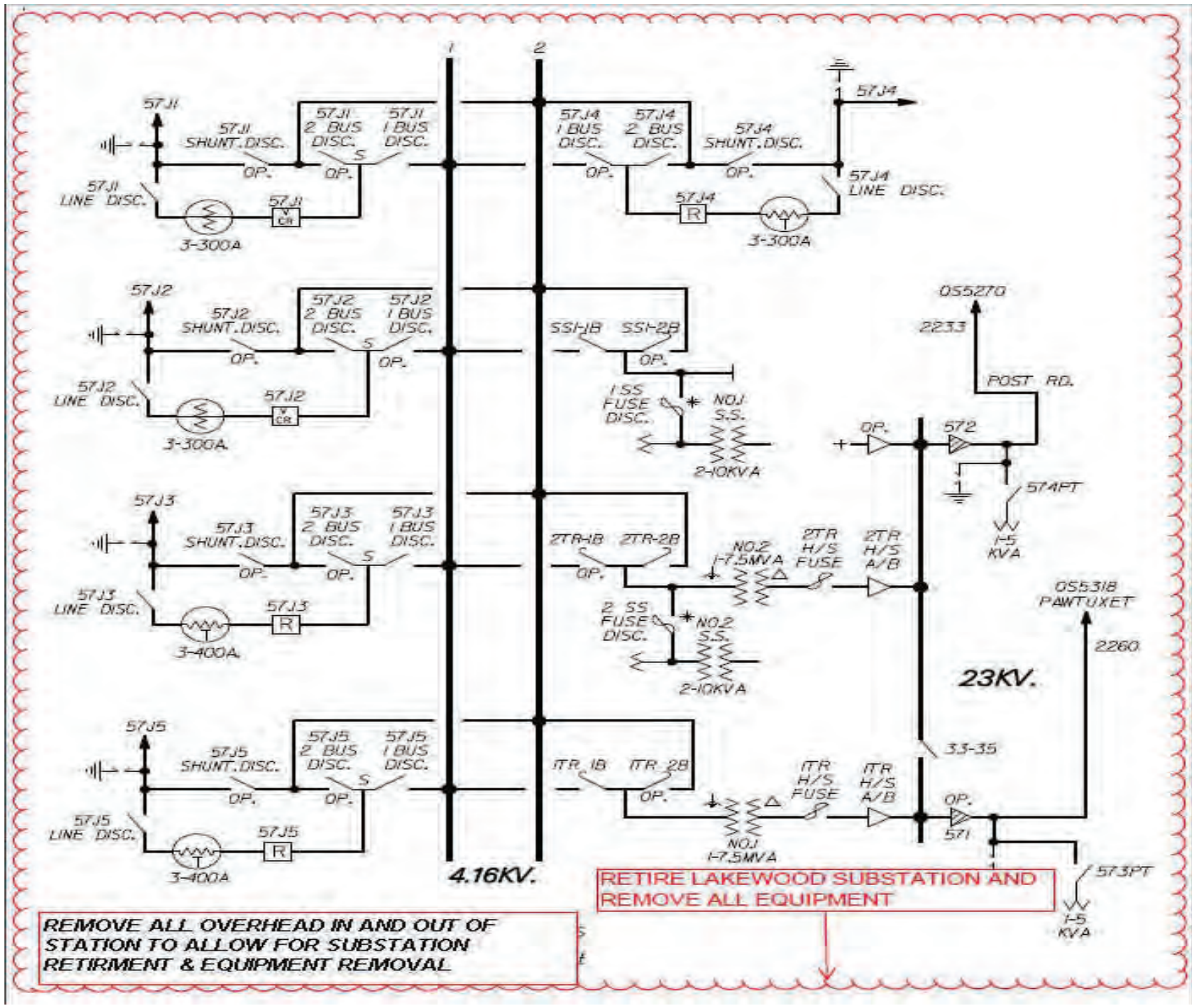


FIGURE 9.9.5 – PROPOSED 23KV SUPPLY SYSTEM – NORTH (PLAN 2)

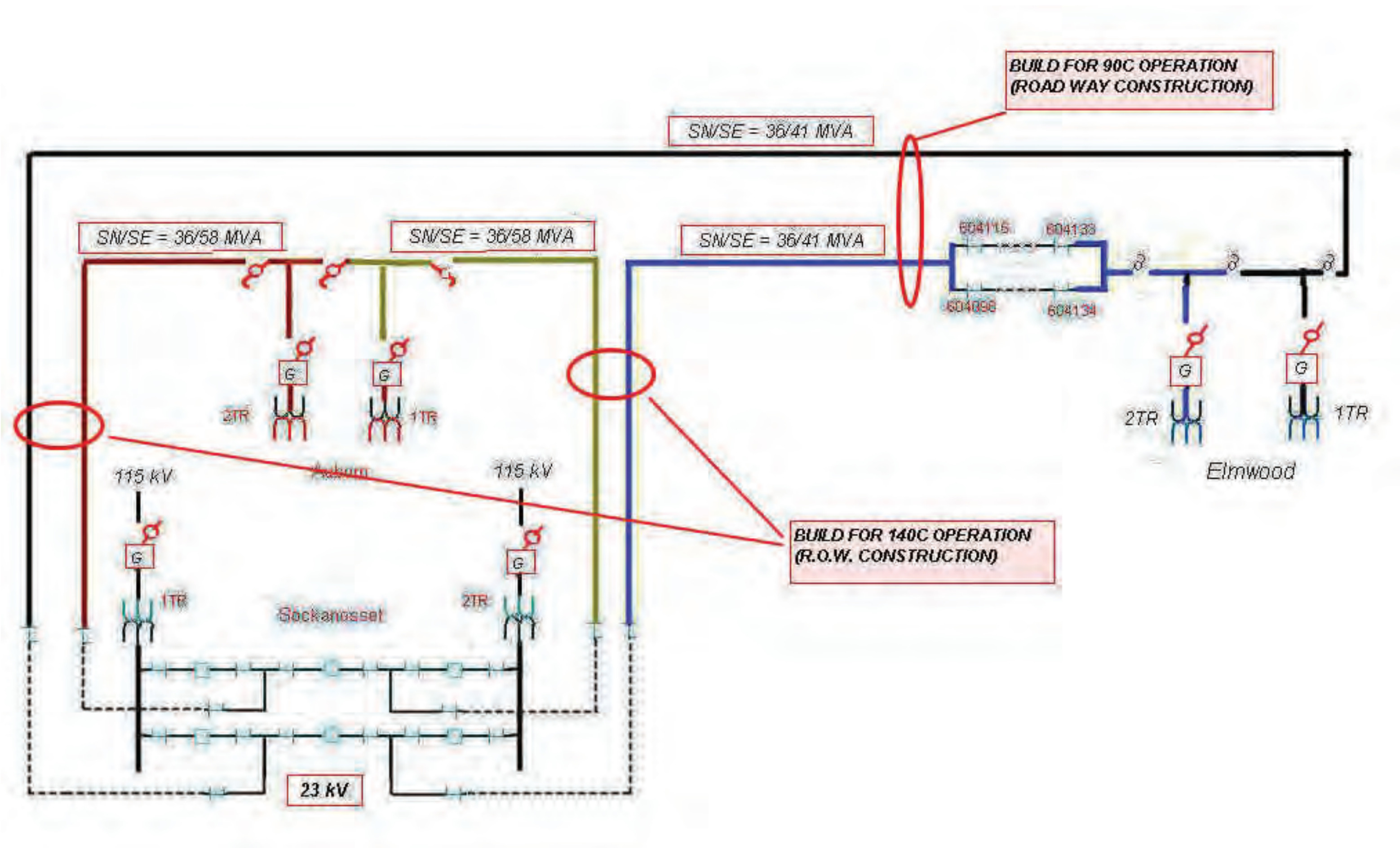


FIGURE 9.9.6 – PROPOSED 23 kV SUPPLY SYSTEM – SOUTH (PLAN 2)

[redacted]

9.10 Plan Development – Plan 3

This plan recommends new distribution capacity supplied from a new 34.5 kV sub-transmission system and minimal 115kV transmission system expansion. The following are the major modifications proposed:

Build a new 115/34.5 kV Substation at Sockanosset: Build a new metal clad substation at the existing Sockanosset substation site consisting of (2) 115/34.5 kV 33/44/55 MVA transformers, (4) circuit positions, and (2) 10.4 MVAr station capacitor banks each with (2) 5.2 MVAr stages. The preferred arrangement is a breaker-in-a-half design. The switchgear would be installed at an elevation of approximately eight feet above finish grade utilizing a steel structure to raise the switchgear above the flood plain. The elevated foundation would require a steel ramp, stairway and work platform with rails. Two circuits would supply a new Auburn substation and two circuits would supply an expanded Elmwood substation.

Build a new 34.5/12.47kV Substation at Auburn: Build a new substation at the existing Auburn substation site consisting of (2) 34.5/12.47 kV 24/32/40 MVA transformers, (4) feeder positions, and (2) 7.2 MVAr station capacitor banks each with (2) 3.6 MVAr stages. The preferred arrangement is open air low profile breaker-and-one-half design. The station would be supplied by two dedicated supply lines from the rebuilt Sockanosset substation. The existing 4.16kV station at Auburn would be retired to provide space for the new station, provide routes for the new feeders, and address the asset condition concerns at the existing station. The four Auburn feeders would follow the route of the existing 4.16 kV feeders.

Expand the Existing Elmwood 12.47kV Substation: Replace the existing 23/12.47 kV 20/26.7/33 MVA transformer at Elmwood substation with a new 34.5/12.47 kV 24/32/40 MVA transformer and install a second 24/32/40 MVA transformer, a new feeder position (7F3) and tie breakers. The station would be supplied by two dedicated supply lines from the rebuilt Sockanosset substation.

Modify Area Distribution: Four Auburn feeders combined with four Elmwood feeders would provide capacity to supply the existing Auburn 4.16kV load, load converted within Huntington Park on the 23 kV and 4.16 kV circuits, a portion of the Knightsville load, a portion of the Sprague Street load, and provide relief to heavily loaded 12.47 kV feeders from Point Street and Pontiac substations.

A new Auburn feeder will be used to retire Lakewood substation. The retirement of Lakewood eliminates a pocket of 4.16 kV and creates new 12.47 kV feeder ties to improve reliability in the area. The retirement of Lakewood also eliminates the overdutied station breakers, the need to replace the gassing transformer, and the obsolete auto-transfer scheme.

The investments and expenses for Plan 3 are detailed in Table 9.10.1 below.

TABLE 9.10.1 – Estimated Investments and Expenses for Plan 3:

Component ($M)	Capex	Opex	Removal	Total
Sockanosset Substation (D-Sub)	$9.050	$0.050	$0.600	$9.700
Sockanosset Substation (D-Line)	$7.086	$0.210	$0.804	$8.100
Auburn Substation (D-Sub)	$8.165	$0.700	$0.335	$9.200
Auburn Substation (D-Line)	$12.000	$0.750	$3.100	$15.850
Elmwood Substation (D-Sub)	$3.150	$0.100	$0.100	$3.350
Elmwood Substation (D-Line)	$0.150	$0.010	$0.000	$0.160
Lakewood Substation Retirement (D-Sub)	$0.000	$0.000	$0.800	$0.800
Lakewood Substation Retirement (D-Line)	$4.094	$0.208	$1.199	$5.500
Total Cost	$43.695	$2.028	$6.938	$52.660

FIGURE 9.10.1 – SOCKANOSSET SUBSTATION ONE-LINE DIAGRAM (PLAN 3)

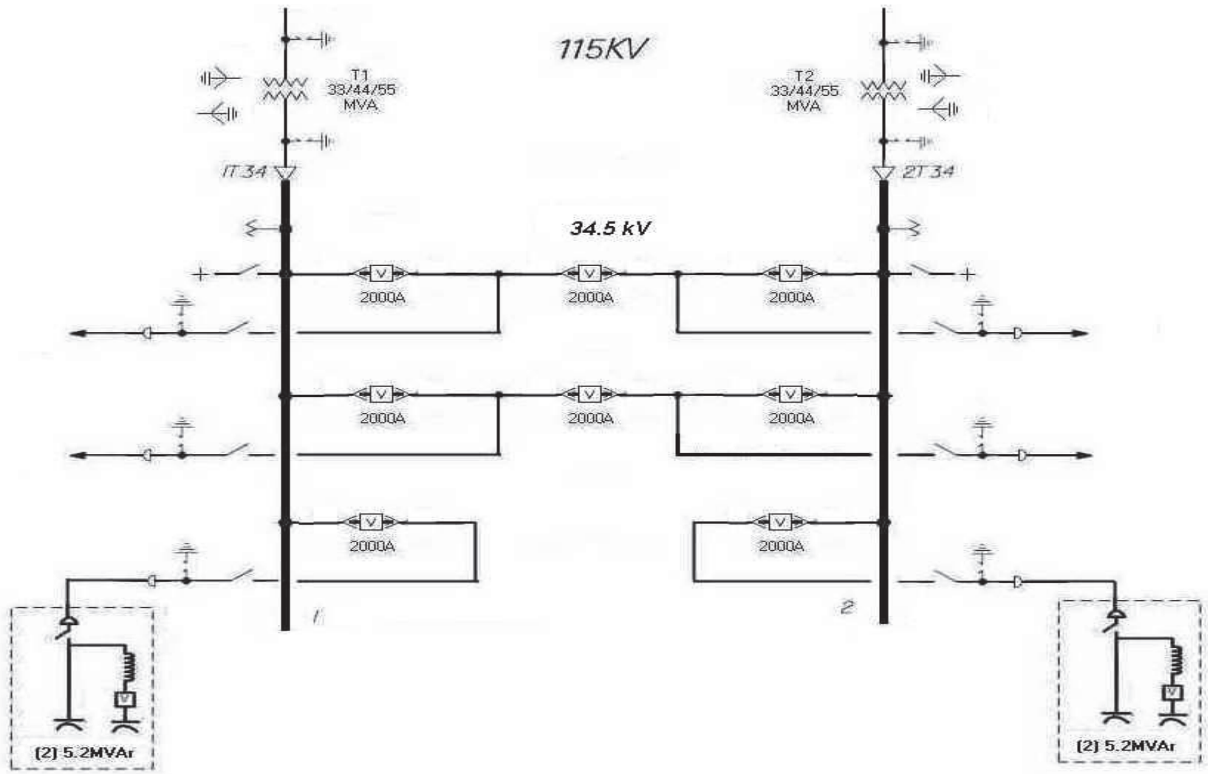


FIGURE 9.10.2 – AUBURN SUBSTATION ONE-LINE DIAGRAM (PLAN 3)

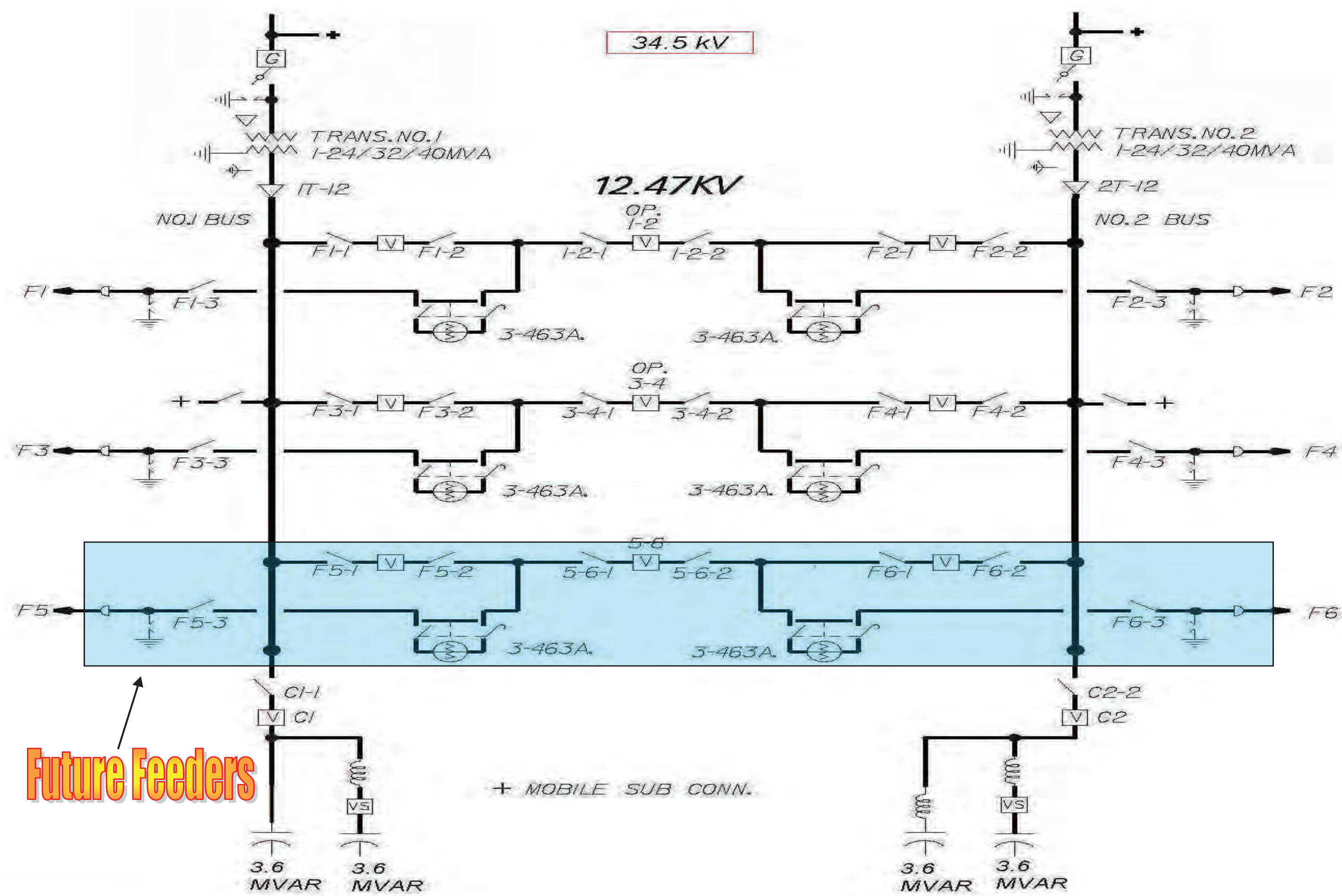


FIGURE 9.10.3 – ELMWOOD SUBSTATION ONE-LINE DIAGRAM (PLAN 3)

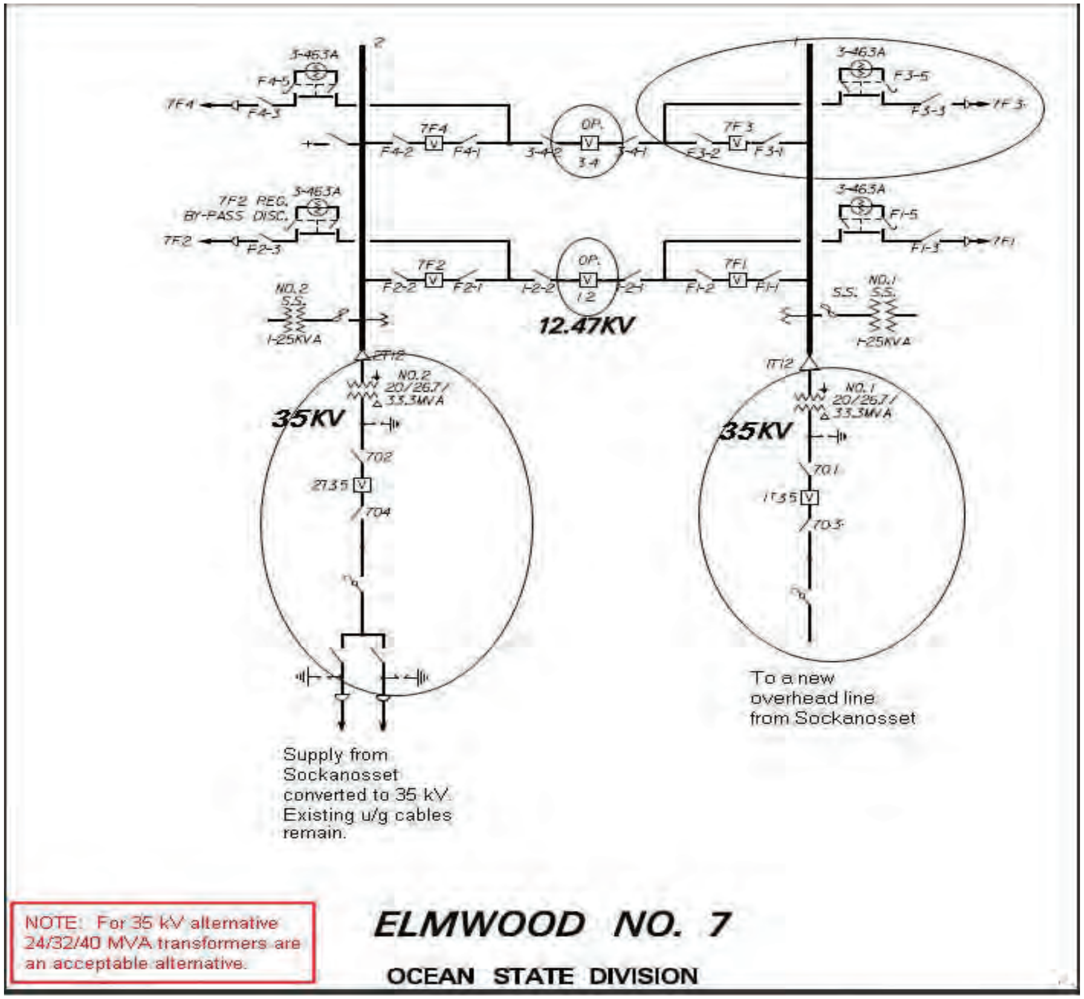


FIGURE 9.10.4 – LAKEWOOD SUBSTATION ONE LINE-DIAGRAM (PLAN 3)

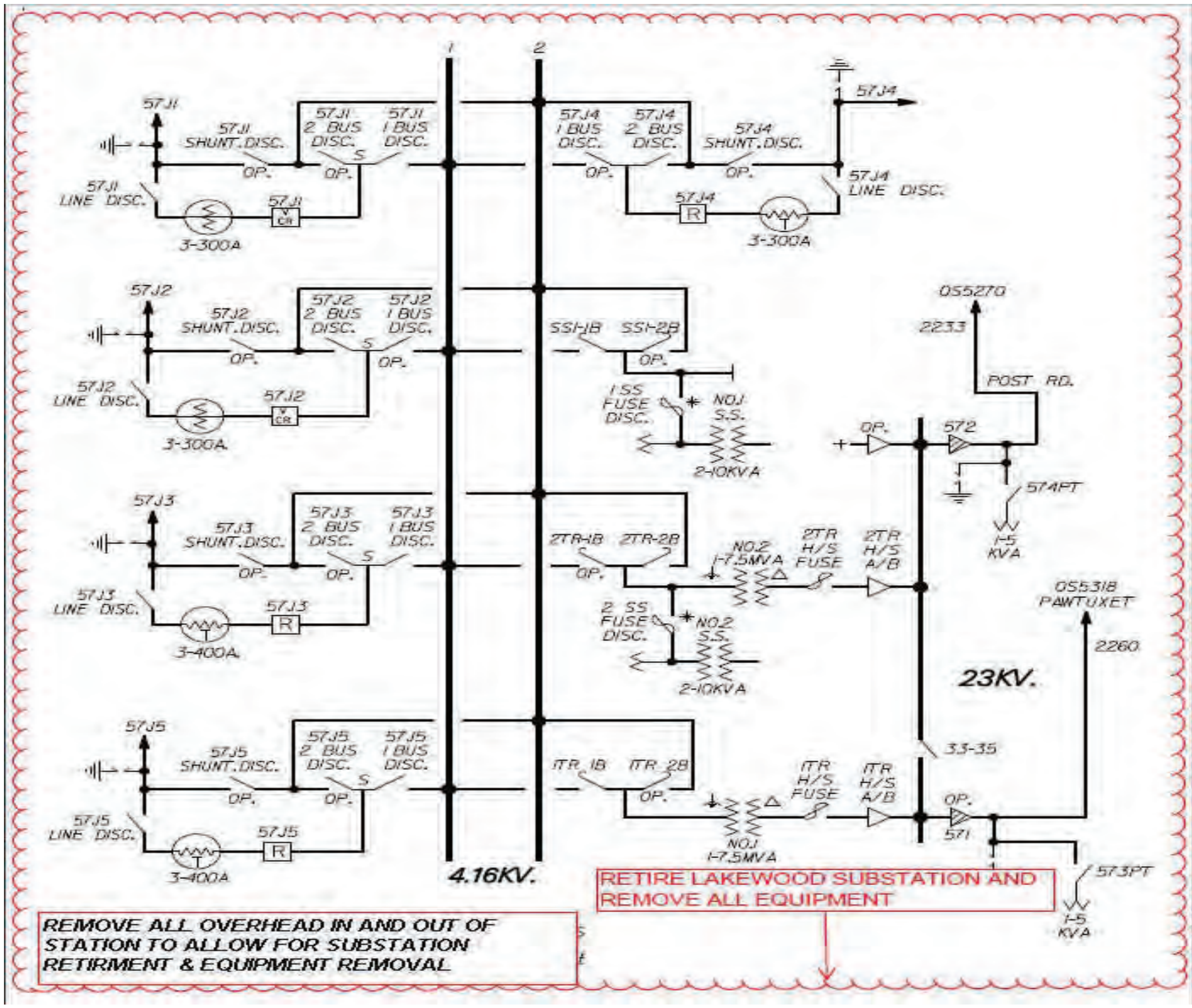


FIGURE 9.10.5 – PROPOSED 34.5 kV SUB-TRANSMISSION SUPPLY – NORTH (PLAN 3)

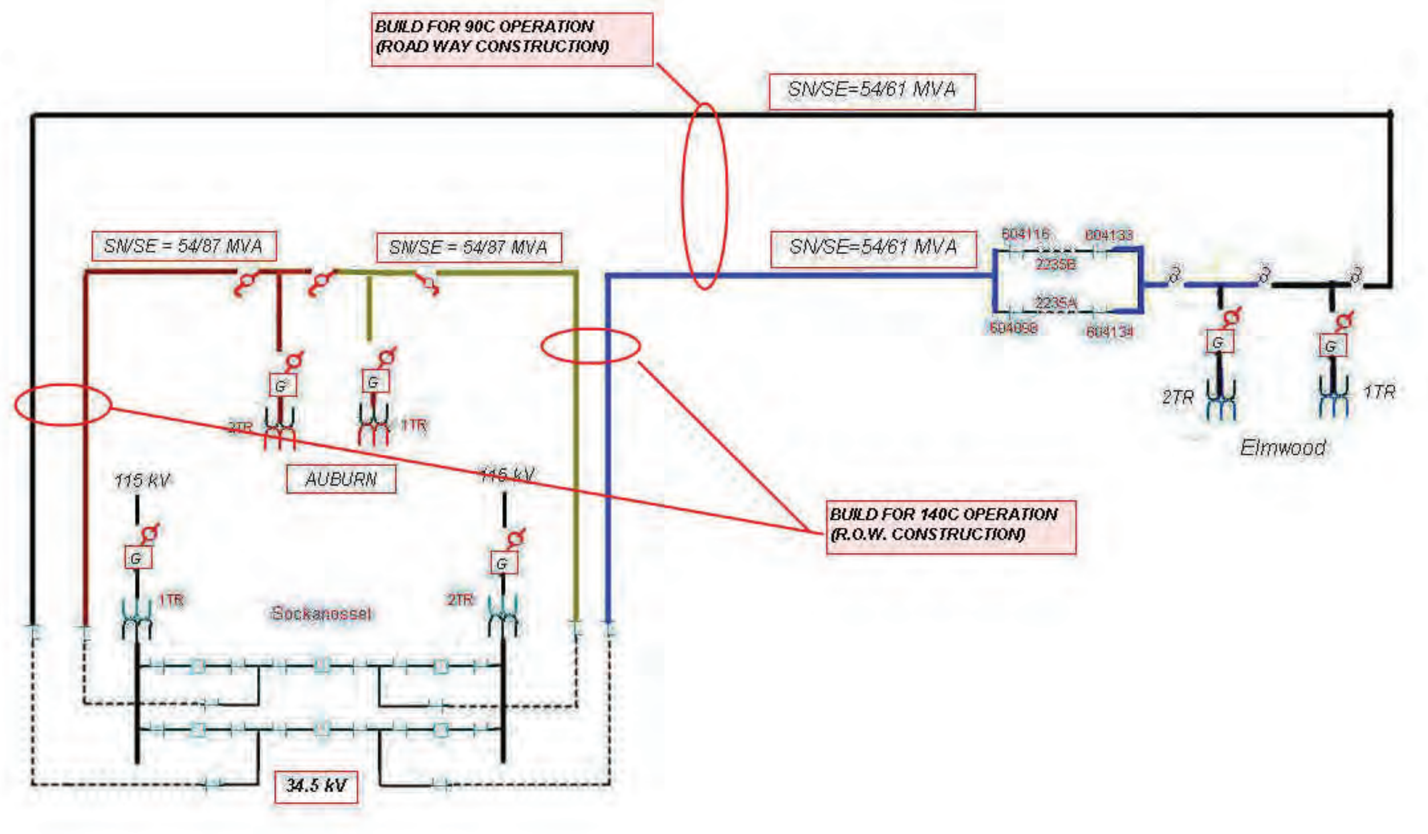


FIGURE 9.10.6 – PROPOSED 34.5 kV SUB-TRANSMISSION SUPPLY – SOUTH (PLAN 3)

[redacted]

9.11 Distributed Generation within Study Area

FIGURE 9.12.1 – Existing and Proposed Distributed Generation within Study Area

Feeder	Proposed Capacity (kW)	Existing Capacity (kW)	Fuel Type	Prime Mover	DG Type
14F1	0	3.5	Solar	PV	Inverter Based - PV
14F1	0	5.5	Solar	PV	Inverter Based - PV
14F3	0	225	Hydro	Hydro	Synchronous
14F4	308	0	Solar	PV	Inverter Based - PV
27F2	500	0	Solar	PV	Inverter Based - PV
27F3	0	300	Solar	PV	Inverter Based - PV
27F4	224	0	Solar	PV	Inverter Based - PV
72F2	0	5.16	Solar	PV	Inverter Based - PV
72F5	5	0	Solar	PV	Inverter Based - PV
83F2	495	0	Solar	PV	Inverter Based - PV
87F1	100	0	Wind	Wind	Wind Turbine
87F1	220.8	0	Solar	PV	Inverter Based - PV
87F5	0	3.5	Solar	PV	Inverter Based - PV
TOTAL	1,853	543			

9.12 Reactive Compensation

ISO-NE conducts an annual survey of actual load power factor operations and compares it against the applicable standards. The latest survey has this overall area compliant at all times. The results of this survey are shown on Table 4.4.5 below:

TABLE 9.12.1: ISO-NE Power Factor Survey Results (Narragansett Electric)

COMPLIANCE REPORT						CURRENT LPF SURVEY SUMMARY					
Spring	Summer		Fall	Winter		Spring	Summer		Fall	Winter	
9,135	22,193	24,409	9,197	18,192	20,556	9,135	22,193	24,409	9,197	18,192	20,556
5/18/14	07/23/2014	07/02/14	10/19/14	12/18/14	1/8/15	5/18/14	07/23/2014	07/02/14	10/19/14	12/18/14	1/8/15
5:00	12:00	15:00	4:00	18:00	18:00	5:00	12:00	15:00	4:00	18:00	18:00
compliant	compliant	compliant	compliant	compliant	compliant	0.971	0.996	0.998	0.974	0.995	0.998

The power factor performance of the study area's feeders is limited to those that have PI data availability. Peak power factor performance for these feeders shows them to be near unity or leading, indicating adequate feeder reactive support. Available data for major 115kV transformer interfaces and the 23 kV sub-transmission lines also show power factor near unity.

9.13 Permitting, Licensing, Real Estate, and Environmental Considerations

Common to all plans is permitting for distribution line poles. Depending on the town, these poles will be set either by Verizon or by National Grid. All three plans would consist of routine requests and standard construction and no major obstacles are expected.

All three plans require the replacement of existing distribution circuits over an interstate highway and the Amtrak electrified tracks. Standard guying practices for the structures carrying the circuits over the interstate highway is not feasible due to the locations of the crossings. Special construction procedures, using either laminated or steel poles, will be used for these crossings to provide a non-guyed alternative.

Common to all plans is to build a new substation at Auburn. This construction has been reviewed at a conceptual level and although space at Auburn is limited, it is anticipated that sufficient space exists to build the proposed station. The existing 23/4.16 kV station must be retired in advance of construction of the new station to provide necessary space. Current load projections indicate there is existing distribution system capacity in the short-term to accommodate the retirement of existing Auburn 4.16 kV load prior to the new Auburn substation being built.

The recommended plan requires an extension of two transmission lines, I-187 and J-188, from Sockanosset substation to Auburn (or approximately 1.1 miles). The right-of-way for this line extension has been reviewed at a conceptual level and it indicates right-of-way has suitable width to accommodate the proposed transmission line extension without the need to acquire new land rights. The extension of the transmission system will require a filling with the Rhode Island Energy Facilities Siting Board (EFSB).

Plan 2 and Plan 3 require a new substation at Sockanosset. The substation would be located within a flood plain zone and would utilize steel structures to raise the station above the flood plain. The elevation would be approximately eight feet above finish grade which would also require a working platform with railing around the switchgear. A conceptual review has been performed and there is suitable space at Sockanosset to accommodate the new station while the existing station remains in-service during construction.

9.14 Asset Condition

FIGURE 9.14.1 – Apponaug Station - Regulators with Wooden Structures

FIGURE 9.14.2 – Apponaug Station – Obsolete 23 kV Control Building

9.15 Distribution Planning Criteria

nationalgrid

Distribution Planning Guide

Rev. 1

Approved by: ______________ **Date:** 2/15/11

Patrick Hogan, Sr. VP
Distribution Asset Management
National Grid USA Service Company

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
0	10/14/2009	Initial draft	Curt J. Dahl Manager, T&D Planning LI John F. Duffy, Jr. Distribution Planning	Patrick Hogan Sr. Vice President Distribution Asset Management
1	2/15/2011	Final approved document	Max F. Huyck Network Asset Planning Jeffery H. Smith Distribution Asset Strategy	

Distribution Planning Criteria Strategy
Table of Contents

Strategy Statement

This document describes the National Grid Electric Distribution Planning Criteria that will be applied by the Distribution Planning Department in future distribution studies. These criteria are applicable to the New England (NE) and upstate New York (UPNY) areas of National Grid.

The electric distribution system on Long Island, NY shall continue to follow the LIPA Transmission and Distribution Planning Criteria.

For normal loading conditions, all types of facilities are to remain within their normal ratings at all times. For N-1 contingency situations it is expected that load shall be returned to service within 24 hours via system reconfiguration through switching, the installation of temporary equipment such as mobile transformers or generators, or by the repair of a failed device. Where practical, switching flexibility should be integrated into the system design to minimize the duration of customer outages following an N-1 contingency to meet reliability objectives. The following shall guide contingency planning on the distribution system:

1.) For the loss of a power transformer or substation bus fault that disrupts distribution load, the following planning criterion applies:

- The initial load increase at the remaining transformers within the area must not exceed either the summer or winter STE rating or 200% of nameplate.
- Load will need to be transferred or shed in a reasonable number of steps to reduce loading to the summer or winter LTE level within 15 minutes.
- Load on remaining transformers will be reduced to the summer or winter normal limit within 24 hours.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 10MW.
- Repairs or the installation of mobile equipment are expected to require 24 hour implementation.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.) For the loss of a sub-transmission supply line, the following planning criteria apply:

- The initial load increase at the remaining sub-transmission supply lines within the area must not exceed the summer or winter LTE rating.
- Every effort must be made to return the failed sub-transmission line to service within 12 hours.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 20MW combined, considering all substations served via the supply line.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a single line fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

3.) For the loss of a distribution feeder, the following planning criteria apply:

- Feeders shall tie to neighboring feeders as much as practical as the flexibility to reconfigure feeders has a positive reliability impact for a wide range of possible contingencies.
- Following a contingency, all adjoining tie feeders can be loaded to their maximum thermal emergency or LTE rating.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload adjoining feeders.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 16MWHrs of load is at risk at peak load periods for a single feeder fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

Application of these criteria will result in somewhat less load at risk than previous criteria in either New York or New England which generally limited load at risk to between 20 and 28 MW pending the installation of a mobile device. Therefore it is expected that the Load Relief budgets will increase from historic levels for a given load growth rate. The capital cost associated with meeting the existing and proposed criteria for both normal and N-1 contingency conditions in New England and upstate New York are shown in Table 1:

Table 1 - Comparison of Capital Costs between Existing and New Criteria

Criteria	Present Value ($ Millions)	15 Year Annualized ($ Millions)
Existing NE/NY Criteria	$800	$80
New Criteria	$1,250	$130

The new criteria may result in an increase in capital requirements up to $50M/year over the existing criteria for the 15-year period studied.

Based on the results of the sample areas (expanded to the overall system) the following approximate quantities of additional facilities may be required over the next 15years.

Transformers (at existing or new substations)	180
Sub-Transmission Lines	46
Distribution Feeders	319

The new criteria will be applied to new installations and/or significant rebuilds initially. This is a long-term strategy and it is expected to take the full 15 year horizon to achieve compliance with existing facilities system-wide.

Performance targets for the adoption of the new planning criteria are:

- Quantification of equipment (sub-transmission lines, transformers, feeders) with load at risk forecast above the guidelines above.
- Identifying high load at risk areas and as part of annual summer preparedness and communicate monitoring plans for the Regional Control Centers.

- Developing project recommendations to eliminate or significantly reduce load at risk areas based on MWHr metrics, reliability performance and mitigation costs.

This policy shall be reviewed and revised as often as needed to reflect any major standards or criteria changes. It is recommended that a 2-3 year review cycle be performed.

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
0 1	10/14/2009 2/15/2011	Initial draft Final approved document	Curt J. Dahl Manager, T&D Planning LI John F. Duffy, Jr. Distribution Planning Max F. Huyck Network Asset Planning Jeffery H. Smith Distribution Asset Strategy	Patrick Hogan Sr. Vice President Distribution Asset Management

Strategy Justification

1.0 Purpose and Scope

This document describes the National Grid Electric Distribution Planning Criteria that will be applied by the Distribution Planning Department in future distribution studies. These criteria are applicable to the New England (NE) and upstate New York (UPNY) areas of National Grid.

A map showing National Grid electric service territory within New England and upstate New York is attached in Appendix A.

The electric distribution system on Long Island, NY shall continue to follow the LIPA Transmission and Distribution Planning Criteria.

This policy shall be reviewed and revised as often as needed to reflect any major standards or criteria changes. It is recommended that a 2-3 year review cycle be performed.

2.0 Strategy Description

2.1 Description of Distribution System

The distribution system of National Grid is comprised of all lines and equipment operated at a voltage below 69kV in New England and below 115kV in New York. The components of the distribution system are distribution substations, sub-transmission lines, and distribution circuits or feeders.

2.1.1 Distribution substations

The distribution substations within National Grid are a mixture of stations with one, two, and three or more transformers. The distribution substations step down voltage to a distribution or sub-transmission level. In Upstate New York approximately 70% of the substations have either a single source or a single transformer. In New England 40% of the substations have a single source and/or transformer.

A typical substation involves a 115/13 kV, 25-40 MVA rated transformer with either a load tap changer built into the transformer or individual voltage regulators applied to the feeders. In many locations, two or three transformers are within one substation and will interconnect via bus tie breakers. Many of the distribution substations supplied by the 115kV circuits also include one or more capacitor banks for reactive support.

National Grid maintains approximately 680 distribution substations containing approximately 1,530 power transformers. The total number of distribution substations, transformers, circuit miles of overhead and underground within NE and UPNY is listed in Distribution Line Overarching Strategy paper dated July 2008.

2.1.2 Sub-Transmission systems

The sub-transmission system within National Grid is designed to provide adequate capacity between transmission sources and load centers at reasonable cost and with minimal impact on the environment. The National Grid sub-transmission system provides supply to distribution substations as well as large three phase customers. It consists of those parts of the system that are neither bulk transmission nor distribution. The typical voltages for the sub-transmission system include 46, 34, and 23 kilovolts. In New York, the sub-transmission also includes the 69 kV.

Sub-transmission systems may be designed in a closed or open loop system originating from transmission substations, and generally providing a redundant supply for distribution substations. In other cases, a single radial sub-transmission supply line may serve load. The substations served from a sub-transmission line will serve approximately 10-40 MW of load depending on the voltage.

Generally, the sub-transmission system is presently designed with conductors ranging from 336.4 ACSR (UPNY) to 795 kcmil AAC (NE) overhead conductor and from 500 to 2000 kcmil copper underground conductor. However, most of the sub-transmission lines are older designs and built with smaller wire such as 2/0 AWG copper installed along right-of-ways or on public streets.

There are approximately 930 sub-transmission lines in New England and upstate New York within National Grid.

2.1.3 Distribution Feeders

Distribution feeders originate at circuit breakers connected within the distribution substations. Feeders are generally comprised of 477 or 336 kcmil aluminum mainline overhead conductors and 1/0 AWG aluminum branch line conductors. Some feeders have underground getaway cables exiting from the substation with 500 to 1000 kcmil aluminum or copper conductor. Feeders are designed in a radial configuration. The feeder mainline will typically have several normal open tie points to one or more adjacent feeders for backup. Protection for faults on the feeders consists of relays at the circuit breaker, automatic circuit reclosers at points on the mainline, and fuses on the branch circuits.

The National Grid Primary distribution system in New England and upstate New York is comprised of approximately 3,770 feeders.

2.1.4 Secondary Networks

Low voltage secondary networks have historically been employed in several urban areas to maximize the reliability for the customers in these areas. They typically have a 120/208V class secondary system that is connected as a grid with many downtown customers connected. Most of the secondary networks have from 4-10 supply feeders. The low voltage secondary network supply feeders will typically have 10-30 network transformers connecting into the secondary grid.

Spot secondary networks are used in areas to serve specific large loads in urban areas. Some of these are served at 120/208V, while others are served at 277/480V. Typically, 2-3 supply feeders are used to serve the spot networks.

2.2 Distribution Planning Criteria

2.2.1 General Items impacting the Distribution Planning Criteria

2.2.1.1 Load Forecasting

The load forecast used by Distribution Planning for New England and New York will be based on a regional econometric regression model that considers historic loading, weather conditions, various economic indicators. The forecast is adjusted for known spot load additions and DSM forecasts. Presently, distribution planning is based on a forecast that considers loading during extreme weather conditions such that those weather conditions are expected to occur once in 20 years. Separate models are used for NE and UPNY.

2.2.1.2 Equipment Ratings

Distribution Planning maintains equipment ratings for New England and New York. The summer and winter normal and summer and winter long time emergency (LTE) ratings will be used. The major equipment ratings to be used by Distribution Planning relate to transformers, overhead lines, and underground cables. The normal and LTE rating limits for these items may be applied for the time associated with each rating. Generally, the durations for emergency loading are as listed below in Table 2. System operators must be aware of the limiting factor involved in any contingency:

Table 2 - Equipment Rating Durations

Equipment		Normal	LTE	STE
Transformer		Continuous	24 hour	15 Min
Overhead Line		Continuous	24 hour	N/A
Underground Cable		Continuous	24 hour	N/A

There is also a short time emergency rating which may be determined for substation transformers, in no instance should this rating exceed 200% of nameplate rating. In addition to the items in the above table, ratings are reviewed for switches, circuit breakers, voltage regulators, and instrument transformers.

2.2.1.3 Planning Study Areas

A planning study area within National Grid is a grouping of distribution substations, feeders, transformers, and sub-transmission lines within a specific geographic area that are interconnected and can be studied as a group. Some areas are totally independent, while others will have points of interconnection with other study areas. A listing of the planning study areas that exist in NE and UPNY to be used by Distribution Planning are presented in Appendix B.

2.2.1.4 Load Flows

Distribution planning studies will utilize the PSS/e load flow program for the study of the sub-transmission lines and networks. The distribution feeder load flow analyses will be done using the Cymedist feeder analysis software program.

2.2.1.5 Distribution Analysis Alternatives

When performing distribution system analyses, Distribution Planning shall consider both traditional capacity enhancements as well as alternatives for "Non-Wires" customer load management alternatives where appropriate. The factors below could impact capacity planning analysis

a. Distributed Generation
b. Controllable Load Curtailment
c. Energy Storage devices
d. Demand Side Management

e. Distribution Automation
f. Smart Grid solutions

2.2.2 Distribution Substation Transformer Planning Criteria

2.2.2.1 Normal transformer load planning criteria

A substation transformer will not be loaded above its Normal rating during non-contingency operating periods.

2.2.2.2 Contingency N-1 substation transformer planning criteria

For an N-1 contingency condition that would involve the loss of a power transformer or substation bus, the following planning criteria apply:

- The initial load increase at the remaining transformers within the area must not exceed either the summer or winter STE rating or 200% of nameplate.
- Load will need to be transferred or shed in a reasonable number of steps to reduce loading to the summer or winter LTE level within 15 minutes.
- Substations will be designed to allow the installation of a mobile transformer within a maximum of 24 hours for a failed transformer.
- Load on remaining transformers will be reduced to the summer or winter normal limit within 24 hours.
- Feeder ties within the area can be utilized to their emergency limits. Cascading of load between feeders and substations may be needed to reduce loading to normal limits within the time frames required.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 10MW.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.2.2.3 Automatic transfer of load

Many locations with two or more transformers at a substation utilize automatic bus transfers. In some stations, one bus tie breaker is used, while in other substations a breaker and half design is utilized and there may be several feeder bus tie breakers. Based on the loading limitations in Section 2.2.2.2, it may be necessary to block the automatic transfer on either the main bus tie or one of the feeder bus tie breakers to avoid exceeding the STE limit during an N-1 contingency. Cases where automatic restoration are disabled will be documented and communicated with Regional Control Centers as part of an annual summer preparedness review. Recommendations to add capacity to the area will be evaluated and prioritized based load at risk, reliability and cost with other Load Relief alternatives.

When available, the use of the Energy Management System (EMS) control shall be implemented as needed to block automatic transfer. During an N-1 contingency, the System Operator will be required to maintain the loading on transformers as specified in Section 2.2.2.2.

2.2.2.4 Substation reactive support criteria

Reactive compensation shall be required for substations in the form of station capacitor banks or static VAR compensators. These should be sized to offset the reactive losses of the transformers at full load. Two or three stage capacitor banks may be needed for larger transformers to manage power factor and to limit voltage fluctuations.

2.2.2.5 Impact of planned maintenance

Capacity in all areas should allow the off loading of any distribution substation transformer for planned maintenance during the off peak months without exceeding the normal ratings of the other area equipment. However, in areas of the system with limited feeder ties, it may be more economical to allow the installation of a mobile transformer for maintenance.

2.2.3 Distribution Sub-transmission Planning Criteria

2.2.3.1 Normal sub-transmission load planning criteria

A sub-transmission supply line will not be loaded above its normal rating during non-contingency operating periods.

2.2.3.2 Contingency N-1 sub-transmission planning criteria

For an N-1 contingency condition that would involve the loss of a sub-transmission supply line, the following planning criteria apply:

- The initial load increase at the remaining sub-transmission supply lines within the area must not exceed the summer or winter LTE rating.
- Load on the remaining sub-transmission line will need to be reduced to normal levels within 24 hours.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload a sub-transmission line.
- Every effort must be made to return the failed sub-transmission line to service within 12 hours.
- The limit of load at risk for the loss of any sub-transmission line will be 20MW.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 20MW combined, considering all substations served via the supply line.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a single line fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.2.3.3 Automatic line transfer systems

Auto transfer of load on the sub-transmission may be employed, but may not exceed the emergency (LTE) ratings of the remaining supply lines. When available, EMS control of sub-transmission lines will be utilized to block auto transfers and avoid overloading of lines as needed.

2.2.3.4 Sub-transmission reactive support criteria

Reactive compensation for sub-transmission lines shall be required in the form of station and distribution capacitor banks.

2.2.4 Distribution Feeder Planning Criteria

2.2.4.1 Normal feeder load planning criteria

A distribution feeder circuit will not be loaded above its normal rating during non-contingency operating periods.

2.2.4.2 Contingency N-1 feeder planning criteria

For an N-1 contingency condition that would involve the loss of a distribution feeder, the following planning criteria apply:

- Feeders shall tie to neighboring feeders as much as practical as the flexibility to reconfigure feeders has a positive reliability impact for a wide range of possible contingencies.
- Following a contingency, all adjoining tie feeders can be loaded to their maximum thermal emergency or LTE rating.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload adjoining feeders.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 16MWHrs of load is at risk at peak load periods for a single feeder fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.2.4.3 Automatic transfers on feeders

In some cases, it will be necessary to adjust a feeder rating to below normal summer or winter thermal rating due to automatic backup or Second Feeder Service commitments to certain customers.

2.2.4.4 Feeder reactive support criteria

Reactive compensation for feeders should be installed to provide additional capacity, improve voltage regulation and meet external power factor standards where applicable. A mixture of fixed and switched capacitor banks may be used as needed. All feeders in a planning area shall have proper reactive compensation prior to any requests for other load relief infrastructure improvements.

2.2.4.5 Feeder load balance criteria

Distribution Planning studies are based on three phase average loading. Load balance between the three phases on any feeder is assumed to be within a reasonable level.

Distribution feeder load balance shall require correction of the load imbalance for either of the following cases:

- Any feeder with the calculated neutral current exceeding 30% of the feeder ground relay pickup setting.

- Any feeder exceeding 100A between the high and low phase amps.

2.2.5 Network criteria

Secondary network criteria and loading limitations are defined in the National Grid distribution standards. The criteria are different for NE and UPNY based on the history of how various networks evolved.

2.2.6 Voltage criteria

2.2.6.1 Allowable Voltage Range at Service Point for Distribution Customers

The normal and emergency voltage to all customers shall be in line with limits specified by state regulators and within the limits of ANSI C84.1

These upper and lower voltage limits for each state in the service territory are listed in Table 3 below:

Table 3 - Voltage Requirements by State

State	Upper	Nominal	Lower
Massachusetts	126	120	114
New Hampshire	126	120	114
New York	123	120	114
Rhode Island	123	120	113

The values in Table 3 are in line with the National Grid Overhead Construction Standards.

Voltage on the sub-transmission and primary feeders is determined by many factors including:
- Primary mainline conductor sizes
- Distance of lines
- Reactive compensation

Voltage on the feeders is controlled by the station load tap changer or station regulators on feeders, the application of distribution capacitor banks, and the application of pole or padmounted line regulators. Voltage regulation of the feeders and supply lines must be adequate to ensure the voltage requirements in Table 3 above are maintained.

2.3 Residual risk and project prioritization

2.3.1 Residual risk after compliance with new criteria

The goal of the new planning criteria is to maintain the performance of the electric distribution system. Generally, after compliance with the new criteria, the residual risk for the worst case will be 10 MW of load out for 24 hours for a substation transformer failure or 20 MW out for 12 hours for an overhead supply line failure.

2.3.2 Methodology to prioritize capital projects

Prioritization of capital projects utilizes scoring system that considers the consequence of not completing the project and the probability that the consequences will be realized. A risk score between 1 and 49 is developed utilizing a 7x7 scoring matrix.

3.0 Risks/Benefits

The principal impacts of the planning criteria are reliability performance, customer service and efficiency. Due to the extended time frame for strategy compliance, the impact of the strategy will not be initially visible at the system level. These benefits will be most apparent in those areas where it has been implemented.

3.1 Safety & Environmental

Safety and environmental factors are not principal drivers of the planning strategy. However, the planning criteria will ensure equipment loading is maintained within accepted ratings reducing the risk of premature equipment failure that could result in environmental and public safety concerns.

3.2 Reliability

The planning criteria will provide operating flexibility to facilitate the restoration of customer outages following an N-1 contingency event. With an expected long implementation schedule, the impact will not be initially visible at the system level but will be significant in the areas where the criteria have been implemented. A long range reliability improvement of 11.4 minutes in SAIDI and 0.073 in SAIFI on a system basis is forecasted if the strategy is implemented over a 15 year planning horizon. Additionally, lower feeder loading will support future distribution automation to further improve reliability.

3.3 Customer/Regulatory/Reputation

The customer benefit associated with planning criteria is significant. Improved system reliability and lower equipment loading provide greater flexibility in serving both existing and new customers.

3.4 Efficiency

The planning strategy provides a consistent approach for feeder/substation and study area loading analysis across NE and UPNY. All studies being conducted under one criterion will create a consistent reference for ranking projects as part of the business planning process.

4.0 Estimated Costs

The estimated costs to adopt the new planning criteria are summarized as follows:

The capital cost associated with meeting the existing and proposed criteria for both normal and N-1 contingency conditions in New England and upstate New York are shown in Table 4:

Table 4 - Comparison of Capital Costs between Existing and New Criteria

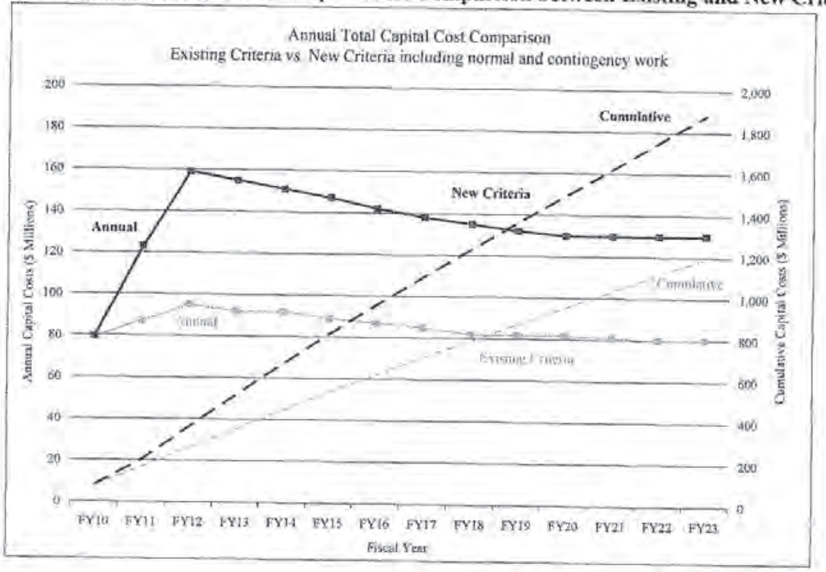
Criteria	Present Value ($ Millions)	15 Year Annualized ($ Millions)
Existing NE/NY Criteria	$800	$80
New Criteria	$1,250	$130

The new criteria may result in increased in capital costs of $50M/year in the Load Relief budget category compared to previous criteria for the 15-year period studied.

Based on an analysis of normal loading issues, it is projected that capital work associated with normal loading will remain at present levels or slightly higher for several years and then ramp down as contingency projects will tend to drive the load relief spending.

These combined normal and contingency capital costs are shown in Figure 1 below:

Figure 1 - Annual and Cumulative Capital Cost Comparison between Existing and New Criteria



5.0 Implementation

Based on the results of the sample areas (expanded to the overall system) the following approximate quantities of additional facilities are forecasted to be required over the next 15 years in NE and UPNY.

Transformers (at existing or new substations)	180
Sub-Transmission Lines	46
Distribution Feeders	319

The new criteria will be applied to new installations and/or significant rebuilds initially. This is a long term strategy and it is expected to take many years to implement system-wide.

6.0 Data Requirements

The data sources required for the proper execution of the planning strategy include:

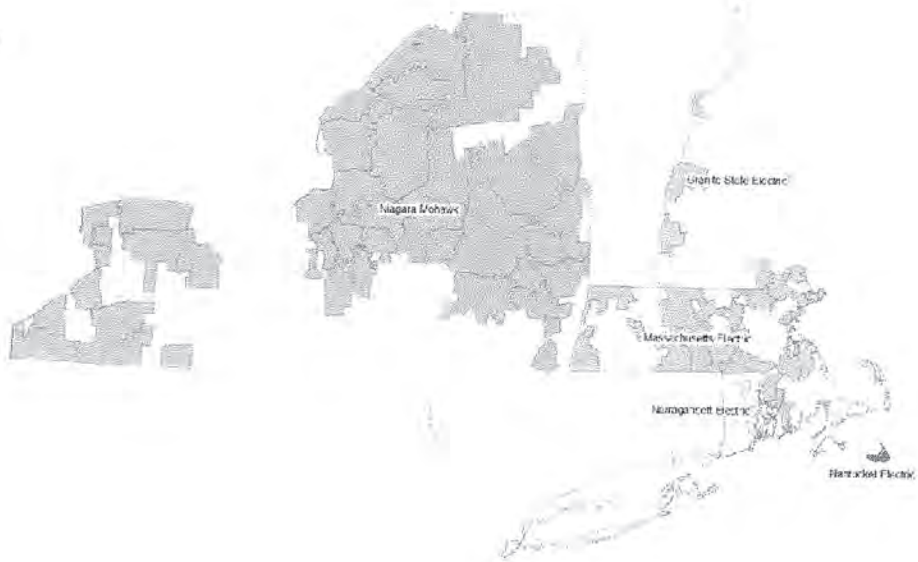
6.1 Planning Tools:

Cymedist (Cyme) – for radial feeder load flow and voltage analysis
Smallworld GIS – to support Cyme analysis
PSS/e – for network load flow analysis
FeedPro - for equipment loading and ratings
EMS and PI or ERS access in NE and UPNY

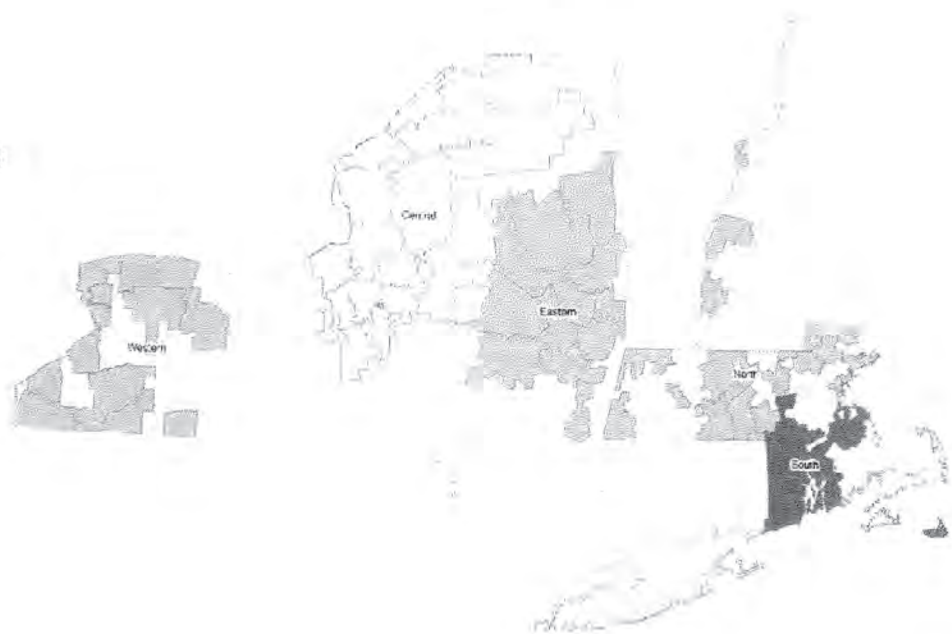
Appendix A – Service Territory Maps

Maps of Electric Distribution Service Territories for five companies and five divisions:

Companies

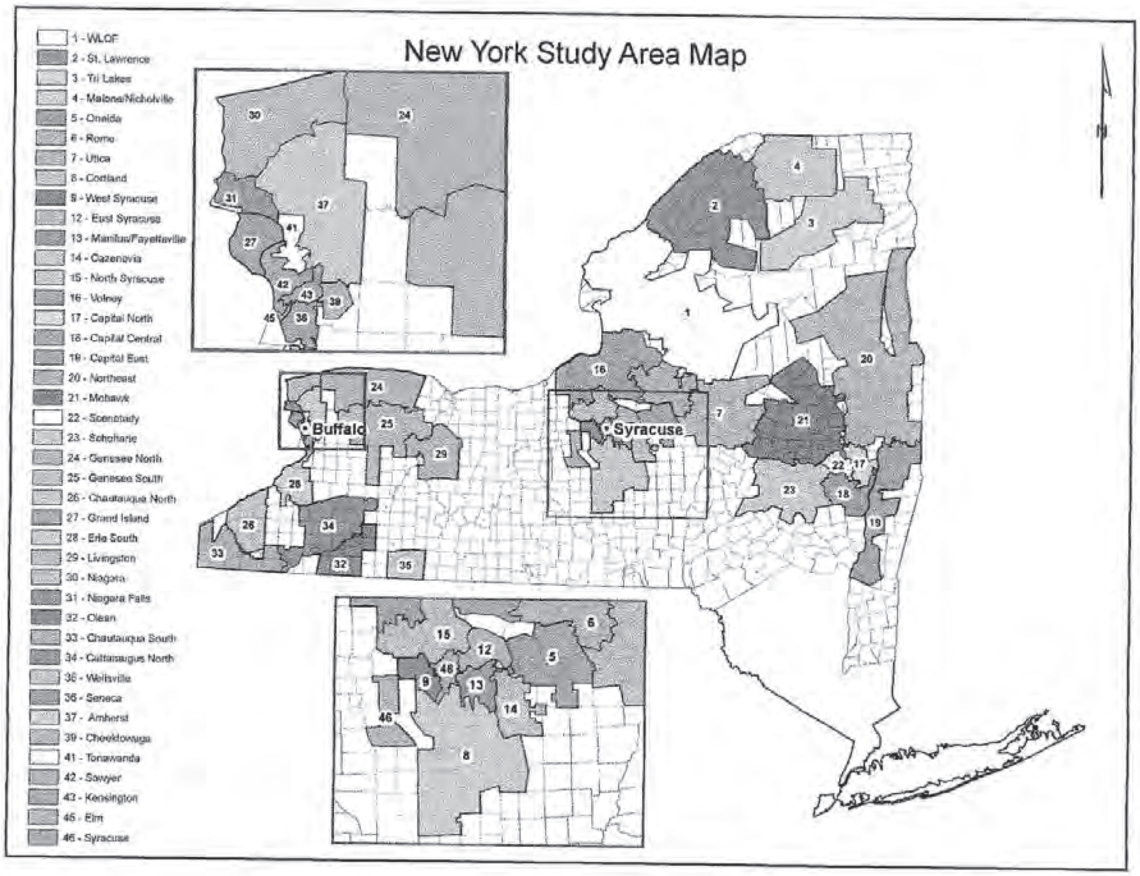


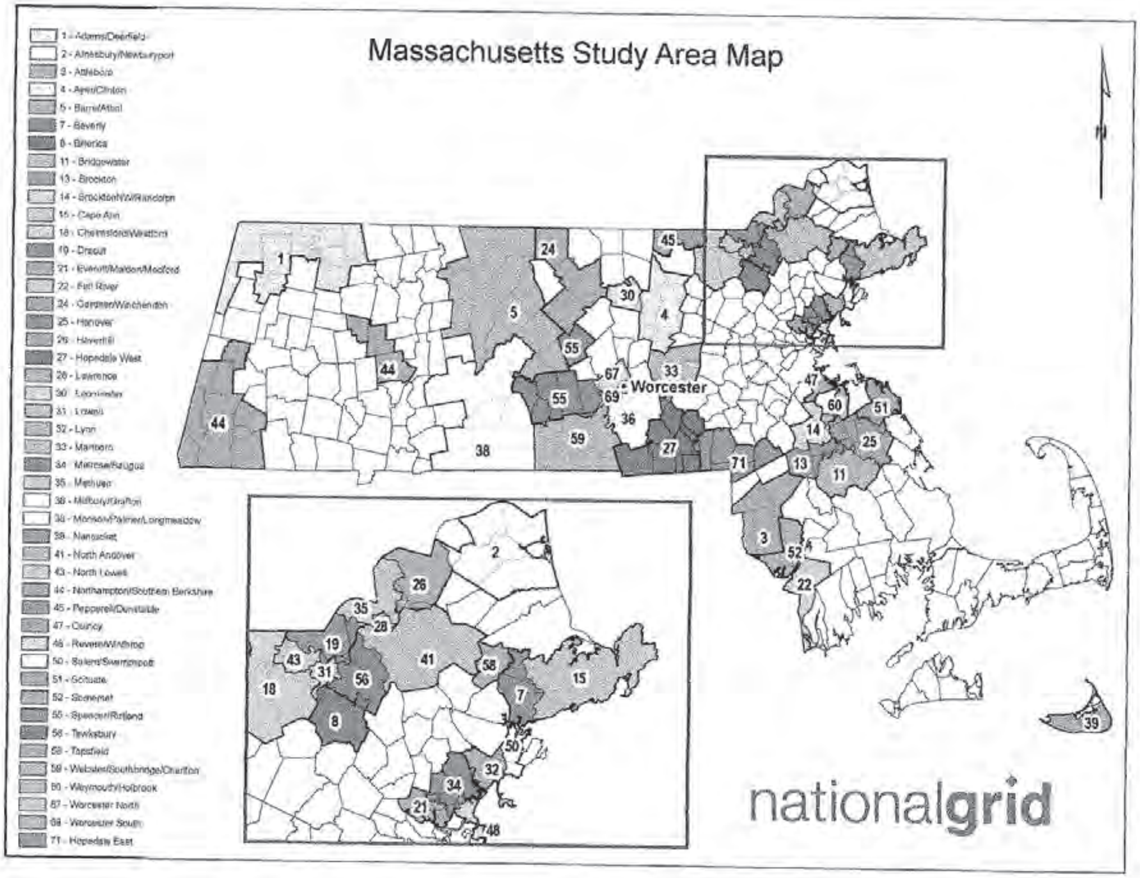
Divisions

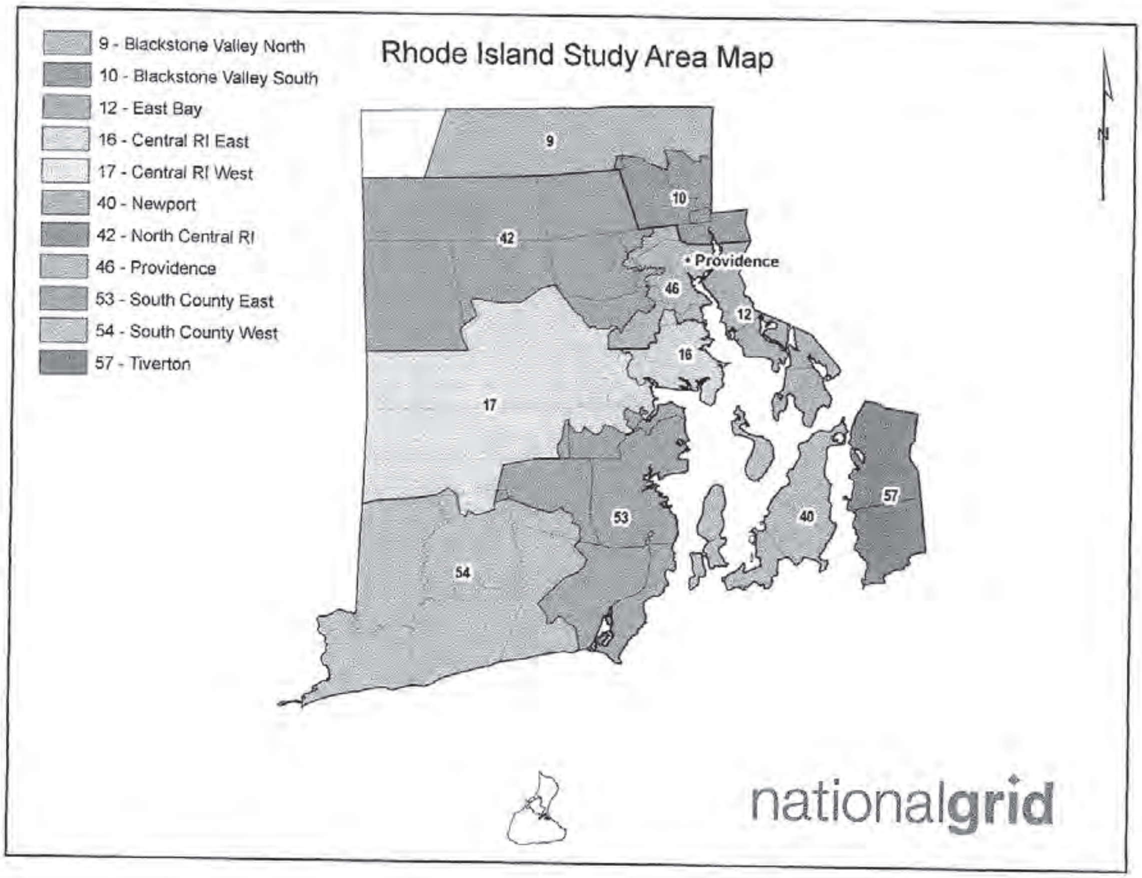


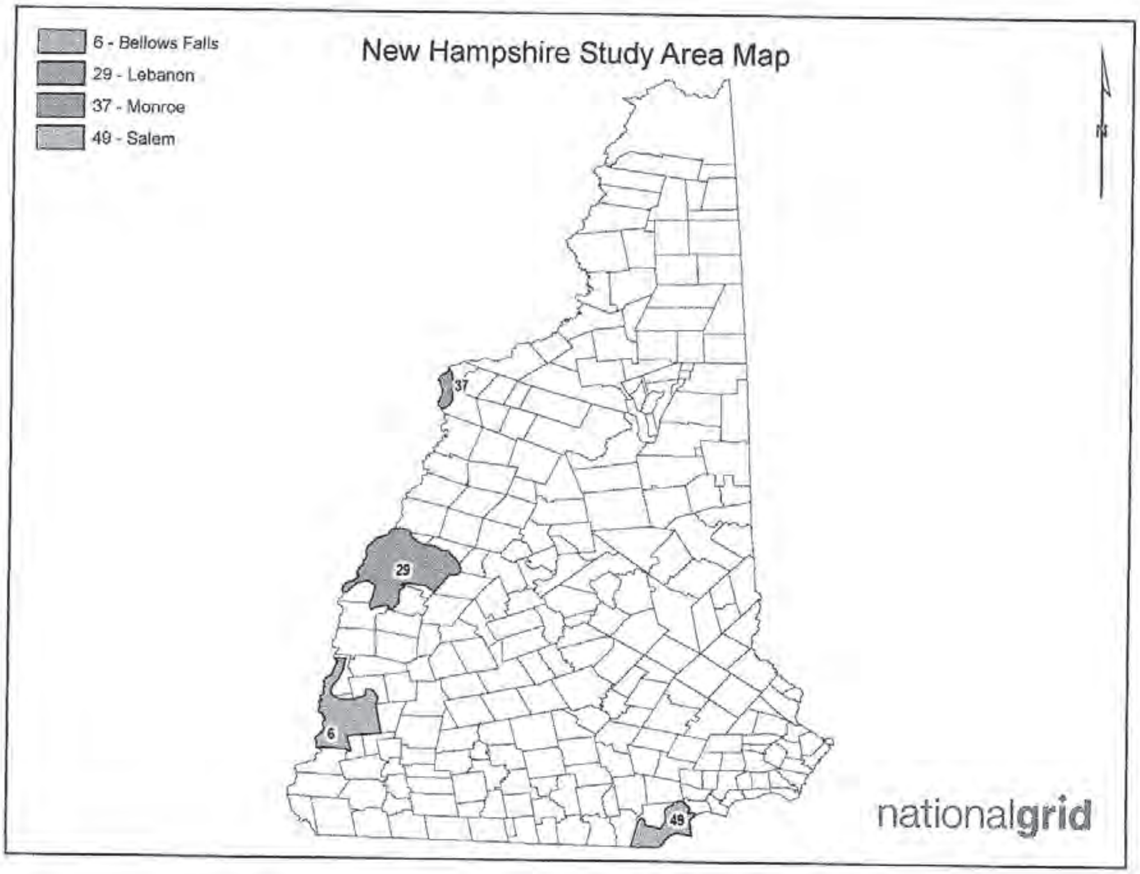
Appendix B - Distribution Planning Study Areas

To foster the annual capacity planning assessment, the distribution system across UNY and NE has been segmented into Planning Study Areas as shown in the following figures.




Massachusetts Study Area Map
2 - Amesbury/Newburyport
3 - Attleboro
4 - Ayer/Clinton
5 - Barre/Athol
7 - Beverly
11 - Bridgewater
13 - Brockton
15 - Cape Ann
19 - Dracut
21 - Everett/Malden/Medford
22 - Fall River
24 - Gardner/Winchendon
25 - Hanover
26 - Haverhill
27 - Hopedale West
28 - Lawrence
32 - Lynn
33 - Marlboro
34 - Melrose/Saugus
35 - Methuen
41 - North Andover
43 - North Lowell
44 - Northampton/Southern Berkshire
45 - Pepperell/Dunstable
47 - Quincy
50 - Salem/Swampscott
51 - Scituate
52 - Somerset
55 - Spencer/Rutland
56 - Tewksbury
58 - Topsfield
59 - Webster/Southbridge/Charlton
60 - Weymouth/Holbrook
67 - Worcester North
68 - Worcester South
71 - Hopedale East
Worcester
nationalgrid


Rhode Island Study Area Map
9 - Blackstone Valley North
10 - Blackstone Valley South
12 - East Bay
16 - Central RI East
17 - Central RI West
40 - Newport
42 - North Central RI
46 - Providence
53 - South County East
54 - South County West
57 - Tiverton
Providence
9
10
42
46
12
16
17
53
40
57
54
N
nationalgrid


New Hampshire Study Area Map
6 - Bellows Falls
29 - Lebanon
37 - Monroe
49 - Salem
37
29
6
49
N
nationalgrid

9.16 Distribution Planning Study Process

Distribution Planning Study Process

1. Introduction
In order to maintain a consistent approach to distribution planning, it is necessary that uniform planning criteria be followed and that there is well executed coordination among stakeholder departments/groups. This document has been prepared to provide guidance on the performance and expected work product of distribution area planning studies.

2. Purpose
This document details the Distribution Planning and Asset Management study process for system planners, the functions that support them, and the stakeholders reliant on their work product. It is expected that execution of a well defined study process will result in timely delivery of infrastructure development recommendations having thoroughly defined project scopes that satisfy the needs and expectations of all stakeholders (especially customers). In addition, it enhances the organization's ability to meet its obligation to provide safe, reliable, and efficient electric service for customers at reasonable costs.

3. Applicability
All personnel within Distribution Planning and Asset Management when assigned to work on:

- Area Studies
- Program Studies (initial or modification)
- Complex Customer Service Requirements Studies – Typically, large services requests, generally 8MW or greater and/or greater than 5MW with requirements for service redundancy

Members of departments that support the study process and associated work product development should be trained in and/or aware of this process.

4. Process
Distribution planning studies will typically be assigned to central planning engineers in the Distribution Planning and Asset Management group by their department manager. Assignment of a study to other engineers in the Distribution Planning and Asset Management group (ex: field engineers) is also possible.

The prioritization of area planning studies to be executed and the engineering analysis conducted within an area study is supported by the Annual Planning Screening Process. This process is a recurring annual effort which aides in the identification of thermal system performance concerns. As part of this effort, the following is recorded or estimated:
Area (feeder, substation, and supply line) summer* peak loads (date, time, and value) both coincident and non-coincident with the system peak load.
System summer peak load (date, time, and value).

*In areas that are winter peaking and winter limited, winter peak load data will be collected.

Distribution Planning Engineers are responsible for assembling, screening, and recording of facility peak loads. Peak load data will be stored in FeedPro and the annual planning screening spreadsheets. Load forecasts will be applied to facility peak loads and recorded in the annual planning spreadsheets.

As already noted, the Annual Planning Screening Process work product facilitates the prioritization of area studies to be conducted. Once a decision has been made to execute a specific area study, the assigned engineer will bring the effort through the following major milestones:

- Scoping Activities
- Initial System Assessment
- Study Kickoff
- Detailed System Assessment / Engineering Analysis
- Plan Development and Project Estimating
- Identification of Recommended Plan
- Technical Review
- Documentation
- Sanctioning

Further detail on each of these milestones follows:

4.1. Scoping

The study engineer starts by preparing to execute the study. All area distribution studies will require the same basic preparation steps. The engineer will:

- Gather the most recent version of the Distribution Planning Guidelines ("DPG")
  - o Upon consultation with the manager, gather any other emerging guidelines that have not been formally incorporated into the DPG (ex: grid modernization or volt-var optimization guidelines).
- Gather equipment rating data, settings data, specifications data, etc.
- Gather the most recent Distribution Standards including, but not limited to:
  - o Overhead conductor ratings (section 6.0)
  - o Generic underground cable ratings (section 35.14)
  - o Latest recloser controls (pages 12-338 to 12-340)
  - o Latest capacitor controls (pages 15-335 to 15-336, 15-404 to 15-405)
  - o Latest sensor controls (page 15-600)
  - o Storm Hardening (section 4.0)
- Define the electrical scope (lines and substations to be studied)
- Define the geographic scope (towns and portions or towns to be included in study)
- Building/correcting/updating system models in CYME, PSS/e, ASPEN
- Gather the latest forecast and review/refine the area/facility load and expected load growth from the present to the study's horizon year (typically 15 years)
- Gather service territory maps
- Gather large commercial and industrial customer load data[1]
- Gather or request asset condition reports[2]
- Identify all infrastructure development limitations (ex: river, highway, state forest, etc)
- Gather documentation of existing system performance concerns (ex: thermal, reliability, voltage, reactive support, arc flash, fault duty, etc.)[3]
- Gather recently completed area projects or ongoing area projects within the work plan. This will set the base year and base configuration.[4]

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[1] Consult with Customer and Community
[2] Consult with Substation O&M Services
[3] At a minimum, include annual plan screening information. Consult with area engineering and operations experts as time allows.

- Gather existing and in-queue distributed generation or distributed energy resources
- Gather state information or policies regarding distribution planning or distributed energy resources

The engineer will then develop a scope that details the study area boundaries and concerns. The study scope will be reviewed by their respective manager. The manager must approve the study scope before next steps are executed.

The final scoping activity is to request study team members. The study engineer will request formal team members from the following departments, via Study Engineering Request form.

- Transmission Planning
- Transmission Line Engineering
- Substation Engineering
- Protection Engineering (Relay, Communications, and Controls and Integration)

The following additional departments may be expected to provide input during various stages of the study and will be included in study meetings as required:

- Substation O&M Services Operations
- Transmission Control Center and/or Regional Control Center
- Project and Program Management
- Community and Customer Management
- Distribution Design
- Safety
- Environmental
- Legal
- Real Estate

All study contributors will be provided proper accounting to charge their time in support of the study. Once a study team is formed, the study engineer will schedule the study kickoff meeting.

4.2. Initial System Assessment

Study area initial system assessment consists of a quick analysis of facilities and system performance within the identified study geographic and electric scope. As part of the assessment, the study engineer will conduct the following:

- Existing and in-queue distributed generation and distributed energy resources
- A review for compliance with Planning Guidelines:
  - Thermal (load vs. capability) issues using the annual planning screening spreadsheet, CYME, and PSS/e
  - Voltage – using CYME, PSS/e
  - Reactive Support
- Asset condition assessments and consideration of active asset programs including, but not limited to:

---

[4] For example a study starting in year X may set a base year of X+3 if substantial system modification will be completed in year X+3.

- Breaker Replacement
- EMS
- Metal Clad Substations
- Indoor Substations
- Underground Cable
- Distribution Line Inspection & Maintenance

- Screening review of arc flash and fault duty data
- Screening review of CKAIDI and CKAIFI reliability indices[5] against state targets or average values

Initial system assessment is completed when the planner has enough information to consult with the wider group of subject matter experts and internal departments at the study kickoff. A careful balance of analysis to ensure study timeline efficiency is required. Too little analysis leaves the planner unable to lead a robust discussion during the kickoff meeting to gather those asset, operational, and construction complexities that help refine issues and generate comprehensive alternatives. Too much analysis may lead to rework by the planner should new information result from the kickoff. It is preferable that high level alternative concepts are developed during Initial System Assessment simply to generate discussion. Never should alternatives be fully developed or considered final within this step. Throughout the Initial System Assessment, it is expected that informal and regular consultations will be required with Transmission Planning, Distribution Design, Substation Engineering, Transmission Line Engineering, Substation O&M Services, and/or Operations.

4.3. Study Kickoff

The study kickoff is a meeting held to inform the larger stakeholder group that an area study is underway and to solicit inputs from those with knowledge of the system infrastructure in the area under review.

The study engineer will invite the following groups/representatives to the Kickoff meeting:

- Community & Customer Management
- Operations:
  - Distribution Line (OH & UG) Supervisors
  - Substation O&M Supervisors
  - Distribution Design
- Substation O & M Services
- System Control Center
- Project Management
- Program Management (Substation and Line)
- Distribution Engineering and Asset Management
  - Field Engineer
  - Field Engineering Manager
- Transmission Engineering and Asset Management
  - Transmission Planning Engineer
  - Transmission Asset Management Engineer
- Transmission Line Engineering
- Substation Engineering
- Protection Engineering
- Resource Planning
  - Short Term Resource Planning

[5] 5 year reliability data is preferred. 3 year data may be used to avoid years of significant major storm activity or significant system reconfiguration.

    - Long Term Resource Planning
- Product Energy Services (NWA)
- IT/ IS

The study engineer will present the following:
- Proposed study electrical and geographic scope
- Recent area studies and infrastructure development projects impacting the area
- Study area load and initial understanding of load growth expected in the area
- Known concerns in the area
- Using one-lines, possible infrastructure development plans for discussion
- Using area maps, possible distributed energy resource ideas fro discussion
- Study schedule and the names of representatives of departments assigned to support it

Upon completion of this presentation, the study engineer will open the meeting for group discussion. Specific input that the study engineer is looking for includes:

- Acceptance of electrical and geographic boundaries
- Operational concerns, examples:
    - Switching flexibility
    - Restoration areas of concern (ex: rights-of-way, direct buried cables)
- Asset condition concerns not already identified
- Safety by Design
- System performance concerns not already identified, examples:
    - Reliability
    - Voltage
    - Loading
- Details on any significant near term load additions in the area not already identified
- Details on any significant distributed energy resources in the area not already identified
- Details on potential alternative ideas or concerns, examples:
    - Locations that should/could be considered for new substation development
    - Substation expansion opportunities
    - Feeder routing (new feeders and feeder ties)
    - Local issues that might impact infrastructure development options, examples
        1. Local regulations requiring underground vs. overhead construction
        2. Status of community relationships with the Company
- Details on any distributed energy resource opportunities that should be considered

Representatives assigned from all groups are expected to support the study throughout the entire process and document any concerns their department may have along the way.

All individuals invited to the kick off meeting should be asked to forward the meeting notice to any other individuals they would like to have take part in the meeting.

It is expected that the study engineer will prepare minutes of this meeting. Minutes will be shared with all those invited to participate in the meeting.

4.4. Detailed System Assessment / Engineering Analysis

The study engineer will utilize input received at the study kickoff meeting in subsequent detailed analysis and comprehensive plan development. All area distribution studies will require the same basic analysis steps.

The study engineer should look to optimize existing system performance and identify any common infrastructure development needs of the area prior to engaging in the detailed analysis associated with finalizing the development of alternative plans. Simple no-cost or low-cost system adjustments such as switching or load balancing can be progressed immediately by the planner and do not need to be formally included in the study report. Instead the study base case should be adjusted to include these simple changes.

The study engineer should:

- Conduct system fault studies, associated protective device coordination, and breaker capability reviews
- Conduct incident energy calculations (arc flash)
- Conduct system thermal assessments
- Conduct system loss studies
- Conduct system reliability assessments
- Conduct system voltage performance evaluation
- Analyze Distributed Energy Resources (DER) impacts

Typical Analysis tools:

- PSS/e load flow software for analysis of:
  - Supply system (transmission and sub-transmission)
  - Network system
- CYME and other radial distribution feeder analysis software
- CYME, ASPEN, and other protective device coordination software including short circuit analysis
- ArcPro for Arc Flash analysis
- GIS systems
- Annual Planning Screening Spreadsheets
- Equipment ratings programs
- Cascade and other asset information systems

Note that the presentation of results and defense of recommendations is significantly enhanced by the functionality of these tools (particularly load flow and radial distribution feeder analysis software). These tools will strengthen response to questions posed during the review of recommendations. These tools enable quick evaluation of "what if" questions that could otherwise cause unacceptable delays in study delivery.

4.5. Plan Development and Project Estimating

Once the engineering analysis is performed, the study engineer develops and refines alternative infrastructure development and non-wires alternative plans and updates associated plan one-lines. The plans should be technically comparable to the furthest extent possible. Infrastructure and non-wires alternatives can be combined to create comparable plans.

The following team members/departments will provide a feasibility review of these one-lines:

- Field Engineer
- Substation Engineer
- Transmission Line Engineer
- Distribution Design Engineer
- Operations
- Transmission Planning

OPTIONAL - It is suggested the planner gather all internal stakeholders[6] at a Plan Development meeting to review and gain acceptance of the various plans immediately prior to requesting estimates. It is important that the various engineering functions understand the interrelationship between their individual portions of the comprehensive plans. Without this review, it is often difficult for the engineering functions to understand the segmented nature of estimate requests.[7]

As the one-lines and plans are modified with this cross functional input, engineering analysis will be refined as needed to accommodate for any scope changes. Once the plans and one-lines are completed, the study engineer will request study estimates from the respective team members (substation engineer, transmission line engineer, and distribution design engineer) for all alternative plans.[8]

It is expected that estimates will be returned within 8-12 weeks of the request date. Estimators will use primary equipment scope and known field conditions along with recent costs for comparable projects to develop estimates. Field visits are not required, but are encouraged especially if constructability or future system maintenance (ex. R/W accessibility) is a concern. Estimates are expected to be suitable for plan comparison/selection and enable initial partial sanction of more detailed engineering activities. Substation and transmission line conceptual engineering reports and estimates may be requested if they can be completed within the 8-12 weeks. Distribution line estimates can be completed by the planner using the Company's Success Enterprise estimating tool and can be considered at a conceptual level of accuracy.

Note: When considering alternate locations for a new substation. The site where a new substation will be constructed should be selected by the sponsor with input from the project team. Where alternate sites are required for regulatory reasons or are desirable for other reasons, those alternate sites should also be selected by the sponsor. In addition to the engineering requests, sites should be assessed for other flaws that could warrant them unsuitable for use. These "due diligence" assessments for potentially "fatal flaws" should be performed by the following departments and reported to the sponsor: Environmental, Real Estate, Legal (Siting), Project Management, and Construction or Operations.

While estimates are under development, the planner should organize and document the technical benefits and issue resolution of each alternative. The planner has discretion to the level of analysis for alternatives that are expected to be economically non-competitive.

Once the study estimates are returned, the study engineer will review and finalize the identified plans. Study team members will be asked to note their agreement with the scope of projects estimated.

[6] Similar to the kickoff meeting invite list
[7] For example a substation request that asks for a common item such as a capacitor bank to be estimated separately from a feeder position which may be an alternative plan.
[8] Requests should be well documented with clearly defined one-line scope diagrams, using

4.6. Identification of Recommended Plan

As part of this phase, the study engineer reviews the various alternatives with costs, identifies, and finalizes a recommended plan. Once the recommended plan is identified, the study engineer completes (with team member assistance as required):

- Economic comparison of plans
- Technical comparison of plans if not equivalent
- Performance of an environmental and safety review of recommended plan
- Identification of the system outages required to implement the recommended plan
- Statement or summary of alignment with Climate Resiliency standards[9]
- If not formally evaluated as a criteria, strategy, or program within the study, include a statement or summary of alignment with potential or pending Grid Modernization concepts.[10]
- Review of the recommended plan project implementation schedule[11]

The planner should summarize recommended plan risks to the furthest extent possible. For example, permitting or site acquisition delay risks could be noted with the system issues that may result. Potential mitigation concepts, including acceptance of risk, can be described. This is not intended to be an exhaustive review and it is noted that significant internal department consultation and support is necessary. Instead, this risk analysis is only intended to help or guide future efforts.

Once all this analysis is completed and documented, the study engineer updates the project team members on the final recommended plan.

4.7. Technical Review

This meeting will be held once the planner has completed the majority of the study analysis and after an internal review in Distribution Planning and Asset Management has been completed, but prior to the formal study document approval process.

The primary purpose of this meeting is to give those who will be asked to approve the area study report an opportunity to hear a presentation and ask their own questions on the overall study effort. It is expected that this meeting will facilitate the study report approval process that will in most instances follow soon after.

The presentation will provide a description of the issue identification efforts and a comparison of all plans, including estimated costs, describing the advantages and disadvantages of each.

The planner will cover the following topics in presentation format during the meeting. The presentation will be split (between Distribution Planning and Transmission Planning) if study responsibility is split.

- Study scope (electric system one-lines and map of area)
- Study area load and load growth
- Additional study assumptions
- System performance concerns identified (existing and predicted)
- Plans considered to address concerns with detailed description of the scope of proposed projects, time and cost required to implement, technical differences, as well as unresolved stakeholder concerns

[9] All recommendation should be built to the latest storm hardening and substation flood mitigation standards
[10] For example, use of latest controls that prevent near term obsolescence
[11] Consult with Long Term Resource Planning for implementation schedule and cash flow assistance.

- Plan recommended to address concerns with detailed description of the scope of proposed projects, time, and cost required to implement

Meeting participants are expected to constructively challenge study assumptions and analysis (ex. load growth assumptions, load flow models, equipment ratings, interpretation of planning criteria in determining violations, etc.) and the plans developed to address area concerns. If a specific project's scope of work is in question (ex. asset condition concerns not addressed) and can not be resolved in this meeting, the Study engineer will set up subsequent meetings with the project team for more detailed discussion and problem resolution.

The following groups/representatives are part of the Technical Review meeting governance:

- Asset Management (NY or NE), including:
  - Vice President Asset Management
  - Director Distribution Planning and Asset Management
  - Manager of Asset Management
  - Director of Transmission Planning and Asset Management
  - Manger of Transmission Planning
- Electrical Systems Engineering, including:
  - Vice President of Electrical Systems Engineering
  - Director of Substation Engineering Design
  - Director of Protection Engineering
  - Director of Transmission Line Engineering
- Operations (NY or NE), including:
  - Vice President of Operations
  - Director of Distribution Design
  - Director of Overhead Lines
  - Director and Manager of Substation O&M
- Dispatch and Control, including:
  - Vice President of Control Center Operations
- Jurisdictional Leadership, including:
  - Jurisdictional President
  - Community and Customer Management, Director
- Representatives assigned from all groups that are supporting the study (attendance required)

4.8. Documentation

The area study report is the primary documentation delivered upon completion of the area study. This report becomes a source document for many other forms and reports (used both internally and externally). As such, the importance of form and order in reports be as consistent as possible.

In order to properly complete the report template, the study engineer will need to have done the work necessary to prepare the following general report sections:

- <u>Executive summary</u>, including:
  - Explanation of why the study was done and the major concerns/needs for the area
  - A brief description of the alternatives considered
  - A brief description of the recommended plan
  - Reasons for the recommendation
  - Cost and cash flow of the recommended plan
- <u>Introduction</u>, including:
  - Purpose statement
  - Problem statement

- Background, including:
    - A statement on all items gathered in Section 4.1
    - Versions or dates of guidelines, standards, forecasts, databases, screening work, and software used
- Problem/Issue Identification, including:
    - A summary of all analysis done in Sections 4.2 and 4.4
- Plan Development, including:
    - A summary of all efforts done in Section 4.5
- Description of recommended plan, including:
    - A summary of the comparative analysis and conclusions made during Section 4.6
    - A clear summary of the sequencing of projects, project dependencies, proposed cash flow, and risks.
- Conclusion and factors affecting future studies
- Appendices, including but not limited to:
    - Geographic study area maps
    - One-line diagrams for stations, sub-transmission systems, and circuit tie maps - base case and recommended plan
    - Feeder rating sheets
    - Existing and in-queue Distributed Generation tables
    - Annual Plan screening tables – base case and recommended plan
    - CYME, PSSE, and Aspen screens and tabular exports - base case and recommended plan
    - Strategy or program tabular details including criticality rankings
    - Arc flash tables - base case and recommended plan
    - Reliability indices tables
    - Fault duty analysis tables - base case and recommended plan
    - Estimate data

Appendix A and B of this document provide a detailed outline of area study and program study report content respectively.

Study reports will be issued following the Study Results presentation (and resolution of any issues it raised). The report will be electronically issued with a cover letter to the following individuals for approval:

- Respective Manager of Distribution Asset Management
- Respective Director of Distribution Planning and Asset Management
- Vice President Asset Management

The study report will be electronically stored on Distribution Planning and Asset Management's SharePoint site.

It is expected that the Customer and Community Management group will communicate the recommended plan with external stakeholders as appropriate. Consultation with jurisdictional leader for approval of the external communication plans is required.

4.9. Sanctioning

Per the National Grid US Sanctioning Committee (USSC) Procedure, all investments must receive proper Delegation of Authority (DOA). The National Grid US Sanctioning Committee procedure and document templates can be found on the Investment Planning website.

It is expected that the study engineer will, upon study approval, seek initial sanction of any recommended projects having forecasted spending within the next three fiscal years. Long Term Resource Planning will track and schedule initial sanctioning activities for all projects that will be initiated beyond the first two full fiscal years from study completion.

5. Appendix A

Study Report Table of Contents

Appendix B

Program Report Table of Contents

1. Executive Summary
2. Introduction
- **2.1 Purpose**
- **2.2 Problem**
- **2.3 Scope**

3. Background
4. Program Description
- **4.1 Infrastructure Development**
- **4.2 Identification**
- **4.3 Prioritization**
  - **4.3.1 Resource Considerations**
  - **4.3.2 Objectives and Benefits**
  - **4.3.3 Costs**

5. Conclusions and Recommendations
6. Factors Requiring Program Review
7. Appendix

nationalgrid

This document has been redacted for Critical Energy Infrastructure Information (CEII). 10/9/2015

East Bay Area Study

Jack P. Vaz, PE

August 2015

Reviewed by: ______________________________ Date: ______________________
Ryan Constable, Distribution Planning & Asset Manager – New England, Network Strategy

Approved by: ______________________________ Date: ______________________
Alan LaBarre, Director, Distribution Planning and Asset Management, NE, Network Strategy

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Pages

LEGEND	
Al	Aluminum wire or cable
ARP	Asset Replacement Program
Cal/cm^2	Calories/square centimeter
capex	Capital expenditure (budget expenditure type)
Cu	Copper wire or cable
DPG	Distribution Planning Guide rev 1, dated February 2011
EMS	Energy Management System
GIS	Geographic Information System
ISO	Independent System Operator
kV	Kilovolts
LTC	Load Tap Changer
MVA	Megavolt Ampere
MVAR	Megavolt Ampere Reactive
MW	Megawatts
MWh	Megawatt hour
MOV	Metal-Oxide Varistor
NE	New England
opex	Operations/Maintenance expenditure (budget expenditure type)
PT	Potential Transformer
RAPR	Remote Access Pulse Recorder
RI	Rhode Island
PUC	Public Utility Commission
SN	Summer Normal Rating of Equipment
SE	Summer Emergency Rating of Equipment

1. Executive Summary

A comprehensive study of the East Bay area was performed to identify existing and potential future distribution system performance concerns. System evaluation included comparison of equipment loading to thermal (capacity) limits, contingency response capability (Distribution Planning Criteria), voltage performance (RI PUC requirements), breaker operating capability, arc flash review, reactive compensation performance, asset condition, and safety and environmental issues. The recommendations provide a comprehensive solution to address all the system performance concerns existing and anticipated in the study area thru 2030.

The most recent major infrastructure development investment in the study area occurred in the 1990's with the construction of Wampanoag substation in East Providence and the expansion of Bristol substation. These investments relieved a highly utilized distribution and sub-transmission system. New investments are required to provide additional relief to the supply and distribution systems in the area. Additionally, there are a number of asset condition, safety, and reliability concerns that need to be addressed.

Three plans were developed to address existing area problems and to provide for future needs within the study area thru the year 2030. Each plan provides a comprehensive solution to address all concerns in the study area. The concerns include thermal loading near or above rated capability of equipment, contingency response capability that does not meet distribution planning guidelines, asset condition concerns, safety concerns, and reliability concerns.

Plan 1 includes building two new substations supplied from the 115kV transmission system. System rearrangement proposed within this plan reduces loading and dependence on the 23kV sub-transmission system. The following are the major modifications proposed:

- Replace the out of phase 23/12.47kV substation at Phillipsdale with a new 115/12.47kV station. Initial construction would consist of a single 40MVA LTC transformer, straight-bus metal-clad switchgear, four feeder positions, and a 7.2MVAR two-stage capacitor bank. The ultimate build-out would be two 40MVA LTC transformers supplying straight-bus metal-clad switchgear with a tie breaker, eight feeder positions, and two 7.2MVAR two-stage capacitor banks.
- Build a new 115/12.47kV substation in the city of East Providence on a gas company owned land parcel adjacent to the 115kV transmission right-of-way. Initial construction would consist of a single 40MVA LTC transformer, straight-bus metal-clad switchgear, four feeder positions, and a 7.2MVAR two-stage capacitor bank. The ultimate build-out would be two 40MVA LTC transformers supplying straight-bus metal-clad switchgear with a tie breaker, eight feeder positions, and two 7.2MVAR two-stage capacitor banks.
- Expand the existing 115/12.47kV substation at Warren by installing two new 12.47kV distribution feeder positions and a two-stage 7.2MVAR capacitor bank on each bus.

The Plan 1 total cost estimate (over all years) is $37.70M ($31.68M capex, $2.14M opex, $3.88M removal).

Plan 2 includes adding new distribution capacity supplied from an upgraded 23kV sub-transmission system and has limited investment in expansion of the 115kV transmission system. The following are the major modifications proposed:

- Replace the existing 23/4.16kV substation at Kent Corners with two 23/12.47kV modular feeders supplied from an upgraded 23kV system. The sub-transmission upgrades require approximately 7.50 miles of line reconductoring along a public roadway system.
- Build two new 23/12.47kV modular feeders on a Company owned site in East Providence. This was the location of Rumford substation which was retired and removed in the 1990's.
- Replace the existing out of phase 23/12.47kV substation at Phillipsdale with two new 23/12.47kV modular feeders. The new feeders would phase with the rest of the distribution system in the area.
- Build a new 115/23kV substation at Mink Street to supply the reinforced, upgraded, and expanded 23kV system. Construction would consist of a single 40MVA transformer supplying a single 23kV line.
- Address asset condition concerns at Phillipsdale and Warren 115/23kV substations. These two stations, along with Mink Street, will supply the 23kV system.

The Plan 2 total cost estimate (over all years) is $50.00M ($42.29M capex, $3.19M opex, $4.52M removal).

Plan 3 is a hybrid of Plan 1 and Plan 2. It includes expanding the 115kV transmission system along with expanding and reinforcing the 23kV sub-transmission system. The following are the major modifications proposed:

- Replace the existing out of phase 23/12.47kV substation at Phillipsdale with a new 115/12.47kV station. Initial construction would consist of a single 40MVA LTC transformer, straight-bus metal-clad switchgear, four feeder positions, and a 7.2MVAR two-stage capacitor bank. The ultimate build-out would be two 40MVA LTC transformers supplying straight-bus metal-clad switchgear with a tie breaker, eight feeder positions, and two 7.2MVAR two-stage capacitor banks.
- Build a new 115/23kV substation at Mink Street to supply the reinforced, upgraded, and expanded 23kV system. Construction would consist of a single 40MVA transformer supplying a single 23kV line.
- Replace the existing 23/4.16kV substation at Kent Corners with two 23/12.47kV modular feeders supplied from an upgraded 23kV supply system. The sub-transmission upgrades require approximately 7.50 miles of line reconductoring along a public roadway system.
- Address asset condition concerns at Warren 115/23kV substation. This station, along with Mink Street, will supply the 23kV system.

The Plan 3 total cost estimate (over all years) is $41.20M ($34.29M capex, $2.45M opex, $4.46M removal).

Plan 1 is recommended for implementation. It provides a comprehensive solution to address all the concerns in the study area at least cost. The total cost of Plan 1 is $37.70M which is $13.00M lower in cost than Plan 2 and $3.50M lower in cost than Plan 3.

Plan 1 is least sensitive to load growth and offers the most flexibility for future expansion. Plan 1 eliminates most of 23kV sub-transmission system installed along public roadways which has significant exposure to motor vehicle accidents and tree related outages. Plan 2 and Plan 3 offer no economic or reliability benefits over Plan 1 and are more sensitive to higher than forecasted load growth.

2. Introduction

2.1 Purpose

A comprehensive study of the East Bay area was performed to identify existing and potential future distribution system performance concerns. System evaluation included comparison of equipment loading to thermal (capacity) limits, contingency response capability (Distribution Planning Criteria), voltage performance (RI PUC requirements), breaker operating capability, arc flash review, reactive compensation performance, asset condition, and safety and environmental issues. The recommendations provide a comprehensive solution to address all the system performance concerns existing and anticipated in the study area thru 2030.

2.2 Problem

A study's initial system assessment is typically based on the needs identified through the Annual Planning process. The latest Annual Planning review showed a variety of normal and contingency capacity issues in the East Bay Area. Furthermore, informal asset condition reviews and inspection results indicated there may be growing asset condition concerns.

3. Background

3.1 Scope

3.1.1 Geographic Scope

The East Bay study area consists of the city of East Providence and the towns of Barrington, Bristol, and Warren. The study area is bounded to the east by the Commonwealth of Massachusetts, to the north by the City of Pawtucket, and to the west and south by the Providence River. The study area is shown geographically in Appendix 9.1.

3.1.2 Electrical Scope

Three 115kV transmission lines supply the load in the study area. Two lines, E-183E and F-184, originate at Brayton Point substation and one line, X-3, originates at Somerset substation. The study area has an extensive sub-transmission system consisting of five 23kV lines (2242, 2243, 2267, 2291, and 2295). One line diagrams are shown in Appendix 9.2.

Three 115/12.47kV substations (Bristol, Wampanoag, and Warren) supply approximately 115MW of area load. The remainder of the load, or approximately 63MW, is supplied from the 23kV sub-transmission system originating at Warren, Phillipsdale, and Mink Street substations. There is a small pocket of 4.16kV load, approximately 7.3MW, supplied from Kent Corners substation. Nine industrial customers are supplied directly from the 23kV sub-transmission system.

Mink Street, located in Massachusetts, has a 115/23/13.2kV 3-winding transformer that supplies both a 23kV line and a 13.2kV station. The 23kV line only supplies customers in Rhode Island. Mink Street is the only station located outside the study area that supplies East Bay customers.

3.2 Area Load and Load Forecast

The study area has approximately 43,000 customers with a peak electrical demand of 178MW. The study area is summer peaking and summer limited. This study used the most recent forecast developed by National Grid, the "2014 New England Electric Peak Forecast". It utilized the 95/5 extreme weather scenario case. Table 1 shows the forecasted load growth rate for the study area from 2015 to 2030.

TABLE 3.2 – Forecasted Load Growth Rate from 2015 to 2030 for Study Area

Forecasted Growth – East Bay					AVG	AVG
2015	2016	2017	2018	2019	'20 to '23	'24 to '30
2.3%	1.4%	1.0%	0.6%	0.7%	0.7%	0.8%

3.3 Active Projects

Two active transmission studies were reviewed to determine potential impacts on the East Bay study area infrastructure and the plans being considered in this study.

The Southeastern Massachusetts and Rhode Island (SEMA/RI) study is expected to address transmission supply constraints in the southeastern Massachusetts and Rhode Island areas which includes the East Bay area. The results from this transmission study are not expected to impact any of the improvements being proposed in the East Bay Area Study.

The state of Rhode Island has requested the company investigate the feasibility of undergrounding the E-183W transmission line from the Phillipsdale substation tap in East Providence to Franklin Square substation in Providence. One option identified is the installation of a transition structure for this 115kV line on the site being considered for a proposed East Providence substation. A preliminary review has not identified any major concerns with the site's ability to accommodate both projects.

3.4 Limitations on Infrastructure Development

The study area is an electrical island. It is bounded to the east by the Commonwealth of Massachusetts with a 13.2kV distribution system, to the north by the City of Pawtucket with a 13.8kV distribution system, and to the west and south by the Providence River. The study area is shown geographically in Appendix 9.1.

3.5 Assumptions & Guidelines

The current Distribution Planning Guide rev 1, February 2011 ("DPG") was used when performing this study. The guide describes the normal and contingency analysis, as well as considerations for safety, the environment, reliability, reactive compensation, load balance, voltage, and efficiency, used in National Grid's distribution planning studies.

The Distribution Planning & Asset Management department uses the Siemens PTI PSS/e loadflow program to analyze the transmission and sub-transmission system. This is the same program that is used by ISO NE and the National Grid Transmission Planning department.

The CYMdist 5.04 Revision 5.0 program was used to analyze radial three-phase unbalanced systems (distribution feeders). Databases are extracted from the GE-SmallWorld GIS System into a Microsoft Access format.

The ASPEN program was used to determine short circuit duty values at all substations.

4. Problem Identification

4.1 Thermal Loading

4.1.1 Normal Configuration - Thermal Loading

The distribution system in the East Bay area is heavily loaded with limited capacity to supply new load. Table 4.1.1 shows the projected feeder loading on the distribution system for the main limiting element of each circuit. Excluding the out of phase feeders and the small pocket of 4.16kV load, by 2020 approximately 50% of the feeders are projected to be loaded above 90% of SN rating. By 2026, 70% of the feeders are projected to be loaded above 90% of SN rating.

TABLE 4.1.1 - Projected Summer Normal Feeder Loading

Substation	Fdr	2020		2026		2028		2030	
		Amps	%SN	Amps	%SN	Amps	%SN	Amps	%SN
BARRINGTON	4F1	330	64%	344	67%	350	68%	355	69%
BARRINGTON	4F2	468	92%	488	96%	496	97%	504	99%
BRISTOL	51F1	519	81%	543	84%	552	86%	561	87%
BRISTOL	51F2	481	91%	503	95%	511	96%	520	98%
BRISTOL	51F3	431	86%	451	90%	458	91%	466	93%
WAMPANOAG	48F1	488	97%	512	102%	520	104%	528	105%
WAMPANOAG	48F2	445	86%	466	91%	474	92%	482	94%
WAMPANOAG	48F3	559	110%	585	115%	595	117%	604	119%
WAMPANOAG	48F4	542	102%	568	107%	577	109%	586	111%
WAMPANOAG	48F5	461	95%	483	100%	491	101%	498	103%
WAMPANOAG	48F6	420	79%	440	83%	447	84%	455	86%
WARREN	5F1	379	89%	392	92%	398	94%	404	95%
WARREN	5F2	396	91%	411	95%	416	96%	422	97%
WARREN	5F3	393	76%	407	79%	413	80%	419	81%
WARREN	5F4	466	91%	483	95%	490	96%	496	97%
OUT OF PHASE FEEDERS									
PHILLIPSDALE	20F1	336	79%	352	83%	358	84%	363	85%
PHILLIPSDALE	20F2	398	94%	417	98%	424	100%	430	101%
WATERMAN AVE	78F3	263	64%	276	68%	281	69%	285	70%
WATERMAN AVE	78F4	248	61%	260	64%	264	65%	268	66%
4.16kV POCKET OF LOAD									
KENT CORNERS	47J2	336	82%	352	86%	358	88%	364	89%
KENT CORNERS	47J3	349	86%	366	90%	372	91%	378	93%
KENT CORNERS	47J4	382	94%	400	98%	406	100%	413	101%

Loading of distribution line sections of each feeder were analyzed using the CYME software. Minimal overloaded sections were identified as shown in Appendix 9.4.

There are no projected transformer or supply line normal configuration overloads within the study period.

4.1.2 Contingency Configuration - Thermal Loading

A contingency analysis was performed for all feeders in the study area. This analysis calculates a MWh 'exposure' or risk assuming a worst case component failure. The assumptions made for this analysis include:

- A one-hour response time before performing the first switching step to allow sufficient time for a crew to respond to the outage.
- Assumes 30-minutes to execute each additional switching step. This appears reasonable since the feeders in this area are relatively short.
- Assumes a failed component can be repaired within four hours. Some feeders have underground cable getaways which may require a longer repair time. Due to the fact that exposure is relatively small, a cable failure was not assumed in the calculations.
- Some feeders are double circuited on the same pole plant, primarily near the substation. Due to the fact that exposure is relatively small, a failure involving two feeders was not assumed in the calculations.
- The MWh calculations utilize the summer emergency ratings of the feeders.

Table 4.1.2 below shows the MWh exposure for each study area feeder and any remaining un-served load. Because the feeders are heavily loaded, nearly all exceed the MWh exposure recommended in the DPG. The DPG recommends mitigating any exposure in excess of 16MWh.

TABLE 4.1.2 - Calculated MWh exposure and Un-Served Load on Feeders

Substation	Feeder	MWh Exposure	Un-Served MW
BARRINGTON 4	4F1	18.2	3.45
BARRINGTON 4	4F2	22.7	2.91
BRISTOL 51A	51F1	24.7	2.36
BRISTOL 51A	51F2	25.2	4.06
BRISTOL 51A	51F3	21.1	2.52
WAMPANOAG 48	48F1	25.6	4.25
WAMPANOAG 48	48F2	23.5	4.52
WAMPANOAG 48	48F3	29.3	3.80
WAMPANOAG 48	48F4	42.0	10.31
WAMPANOAG 48	48F5	21.6	2.89
WAMPANOAG 48	48F6	26.2	5.15
WARREN 5	5F1	19.4	3.47
WARREN 5	5F2	24.5	5.00
WARREN 5	5F3	22.6	4.18
WARREN 5	5F4	21.0	0.99
WATERMAN AVENUE 78	78F3*	5.4	0.00
WATERMAN AVENUE 78	78F4*	5.3	0.00
PHILLIPSDALE 20	20F1*	23.9	5.67
PHILLIPSDALE 20	20F2*	13.6	1.08

* NOTE: These feeders are not in-phase with the remainder feeders. Any switching involving these feeders will require customers to be exposed to a short duration outage.

There are no MWh exposure issues above guidelines1 for the station transformers and subtransmission system. However, one contingency load-at-risk issue involving the supply from the Mink Street substation should be noted. Mink Street is a low-profile station with two transformers. This station is located in Seekonk, MA, but includes a three-winding power transformer with a 23kV tertiary winding supplying East Bay area load. Peak loading on the 23kV winding is limited to 12MVA because capacity is needed to supply the Massachusetts 13.2kV load. This limit results in approximately 14MW of un-served load for loss of the preferred supply to Barrington substation and limits the ability to add load to the 23kV system. A one line on Mink Street is shown in Appendix 9.2.

4.2 Voltage Performance

The PSS/e load flow program was utilized to model the electrical system to the 23kV sub-transmission level including step-down transformers to the distribution feeder level. The DPG recommends that customer service voltages be maintained to meet ANSI 84.1 guidelines. ANSI 84.1 requires that service voltages be maintained between 0.95 and 1.05 per unit during normal loading conditions and between 0.90 and 1.10 per unit during contingency conditions. Because of the ability to adjust transformer tap settings and with existing voltage regulation equipment, the supply system can vary greater than the required service voltage range. However for study purposes, the supply system is screened for potential issues using the ANSI 84.1 ranges. No

[1] The Distribution Planning Guide, dated Feb 2011, recommends mitigation of station transformer and subtransmission contingency issues when the load-at-risk exceeds 240 MWh.

voltage issues were identified during this screening effort. See Appendix 9.3 for loadflow diagrams.

The CYME program models all three phases of each distribution feeder for its entire length starting at the substation. Voltages at all points should be maintained between the range of 0.95 to 1.05 per unit, or from 114 volts to 126 volts on a 120 volt base. Minor violations were identified but these violations can be corrected through minor feeder balancing. See Appendix 9.4 for CYME diagrams.

4.3 Asset Condition

Asset condition reviews were conducted at each substation within the study area.

Mink Street is a low-profile station with two transformers. This station is located in Seekonk, MA, but includes a three-winding power transformer with a 23kV tertiary winding supplying East Bay area load. The asset condition review (for this study's purposes) is limited to this three-winding transformer and there are no immediate issues.

Barrington is a 23/12.47kV substation with a single transformer supplying two feeders with approximately 17MW of peak load. Appendix 9.2 shows a one-line of the station. A number of concerns exist at this station:

- The sacrificial air break (1T23) on the 25MVA power transformer does not provide adequate protection and results in an elevated risk of transformer failure.
- The station bus does not comply with current minimum clearance requirements. Jersey barriers are currently used to prevent accidental contact as a temporary measure.
- The 4F2 recloser is no longer reliable. This recloser has been identified for replacement in the ARP.
- This station has no remote status, control and monitoring of all switching devices, transformers, voltage regulation and battery systems (no EMS).

Kent Corners is a 23/4.16kV substation supplying 7.3MW of peak load. Appendix 9.2 shows a one-line of the station. This station is the only 4.16kV station left in the area. It is a 1950's vintage station with mostly original equipment. A number of concerns exist at this station:

- The circuit breakers are no longer reliable.
- The 23kV air-break motor operators and live parts are obsolete and require custom made parts to continue to maintain these air-breaks.
- The station power transformers are 1950's vintage. Parts for transformer bushings are no longer manufacturer supported.
- There have been neighborhood complaints about transformer noise. Station is located in a heavily congested residential neighborhood.
- This station has no remote status, control and monitoring of all switching devices, transformers, voltage regulation and battery systems (no EMS).

The Phillipsdale 115/23kV substation supplies two 23/12.47kV stations and a number of industrial customers with a combined peak load of approximately 30MW. Appendix 9.2 shows a one-line of the station. A number of concerns exist at this station:

- The power transformers are 1960's vintage. T1 transformer is the only transformer in the system with attached coolers. T2 transformer shows significant signs of aging and has been identified for replacement in the ARP. Replacement of the T2 transformer has been deferred pending completion of this study.
- Transformer grounding reactors are concrete encased with small visible cracks. There is no spare grounding reactor to respond to a failure.
- Transformer 23kV disconnect switches are non-gang operated and are not readily accessible to operate.
- The 23kV breakers are no longer reliable.
- The transformer and bus arrestors are obsolete.
- A timed scheme at the station prevents bus ties from occurring unless disabled. This scheme is complex to operate.

The Phillipsdale 23/12.47kV substation consists of non-standard equipment and construction. Appendix 9.2 shows a one-line of the station. A number of concerns exist at this station:

- A single LTC transformer supplies two 12.47kV feeders with pole mounted line reclosers. The reclosers have a history of poor reliability.
- The distribution voltage from this station only phases with Waterman Avenue feeders. This results in a pocket of load being out of phase with the rest of the system and makes maintenance of the station equipment challenging.
- The LTC transformer is a delta/zig-zag with no system spare and only a single mobile transformer in the system suitable for this location. A transformer failure would tie up this mobile for an extended period.

The Warren 115/23kV station consists of two 30/40/50 MVA transformers supplying two 23kV lines with approximately 34MW of peak load. Appendix 9.2 shows a one-line of the station. A number of concerns exist at this station:

- The 23kV breakers have reliability concerns.
- The pin type insulators on the 23kV bus are obsolete.
- The 23kV protection is located in an old control house with electro-mechanical relays. Most of this protection is obsolete.
- There are obsolete GE Butyl Rubber PT's
- The RAPR system is obsolete.

The Waterman 23/12.47kV station is located just north of Wampanoag substation. It consists of two 10/12.5 MVA transformers supplying four feeders. Appendix 9.2 shows a one-line of the station. Only two Waterman feeders supply customer load because the other two feeders are landlocked by Wampanoag substation to the south. In addition, these two feeders only phase with Phillipsdale feeders which creates a pocket of out-of phase load in the area. A number of concerns exist at this station:

- The 23kV air-break switch is obsolete.
- The transformers have sacrificial high side air breaks switches which are obsolete.
- The 23kV capacitor bank has an obsolete VBM switch.
- The 23kV equipment is mounted on wood poles.

Most of the 23kV sub-transmission system consists of aged pole plant and small wire installed on congested public roadways. A one-line of the 23kV supply system is shown in Appendix 9.2. Only a small portion of this system has been rebuilt in the last 20-years. The remainder of the system consists of a mixture of 795 Al, 336.4Al, 2/0Cu, and 1/0Cu wire with 12.47kV under-build. A major investment to replace both the pole plant and wire size would be required to increase the capacity of this system.

4.4 Additional Analysis

4.4.1 Reliability Performance

A reliability review was conducted to check feeder indices against system targets. For calendar year 2014, the SAIFI target was 1.05 and SAIDI target was 71.9 minutes. No three year trends were identified requiring further reliability analysis. See Table 4.4.1 below.

TABLE 4.4.1 – Study Area Reliability Indices

	2014		2013		2012	
FEEDER	CKAIFI	CKAIDI	CKAIFI	CKAIDI	CKAIFI	CKAIDI
53-20F1	1.019	101.75	3.122	112.71	0.045	0.27
53-20F2	1.063	139.31	1.243	82.38	0.159	18.04
53-47J2	0.003	0.29	0.291	5.88	0.025	6.82
53-47J3	0.106	4.64	0.000	0.00	0.051	6.73
53-47J4	0.011	0.72	0.098	7.23	0.103	15.25
53-48F1	0.157	6.75	0.039	4.06	0.891	54.20
53-48F2	1.055	100.74	0.136	33.91	2.436	123.97
53-48F3	0.056	5.28	0.139	15.59	1.661	160.22
53-48F4	0.040	5.47	0.109	9.97	0.077	20.58
53-48F5	0.064	7.10	0.143	23.63	0.073	6.94
53-48F6	0.071	7.35	0.059	4.20	0.504	30.07
53-4F1	0.215	28.54	1.151	90.14	1.016	96.34
53-4F2	0.333	26.31	1.861	106.53	1.339	131.67
53-51F1	0.623	103.16	0.189	24.17	0.143	11.33
53-51F2	0.239	18.33	0.086	5.70	0.160	6.38
53-51F3	0.227	17.55	1.088	97.15	0.428	19.07
53-5F1	2.040	130.98	1.468	98.81	0.259	28.43
53-5F2	0.209	16.38	0.245	79.90	2.716	196.41
53-5F3	0.110	5.02	0.342	82.02	1.767	232.77
53-5F4	0.225	49.33	1.178	79.47	1.197	285.36
53-78F3	0.073	14.81	0.850	50.80	0.083	8.11
53-78F4	1.254	81.31	0.045	2.70	0.040	3.27

4.4.2 Arc Flash

On April 1, 2014, the United States Department of Labor's Occupational Safety and Health Administration ("OSHA") issued final rule 1910.269 requiring the employer to assess the workplace to identify employees exposed to hazards from flames or electric arcs. 1910.269 proposed compliance dates of January 1, 2015 and April 1, 2015 for completion of the hazard assessment and implementation of the assessment results respectively. As the industry adjusted to these new requirements and calculation methods, the dates were adjusted to March 31, 2015 and August 31, 2015.

As described above arc flash regulations were issued and analysis methods were reviewed and adjusted during the course of this study. A review using CYME fault current analysis and protection coordination values with ArcPro incident energy calculations provided an analysis in compliance with OSHA requirements. Appendix 9.5 shows the results of this analysis with no study area feeders indicating incident energies above 8 calories per centimeter squared (cal/cm2).

4.4.3 Fault Duty/Short Circuit Availability

The ASPEN program was used to calculate single phase to ground and three phase short circuit duty values at each area substation. These values were compared to the station breaker interrupting capabilities. The table in Appendix 9.6 summarizes the results of this analysis. No breakers in the study area where identified to have a short circuit duty exceeding their interrupting capability.

4.4.4 Reactive Compensation

ISO-NE conducts an annual survey of actual load power factor operations and compares it against the applicable standards. The latest survey has this overall area compliant at all times. The results of this survey are shown on Table 4.4.4 below:

TABLE 4.4.4: ISO-NE Power Factor Survey Results

	CURRENT LPF SURVEY SUMMARY						COMPLIANCE REPORT					
	Spring	Summer		Fall	Winter		Spring	Summer		Fall	Winter	
	9,195	22,177	27,360	9,271	18,180	21,448	9,195	22,177	27,360	9,271	18,180	21,448
	5/19/13	08/21/2013	07/19/13	9/29/13	12/4/13	12/17/13	5/19/13	08/21/2013	07/19/13	9/29/13	12/4/13	12/17/13
	4:00	18:00	17:00	5:00	18:00	18:00	4:00	18:00	17:00	5:00	18:00	18:00
Narragansett	0.983	0.997	0.995	0.983	0.998	0.999	compliant	compliant	compliant	compliant	compliant	compliant

The power factor performance of the study area's feeders is limited to those that have PI data availability. This includes only the 12.47kV feeders at Warren substation. Peak power factor performance for these feeders shows them to be near unity or leading, indicating adequate feeder reactive support. Available data for major 115kV transformer interfaces and the 23 kV sub-transmission lines also show power factor near unity or slightly lagging.

5. Plan Development

5.1 Consideration of Distributed Generation in Plan Development

The impact of existing and planned distributed generation ("DG") installations were considered in the plan formation. Installations of significant size (greater than MW) appear on one 23 kV sub-transmission line (2267 line). There are two solar array sites on this line, one existing and one proposed, each sized at 3 MWs. Appendix 9.11 lists the existing and proposed DG within the study area.

The DG was analyzed from a hypothetical peak reduction perspective. Peak contribution factors, the ratio of the megawatts generated on peak versus the nameplate rating of the generator, can vary greatly on a daily or yearly basis as a result of location, weather, and other factors. Observing the 2014 summer data for the in-service solar array shows peak contribution factors of 77%, 40%, 23%, and 10% for 12:00PM, 3:00PM, 4:00PM, and 6PM respectively. Using a conservatively high peak contribution factor of 30% of nameplate, results in a possible peak reduction of 1.8 MW for the existing and proposed DG. This equates to approximately 45 amps at 23kV. There are no projected sub-transmission normal configuration overloads predicted in the study period. This peak reduction analysis resulted in no impact to the proposed plans.

Area DG was also analyzed from a comprehensive study-wide perspective. All area stations, except Wampanoag, have contingency load-at-risk issues and asset conditions issues (see Sections 4.1.2 and 4.3). The existing and proposed DG does not address or avoid necessary asset condition issues and is not significant or dependable in load levels to mitigate capacity issues. As a result, the comprehensive plans are also unaffected by the existing or proposed distributed generation.

5.2 Common Items

The Bristol/Warren area is electrically isolated from the East Providence/Barrington area. There are no feeder ties between these areas because of the Barrington River. The river forms a natural barrier that makes feeder ties between the areas neither practical nor economical.

Although there are no thermal concerns to resolve in the Bristol/Warren area, the feeders are highly utilized resulting in contingency load-at-risk exceeding the DPG guidelines. To resolve this issue, the following investments are recommended.

- Install a new feeder, 51F4, at Bristol substation. A one-line of the proposed work is shown in Appendix 9.7.
- Upgrade the thermal capability of the Warren 5F2 and 5F4 feeders. This involves upgrading the front end of both circuits.

The investments and expenses for the common items are shown in Table 5.2 below:

TABLE 5.2 - Estimated Cost of Common Items ($M)

Description	**Capex**	**Opex**	**Removal**	**Total**
East Bay Common Item (D-Sub)	$0.590	$0.075	$0.005	$0.670
East Bay Common Item (D-Line)	$0.620	$0.042	$0.153	$0.815
TOTAL (COMMON)	**$1.210**	**$0.117**	**$0.158**	**$1.485**

5.3 Plan – 1

This plan includes building two new substations supplied from the 115kV transmission system. System rearrangement proposed within this plan reduces loading and dependence on the 23kV sub-transmission system. The following are the major modifications proposed:

Construct a new 115/12.47kV Station at Phillipsdale:
Build a new 115/12.47kV substation at Phillipsdale. Initial construction would consist of a single 40MVA LTC transformer, straight-bus metal-clad switchgear, a 7.2 MVAR station capacitor bank, and four feeder positions. The ultimate build-out would be two 40MVA LTC transformers supplying straight-bus metal-clad switchgear with a tie breaker, two 7.2MVAR capacitor bank, and eight feeder positions. A one line of this proposed station is shown in Appendix 9.8. The station would be supplied from the 115kV lines, X-3 and E-183W. The four new feeders from this station would:

- Replace the 23/12.47kV non-standard construction at Phillipsdale substation with standard station equipment, address the asset condition concerns, and provide capacity to supply new customers in the northern section of the City of East Providence.
- Eliminate out of phase feeder ties by correcting the voltage phasing. This would increase switching flexibility, reduce restoration time, and improve reliability since customers would not be exposed to short outages during switching.
- Retire Waterman substation to address asset condition concerns, eliminate the need for a major investment to upgrade the 23kV supply system, and eliminate the out of phase feeder ties that exist at Waterman.
- Reduce load on the 115/23kV station at Phillisdale from 30MW to 3MW. The long-term strategy would be to convert the two remaining 23kV customers to 12.47kV and retire the 23kV station. This approach eliminates a major investment on the 23kV station to address the asset condition and obsolete equipment concerns.

The new feeders would be routed on public roadways in new manhole and ductline infrastructure. Five industrial customers would be converted from 23kV to 12.47kV which would reduce load on the 23kV system, eliminate circuits installed in a difficult to access right-of-way adjacent to the railroad corridor, and eliminate a major investment to address the poor condition of the pole plant along this 23kV right-of-way.

The customers to be converted to 12.47kV are: Hasbro with (3) 500kVA transformers; Handy Harmon with (3) 667kVA transformers; Cape Cod Ice with (3) 333kVA transformers; BA Ballou with (3) 500kVA transformers; and Nyman Manufacturing which is primary metered customer with a peak demand of 1.70MW.

Construct a new 115/12.47kV Station in East Providence:
Build a new 115/12.47kV substation on First Street in East Providence on a gas company owned parcel next to the 115kV transmission right of way. Initial construction would consist of a single 40MVA LTC transformer, straight-bus metal-clad switchgear, a 7.2 MVAR station capacitor bank, and four feeder positions. The ultimate build-out would be two 40MVA LTC transformers

supplying straight-bus metal-clad switchgear with a tie breaker, two 7.2MVAR capacitor banks, and eight feeder positions. A one line of this proposed station and the site plan is shown in Appendix 9.8. The station would be supplied from the 115kV line, E-183W. The four new feeders from this station would:

- Provide capacity to relieve the heavily loaded distribution feeders in the area, address MWh violations, and provide capacity to supply load growth.
- Retire Kent Corners 23/4.16kV substation. This retirement would address the only remaining pocket of 4.16kV load in the area and is a component of a comprehensive plan to eliminate the need for a new 115/23kV station at Mink St.
- Be a component of a comprehensive approach that eliminates the need for a major upgrade of the 23kV supply system. The sub-transmission upgrades would require approximately 7.50 miles of line reconductoring along a public roadway system.

The four new feeders would be routed on public roadways in new manhole and ductline infrastructure. Kent Corners 4.16kV load would be converted to the 12.47kV system thru direct conversions and the use of step-down transformers to reduce cost. One industrial customer and a solar generator would be converted from 23kV to 12.47kV. The conversion of these customers is required to provide routes for the new 12.47kV feeders.

Add two new feeders at Warren Substation:
Expand Warren 115/12.47kV substation by adding two new distribution feeders and two 7.6MVAR station capacitor banks. The new feeders would be routed into Barrington and be used to retire Barrington substation. A one line of the proposed station expansion is shown in Appendix 9.8. This investment would address the asset and safety concerns at Barrington substation, eliminate the need for a new 115/23kV station at Mink Street, and eliminate the need for major upgrades on the 23kV supply system.

Substation Retirements:
The final component of this plan is to retire a number of substations in the study area and remove all equipment and foundations to below grade. The stations retirements are Mink Street 23kV station; Barrington substation; Kent Corners substation; Phillipsdale 23/12.47kV substation; Waterman substation; and retire the 2291 Line position at Warren substation. These substation retirements are part of a comprehensive plan to address all the issues in the study area at least cost.

The proposed mainline distribution for Plan 1 is shown in Appendix 9.8. The investments and expenses for Plan 1 are detailed in Table 5.3 below.

TABLE 5.3 - Estimated Investments and Expenses for Plan 1

Investment Description ($M)	Capex	Opex	Removal	Total
Phillipsdale Substation (T-Line)	$0.400	$0.020	$0.010	$0.430
Phillipsdale Substation (T-Sub)	$0.300	$0.000	$0.000	$0.300
Phillipsdale Substation (D-Line)	$3.716	$0.064	$0.260	$4.040
Phillipsdale Substation (D-Sub)	$6.020	$0.600	$0.380	$7.000
East Providence Substation (T-Line)	$0.400	$0.000	$0.000	$0.400
East Providence Substation (T-Sub)	$0.300	$0.000	$0.000	$0.300
East Providence Substation (D-Line)	$7.371	$0.405	$1.424	$9.200
East Providence Substation (D-Sub)	$6.020	$0.550	$0.030	$6.600
Warren Substation (D-Line)	$3.700	$0.100	$0.350	$4.150
Warren Substaion (D-Sub)	$3.450	$0.290	$0.175	$3.915
Mink Street Retirement (D-Sub)	$0.000	$0.020	$0.220	$0.240
Barrington Sub Retirement (D-Sub)	$0.000	$0.030	$0.345	$0.375
Kent Corners Sub Retirement (D-Sub)	$0.000	$0.030	$0.345	$0.375
Waterman Sub Retirement (D-Sub)	$0.000	$0.030	$0.345	$0.350
Plan 1 (T-Spend)	$1.400	$0.020	$0.010	$1.430
Plan 1 (D-Spend)	$30.277	$2.119	$3.874	$36.270
Total Spend	$31.677	$2.139	$3.884	$37.700

5.4 Alternative Plans

5.4.1 Plan – 2

This plan includes adding new distribution capacity supplied from an upgraded 23kV sub-transmission system and has limited investment in expansion of the 115kV transmission system. The following are the major modifications proposed:

Install two new 23/12.47kV Feeders at Phillipsdale substation
This alternative would build two new 23/12.47kV modular feeders at Phillipsdale substation. The new feeders would be used to retire the existing non-standard construction that currently exists at Phillipsdale and would correct the out-of-phase feeder ties. A one-line of the proposed station is shown in Appendix 9.9.

The existing 115/23kV station at Phillipsdale would supply the new modular feeders requiring the asset condition issues described in Section 4.3 to be addressed. The 1960's vintage power transformer would be replaced with 40 MVA transformers to address the reliability concerns. The 23kV breakers would be replaced along with the obsolete bus and transformer arrestors. The electromechanical relays would be upgraded with modern solid state relays. The timed bus tie scheme would be removed and EMS would be installed.

Install two new 23/12.47kV Feeders at Rumford substation
Plan 2 would install two new 23/12.47kV modular feeders at the former Rumford substation site located at 127 North Broadway in East Providence. Feeders would be supplied from the 115/23kV station at Phillipsdale. Access to the right-of-way along the railroad corridor would be improved and the obsolete pole plant would be replaced. A one-line of the proposed station is shown in Appendix 9.9.

The new Rumford substation feeders would provide capacity to supply new load growth, address MWh violations, and be used to retire Waterman Ave substation. The new feeders would also correct out-of-phase feeder ties, eliminate the need for asset replacement work at Waterman Ave substation, relocate the station away from Wampanoag substation, and move the station to a more robust 23kV supply system.

Waterman substation feeders are landlocked to the south by Wampanoag substation and the 23kV supply consists of small wire and aged pole plant that does not meet current standards for 23kV construction. As such, there is no economic or reliability benefit to maintaining Waterman Ave substation in its current location.

Install two new 23/12.47kV Feeders at Kent Corners substation
Plan 2 would install two new 23/12.47kV modular feeders at Kent Corners substation. The new feeders would provide capacity to relieve the heavily loaded distribution system in the area, address contingency load-at-risk issues, and provide capacity to supply new load growth. Investment would also eliminate the small pocket of 4.16kV load in the study area by retiring the existing Kent Corners 23/4.16kV station. A one-line of the proposed station is shown in Appendix 9.9.

Build a New 115/23kV Substation at Mink Street[2]
A new 115/23kV substation would be built at Mink Street to supply Kent Corners and Barrington substations. Construction would consist of a single 40MVA transformer supplying a single 23kV line. The station would be supplied by an existing 115kV line at Mink Street. A one-line of the proposed station is shown in Appendix 9.9.

Address Concerns at Barrington Substation
Plan 2 would address asset and safety concerns with Barrington substation. The sacrificial air break on the station transformer would be replaced with a circuit switcher, the bus work and taps would be raised to comply with current standards, the 4F2 VSA recloser would be replaced to address asset condition concerns and EMS would be installed at the station.

Upgrade and Reinforce the 23kV Sub-Transmission System
The 23kV sub-transmission system from Mink Street consists of a mixture of 336 Al, 2/0 Cu and 1/0 Cu wire. This system is not adequate to supply the proposed Kent Corners and Barrington substations. To supply these stations the small wire would have to be replaced with 795 Al open wire. Construction would consist of approximately 7.5 miles of double circuited roadway infrastructure along highly utilized and congested public roadways. This would require replacement of all the aged pole plant to meet current standards and to accommodate the larger wire size.

The normal supply to Barrington substation would be from the Warren 115/23kV station, a station with numerous asset condition concerns. As part of this plan, the asset condition concerns at Warren would be addressed. The 23kV breakers would be replaced along with all the obsolete pin type bus insulators. The obsolete protection would be upgraded and relocated from the old control house to the new control house. A one line of the proposed 23kV supply system is shown in Appendix 9.9.

This plan results in a comprehensive solution for the East Bay area and addresses all asset condition, safety, and reliability concerns. Plan addresses all thermal concerns, provides capacity to supply load growth, and addresses all distribution planning criteria violations. The required investments and expenses for Plan 2 are detailed in Table 5.4.1 below.

[2] Mink Street 115/23kV substation will be located in Massachusetts and supply customers in Rhode Island. It will be built, owned, and operated by the New England Power Company (NEPCo). An appropriate rate recovery mechanism needs to be developed. Rate recovery could occur thru a Transmission Rate Tariff or thru a Direct Assignment Charge. A Local Service Agreement may also need to be filed with the Federal Energy Regulatory Commission (FERC). If this plan were to be implemented, the legal department will be consulted to determine the most appropriate rate recovery mechanism for these assets.

TABLE 5.4.1 - Estimated Investments and Expenses for Plan 2

Investment Description ($M)	Capex	Opex	Removal	Total
Mink St Substation (T-Line)	$0.500	$0.000	$0.000	$0.500
Mink St Substation (T-Sub)	$3.500	$0.020	$0.220	$3.740
Phillipsdale Substation (T-Sub)	$9.000	$0.600	$0.080	$9.680
Phillipsdale Substation (D-Sub)	$3.550	$0.400	$0.350	$4.300
Phillipsdale Substation (D-Line)	$2.250	$0.050	$0.160	$2.460
Kent Corners Substation (D-Sub)	$3.600	$0.400	$0.350	$4.350
Kent Corners Substation (D-Line)	$10.200	$0.800	$2.600	$13.600
Rumford Substation (D-Sub)	$3.600	$0.360	$0.000	$3.960
Rumford Substation (D-Line)	$1.450	$0.050	$0.400	$1.900
Warren Substation (D-Sub)	$2.835	$0.300	$0.025	$3.160
Barrington Substation (D-Sub)	$1.800	$0.180	$0.020	$2.000
Waterman Sub (D-Sub)	$0.000	$0.030	$0.320	$0.350
Plan 2 (T-Spend)	$13.000	$0.620	$0.300	$13.920
Plan 2 (D-Spend)	$29.285	$2.570	$4.225	$36.080
Total Spend	$42.285	$3.190	$4.525	$50.000

5.4.2 Plan – 3

This plan is a hybrid of Plan 1 and Plan 2. It includes expanding the 23kV sub-transmission system to supply both existing and new 23/12.47kV distribution substations and includes expanding the 115kV system to supply a new 115/12.47kV station at Phillipsdale. The following are the major modifications proposed:

Construct a new 115/12.47kV Station at Phillipsdale

This option would build a new 115/12.47kV substation at Phillipsdale. Initial construction would consist of a single 40MVA LTC transformer, straight-bus metal-clad switchgear, a 7.2 MVAR station capacitor bank, and four feeder positions. The ultimate build-out would be two 40MVA LTC transformers supplying straight-bus metal-clad switchgear with a tie breaker, two 7.2MVAR capacitor banks, and eight feeder positions. A one line of this proposed station is shown in Appendix 9.10. The station would be supplied from the 115kV lines, X-3 and E-183W. The four new feeders from this station would:

- Replace the 23/12.47kV non-standard construction at Phillipsdale with standard substation equipment, address the asset condition concerns, and provide capacity to supply new customers in the northern section of the City of East Providence.
- Eliminate out-of-phase feeder ties by correcting the voltage phasing. This would increase switching flexibility, reduce restoration time, and improve reliability since customers would not be exposed to short outages during switching.
- Retire Waterman substation to address asset condition concerns, eliminate the need for a major investment to upgrade the 23kV supply system, eliminate the out-of-phase feeder ties that exist at Waterman, and eliminate the need to build a new 115/23kV station at Mink Street.
- Reduce load on the 115/23kV station at Phillisdale from 30MW to 3MW. The long-term strategy would be to convert the two remaining 23kV customers to 12.47kV and to retire the 23kV station. This eliminates a major investment on the 23kV station to address the asset condition and obsolete equipment concerns.

The new feeders would be routed along city streets in new manhole and ductline infrastructure. Five industrial customers would be converted from the 23kV system to the 12.47kV system. This conversion eliminates circuits installed in a difficult to access right-of-way adjacent to the railroad corridor, and eliminates a major investment to address the poor condition of the pole plant along this 23kV right-of-way.

The customers to be converted to 12.47kV are: Hasbro with (3) 500kVA transformers; Handy Harmon with (3) 667kVA transformers; Cape Cod Ice with (3) 333kVA transformers; BA Ballou with (3) 500kVA transformers; and Nyman Manufacturing which is primary metered customer with 1.70MW of peak.

<u>Install two new 23/12.47kV Feeders at Kent Corners substation</u>
Plan 3 would install two new 23/12.47kV modular feeders at Kent Corners substation. The new feeders would provide capacity to relieve the heavily loaded distribution system in the area, address MWh violations, and provide capacity to supply new load growth. Investment would also eliminate the small pocket of 4.16kV load in the study area by retiring the existing Kent Corners 23/4.16kV station. A one-line of the proposed station is shown in Appendix 9.10.

<u>Build new 115/23kV Substation at Mink Street</u>[3]
A new 115/23kV substation would be built at Mink Street to supply Kent Corners and Barrington substations. Construction would consist of a single 40MVA transformer supplying a single 23kV line. The station would be supplied by an existing 115kV line at Mink Street. A one-line of the proposed station is shown in Appendix 9.10.

[3] Mink Street 115/23kV substation will be located in Massachusetts and supply customers in Rhode Island. It will be built, owned, and operated by the New England Power Company (NEPCo). An appropriate rate recovery mechanism needs to be developed. Rate recovery could occur thru a Transmission Rate Tariff or thru a Direct Assignment Charge. A Local Service Agreement may also need to be filed with the Federal Energy Regulatory Commission (FERC). If this plan were to be implemented, the legal department will be consulted to determine the most appropriate rate recovery mechanism for these assets.

Address Concerns at Barrington Substation

Plan 3 would address asset and safety concerns with Barrington substation. The sacrificial air break on the station transformer would be replaced with a circuit switcher, the bus work and taps would be raised to comply with current standards, the 4F2 VSA recloser would be replaced to address asset condition concerns and EMS would be installed at the station.

Upgrade and Reinforce the 23kV Sub-Transmission System:

The 23kV sub-transmission system from Mink Street consists of a mixture of 336 Al, 2/0 Cu and 1/0 Cu wire. This system is not adequate to supply the proposed Kent Corners and Barrington substations. To supply these stations the small wire would have to be replaced with 795 Al open wire. Construction would consist of approximately 7.5 miles of double circuited roadway infrastructure along highly utilized and congested streets. This would require replacement of all the aged pole plant to meet current standards and to accommodate the larger wire size.

The normal supply to Barrington substation would be from the Warren 115/23kV station, a station with numerous asset condition concerns. As part of this plan, the asset condition concerns at Warren would be addressed. The 23kV breakers would be replaced along with all the obsolete pin type bus insulators. The obsolete protection would be upgraded and relocated from the old control house to the new control house. A one line of the proposed 23kV supply system is shown in Appendix 9.10.

This plan results in a comprehensive solution for the East Bay area and addresses all asset condition, safety, and reliability concerns. Plan addresses all thermal concerns, provides capacity to supply load growth, and addresses all distribution planning criteria violations. The required investments and expenses for Plan 3 are detailed in Table 5.3.2 below.

TABLE 5.4.2 – Estimated Investments and Expenses for Plan 3:

Investment Description ($M)	Capex	Opex	Removal	Total
Phillipsdale Substation (T-Line)	$0.400	$0.000	$0.000	$0.400
Phillipsdale Substation (T-Sub)	$0.300	$0.000	$0.000	$0.300
Phillipsdale Substation (D-Line)	$4.430	$0.120	$0.545	$5.095
Phillipsdale Substation (D-Sub)	$6.020	$0.600	$0.380	$7.000
Kent Corners Substation (D-Sub)	$3.600	$0.400	$0.350	$4.350
Kent Corners Substation (D-Line)	$10.300	$0.800	$2.600	$13.700
Mink St Substation (T-Line)	$0.500	$0.000	$0.000	$0.500
Mink St Substation (T-Sub)	$3.500	$0.020	$0.220	$3.740
Mink St Substation (D-Line)	$0.600	$0.000	$0.000	$0.600
Warren Substation (D-Sub)	$2.840	$0.300	$0.025	$3.160
Barrington Substation (D-Sub)	$1.800	$0.180	$0.020	$2.005
Waterman Sub (D-Sub)	$0.000	$0.030	$0.320	$0.350
Plan 1 (T-Spend)	$4.700	$0.020	$0.220	$4.940
Plan 1 (D-Spend)	$29.590	$2.430	$4.240	$36.260
Total Spend	$34.290	$2.450	$4.460	$41.200

5.4.3 Do Nothing

Taking no action would leave all the problems mentioned in Section 4 unaddressed. Violations of the Distribution Planning Criteria would continue to exist and worsen as time goes by, adversely affecting customer service and reliability performance.

Taking no action could make supplying new customer loads very challenging and could result is the company operating the system above its rated capability.

6. Plan Considerations and Comparisons

6.1 Economic, Schedule, and Technical Comparisons

The estimated investments and expenses for the three Plans are shown in Table 6.1 below. The economic comparisons exclude the cost of common items.

TABLE 6.1 – Estimated Investments and Expenses for Plan 1, Plan 2, and Plan 3

	PLAN 1				PLAN 2				PLAN 3			
Description	Capex	Opex	Rem.	Total	Capex	Opex	Rem.	Total	Capex	Opex	Rem.	Total
East Bay (T-Line)	$0.80	$0.02	$0.01	$0.83	$0.50	$0.00	$0.00	$0.50	$0.90	$0.00	$0.00	$0.90
East Bay (T-Sub)	$0.60	$0.00	$0.00	$0.60	$12.50	$0.62	$0.30	$13.42	$3.80	$0.02	$0.22	$4.04
East Bay (D-Sub)	$15.50	$1.52	$1.85	$18.87	$15.29	$1.67	$1.13	$18.08	$14.29	$1.53	$1.14	$16.96
East Bay (D-Line)	$14.80	$0.60	$2.00	$17.40	$14.00	$0.90	$3.10	$18.00	$15.30	$0.90	$3.10	$19.30
TOTAL	$31.70	$2.14	$3.86	$37.70	$42.29	$3.19	$4.53	$50.00	$34.29	$2.45	$4.46	$41.20

Plan 1 is least sensitive to load growth and offers the most flexibility for future expansion. It eliminates most of the 23kV supply system installed along the roadway and with significant exposure to motor vehicle accidents and tree related outages. It adds new distribution capacity supplied from a more reliable 115kV system with little exposure to motor vehicle accidents and tree related outages. It has flexibility to add additional distribution feeders with a minimal investment on the supply system and with minimal permitting.

Plan 2 is the most sensitive to load growth. It upgrades the 23kV system to supply new 23/12.47kV distribution stations. The 23kV supply upgrades would consist of predominantly highly congested roadway construction and be limited to 795 aluminum open wire, which limits the capacity to 35MVA. Once this capacity is reached, the only economical approach would be to utilize the 115kV transmission system to supply new distribution stations. The 23kV supply system would have exposure to motor vehicle accidents and tree related outages due to the roadway construction. Although beyond the 15 year study horizon, this plan only defers the eventual need to implement portions of Plan 1 once the capacity of the 23kV supply system is utilized.

Plan 3 is a hybrid of Plan 1 and Plan 2. It is less flexible than Plan 1 but more flexible than Plan 2. It installs a new station supplied from the 115kV system and new distribution capacity supplied from a reinforced 23kV system. The 23kV supply would consist of predominantly roadway construction and be limited to 795 aluminum open wire, which limits the capacity to 35MVA. As with Plan 2, once this capacity is reached, the only economical approach would be to utilize the 115kV system to supply new distribution stations. The 23kV supply system would have exposure to motor vehicle accidents and tree related outages due to the roadway construction.

6.2 Non-Wires Alternatives Considerations

Where an issue has been identified, a Non-Wires Alternative may also be considered as an option to defer a transmission, sub-transmission, or distribution wires solution for a period of time. Considering Non-Wires Alternatives to every wires solution is not practical given the low cost of a large volume of potential wires solutions, the magnitude of load relief required in certain situations, the time to acquire Non-Wires Alternatives (and verify their availability) or instances where the issue is poor operating condition of the asset. As a result, Non-wires Alternatives are screened against the following four guidelines:

A. The Wires solution, based on Engineering judgment, will likely be more than $1M;
B. If load reduction is necessary, then it will be less than 20 percent of the total load in the area of the defined need;
C. Start of construction is at least 36 months in the future; and
D. The need is not based on Asset Condition.

Although the plans developed for this study will exceed $1M and the start of construction for the majority of the work will be at least 36 months in the future, there are significant asset condition issues within the study area as described in Section 4.3. Therefore Non-Wires Alternatives are not considered feasible to provide a comprehensive study area solution.

However, a Non-Wires solution could be investigated to address the contingency load-at-risk issues in Bristol and Warren in lieu of installing a new feeder at Bristol substation and upgrading the feeders at Warren substation. This solution, common to all plans (see Section 5.1), does not have an asset condition component. Since this investment is recommended in the outer years of the study (see Section 7.0), it provides sufficient lead time to investigate the feasibility of a non-wires solution for the area.

6.3 Permitting, Licensing, Real Estate, and Environmental Considerations

Common to all plans is permitting for distribution line poles. Depending on the town, these poles will be set either by Verizon or by National Grid. Pole sets for Plan 1 would consist of routine requests and standard construction and no major obstacles are expected. Plan 2 and Plan 3 would require upgrading the 23kV supply system with 795 bare aluminum conductors and would have 12.47kV distribution under-build. This construction would occur along highly congested public roadways and could face opposition from the Town of Barrington and the City of Providence. Guying this type of construction may require private property easements which could be challenging to obtain and could increase the cost of the plans.

The Warren 115/12.47kV substation was initially permitted for six feeders. Therefore, the addition of two feeders at this station should be routine with no major issues anticipated. The station SPCC plan will need to be updated with the additional equipment. The new Warren feeders would be routed to Barrington. The feeders would utilize a bridge crossing and underground infrastructure to be built on a bike path as part of a Department of Transportation

(DOT) bridge rebuild project. The company is currently coordinating the bridge crossing with the DOT bridge rebuild project.

The option to build a new 115/12.47kV station at Phillispdale has been reviewed at a conceptual level. Space at the station is limited, however, it is anticipated that sufficient space exists to build the proposed station. Construction of the new station will impact the existing 23/12.47kV station which needs to remain in-service during construction. It is anticipated that some of the existing equipment will need to be temporarily relocated while the new station is built. The existing station SPCC plan will need to be revised due to the new station.

The proposed 115/12.47kV station on First Street in East Providence will be built on a gas company owned site. The station will be supplied by a short tap from the 115kV line running thru the property. The 115kV tap will require a notification to the Rhode Island Energy Facility Siting Board (EFSB). The company is in the process of placing an Environmental Land Use Restriction (ELUR) on this site but it will not restrict the property from being used as a substation. The City of Providence has requested the company investigate undergrounding the 115kV line, E183W, to Franklin Square substation. One option is to install the E183W line riser structure at this site. The site appears to be large enough to accommodate both undergrounding the 115kV line and the proposed substation. Both projects will need to be coordinated.

The former Rumford substation site used to house a 23/4.16kV substation and has two 23kV supply lines running behind the site. This site is presently undeveloped. There are no major obstacles anticipated at this time that would prohibit the use of this site to install the proposed 23/12.47kV modular feeders and new taps from the 23kV supply lines.

Kent Corners substation is located in a small parcel of land as is located within a congested residential area. The proposed installation of two modular feeders at this station could face local opposition. In addition, the existing 4.16kV station would have to remain in service while the new 23/12.47kV modular feeders are being constructed which could impact the ability for the company to screen the station from the neighborhood. There have been numerous complaints about transformer noise at the station. Any construction at this location could result in potential neighborhood opposition.

6.4 Planned Outage Considerations

All three plans require work on 115kV supplied stations. Plan 1 and Plan 3 require tapping 115 kV transmission lines. Any required 115kV line outages will have to be coordinated with ISO-NE.

The existing Phillipsdale 23/12.47kV substation will have to remain in-service while the new 115/12.47kV substation at Phillipsdale in energized. This will required relocating some of the 12.47kV circuits. A preliminary review has not identified any major concerns with these relocations.

6.5 Asset Physical Security Considerations

National Grid Security department will be consulted during the design process for the new substations. Recommendations for improved security at existing area substations will also be solicited and incorporated.

6.6 System Loss Analysis

A loss analysis was conducted to compare Plan 1 to the existing system. The purpose of this comparison was to check that the recommended plan reduced losses, and by such a result would create a more efficient system. Table 6.6 demonstrates over 1MW of peak load loss savings with Plan 1.

TABLE 6.6 – Megawatt Loss Savings Analysis

Voltage Level	Existing Configuration	Plan 1 Configuration	MW Loss Savings
115kV	2.42	2.43	**-0.01**
23kV	0.99	0.27	**0.72**
12.47kV	4.96	4.79	**0.17**
4.16kV	0.28	0	**0.28**
Total	**8.65**	**7.49**	**1.16**

7. Conclusions and Recommendations

The three plans provide a comprehensive solution for the area and address all asset condition, safety, and reliability concerns. The plans address thermal loading concerns, provide capacity to supply new load growth, and addresses distribution planning criteria violations thru the study horizon period of 2030.

Plan 1 is recommended for implementation. Plan 1 provides a comprehensive solution to address all the concerns in the study area at least cost. The total cost of plan 1 is $37.70M which is $13.00M lower in cost then Plan 2 and $3.50M lower in cost than Plan 3.

Plan 1 is least sensitive to load growth and offers the most flexibility for future expansion. Plan eliminates most of 23kV supply system consisting of predominantly roadway construction with exposure to motor vehicle accidents and tree related outages. When needed, additional distribution capacity can be added with a minimal investment on the supply system and minimal permitting impact. The recommended capital spending by fiscal year for Plan 1 is shown in Table 7.0 below:

TABLE 7.0: Recommended Capital Spend by Fiscal Year:

Description	FP	TOTAL	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27
East Providence Sub (T-Line)	C049819	$0.40	0.00	0.02	0.08	0.12	0.12	0.06				
East Providence Sub (T-Sub)	C049820	$0.30	0.00	0.02	0.06	0.09	0.09	0.04				
East Providence Sub (D-Sub)	C046726	$6.00	0.06	0.30	1.20	1.80	1.80	0.84				
East Providence Sub (D-Line)	C046727	$7.40	0.07	0.37	1.48	2.22	2.22	1.04				
Warren Sub Expansion (D-Sub)	C065166	$3.50	0.04	0.18	0.70	1.05	1.05	0.49				
Warren Sub Expansion (D-Line)	C065187	$3.70	0.04	0.19	0.74	1.11	1.11	0.52				
Mink Street 23kV Retirement (D-Sub)	C065806	$0.00										
Barrington Sub Retirement (D-Sub)	C065293	$0.00										
Kent Corners Retirement (D-Sub)	C065295	$0.00										
Waterman Ave Re irement (D-Sub)	C065297	$0.00										
Phillipsdale Sub (T-Line)		$0.40				0 00	0.02	0.08	0.12	0.12	0 06	
Phillipsdale Sub (T-Sub)		$0.30				0 00	0.02	0.06	0.09	0.09	0 04	
Phillipsdale Sub (D-Sub)		$6.00				0 06	0.30	1.20	1.80	1.80	0 84	
Phillipsdale Sub (D-Line)		$3.72				0 04	0.19	0.74	1.11	1.11	0 52	
Common Items		$1.21							0.11	0.20	0 50	0.40
T-Spend		$1.40	$0.01	$0.04	$0.14	$0.22	$0.25	$0.24	$0.21	$0 21	$0.10	$0.00
D-Spend		$31.53	$0.21	$1.03	$4.12	$6.28	$6.67	$4.83	$3.02	$3.11	$1.86	$0.40

8. Factors Influencing Futures Studies

Unexpected significant load growth is one factor that could affect future studies. The recommended plan initially installs a single transformer and four feeders at Phillipsdale and East Providence substations. However, both substations will be permitted for two transformers and eight feeders. At least eight additional feeders (or approximately 80MW of distribution capacity) can be installed to accommodate unexpected future load growth.

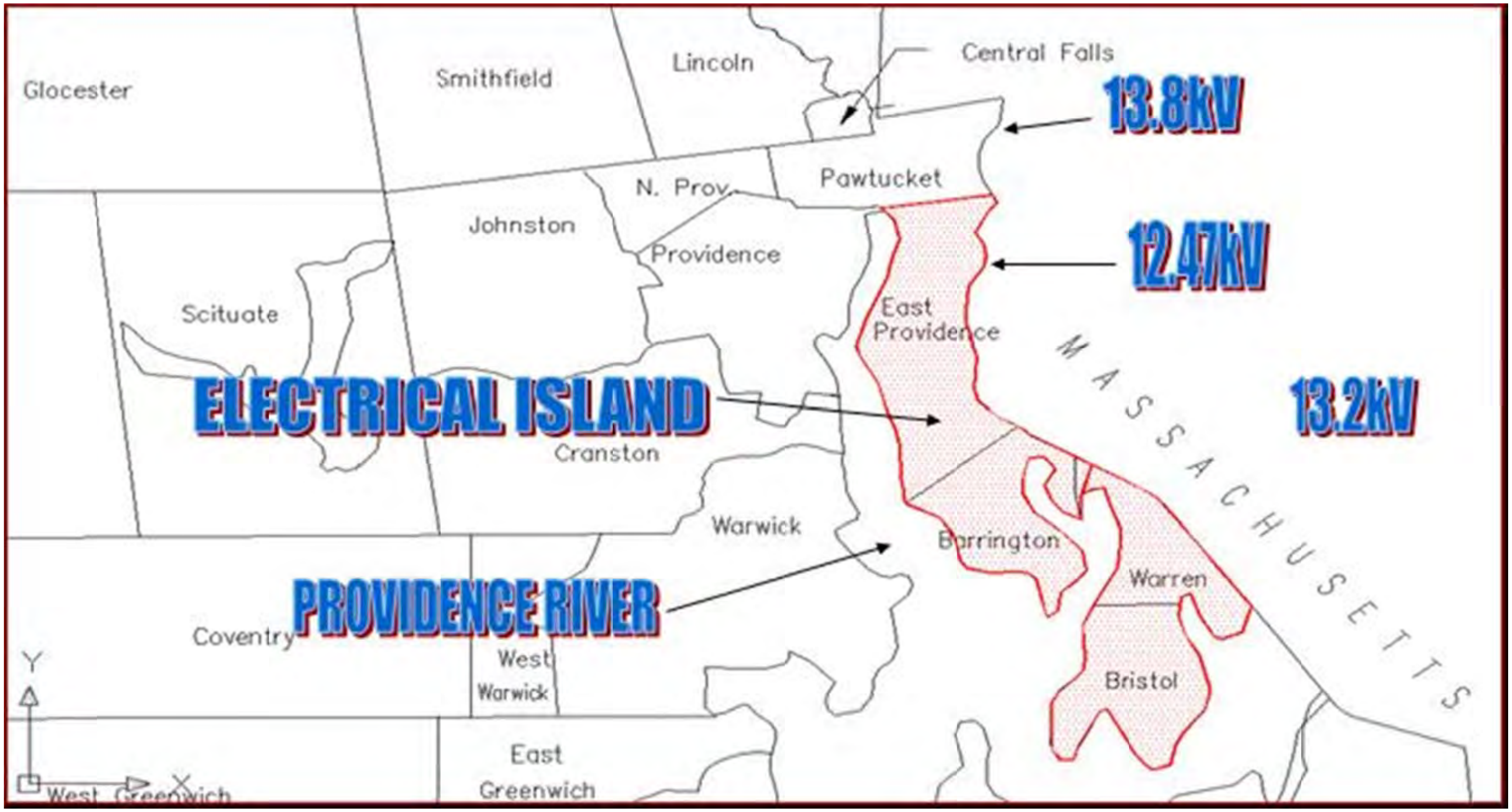
The Phillipsdale 115/23kV substation has numerous asset condition concerns which are being deferred. Loading on the 23kV station will be reduced to approximately 3MW and the station will supply only two industrial customers. It is recommended that this area be reviewed in the next few years and consideration be given to fully retire Phillipsdale 23kV station in lieu of performing any major asset replacement work.

A transmission study is currently being performed for the Southeastern Massachusetts and Rhode Island area. One potential plan involves extending the 115kV line from Bristol substation to Aquidneck Island. This will provide an option to eliminate the 23kV supply to Bristol substation and allow for the retirement of the 23kV station at Warren. If this transmission investment is to occur, it is recommended that any asset replacement work at the Warren 23kV station be compared against supplying Bristol substation with a second 115kV line. Even today, for various n-1 contingencies, the 23kV line is not capable of supplying the full Bristol load.

9. Appendix

9.1 Area Maps

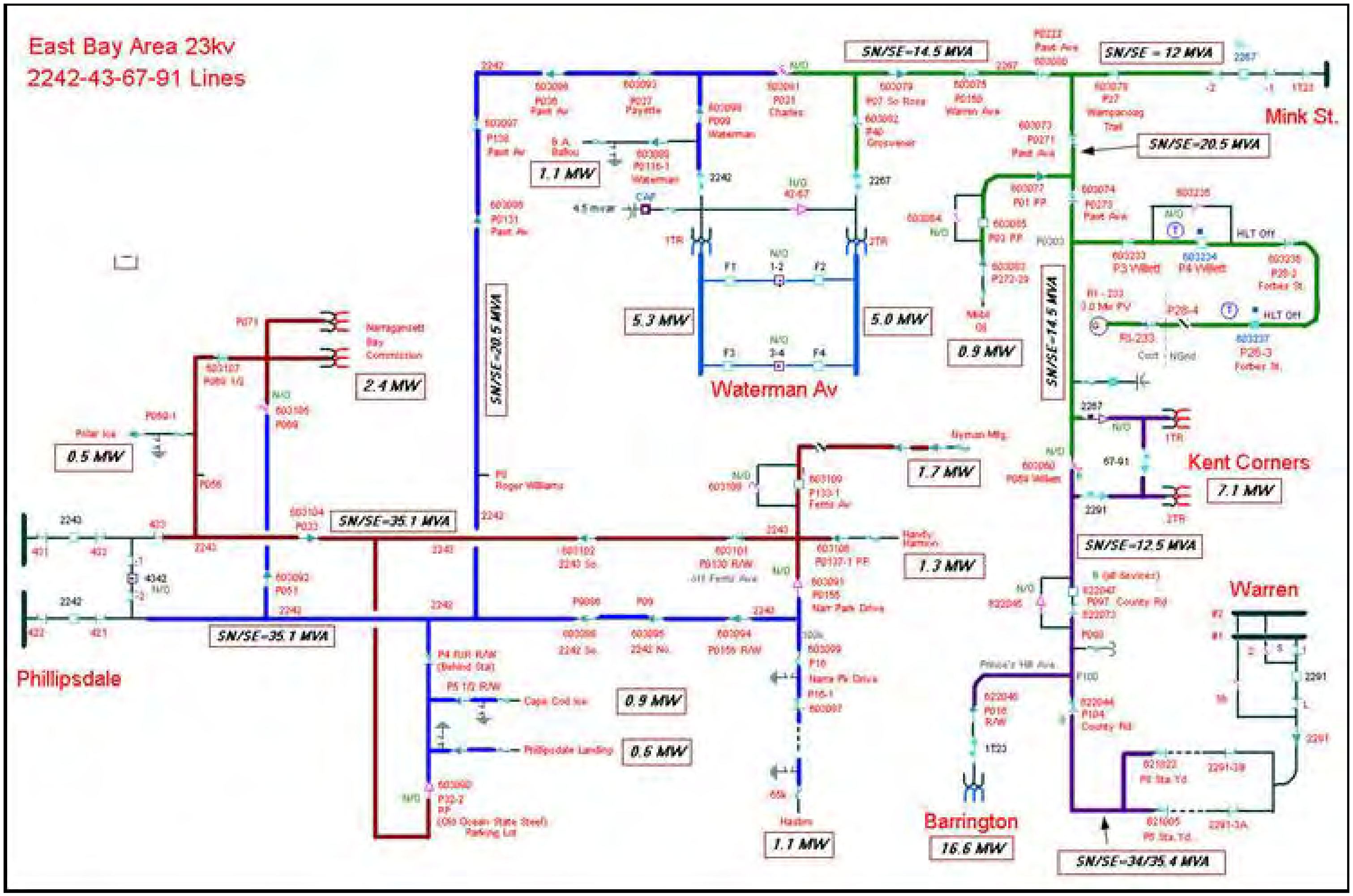
FIGURE 9.1.1 – STUDY AREA



9.2 One Line Diagrams

[redacted]

FIGURE 9.2.2 – 23kV SUPPLY SYSTEM ONE-LINE DIAGRAM



[redacted]

FIGURE 9.2.4 – BARRINGTON SUBSTATION ONE-LINE DIAGRAM

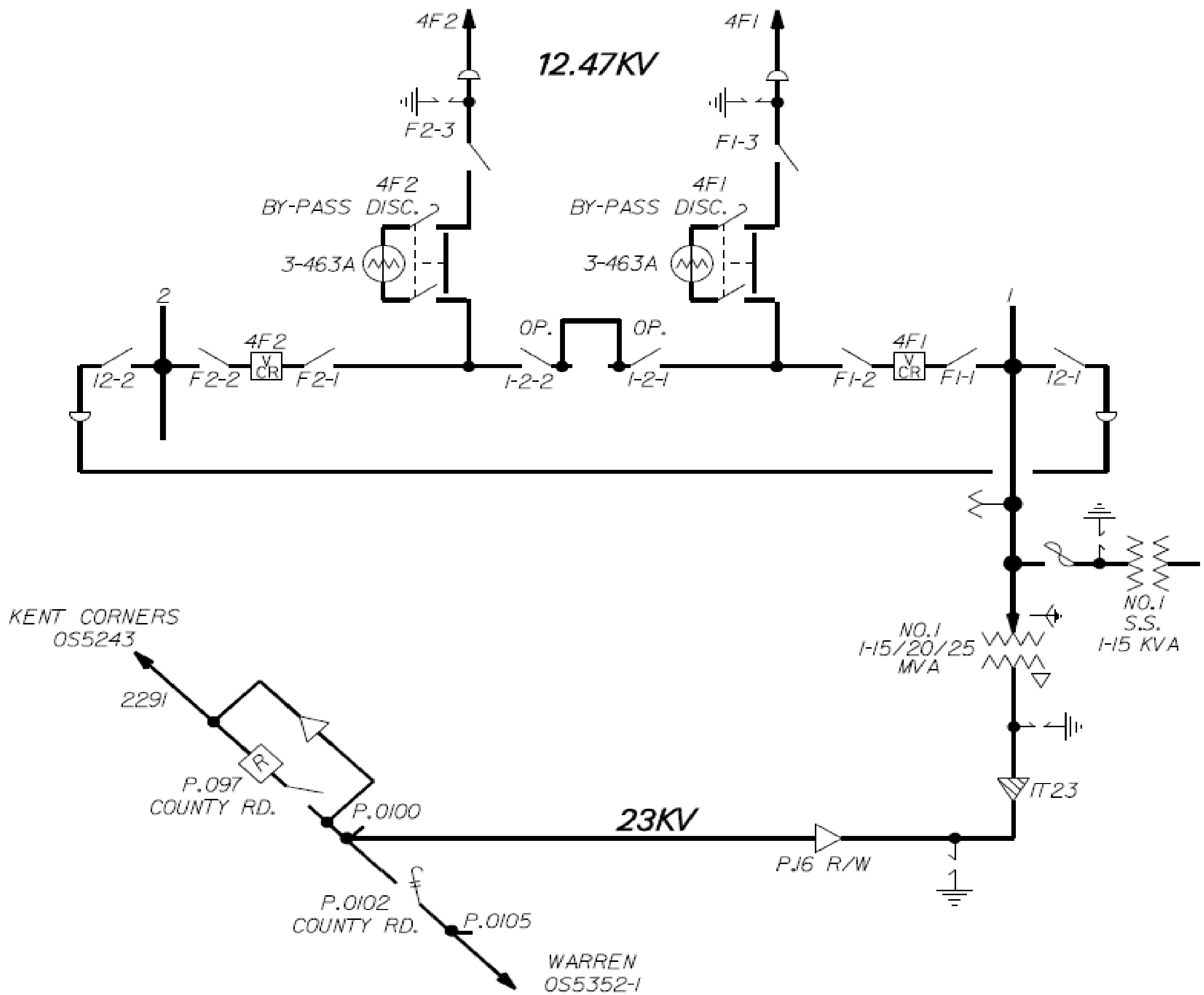


FIGURE 9.2.5 – KENT CORNERS SUBSTATION ONE-LINE DIAGRAM

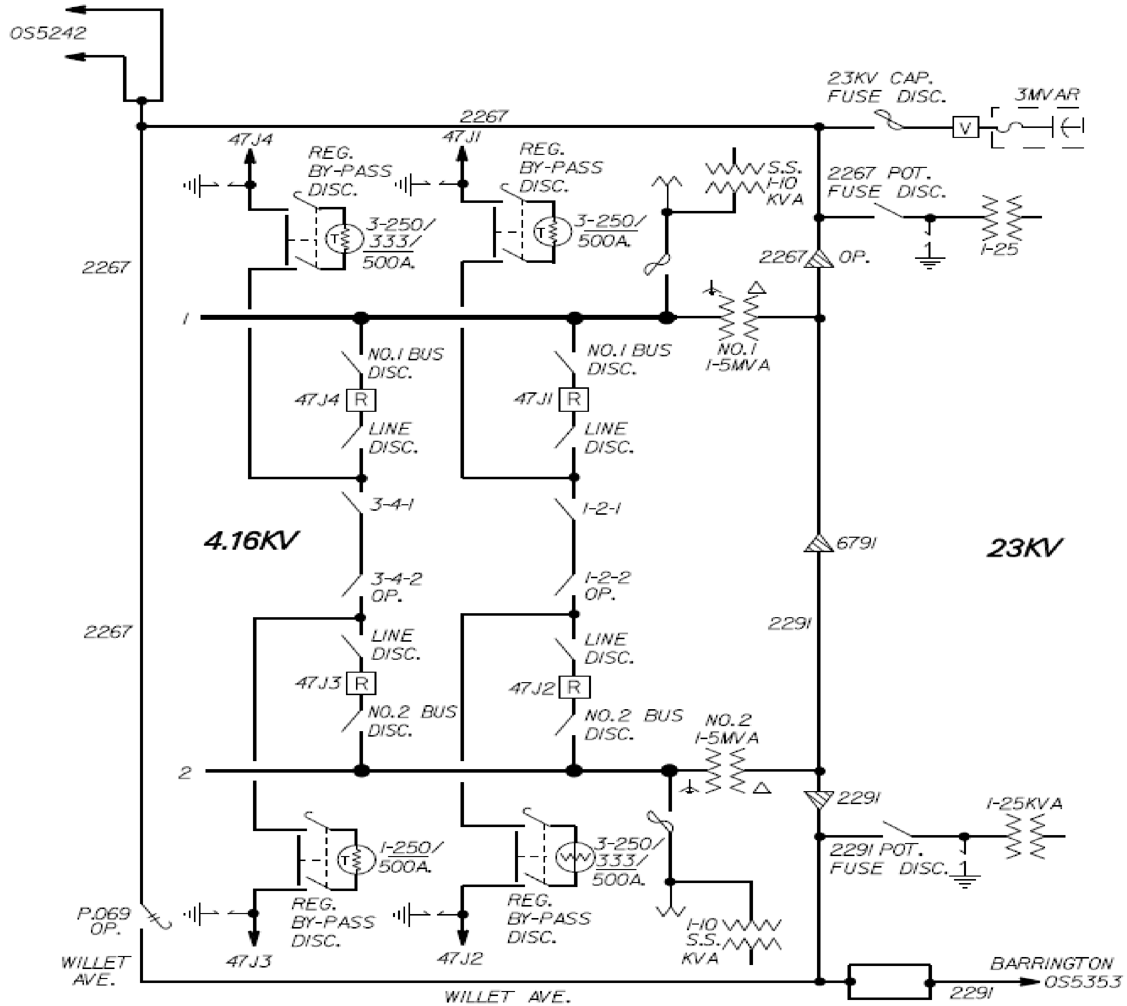
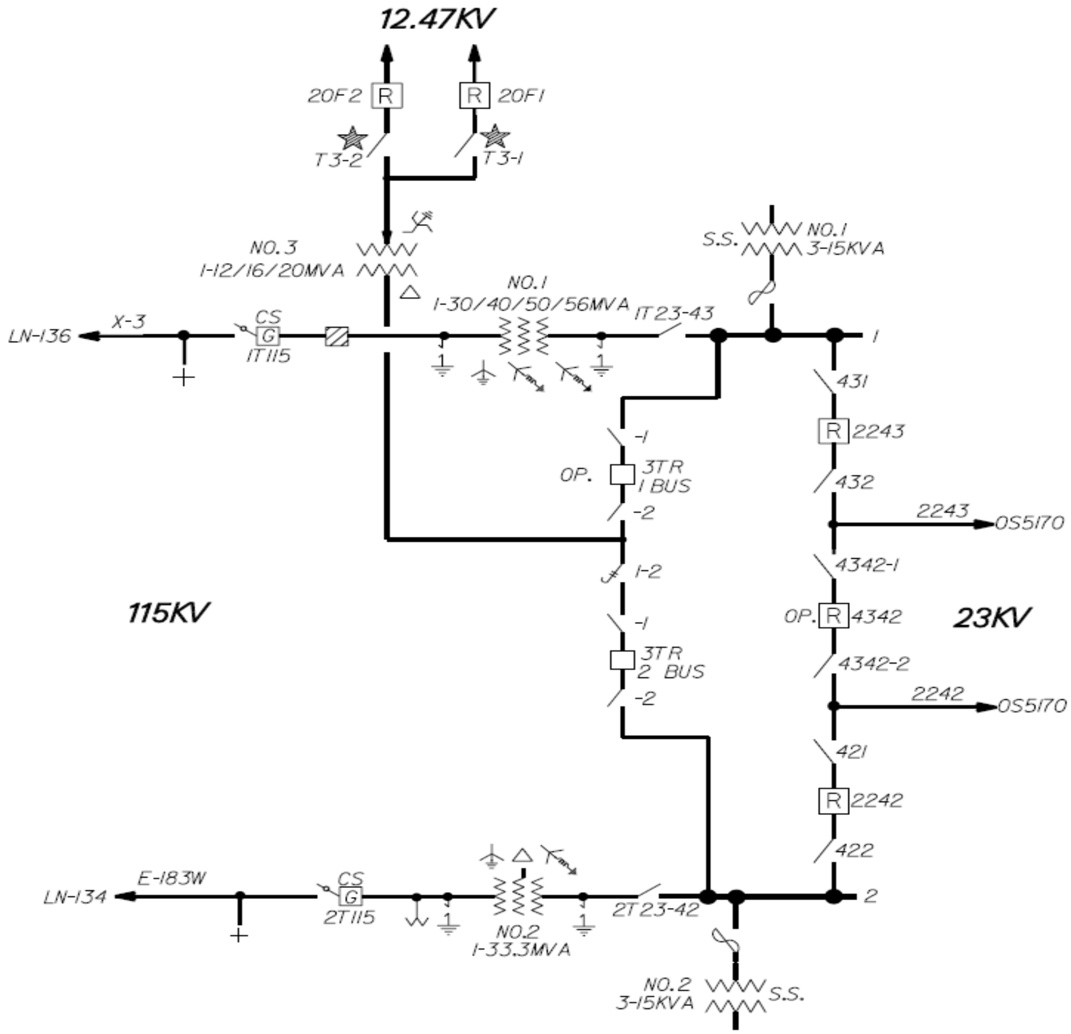
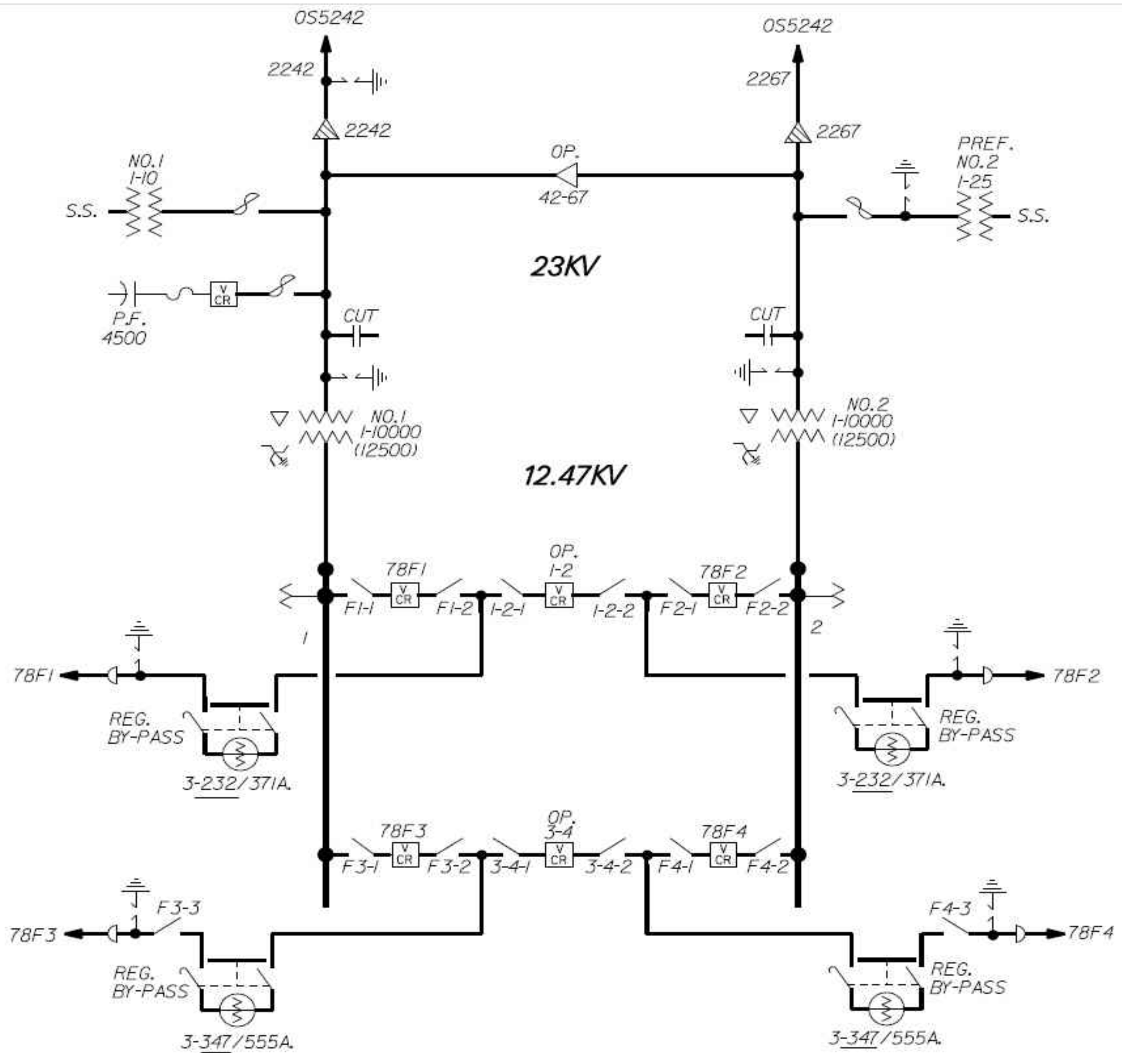


FIGURE 9.2.6 – PHILLIPDALE SUBSTATION ONE-LINE DIAGRAM



[redacted]

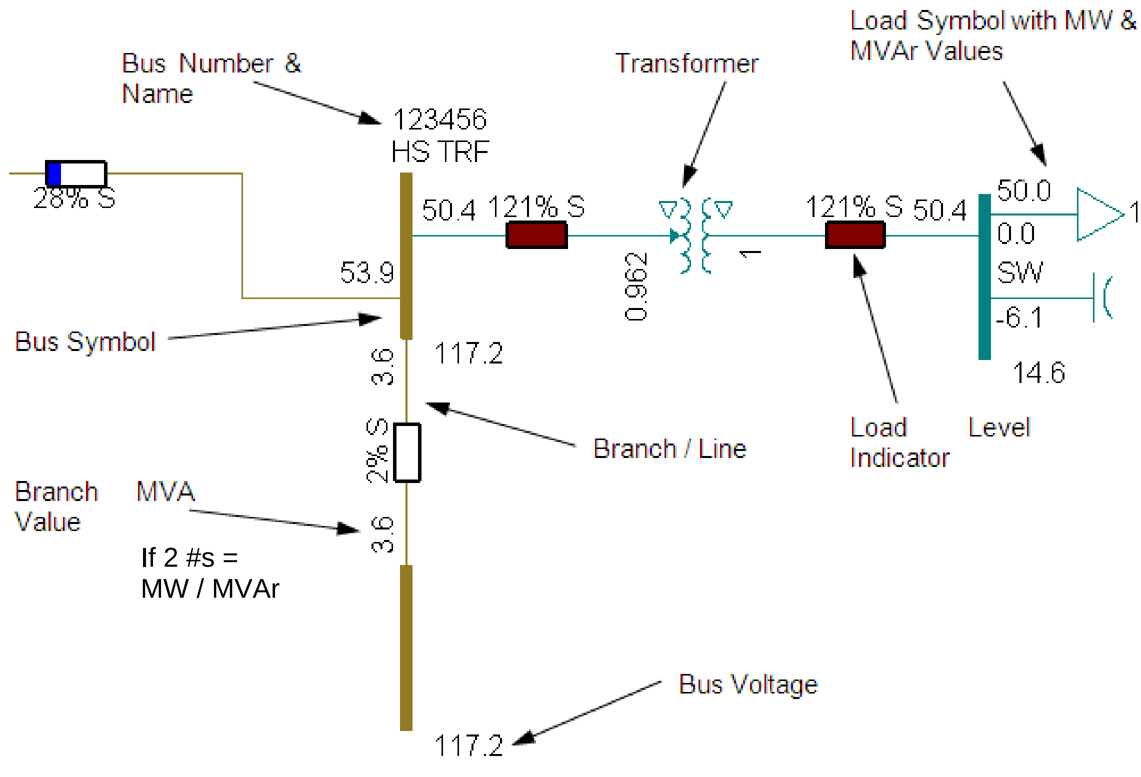
FIGURE 9.2.8 - WATERMAN SUBSTATION ONE-LINE DIAGRAM



9.3 Loadflow Diagrams

This section contains the electrical one-line loadflow diagrams. The diagrams show transformer and subtransmission power flows throughout the study area. Included below are notes and guides to assist the review of these diagrams.

General Layout



LEGEND
Green = 5kV Class Equipment
Blue-Gray = 15kV Class Equipment
Aqua = 25kV Class Equipment
Tan = 35kV Class Equipment
Salmon = 46kV Class Equipment
Green = 69kV Class Equipment
Brown = 115kV Class Equipment

[redacted]

[redacted]

[redacted]

[redacted]

9.4 CYME Radial Distribution Analysis Diagrams

Figure 9.4.1 – CYME East Bay Existing Configuration – :ircuit Arrangement

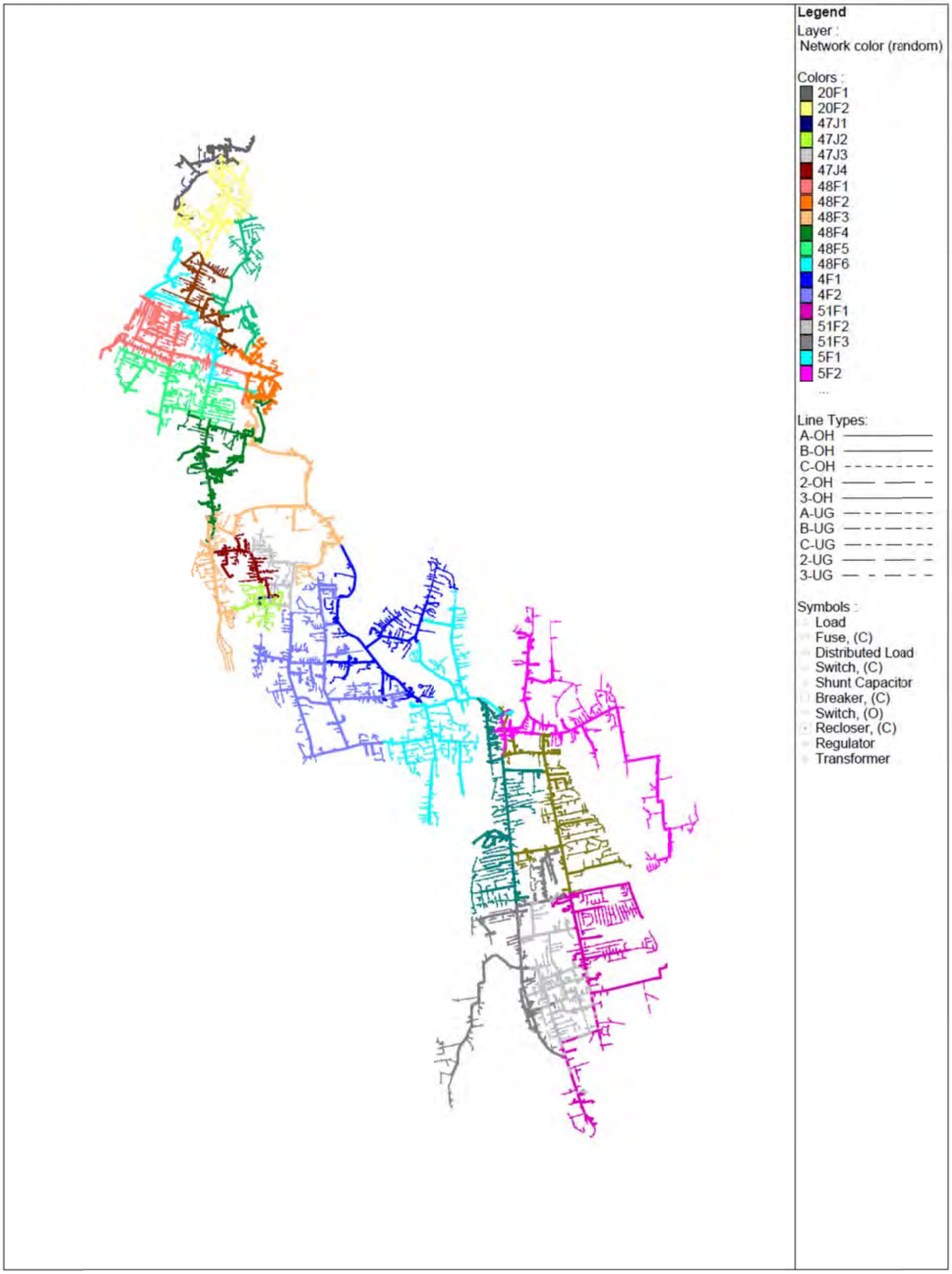


Figure 9.1.2 – CYME East Bay Existing Configuration – Loading Analysis

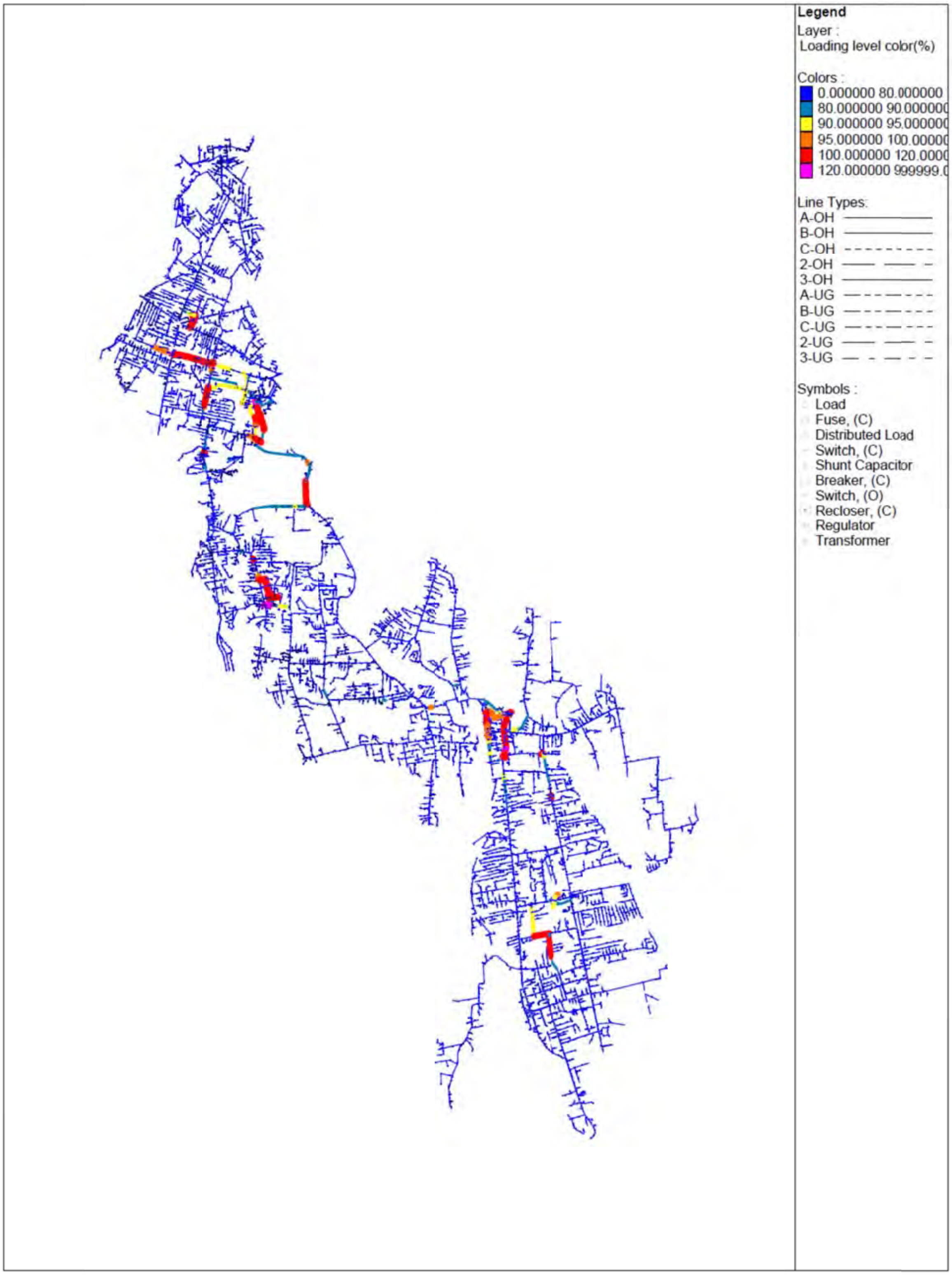


Figure 9.4.3 – CYME East Bay Existing Co figuration – Voltage Analysis

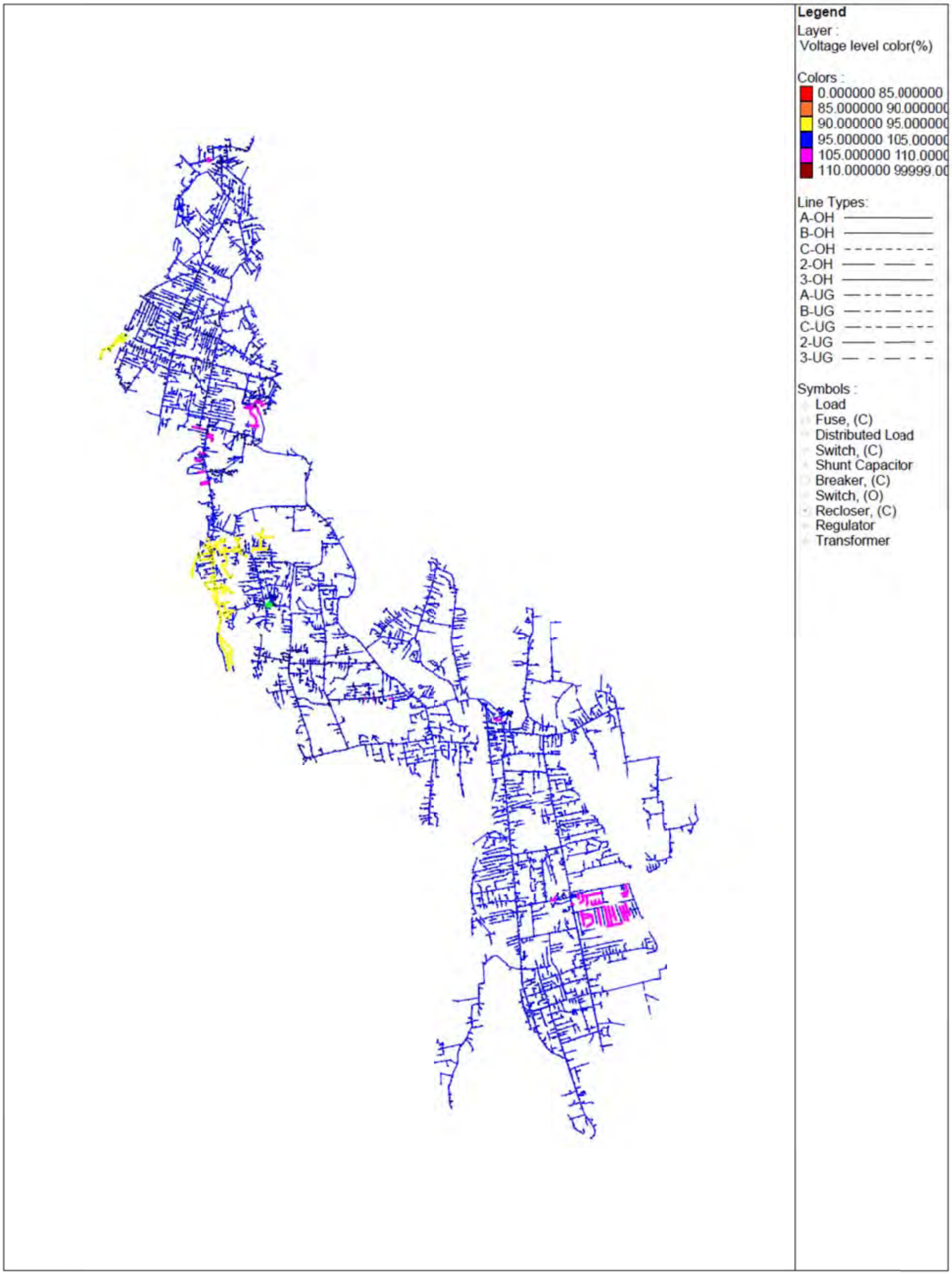


Figure 9. .4 – CYME East Bay Plan 1 Configuration – C rcuit Arrangement

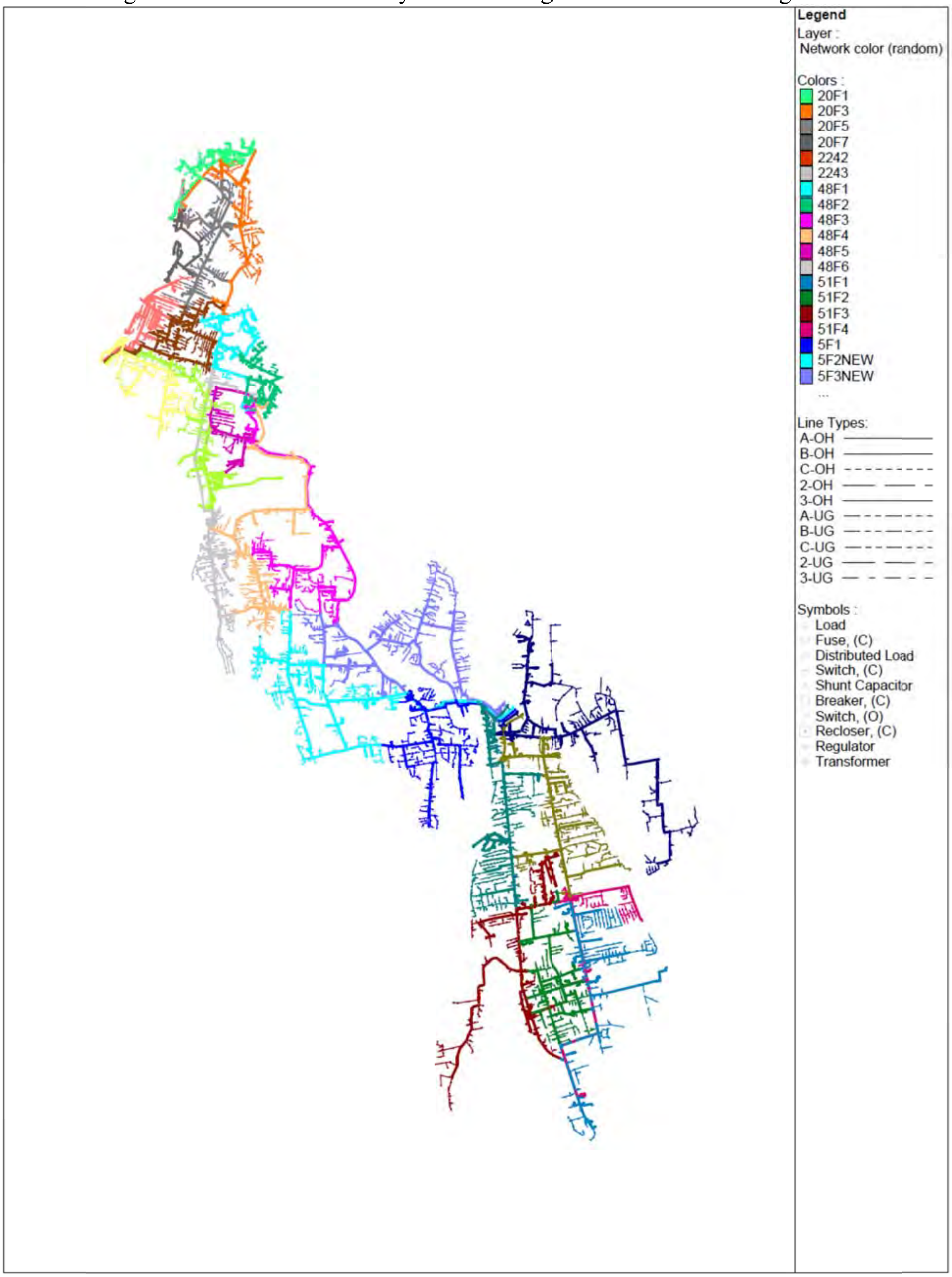


Figure 9.4.5 – CYME East Bay Plan 1 Configuration – Loading Analysis

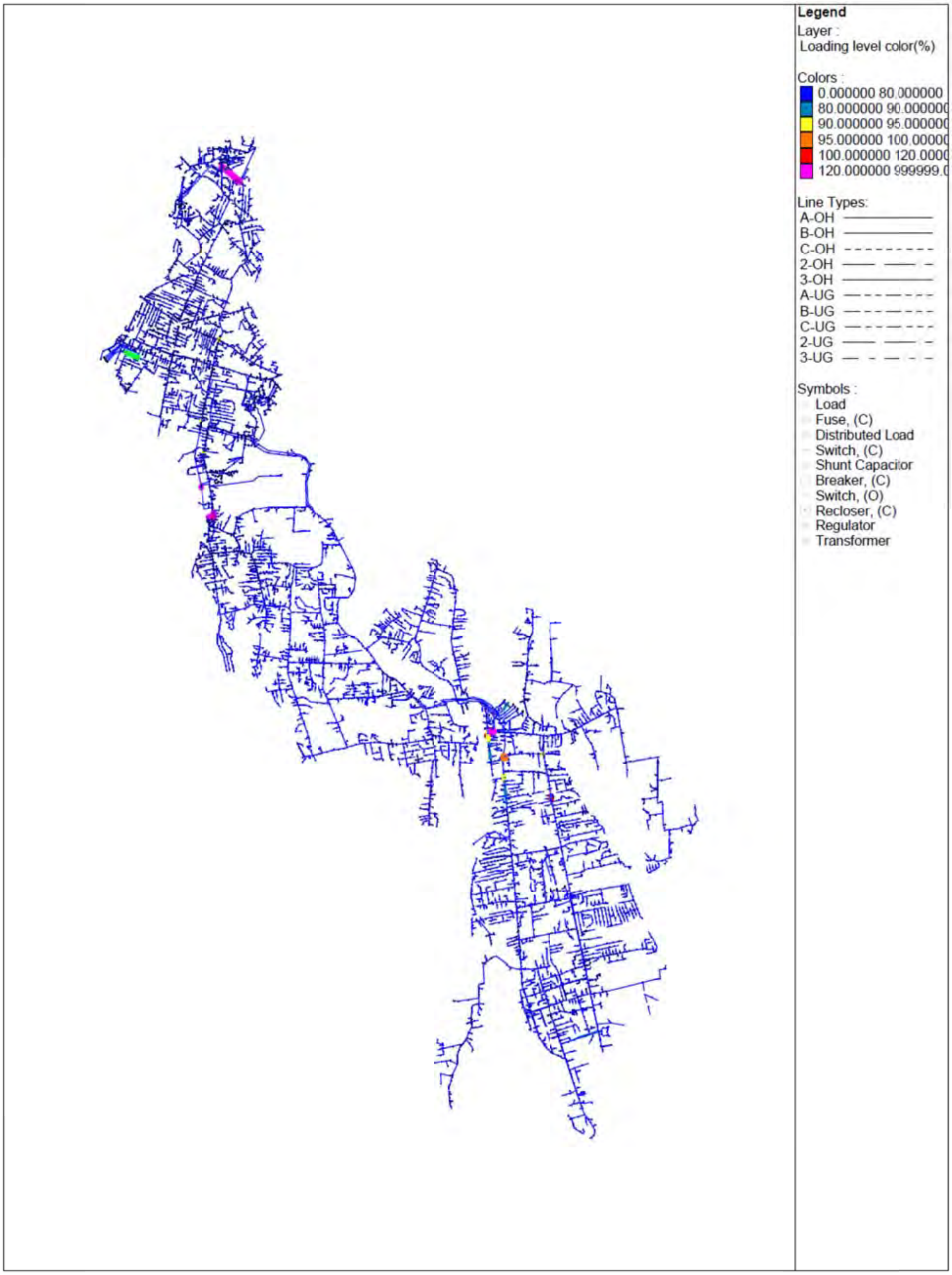
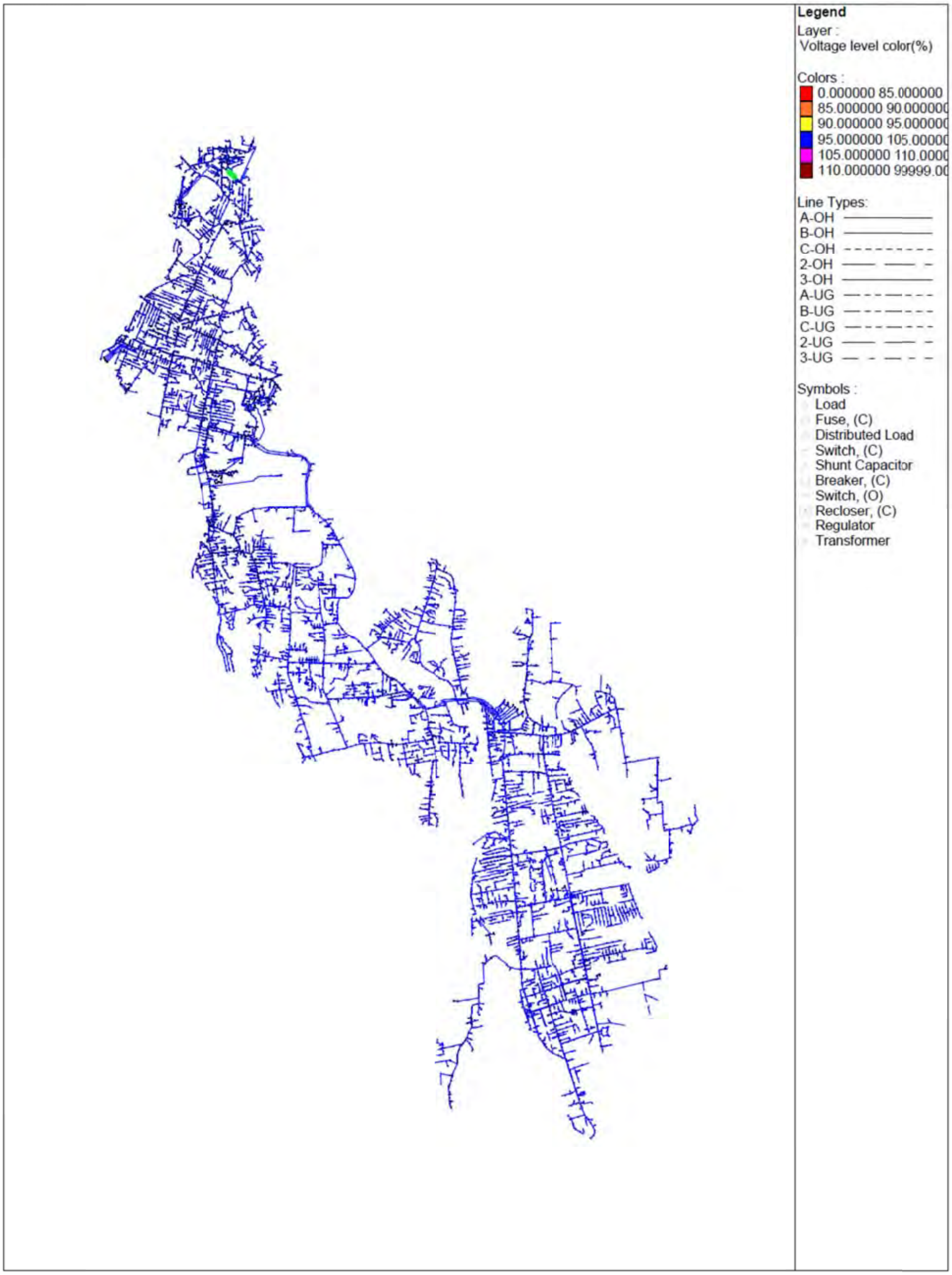


Figure 9.4.6 – CYME East Bay Plan 1 Configuration – Voltage Analysis



9.5 Arc Flash Analysis

Substation	Feeder	Voltage (kV)	LG Fault Current (Amps)	Clearing Time (secs)	Incident Energy (cal/cm^2)
BARRINGTON 4	4F1	12.47	4,972	0.2269	1.16
BARRINGTON 4	4F2	12.47	5,011	0.1404	0.73
BRISTOL 51A	51F2	12.47	4,590	0.3278	1.51
BRISTOL 51A	51F1	12.47	6,275	0.2951	2.07
BRISTOL 51A	51F3	12.47	6,797	0.3947	3.09
KENTS CORNER 47	47J2	4.16	7,673	0.1553	1.44
KENTS CORNER 47	47J1	4.16	7,756	0.1562	1.47
KENTS CORNER 47	47J3	4.16	7,872	0.1555	1.49
KENTS CORNER 47	47J4	4.16	8,142	0.1509	1.51
PHILLIPSDALE 20	20F2	12.47	4,711	0.2222	1.06
PHILLIPSDALE 20	20F1	12.47	4,712	0.1656	0.79
WAMPANOAG 48	48F5	12.47	6,077	0.3043	2.05
WAMPANOAG 48	48F6	12.47	6,080	0.3042	2.05
WAMPANOAG 48	48F2	12.47	6,165	0.3001	2.06
WAMPANOAG 48	48F1	12.47	6,351	0.2918	2.09
WAMPANOAG 48	48F3	12.47	6,472	0.2210	1.62
WAMPANOAG 48	48F4	12.47	6,590	0.2825	2.12
WARREN 5	5F2	12.47	6,586	0.2215	1.66
WARREN 5	5F4	12.47	6,597	0.3949	2.97
WARREN 5	5F1	12.47	7,069	0.4716	3.90
WARREN 5	5F3	12.47	7,199	0.3176	2.69
WATERMAN AVENUE 78	78F4	12.47	4,348	0.1691	0.73
WATERMAN AVENUE 78	78F3	12.47	4,551	0.1466	0.67

9.6 Fault Duty Analysis

Substation	Description	Position	Operating kV	Rated IC (A)	3-Phase Fault (A)	1-Phase Fault (A)
Barrington 4	VSA-12	4F1 VCR	12.4	12,000	4,286	5,054
Barrington 4	VSA	4F2 VCR	12.4	12,000	4,286	5,054
Bristol 51	SDV	2T23 VCB	23	20,000	4,033	2,583
Bristol 51	PVDB1 15.5-20-2	51F1 VCB	12.4	20,000	6,714	6,897
Bristol 51	PVDB1 15.5-20-2	51F2 VCB	12.4	20,000	3,869	4,660
Bristol 51	PVDB1 15.5-16-1	51F3 VCB	12.4	20,000	6,714	6,897
Bristol 51	PVDB1 15.5-20-1	1-2 VCB	12.4	20,000	6,714	6,897
Bristol 51	PVDB1 15.5-20-2	3-4 VCB	12.4	20,000	6,714	6,897
Bristol 51	PVDB1 15.5-20-2	51C2 VCB	12.4	20,000	3,869	4,660
Kents Corner 47	OZ-15-100	47J4 OCB	4.16	10,000	6,900	8,150
Kents Corner 47	OZ-210	47J3 OCB	4.16	10,000	6,900	8,150
Kents Corner 47	OZ-110	47J1 OCB	4.16	10,000	6,900	8,150
Kents Corner 47	OZ-210	47J2 OCB	4.16	10,000	6,900	8,150
Phillipsdale 20	23KS500-12C	3 TRF 2 BUS	23	18,000	8,890	1,101
Phillipsdale 20	FKD-25.8-11000	2243 OCB	23	11,000	8,890	1,101
Phillipsdale 20	SDO 23 500	2242 OCB	23	11,000	7,411	754
Phillipsdale 20	SDO 23 500	4342 OCB	23	11,000	8,890	1,101
Phillipsdale 20	FKD-25.8-11000-3	3 TR 1 BUS	23	18,000	8,890	1,101
Wampanoag 48	PVDB1 15.5	48F1 VCB	12.4	20,000	6,712	6,774
Wampanoag 48	PVDB1 15.5-16-1	48F2 VCB	12.4	20,000	7,120	7,190
Wampanoag 48	PVDB1 15.5-16-1	48F3 VCB	12.4	20,000	6,712	6,774
Wampanoag 48	PVDB1 15.5-20-2	48F4 VCB	12.4	20,000	7,120	7,190
Wampanoag 48	PVDB1 15.5-20-2	48F5 VCB	12.4	20,000	6,712	6,774
Wampanoag 48	PVDB1 15.5-20-2	48F6 VCB	12.4	20,000	7,120	7,190
Wampanoag 48	PVDB1 15.5-20-2	1-2 VCB	12.4	20,000	7,120	7,190
Wampanoag 48	PVDB1 15.5-20-2	3-4 VCB	12.4	20,000	7,120	7,190
Wampanoag 48	PVDB1 15.5-20-2	5-6 VCB	12.4	20,000	7,120	7,190
Warren 5	FKA-38-22000-6Y	5 TR OCB	23	22,000	16,463	16,280
Warren 5	345G1500	6 TR OCB	23	22,000	16,463	16,280
Warren 5	345G1500	2295 OCB	23	22,000	16,463	16,280
Warren 5	34.5KS1500-12D	2291 OCB	23	22,000	16,463	16,280
Warren 5	PVDB1 15.5-20-2	5F1 VCB	12.4	20,000	7311	7424
Warren 5	PVDB1 15.5-20-2	5F2 VCB	12.4	20,000	6652	6764
Warren 5	PVDB1 15.5-20-2	5F3 VCB	12.4	20,000	7311	7424
Warren 5	PVDB1 15.5-20-2	5F4 VCB	12.4	20,000	6652	6764
Warren 5	PVDB1 15.5-20-2	1-2 VCB	12.4	20,000	7311	7424
Warren 5	PVDB1 15.5-20-2	3-4 VCB	12.4	20,000	7311	7424
Waterman Ave 78	VSA-12	78F4 VCR	12.4	12,000	3920	2914
Waterman Ave 78	VSA	78F3 VCR	12.4	12,000	3920	2914
Waterman Ave 78	VSA	3-4 VCR	12.4	12,000	3920	2914

9.7 Plan Development – Common Items

[redacted]

9.8 Plan Development – Plan 1

FIGURE 9.8.1 – PHILLIPSDALE SUBSTATION ONE LINE-DIAGRAM (PLAN 1)

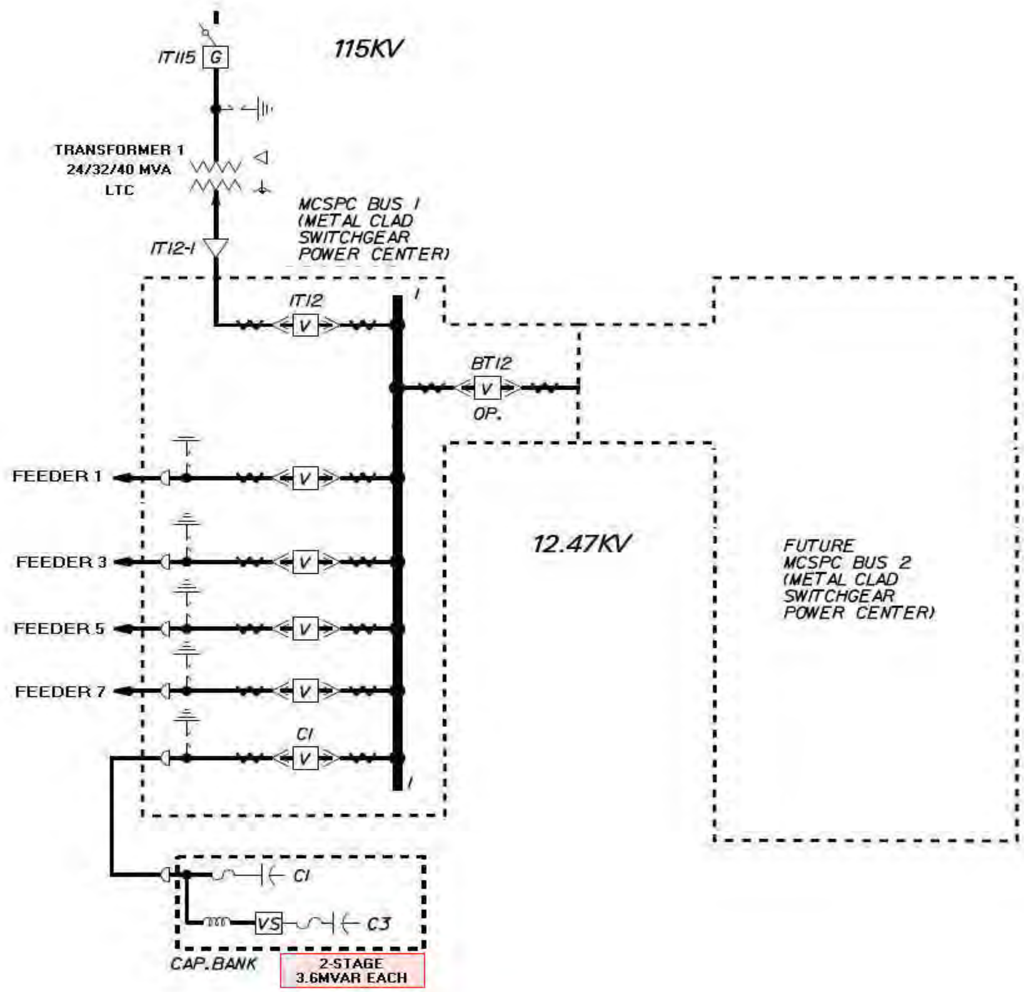


FIGURE 9.8.2 – EAST PROVIDENCE SUBSTATION ONE LINE-DIAGRAM (PLAN 1)

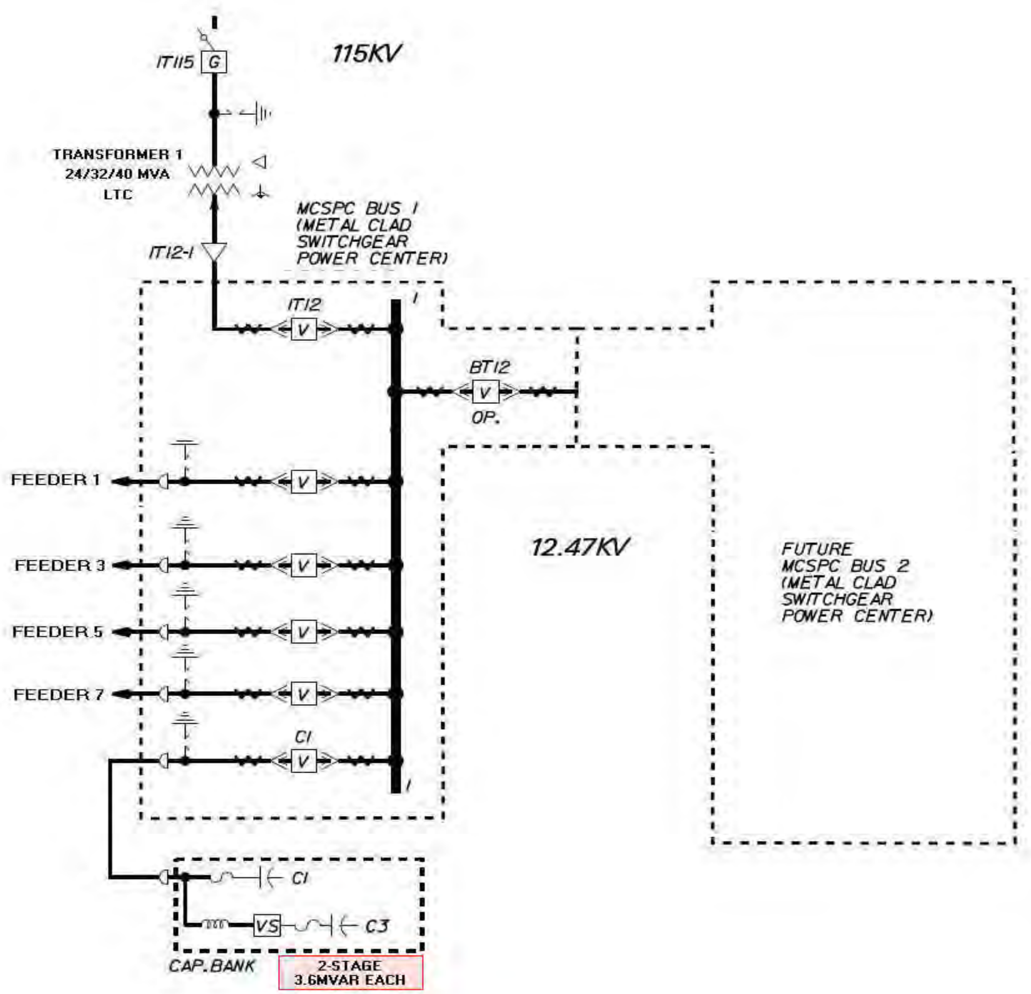


FIGURE 9.8.3 – EAST PROVIDENCE SUBSTATION SITE PLAN (PLAN 1)

[redacted]

FIGURE 9.8.5 – PROPOSED MAINLINE DISTRIBUTION NORTH (PLAN 1)

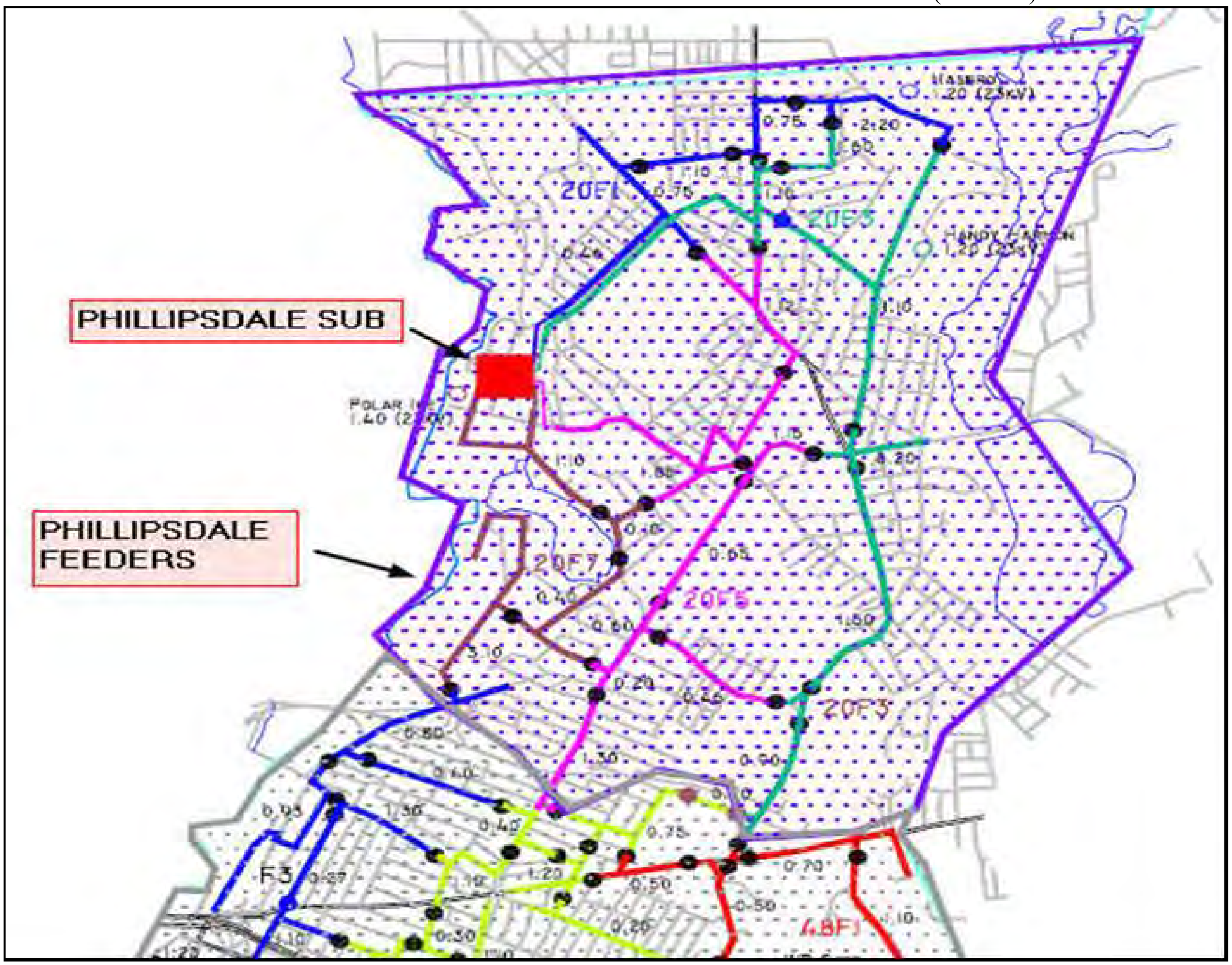
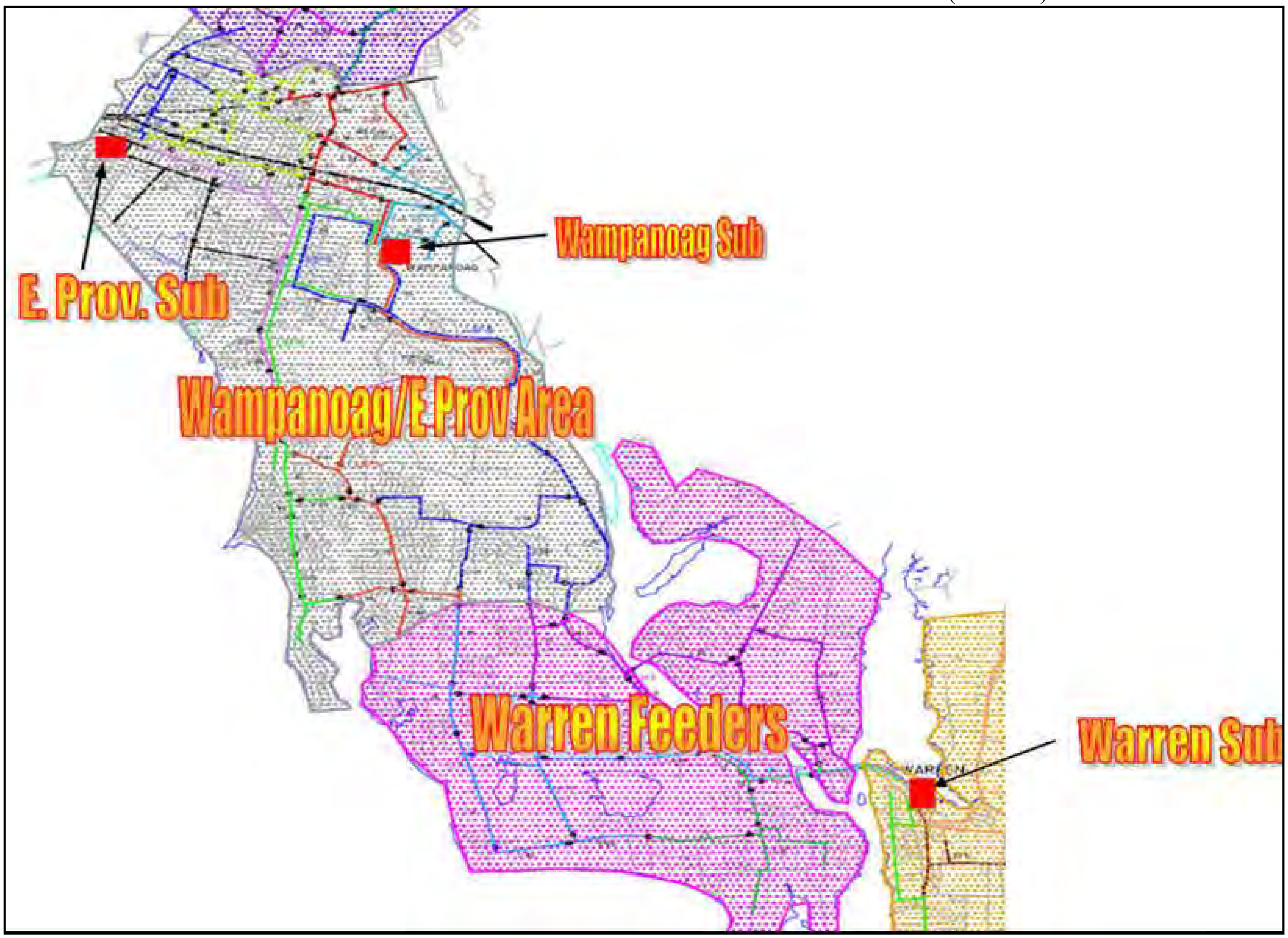


FIGURE 9.8.6 – PROPOSED MAINLINE DISTRIBUTION SOUTH (PLAN 1)



9.9 Plan Development – Plan 2

FIGURE 9.9.1 – PHILLIPSDALE SUBSTATION ONE-LINE DIAGRAM (PLAN 2)

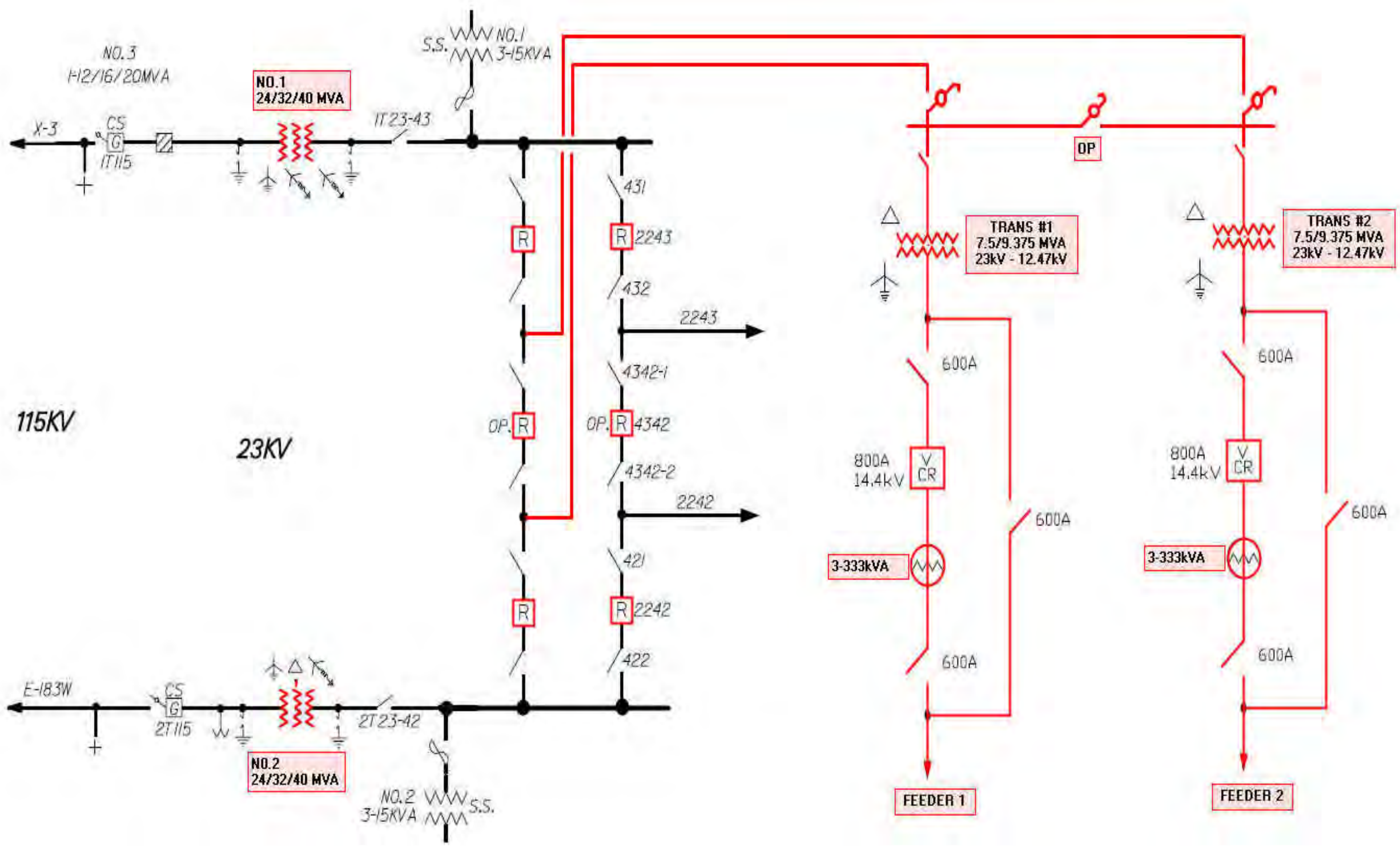


FIGURE 9.9.2 – RUMFORD SUBSTATION ONE-LINE DIAGRAM (PLAN 2)

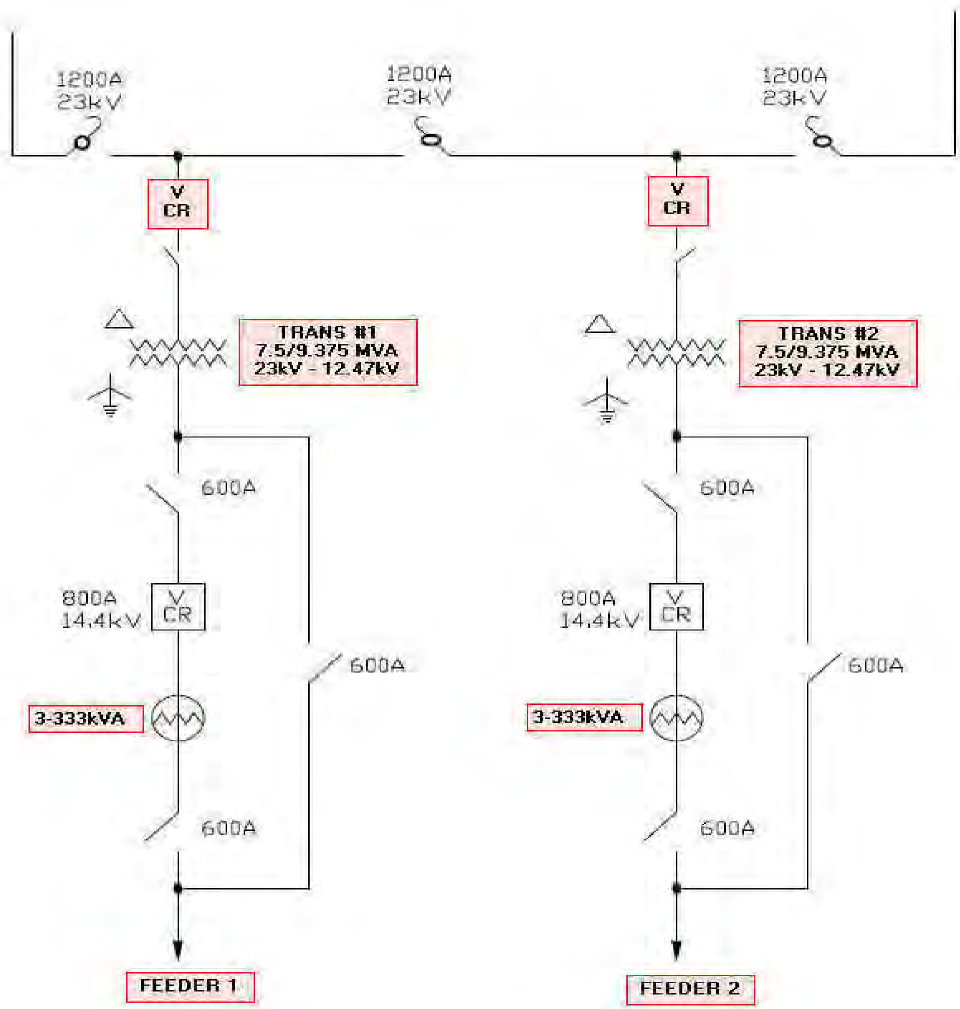


FIGURE 9.9.3 – KENT CORNERS SUBSTATION ONE-LINE DIAGRAM (PLAN 2)

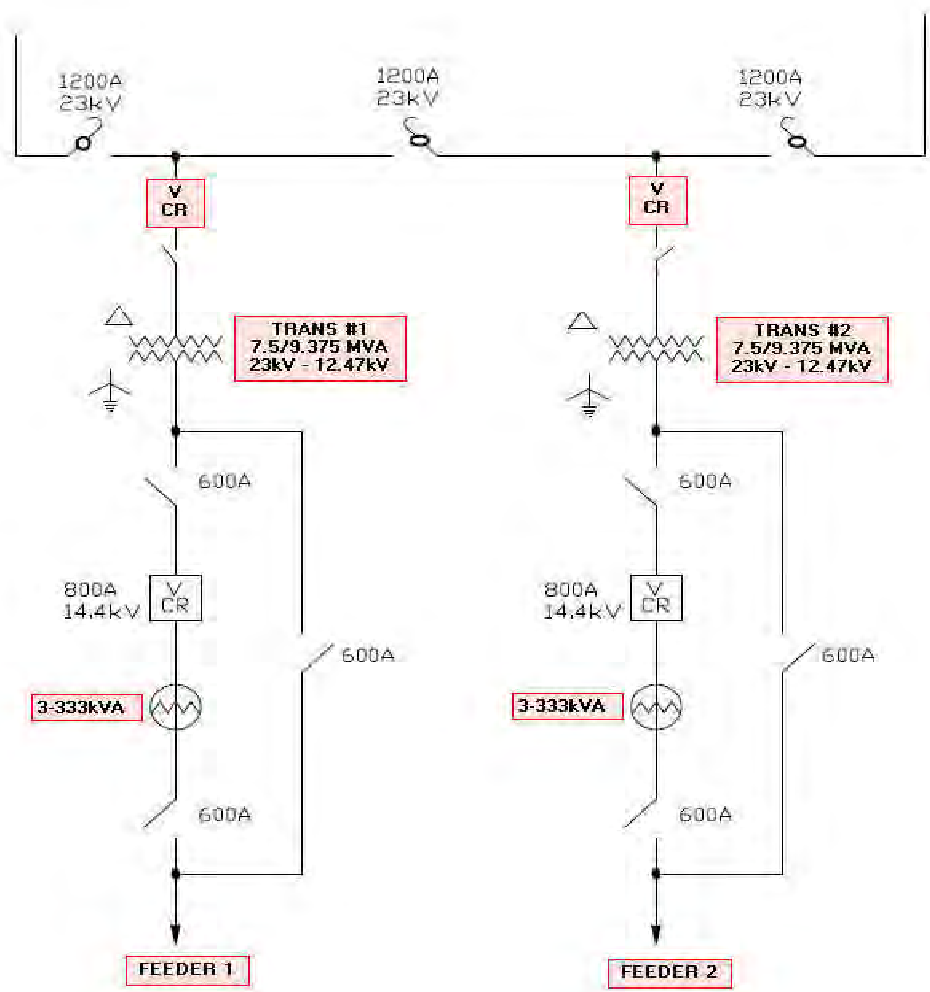
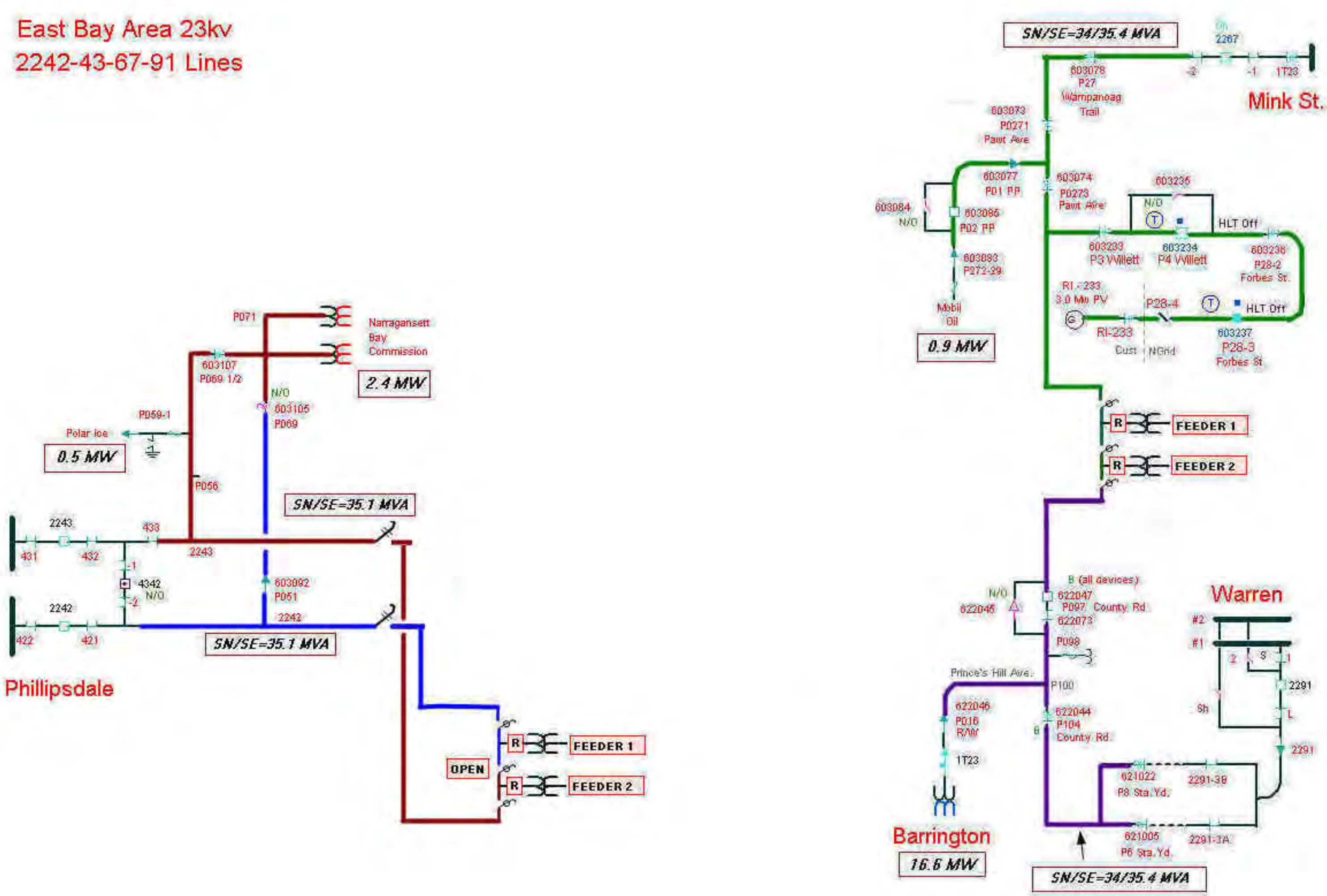


FIGURE 9.9.4 – MINK STREET SUBSTATION ONE-LINE DIAGRAM (PLAN 2)

[redacted]

FIGURE 9.9.5 – PROPOSED 23KV SUPPLY SYSTEM (PLAN 2)



9.10 Plan Development – Plan 3

FIGURE 9.10.1 – PHILLIPSDALE SUBSTATION ONE-LINE DIAGRAM (PLAN 3)

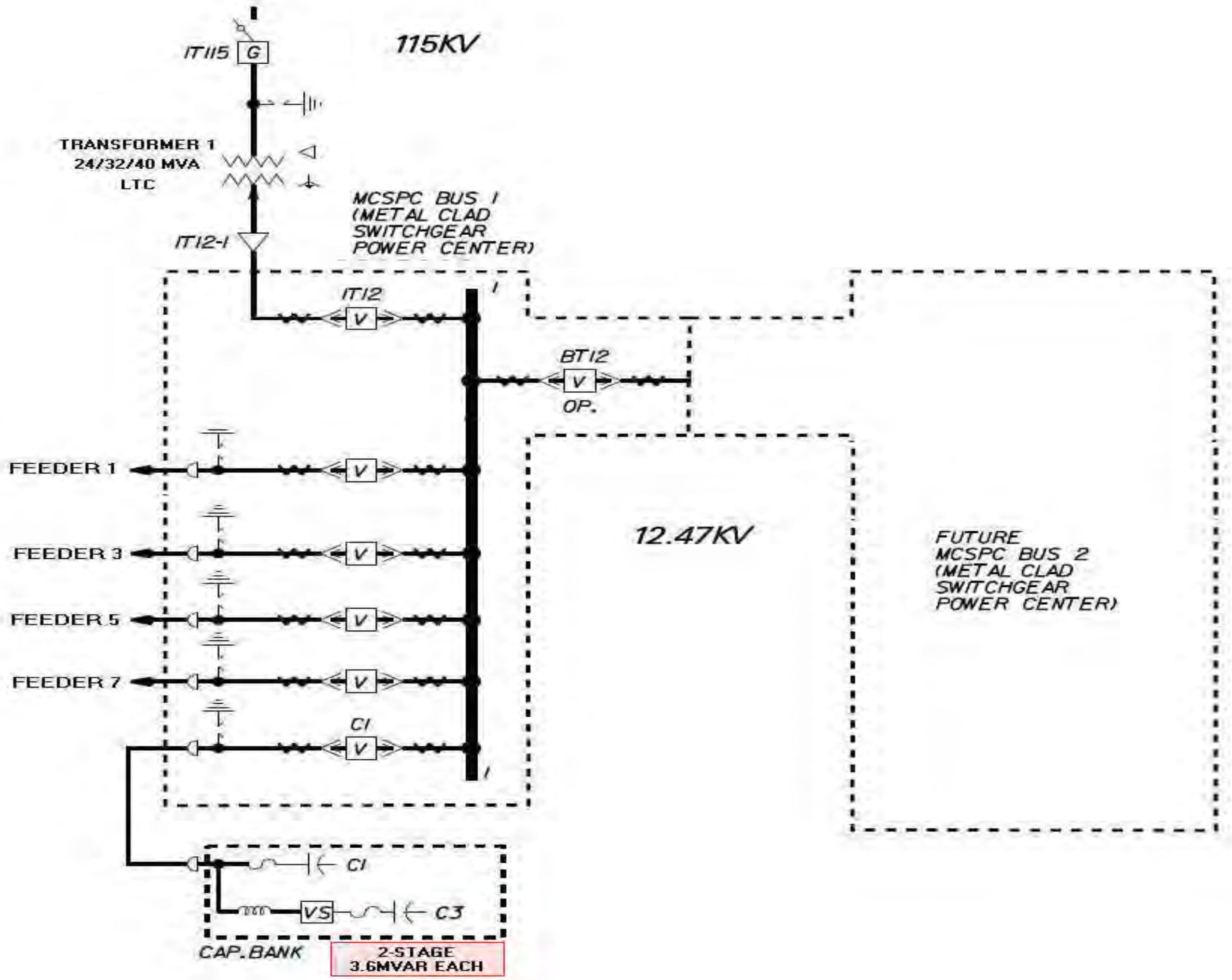
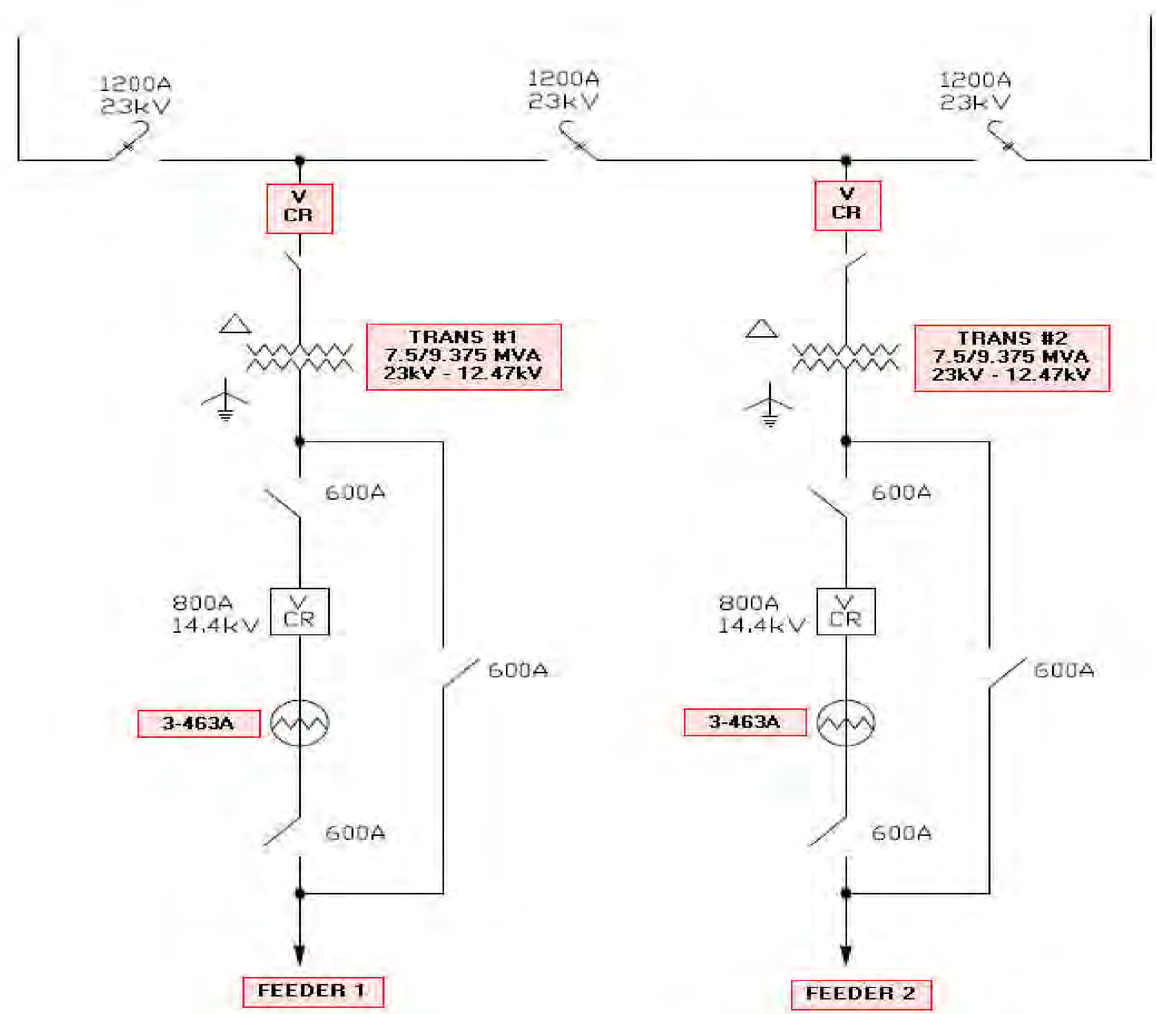
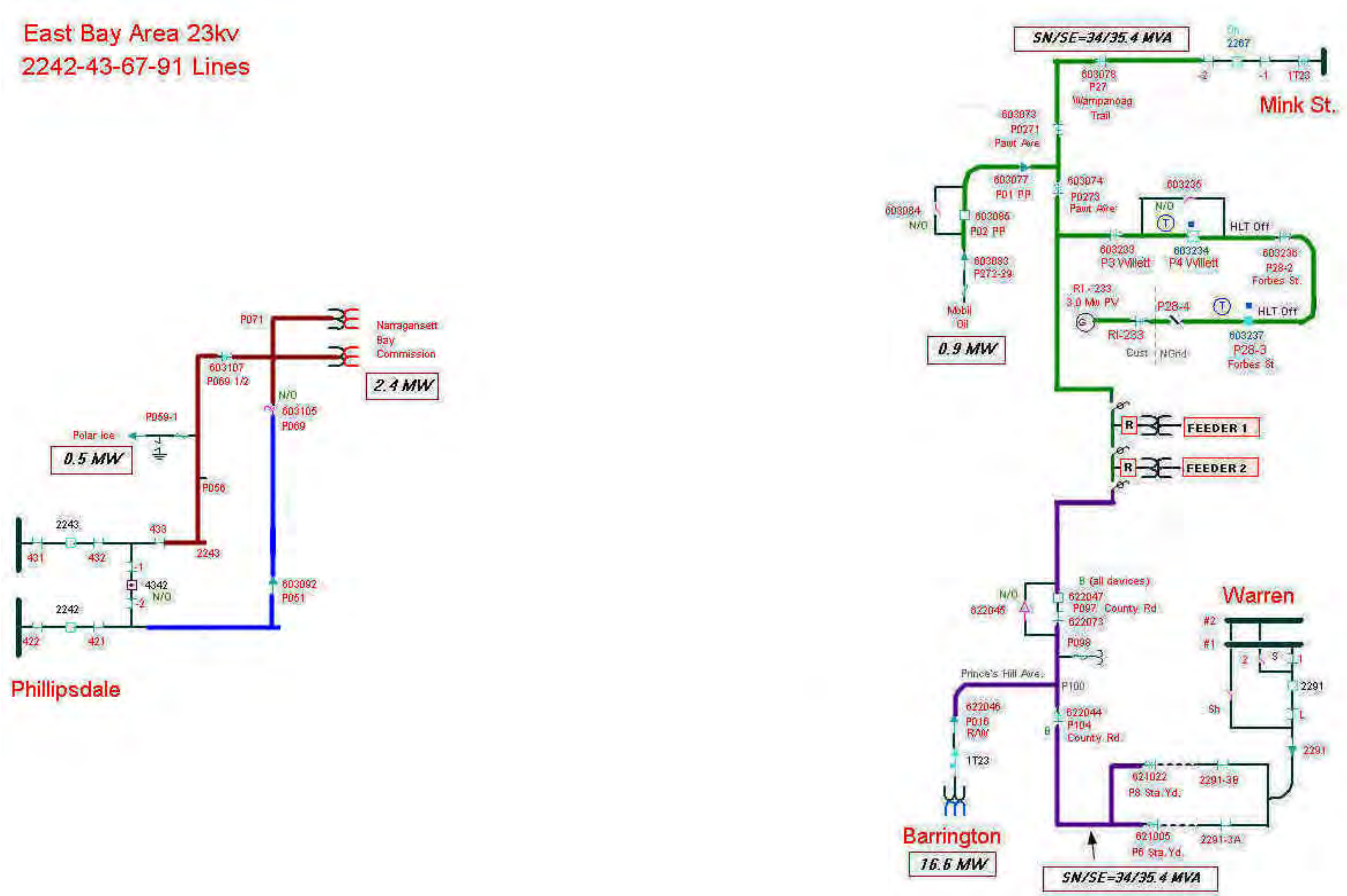


FIGURE 9.10.2 – KENT CORNERS SUBSTATION ONE-LINE DIAGRAM (PLAN 3)



[redacted]

FIGURE 9.10.4 – PROPOSED 23KV SUPPLY SYSTEM (PLAN 3)



9.11 Distributed Generation Within the Study Area

FIGURE 9.11.1 – Existing and Proposed Distributed Generation – East Bay Area

Feeder #	Organization Name	Existing Capacity (kW)	Proposed Capacity (kW)	Type
2267	FORBES STREET PROJECT LLC	3000	0	Solar
2267	FORBES STREET PROJECT LLC	0	3000	Solar
53-20F1	NATIONAL SECURITY CORP	45.6	0	Solar
53-20F2	DAVID CHOPY	4	0	Solar
53-48F1	MARVIC ENTERPRISES INC	0	7	Solar
53-48F3	JENNY K FLANAGAN	0	2.15	Solar
53-48F4	EAST BAY STORAGE	0	75	Solar
53-4F2	ROGER E DESLAURIERS	3.87	0	Solar
53-4F2	NOAH PHILIP	3.44	0	Solar
53-51F2	JOHN BRANDO	4	0	Solar
53-51F2	ELIZABETH RADUCHA	5	0	Solar
53-51F3	SAFE-WAY AUTO SALES INC	50	0	Wind
53-51F3	CLEMS ELECTRIC CO	28	0	Solar
53-5F1	GEOFFREY ALLEN	0	3.6	Solar
53-5F2	WESLEY J MILLER	3.66	0	Solar
53-5F2	TYSAS AND COMPANY INC	1.29	0	Solar
53-5F3	THOMAS FAIRCHILD	0	0.57	Solar
53-5F3	BEN LUK	0	6.45	Solar
TOTAL		3,149	3,095	

nationalgrid

Form 3A Recloser Replacement Study NE

Emilio Agustin

March 14, 2016

Reviewed by 3/14/16

Approved by 3/24/16

Table of Contents **Page**

1. Executive Summary

This study documents the need for the replacement of Cooper pole top reclosers (PTRs) equipped with Form 3A controls (Form 3A Reclosers) in New England. There are 200 identified locations over 8 districts in Massachusetts and Rhode Island. The replacements will be scheduled over a 5 year period.

The purpose of this program is to address multiple issues and concerns with in service Form 3A Reclosers in regards to operations, maintenance, safety, reliability, and asset condition. These units have been in service for more than 25 years and are exhibiting a variety of problems including but not limited to; battery charging circuit problems, battery failures, and exterior deterioration/rust, all of which have caused multiple malfunctions.

The intention of this program is to eliminate all Form 3A Reclosers from service. The primary means of doing so will be a one for one replacement with a standard recloser (presently a G&W Viper). However, before individual replacements are completed, Field Engineering will complete a review of field conditions and current feeder configurations. Results of this review will determine if elimination of a Form 3A Recloser will be addressed with one for one replacement, one for multiple replacement, or replacement with another switching device (ex. load break switch).

A Criticality Scoring Model (CSM) was developed for this program and it was used to produce a prioritized recloser replacement list. This list will be used for budgeting, work planning, and to provide direction for the further engineering review which will provide the development of specific replacement recommendations. The quality of the data evaluated in the model varied across the service territory and is expected to improve over time. As such, the candidate list will be refreshed as needed to consider recent recloser failures and system data.

2. Introduction

2.1 Purpose

In an effort to improve system service reliability, National Grid has, over the course of several decades, very successfully deployed thousands of line reclosers on its distribution feeders. Line reclosers are devices that sense and interrupt fault current and, after prescribed time delays, re-energize the line. This reduces the frequency of permanent interruptions resulting from system faults that are temporary in nature. In addition, reclosers significantly limit outage exposure when they operate to clear permanent faults since customers ahead of the line recloser installation will not experience an outage.

This study focuses on performance concerns that have developed with some of the earliest reclosers installed by the Company (Cooper reclosers equipped with Form 3A controls) located in MA and RI.

2.2 Problem

Operational, maintenance, safety, reliability and asset condition concerns exist with the Cooper Form 3A Reclosers. The specifics are detailed below:

2.2.1 Operational Problems and Worker Safety

These reclosers have been exhibiting battery charging circuit problems, causing battery failures. The battery in a recloser control is needed during normal operations. A dead battery prevents device operation (tripping) in response to system fault conditions because the main circuit path goes through the battery and battery charging circuit. Charging circuit problems have required additional procedures to be put in place when work is being done downstream of a Form 3A Recloser. In these situations, workers complete recloser battery checks before work commences. This inspection procedure adds time to all these jobs.

Additionally, construction Standards have changed significantly since most of these units were installed. Many do not have a shunt or in-line disconnects making switching and tagging or bypassing a faulty unit very difficult.

2.2.2 Maintenance problems

Form 3A Reclosers are oil filled. As unit failure frequency has increased, so have the occasions involving a release of oil. The modern replacement units are maintenance free solid dielectric with no such environmental concerns.

Additionally, maintenance and repair issues with these aging units are currently problematic. Form 3A controls are incompatible with all other newer Cooper controls (4C, 5, etc.), and when a unit fails the repair time is very lengthy because there is only one vendor in the U.S. that works on them.

2.2.3 System Reliability

Since Form 3A Reclosers were the first reclosers used by the company, they were placed in locations on feeders that would derive the greatest benefit from their functionality. As such, control failures can often result in very significant and disruptive outages impacting “critical customers” (hospitals & public safety facilities) and large numbers of customers.

Fault restoration procedures are complicated with these reclosers. Dead batteries and/or blown control fuses make the units unusable to a switch person. This extends outage times, and also increases the customer minutes interrupted (CMI). The lack of targets (phase identification), or fault info compared to modern devices, increases the time to isolate the problem in the feeder and further increases CMI. Device repair complexities have led to units being left inoperable for long periods of time. This negates all the benefits that this switching and protective device would have provided the circuit and its customers.

Additionally, load readings for maintenance switching or annual circuit analysis are not available on these devices. Therefore, operators and engineers rely on load estimates to make decisions instead of actual values.

2.2.4 Limited functionality

Form 3A reclosers lack the modern functionality which has become essential to system operators and the engineering groups. They have no over current target indications or load readings so they can’t provide critical information during emergency situations. They have limited protection settings making it hard to coordinate with the station breakers, upstream or downstream reclosers and main line fuses. Additionally, they have sparse control interfaces (a few LED’s and toggle switches), they lack modern controls like Supervisory Control and Data Acquisition (SCADA) which allows remote open/close and data sharing, telemetered loads, modern TCCs (Time Current Curves), fault value reports, computer interfaces, and logging functions.

Form 3A Reclosers are also not directionally independent, so the units will only close when energized from the normal source side, limiting switching options during both normal and contingency switching operations.

2.2.5 Age and Asset Condition

Form 3A reclosers were last installed as new in the early 1990’s. As such, almost all units have been in service in excess of 25 years. Control boxes (mostly installed at street level) have been exposed for all this time to the environment and road salt, and corrosion has become a significant concern. Lastly, these reclosers were not built with 23 or 35kV insulators, as current PTR installation standards dictate, making them more susceptible to faults caused by animal contacts. These faults cause large customer interruptions and can damage equipment.

2.3 Scope

This program will cover the replacement of the 200 Form 3A Reclosers presently in service in the NE area over a 5 year period.

3. Background

National Grid uses reclosers to improve customer reliability, provide load side fault protection and to enhance worker safety. These units are basically over current protective devices, and their general function is to sense and interrupt fault current, re-energize the line if the fault is of temporary nature, and sectionalize faulted sections of distribution circuits.

In our systems we have numerous reclosers from different vintages and models from at least two different manufactures. Form 3A Cooper Reclosers were installed as early as the 1980's. Although innovative at that time, they are now considered outdated. These units have been in operation for more than 25 years and have all the operational concerns detailed in Section 2.2.

Feeder sizes and customers downstream from these units have changed through the years.

4. Program Description

4.1 Infrastructure Development

National Grid's Distribution Construction Standards have changed considerably over the last 35 years. For example, current standards for switch installations require the use of an H1 class pole, bypass disconnects and a sectionalizing switch. Many Form 3A Recloser installations occurred prior to these requirements. An initial review with the data available from EMS and GIS provided an assessment of what are the current construction conditions are at each field location. This provided a possible construction scope which we used to estimate the program cost. Actual work required however, won't be determined until after complete review by Distribution Field Engineering. A complete review of each circuit location and configuration will be performed including a visual inspection to validate priority. When replaced, the following three possible construction scenarios will result from this review, in addition to adhering to the latest construction standards:

Scenario 1 - Review determines the need for a single pole top recloser, either on the same location or a different position on the feeder.

Scenario 2 - Review determines the need to install more than one recloser to optimally sectionalize the circuit.

Scenario 3 - Review determines that there is no need for a recloser given existing circuit configuration and that installation of a load break switch will be adequate for operational needs.

New recloser installations require a ground mesh installation when control boxes are installed within 8 feet from the ground. A ground mesh installation is expensive and often complex, requiring additional permitting and most of the existing locations do not have them. Installing recloser controls above 8 feet also reduces the threat from vandalism and unintended sidewalk issues, such as; damage from motor vehicle accidents or municipal equipment when performing work in or near the sidewalks. The new Viper Recloser's remote control features and the minimum maintenance requirements actually reduce the need for direct access to the control box. Locations with limited access, like ROW's and rural areas, obviously present less installation complexities and therefore reduce the costs of ground mesh installations. Therefore, the Operation's departments in each area are encouraged to avoid ground level installations. A decision to install a ground level installation must weigh the operational benefits with the installation cost, scope and maintenance increases.

4.2 Identification

This program has identified 200 Form 3A Reclosers that are still in operation inside our NE service territory. The EMS and GIS systems were used to identify these units. Table 1 below shows the existing locations per state and districts:

Table 1: Cooper Form 3A Recloser locations

Massachusetts		**Rhode Island**	
Central	61	Capital	19
West	27	Coastal	19
North Shore	2		
Merrimack Valley	18		
South East	50		
South Shore	4		
Total	**162**	**Total**	**38**

Existing locations include substations , Rights-of-Way, private driveways to businesses, parking lots, main roads and side streets. These units could have one large customer or large portions of feeders downstream of their installation location. EMS & GIS were used to not only obtain the location but also other physical unit data that was used in the prioritization process, including; % Feeder Load, Customer Count, Pole Ownership (SO, JO), Pole Size and Set Date, Station Breaker, and Location (ROW, Street, Private property).

The Business Services customer database was also queried to obtain the "critical customer" data for the distribution feeders that have an in service Form 3A Recloser. Reclosers with "critical customers" downstream of them where given special consideration and a higher value under the prioritization criteria due to the high sensitivity of these customers.

4.3 Prioritization

A CSM was developed for this program and it was used to produce a prioritized recloser replacement list. This list will be used for budgeting, work planning, and to provide direction for further engineering review which will provide the development of specific replacement recommendations. The quality of the data evaluated in the model varied across our territories and is expected to improve over time. As such, the candidate list will be refreshed as needed to consider recent, recloser failures and system data.

Our CMS includes standardized weighting factors; Safety/Exposure (30%), Asset Condition (20%), Customer (40%) and Reliability/Performance (10%) as shown in Appendix 1.

The detailed criterion and its relative impact in the CSM is shown in Appendix 2.

The data is weighted exponentially by level as shown at the top of the tables found in Appendix 2, with most risk assigned the highest level and score. In the Excel based scoring tool used for this program, the weighting of each data set and the criteria for each level within the data set can be altered, and are shown in red in the scoring matrices. This allows scoring to be varied depending on the availability of data. In this case, the Customer category was the biggest driver ensuring reclosers on feeders with large and "critical customer" exposure are addressed first. Other main drivers considered in the evaluation are; location of unit, existing construction versus current construction standards, if the unit serves as a Station Breaker, existing pole size and age, pole ownership and if device is on a Worst Performing Feeder.

The final outcome from this prioritization model is a list of reclosers to be replaced, in order of priority from 1 to 200, to be used by Program Management in the decision making when deciding when and what reclosers to be replaced in years 1 to 5 of the program.

4.3.1 Resource Considerations

Other Departments
The volume of work proposed in this program requires additional resources from Engineering, Program Management, and Operations.

Verizon & Special Equipment
In addition to National Grid resources, resources from our joint pole owner (typically Verizon) will also be required. Verizon sets poles in multiple locations around the NE area as assigned through our Joint Owner Pole (JO) Agreement. Replacement of PTRs often requires the replacement of one or more poles for equipment and line clearances. Notification and documentation to the JO should be expedited to prevent construction delays due to pole setting needs.

Additionally, recently updated construction standards, Section 4 – Storm Hardening, require the use of Class H1 poles for the installation of new PTRs and load breaks. Verizon has informed National Grid they will not be installing class H1 poles or poles larger than 50 feet in their maintenance areas. Hence, our crews will have to install all H1 class poles for the PTRs. Distribution Design has created an internal process to expedite this procedure. They send a manually created 605 Form to Verizon indicating our intent to replace an existing pole with an H1 pole, and therefore we do not wait for the rejection process to complete before releasing the job to construction. National Grid then charges Verizon a set fee per our JO Agreement. Operations also has to manage equipment concerns when installing H1 class poles. The diameter of H1 pole butts require our pole setting digger trucks to use 24 inch augers which are larger than the standard 18 inch augers our vehicle use today. Some operating districts may need to purchase the larger augers or existing 18 inch augers can be used and the holes would need to be manually widened during the installation.

Outages
The replacement of PTRs usually does not require a main line outage to perform the work, but a small portion of Form 3A Reclosers feed single commercial customers and therefore will

require an outage. Coordination with these commercial customers will be required to setup the outages.

Grid Mod
National Grid's future Grid Modernization projects will require field switching devices that are capable of sensing voltage and current, and are equipped with special communication features. Units installed by this replacement effort should have the ability to be modified as required, and be compatible with any technology we are currently adopting. Today's construction standards call for the use of modern Viper reclosers which offer multiple alternatives for communications, provide readings for voltage and current, and are reasonably flexible to allow some future modifications, so they are the best choice for replacement at this time.

Radios
In August 2012, AT&T announced support for the 2G cellular technology will reach its end-of-life by the end of 2016. In addition, Sensus will also be upgrading PowerVista to a new system called Automation Control. Therefore, National Grid will be required to visit approximately 1900 reclosers in the field to upgrade the radios and firmware to retain remote communications. A team from multiple departments has been initiated to look at possible solutions and an implementation plan. New reclosers installed within this project will need to have the latest preferred NGrid communications equipment.

Equipment Availability
Implementation of this project will create a higher demand for PTRs than usual. These devices are already in high demand for existing commercial service and infrastructure jobs, including Distributed Generation projects that are emerging all over our service territory. Given this concurrent demand and the required manufacturer three to five month lead time, continuous coordination will be required with Supply Chain and the CDC.

Project Management
There are many coordination complexities associated with this PTR replacement process that will demand proper and prior planning. Distribution Control Center commissioning process requires documentation to be submitted in advance for planning and review. Coordination between Distribution Planning and Distribution Design is required to ensure all drawings and documents are completed and submitted as required. Execution strategies for this recloser replacement program should consider the use of a dedicated Project Manager following a beginning to end process that will identify handoff points to key players (Distribution Design, Planning, Operations, PTO, and Control Center) throughout the complete life cycle. The coordination required between multiple groups for each install has proven reclosers to be one of our most complex distribution line installations. A project managed approach may improve the priority placed on program execution and would enable the leveraging of lessons learned as initial reclosers are replaced.

4.3.2 Objectives and Benefits

The main objective of this program is to replace all Cooper Form 3A Reclosers in the distribution system.

The reasons for this replacement program are detailed in Section 2.2 and are summarized below:

- Battery and charging circuit problems
- In-Line battery design which makes battery required for unit operation
- Requires additional operating procedures
- Potential for environmental issues w/loss of oil
- Long vendor repair times
- Ground level control box deterioration (severe rusting)

The benefits anticipated from this replacement program are also detailed in Section 2.2 and are again summarized below:

- New installation will be in accordance with the latest construction standards
    - H1 Poles meeting highest storm rating
    - Increased pole spacing for increased worker protection and less animal contacts
    - Bypass/Shunt & In-Line disconnects for improved maintenance
- Improved information and data sharing shortens outage and switching times and increases data accuracy
- Additional and robust protection setting options provides improved coordination which leads to fewer CMI
- Directionally independent devices which provide more flexibility when switching and also leads to lower CMI
- Full remote operation shortens outage and switching times and greatly decreases the amount of times a remote unit must be field visited
- Less required maintenance
- Creating this program to replace existing Form 3A PTRs with today's modern Viper solid Dielectric models will provide a standard, efficient and repeatable process to replace this type of aging infrastructure
- This replacement program will also provide an opportunity to study our system for optimal application of the reclosers on these feeders

4.3.3 Costs

Recloser replacements will be scheduled over a 5 year period, with quantities distributed evenly throughout 8 districts in both MA and RI. Replacement costs for each location will depend on the existing installation type and the results of Planning Engineer's review. Table 2 below shows the different possible construction cost for each scenario:

Table 2: Estimated Construction Cost

Estimate Name	Cap	O&M	Rem	Total
Recloser Study MA Isolation Switch Install	$ 5,527.20	$ 276.36	$ 276.00	$ 6,079.56
Recloser Study MA Isolation Switch Install and Pole	$ 7,926.00	$ 396.30	$ 714.00	$ 9,036.30
Recloser Study MA Replace Rec	$ 47,860.80	$ 2,393.04	$ 3,662.40	$ 53,916.24
Recloser Study MA Replace Rec and Pole	$ 50,505.60	$ 2,525.28	$ 4,100.40	$ 57,131.28
Recloser Study MA Replace Rec and Pole plus 2 poles	$ 57,052.80	$ 2,852.64	$ 5,424.00	$ 65,329.44
Recloser Study MA Replace Rec with LB	$ 25,729.20	$ 1,286.46	$ 3,662.40	$ 30,678.06
Recloser Study MA Replace Rec with LB and Pole	$ 28,374.00	$ 1,418.70	$ 4,100.40	$ 33,893.10
Recloser Study RI Isolation Switch Install	$ 5,968.80	$ 298.44	$ 303.60	$ 6,570.84
Recloser Study RI Isolation Switch Install and Pole	$ 8,563.20	$ 428.16	$ 790.80	$ 9,782.16
Recloser Study RI Replace Rec	$ 50,504.40	$ 2,525.22	$ 4,045.20	$ 57,074.82
Recloser Study RI Replace Rec and Pole	$ 53,354.40	$ 2,667.72	$ 4,532.40	$ 60,554.52
Recloser Study RI Replace Rec and Pole plus 2 poles	$ 60,426.00	$ 3,021.30	$ 5,997.60	$ 69,444.90
Recloser Study RI Replace Rec with LB	$ 27,216.00	$ 1,360.80	$ 4,045.20	$ 32,622.00
Recloser Study RI Replace Rec with LB and Pole	$ 30,064.80	$ 1,503.24	$ 4,532.40	$ 36,100.44

Based on all the available system information discussed in section 4.2 and 4.3, each recloser location was matched with an installation scenario shown above to create a preliminary estimate. These were distributed over a 5 year period to show the replacement of all 200 Form 3A reclosers which will cost a total of $12.152M. Individual work requests (WRs) will be initiated per recloser location under two funding projects, one for MA and one for RI. The projects will be sanctioned on an annual basis. The next table (3) shows the estimated breakdown of annual costs:

Table 3: Five year Cost Forecast

State	Area	Qty	YR1	YR2	YR3	YR4	YR5	Total
MA	Central	61	13	12	12	12	12	**61**
MA	West	27	6	6	5	5	5	**27**
	Total	**88**	**19**	**18**	**17**	**17**	**17**	
	Central		**$ 802,771.00**	**$ 749,707.00**	**$ 734,738.00**	**$ 693,241.00**	**$ 720,703.00**	**$ 3,701,160.00**
	West		**$ 341,996.00**	**$ 356,032.00**	**$ 304,508.00**	**$ 274,734.00**	**$ 263,782.00**	**$ 1,541,052.00**
	Total		**$ 1,144,767.00**	**$ 1,105,739.00**	**$ 1,039,246.00**	**$ 967,975.00**	**$ 984,485.00**	**$ 5,242,212.00**
MA	North Shore	2	1	1	0	0		**2**
MA	Merrimack Valley	18	4	4	4	4	2	**18**
	Total	**20**	**5**	**5**	**4**	**4**	**2**	**20**
	North Shore		**$ 62,476.00**	**$ 62,476.00**				**$ 124,952.00**
	Merrimack Valley		**$ 249,902.00**	**$ 277,404.00**	**$ 231,080.00**	**$ 238,950.00**	**$ 54,606.00**	**$ 1,051,942.00**
	Total		**$ 312,378.00**	**$ 339,880.00**	**$ 231,080.00**	**$ 238,950.00**	**$ 54,606.00**	**$ 1,176,894.00**
MA	Southeast	50	10	10	10	10	10	**50**
MA	South Shore	4	2	2	0	0		**4**
	Total	**54**	**12**	**12**	**10**	**10**	**10**	**54**
	Southeast		**$ 606,982.00**	**$ 625,526.00**	**$ 606,982.00**	**$ 551,489.00**	**$ 496,566.00**	**$ 2,887,545.00**
	South Shore		**$ 117,852.00**	**$ 124,951.00**				**$ 242,803.00**
	Total		**$ 724,834.00**	**$ 750,477.00**	**$ 606,982.00**	**$ 551,489.00**	**$ 496,566.00**	**$ 3,130,348.00**
RI	Capital	19	4	4	4	4	3	**19**
RI	Coastal	19	4	4	4	4	3	**19**
	Total	**38**	**8**	**8**	**8**	**8**	**6**	**38**
	Capital		**$ 294,577.00**	**$ 281,886.00**	**$ 270,011.00**	**$ 231,350.00**	**$ 168,263.00**	**$ 1,246,087.00**
	Coastal		**$ 291,240.00**	**$ 303,115.00**	**$ 279,365.00**	**$ 281,886.00**	**$ 200,906.00**	**$ 1,356,512.00**
	Total		**$ 585,817.00**	**$ 585,001.00**	**$ 549,376.00**	**$ 513,236.00**	**$ 369,169.00**	**$ 2,602,599.00**
	Overall	**200**	**44**	**43**	**39**	**39**	**35**	**200**
	MA		**$ 2,181,979.00**	**$ 2,196,096.00**	**$ 1,877,308.00**	**$ 1,758,414.00**	**$ 1,535,657.00**	**$ 9,549,454.00**
	RI		**$ 585,817.00**	**$ 585,001.00**	**$ 549,376.00**	**$ 513,236.00**	**$ 369,169.00**	**$ 2,602,599.00**
	Total		**$ 2,767,796.00**	**$ 2,781,097.00**	**$ 2,426,684.00**	**$ 2,271,650.00**	**$ 1,904,826.00**	**$ 12,152,053.00**

5. Conclusions and Recommendations

It is recommended that the Company pursue a program to replace all existing Form 3A Cooper reclosers in the NE area over a 5 year construction period.

Field Engineering will perform an engineering review of each recloser location and provide construction recommendations in the first year. Individual WRs created under each project will be managed according to complexity and a Program or Project Manager will track the progress.

6. Factors Requiring Program Review

It is not expected that the work required by the program will require further technical reviews.

We will however assess the average cost of these replacements at the end of the first construction year to refine our estimates. We will review the optimal amount of yearly spend with the Resource Planning Department every year through our resanctioning process. As the budget is managed throughout the year by Resource Planning and Investment Planning, they may dictate spending levels that may slightly decrease or increase the actual length of this proposed five year construction program. DAMs input into this process will ensure that the intent of this program is not compromised.

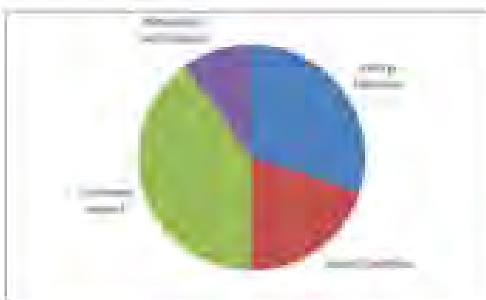
Furthermore, the weighting factors in the CSM developed in this study will be re-evaluated as necessary, as more information becomes available, such that the DAM Department can ensure that the most critical PTRs are being addressed first.

7. Appendices

Appendix 1 - Criticality Scoring Model – Input Data Weighting

Prioritization – Input Data Weighting

- Safety/Exposure Impact: 30%
  What is the risk of potential injury in case of an event?
- Asset Condition: 20%
  What is the current state of the asset and what is the likelihood/rate for continued deterioration?
- Customer Impact: 40%
  How is the customer (and how many) impacted by an event?
- Reliability/Performance: 10%
  How does the asset perform and what is the likelihood/rate for continued performance degradation?



Appendix 2 - Block Scoring Matrix for Identifying System Improvement

Recloser Scoring

Category	Data Source	Weight	Level 1 1	Level 2 20	Level 3 100	Level 4 400	Level 5 1000
Safety/Exposure		**25.0%**					
ROW/Street	GIS	8.0%	na	na	Street	ROW	na
Construction Standards	GIS/EMS	8.0%	na	na	Yes	No	na
Station Breaker	GIS/EMS	9.0%	na	na	na	No	Yes
Asset Condition		**15.0%**					
Pole Size	GIS	7.5%	50 ft	45 ft	40 ft	35 ft	30 ft
Pole Set Year/Age	GIS	7.5%	na	1-10 Years	10-30 Yrs (2006)	30-50 Yrs (1986)	50+ Yrs (1966)
Customer		**30.0%**					
%Feeder Load	EMS	8.0%	na	0-50%	50-75%	75-90%	>90%
# Customer	Analytical Group	8.0%	na	na	0-1000	>1000	>2000
Critical Facilities	CF Table	14.0%	na	na	None	Tier 2	Tier 1
Reliability/Performace		**30.0%**					
SO/JO	GIS	2.5%	na	JO	SO	na	na
Verizon/ Ngrid Set	GIS	2.5%	na	na	None	Verizon	Ngrid
Worst Performing Feeder 2015	Reliability	10.0%	No	na	na	na	Yes
Coordination Problem	Reliability	15.0%	No	na	na	na	Yes

Appendix 3 – Prioritization Table

"Large format spreadsheet attached separately"

The Company conducts routine system analyses on its distribution system in the form of Capacity Reviews and Area Planning Studies.

The Company Capacity Review is completed on an annual schedule and identifies thermal capacity constraints, assesses system performance to ensure that the network maintains adequate delivery voltage, and assesses the capability of the network to respond to contingencies that might occur. The capacity planning process includes the following tasks:

- Review of historic loading on each sub-transmission line, substation transformer, and distribution feeder;
- Review of a weather adjustment of recent actual peak loads as per the Electric Peak (MW) Forecast;
- Review of econometric forecast of future peak demand growth as per the Electric Peak (MW) Forecast;
- Analysis of forecasted peak loads with comparison to equipment ratings; and
- Consideration of system operational flexibility to respond to various contingency scenarios;

When Capacity Reviews highlight an area that has capacity constraints of a level where a detailed and comprehensive analysis is warranted, that area is identified as needing an Area Planning Study. Other prompts for an Area Planning Study include the identification of asset condition issues, a large new customer load request, or acute reliability issues.

Area Planning Studies include the following stages:

Stage 1: Definition of electrical and geographical scope of study and gathering necessary data needed to execute the study;
Stage 2: Initial System Assessment consisting of a quick analysis of facilities and system performance within the identified study geographic and electric scope;
Stage 3: Study Kick off meeting held to inform the larger stakeholder group that an area study is underway and to solicit inputs from those with knowledge of the system infrastructure in the area under review;
Stage 4: Detailed System Assessment / Engineering Analysis;
Stage 5: Development and Project Estimating of alternative infrastructure and non-wires alternative plans;
Stage 6: Review of various alternatives' relative costs and benefits, and identifying and finalizing a recommended plan;
Stage 7: Technical Review presentation with approval committee;
Stage 8: Delivery of area study report documentation upon completion of the study;
Stage 9: Sanction of any recommended projects having forecasted spending within the next three fiscal years.

During the Development and Project Estimating stage (Stage 5, above), Engineers screen projects for non-wires alternatives (NWA). NWA screening is based on criteria defined in Docket 4684 – The Narragansett Electric Company, d/b/a National Grid 2018-2020 Energy Efficiency and System Reliability Procurement Plan (SRP). This 3-year plan was submitted in compliance with the R.I. Gen. Laws § 39-1-27.7 and the revised Least Cost Procurement

Standards (Standards). The Company agrees to consider all alternatives in order to identify the least cost option.

Assessment of Applicability of Non-Wires Alternatives (SRP Planning)
Identified electric distribution system needs that meet the following criteria will be evaluated for potential NWAs that could reduce, avoid or defer a T&D wires solution over an identified time period.

i. The need is not based on asset condition;
ii. The wires solution, based on engineering judgment, will likely cost more than approximately $1 million; the cost floors may vary across different project types and time frames;
iii. If load reductions are necessary, then they are expected to be less than 20 percent of the relevant peak load in the area, or sub area in the event of a partial solution, of the defined need;
iv. Start of wires alternative construction is at least 30 months in the future;
v. At its discretion, the Utility may consider and, if appropriate, propose a project that does not pass one or more of these criteria if it has reason to believe that a viable NWA solution exists, assuming the benefits of doing so justify the costs.

At this point NWAs are progressed for regulatory review and funding through the Company's System Reliability and Procurement Plan. There are no investments within the FY2021ISR plan that have an overlapping NWA being progressed through the SRP.

Below are the current projects in the FY2021 ISR that originated from an area study or legacy project.

Project	Respective Planning Study area
Southeast (aka Dunnell Park)	Legacy Project – Blackstone Valley North
Dyer Street-Indoor Substation	Legacy Project - Respected in Providence System Area Study
Providence LT Study	Providence
Aquidneck Island (Newport projects)	Legacy Project - Newport
New Lafayette Substation	South County East
Warren Substation	East Bay
East Providence Substation	East Bay

The Annual Capacity Review, asset condition evaluations, large customer requests, and reliability reviews inform the prioritization of area planning studies to be completed. The attached table provides the current prioritization and status of annual Capacity Reviews and Area Planning Studies. Studies typically address issues in a 10- to 15-year window. The next study in a particular area typically starts 5 – 7 years after the last study is complete. These dates are subject to change based on annual system assessments that will inform the commencement and prioritization of future studies.

Rank	Study Area	Load (MVA)	% State Load	# Feeders	# Stations	Annual Planning Review % Complete	Area Planning Study % Complete	Area Planning Study Stage	Estimated Planning Study Complete Date	Expected Commencement of next Area Study
1	Providence	358	19%	95	17	100%	**100%**	Stage 9	Complete 2017	2024
2	East Bay	147	8%	22	7	100%	**100%**	Stage 9	Complete 2015	2022
3	Central Rhode Island East	204	11%	37	9	100%	**100%**	Stage 9	Complete 2017	2024
4	South County East	159	9%	22	9	100%	**100%**	Stage 9	Complete 2018	2025
5A	Blackstone Valley North	139	8%	27	6	100%	85%	Stage 7	Oct-2020	2026
5B	North Central Rhode Island	269	15%	35	10	100%	85%	Stage 7	Oct-2020	2026
6	South County West	98	5%	14	5	100%	40%	Stage 4	March-2021	2027
7	Central Rhode Island West	167	9%	33	11	100%	40%	Stage 4	Dec-2020	2027
8	Tiverton	28	2%	4	1	100%	40%	Stage 4	Dec-2020	2027
9	Blackstone Valley South	171	9%	54	11	100%	10%	Stage 2	Dec-2020	2027
10	Newport	105	6%	42	12	100%	0%	NA	Jun-2021	2020
	Totals	**1845**	**100%**	**385**	**98**	**100%**	70%[i]			

[i] Percent complete based on total state load studied.

This document has been redacted for Critical Energy/Electric Infrastructure Information (CEII)

nationalgrid

Providence Area Study Implementation Plan 2016 - 2030

September 2017

Reviewed by: ______________________________ Date: ____________________
Ryan Constable, Manager, Distribution Asset Management – New England

Approved by: ______________________________ Date: ____________________
Alan LaBarre, Director, Distribution Planning & Asset Management NE

Table of Contents

Pages

1. Executive Summary

A long term supply and distribution study for the Providence area was completed by PLM for National Grid in May 2014. The study identified issues in the Providence area and evaluated alternatives to address those issues and to supply projected load growth through 2063. A long term strategy was presented to guide the development of the electrical supply and distribution system.

This study provides a plan for the period 2016 – 2030 to implement the long term strategy presented in the long range study. Projects such as the Dyer Street and South Street substation rebuilds were advanced upon completion of the long term study due to priority asset condition issues and not included in this implementation plan.

The long term study developed a comprehensive plan to address the asset condition issues through expansion of the 12.47 kV distribution system and conversion of a majority of the 11.5 kV and 4 kV distribution feeders. An initial step for the implementation plan was to prioritize the indoor stations through consultations with the Operations group. Prioritization of asset concerns together with existing capacity on the 12.47 kV distribution system was used to develop the sequence of the implementation plan.

The major components of the 15-year plan are the construction of two new 115/12.47 kV stations at Admiral Street and Auburn, which are in the northern and southern sections of the study area respectively. Other smaller infrastructure developments are required to complete the plan.

The major components of the Admiral Street Substation Plan are to:

- Build a new 115/12.47 kV breaker and one half metal clad substation at Admiral Street with two circuit switchers, two 115/12 kV 33/44/55 MVA LTC transformers, eight feeder positions, and two 7.2 MVAr multistage capacitor banks. Tap the Q-143 and R-144 circuits in the substation yard to supply the transformers.
- Retire the 11.5 kV and 4.16 kV substations in the northern half of the study area and supply the load from the new 12 kV Admiral Street station.

The major components of the Auburn Substation Plan, which were co-studied in the Central Rhode Island Study, are to:

- Build a new 115/12.47 kV substation, open air low profile with a breaker and one half design, at the existing Auburn substation site with two 115/12.47 kV 33/44/55 MVA transformers, eight feeder positions, and two 7.2 MVAr station capacitor banks.
- Extend two 115 kV transmission lines, I-187 and J-188, from Sockanosset substation approximately 1.10 miles north to the proposed Auburn substation. This proposed transmission line extension will be located within the existing 23 kV sub-transmission right-of-way and no new rights are anticipated to be required.
- Modify the area distribution due to the eight new feeders from Auburn substation. Retire the Auburn 23/4.16 kV station, the Lakewood 23/4.16 kV station, and the Sockanosset 115/23 kV station. The 12.47 kV capacity at Auburn will also be used to convert the 4.16 kV load at Huntington Park and Sprague Street substations and allow for their retirement.

Table 1 shows the estimated capital spending per project with Admiral Street substation plan, Auburn substation plan and other infrastructure development plan subtotals. The total capital cost to implement the 15-year plan is estimated at $104.8M.

Table 1 – Estimated Capital Spending By Project ($M)

Description	Rationale	TOTAL	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Admiral Street Substation Plan															
Admiral Street (T-Sub)	Asset Condition	$0.50				0.05	0.10	0.30	0.05						
Admiral Street (D-Sub)	Asset Condition	$10.59		0.25	0.50	2.30	1.87	4.86	0.81						
Admiral Street (D-Line)	Asset Condition	$50.74	0.29	1.81	4.68	8.12	8.34	10.39	10.02	7.09					
Admiral Street Total		$61.83	$0.29	$2.06	$5.18	$10.47	$10.31	$15.55	$10.88	$7.09					
Auburn Substation Plan															
Auburn Substation (T-Sub)	Asset Condition	$0.50								0.05	0.10	0.30	0.05		
Auburn Substation (T-Line)	Asset Condition	$6.00							0.15	0.45	2.85	2.55			
Auburn Substation (D-Sub)	Asset Condition	$8.31								0.83	1.66	4.99	0.83		
Auburn Substation (D-Line)	Asset Condition	$11.99						2.03	4.06	4.43	0.73	0.73			
Lakewood, Sockanosset (D-Line)	Asset Condition	$4.10								0.82	1.64	1.64			
Sprague Street (D-Line)	Asset Condition	$4.68								0.94	1.87	1.87			
Huntington Park (D-Line)	Asset Condition	$0.97								0.19	0.39	0.39			
Auburn Total		$36.54						$2.03	$4.21	$7.71	$9.24	$12.47	$0.88		
Other															
Knightsville, Lippit Hill, Geneva (D-Sub)	Load Relief	$5.21										0.48	0.996	3.218	0.521
Knightsville, Lippit Hill, Geneva (D-Line)	Load Relief	$0.85										0.17	0.34	0.34	
East George (D-Line)	Load Relief	$0.45										0.09	0.18	0.18	
Other Total		$6.51										$0.74	$1.52	$3.74	$0.52
TOTAL (T-Spend)		$7.00				$0.05	$0.10	$0.30	$0.20	$0.50	$2.95	$2.85	$0.05		
TOTAL (D-Spend)		$97.88	$0.29	$2.06	$5.18	$10.42	$10.21	$17.28	$14.89	$14.29	$6.29	$10.36	$2.35	$3.74	$0.52
GRAND TOTAL		$104.88	$0.29	$2.06	$5.18	$10.47	$10.31	$17.58	$15.09	$14.79	$9.24	$13.21	$2.40	$3.74	$0.52

The total cost to implement the 15 year plan is estimated at $137.2M, broken down into $104.8M Capex, $6.7M Opex, and $25.7M Removal. The total estimated distribution, substation and transmission costs are shown in Table 2.

Table 2 – Total Projected Spend ($M)

	Capital	Expense	Removal	Total
Distribution	$73.7	$4.3	$18.5	$96.5
Substation	$24.1	$2.4	$6.9	$33.4
Transmission	$7.0M	-	$0.3	$7.3
Total	$104.8	$6.7	$25.7	$137.2

The infrastructure development in the study period 2016 – 2030 is driven by asset condition and is therefore not sensitive to load growth. Growth rates in excess of those currently projected may require the advancement of other items recommended in the Providence Area Long Term Supply and Distribution Study.

2. Introduction

2.1 Purpose

This study presents a plan to implement the recommendations of the Providence Area Long Term Supply and Distribution Study, completed in May 2014.

The plan covers the fifteen year period, 2016 – 2030 and is to be developed consistent with the recommendations of the long range study. Excluded from the study are Dyer Street and South Street stations as these projects were recommended directly by the long term study and the long term study addendum respectively.

2.2 Problem

Providence is an urban area with a relatively concentrated load. The electrical distribution facilities consist of a mix of older 11 kV and 4.16 kV distribution systems and a newer 12.47 kV distribution system. The distribution circuits are primarily underground in the downtown business district whereas they are overhead in the surrounding residential areas. Much of the underground infrastructure dates back to the period when the system was originally installed in the 1920's.

Six of the older stations supplying the area are indoor stations installed between 1924 and 1939 and have a number of asset related concerns. The health and condition of all indoor stations were assessed and each station assigned a priority score. Three major categories were used to assess the condition of the stations and determine the priority score. These major categories are: equipment condition, loading, and safety.

In addition to the station issues, both the underground supply and distribution circuits for the older stations were installed at the same time the stations were built. The Company has a program to proactively replace the cables on these circuits as part of the Rhode Island Underground Cable Replacement Program. Many of the cables associated with the indoor stations are candidates for replacement in the program.

The Annual Planning process has also identified a number of circuits that are projected to be overloaded in future years based on the projected load growth rates for this area. The Annual Plan process also identified several areas where the calculated load at risk exceeded 16 megawatt hours ("MWh") during a contingency, the criteria set forth in the Distribution Planning Guide.

Without addressing the above issues, it will become increasingly difficult to maintain a reliable electric system in the Providence area and supply new loads.

3. Background

3.1 Scope

3.1.1 Geographic Scope

The study area consists of the City of Providence and sections of the adjacent communities of Cranston, Johnston and North Providence.

The geographic location of the study area is shown in Section 9.1 of Appendix. A complete description of the boundaries of the study area and the City of Providence is included in Section 9.2 of the Appendix.

Although the Providence Network is located within the study boundary it has been excluded from the scope of this study.

3.1.2 Electrical Scope

There are six supply and distribution voltages in the study area: 115 kV, 34.5 kV, 23 kV, 12.47 kV, 11.5 kV and 4.16 kV.

Area load is supplied primarily by the 115 kV transmission system. Two generating plants, Manchester Street (approximately 450 MW) and Pawtucket Power (approximately 60 MW), are connected to the electrical facilities in the study area at 115 kV, 23 kV and 11.5 kV.

There are three transmission corridors running through the study area with a mix of overhead and underground facilities. Approximately 77 % of the area load is supplied by substations connected to the five transmission circuits E-105, F-106, Q-143, R-144 and E-183 located in these transmission corridors. The remaining 23 % of the load is supplied from stations outside the study area and supplied from four overhead transmission circuits: I-187, J-188, S-171S and T-172S.

Twenty-three substations supply the area load with 18 of these substations located within the study boundary. A list of the stations with year of construction, supply and distribution voltages, and number of circuits supplying the study area is shown in Table 9.3.1 in Section 9.3 of the Appendix.

There are 151 supply and distribution circuits consisting of a mix of underground and overhead circuits. The 12.47 kV and 4.16 kV systems are solidly grounded systems whereas the 11.5 kV system is resistance grounded at the source. The 11.5 kV distribution feeders are not suitable for supplying single phase loads and were used primarily to supply larger three phase loads before the 12.47 kV system was available. Figures 9.3.1 and 9.3.2 in Appendix 9.3 show the sub-transmission and distribution arrangement, respectively.

The overhead distribution system is a radial system and feeders typically have multiple ties to other feeders. Customers on the 12.47 kV and 11.5 kV underground systems are generally provided a preferred/alternate supply, however this is not standard for the 4.16 kV system. The newer 12.47 kV underground system includes locations with auto-transfer switchgear with automatic transfer to an alternate feeder. Load on feeders receiving automatic transfers is limited to the long term emergency rating of the feeder during contingency operation.

There are isolated pockets of overhead 4.16 kV distribution supplied by Auburn and Knightsville substations and these are surrounded by 12.47 kV feeders. Load relief to these 4.16 kV feeders is generally provided by conversion to 12.47 kV.

3.2 Area Load and Load Forecast

The load in the Providence Study area includes components from both the Providence Power Supply Area (PSA) and Western Rhode Island PSA. The area is summer peaking and the facilities are summer limited.

The adjusted 2016 summer projected peak load demand for the study area was approximately 430 MVA. Although the area is highly developed, there are some areas available for development. One development location is the surplus land from the I-195 highway relocation. Other areas targeted by the City of Providence in their development plans include the Route 10 corridor, including the Valley Street area, and the Providence waterfront. Spot loads have been included in these targeted areas for the period 2016 – 2020 in addition to the projected area growth rates. With the projected PSA forecasted growth rates and spot loads, the peak load is projected at 458 MVA by 2030. The combined load growth and spot loads result in an average annual growth rate of 0.45% per year. Area growth rate assumptions for the Providence and Western RI PSAs and spot load assumptions are shown in Table 2 and Table 3.

Table 3 – Growth Rates for Providence and Western RI PSA's 2016 to 2030

Year	Providence PSA Growth rate	Western RI Growth Rate	Study Area Load (MW)
2016	1.30%	0.80%	430
2017	0.40%	0%	431
2018	0.30%	0%	433
2019	0.30%	0%	434
2020	0.40%	0.10%	436
2021	0.40%	0.10%	437
2022	0.40%	0.10%	439
2023	0.40%	0.10%	441
2024	0.40%	0.10%	443
2025	0.40%	0.30%	444
2026	0.60%	0.30%	447
2027	0.60%	0.30%	450
2028	0.60%	0.30%	452
2029	0.60%	0.30%	455
2030	0.60%	0.30%	458

Table 4 – Spot Loads Included in the Load Projections by Year and Feeder

Year	Location	Feeder	Load (MW)
2016	I-195 relocation land (west side of river)	1101	0.3
2017	Valley Street corridor	1133	0.7
2017	Development on South Street property	1101	1.0
2017	Allens Avenue – Providence waterfront	76F8	0.5
2018	I-195 relocation land (east side of river)	1103	0.3
2018	Vicinity of Rhode Island Hospital	1121	0.5
2019	I-195 relocation land (east side of river)	1103	0.5
2019	I-195 relocation land (west side of river)	1149	0.5
2020	I-195 relocation land (west side of river)	1149	0.9
2020	Valley Street corridor	1133	0.7

3.3 Active Projects

The Providence Area Long Term Supply and Distribution Study recommended that the existing 11.5 kV station at Dyer Street be removed and the 11.5/4.16 kV station be rebuilt. Dyer Street would continue to supply load in the 4.16 kV underground sections of the City, as well as areas south and east of the City. A project is being sanctioned to rebuild the 4.16 kV station at Dyer Street.

A project at South Street is underway to build a new 115/11.5 kV indoor station to replace the existing station. As part of the South Street project, the 115 kV supply lines between Franklin Square and South Street are being replaced with underground cables.

3.4 Limitations on Infrastructure Development

The study area is a primarily a highly developed urban area with a number of natural and manmade barriers within the area that make infrastructure development difficult. These barriers include rivers, two interstate highways, several limited access highways, an electrified rail corridor and several major utility corridors.

Substation development opportunities are limited and primarily restricted to the redevelopment of existing sites that have access to the supply system.

Adding distribution feeder capacity can also be difficult due to some of the physical barriers. There are limited routes in some locations and this can result in heavily loaded feeders with limited feeder ties.

3.5 Assumptions & Guidelines

The criteria as outlined in the Distribution Planning Guide Rev 1 dated 2/15/2011 was used as the basis for this study. This guide documents the strategy to be applied to power transformers, supply lines and distribution feeders for both normal operation and during system contingencies.

To sufficiently determine an implementation sequence, the construction time line for a 115/12.47 kV station is assumed as 3 years to engineer, design, build and commission the station. Major feeder work is assumed to require one year for engineering and design and two years for construction and conversion. The duration for other work was based on input from the various departments providing construction estimates.

4. Problem Identification

Recognizing the asset condition based recommendations of the "Providence Area Long Term Supply and Distribution Study", the problem identification efforts conducted to develop this implementation plan are primarily used to determine the best sequencing of projects. Due to the significant rearrangement of the system, certain analysis such as Reactive Compensation and Reliability were mainly done in two cases: 1) existing arrangement and 2) recommended arrangement after implementation to check distribution line details with the final proposed arrangement.

4.1 Thermal Loading – Normal

The 2015 Annual Plan was used to develop the load basis for this study. The study took into consideration no cost system reconfigurations to mitigate any near term loading issues. The study basis was revised to incorporate these no cost system changes. Multiple 12.47 kV and 4.16 kV feeders were projected above their thermal limits by the end of the study period in 2030 under the existing configuration. Eight 12.47 kV radial feeders were projected above 100% of their normal summer ratings and an additional five feeders were loaded between 90% and 100%. Two feeders with auto-transfer switchgear were projected over their long term emergency limits. Three 4.16 kV feeders were projected above 100% of their normal rating and another 17 feeders were projected above 90% of their normal rating. Feeder loads projected for 2030 greater than or equal to 90% are shown in Table 5. A CYME feeder loading map, also for the year 2030, is shown in Figure 9.4.1 in Section 9.4 of the Appendix.

Supply line overloads were projected on the 2235 circuit between Auburn and Elmwood. The capacity of the 2235 supply line limited the load that could be carried by the Elmwood substation during both normal and contingency operation thereby limiting the load that could be carried on the Elmwood 12.47 kV feeders.

There are no projected transformer normal configuration overloads within the study period. Table 9.5.1 in Section 9.5 of the Appendix shows the summer normal loading on the study area transformers.

Table 5 – Feeder Loads for Year 2030 ≥ 90% (no new facilities)[1]

Substation	Voltage (kV)	Feeder	%Summer Normal Rating
CLARKSON STREET 13	12.47	13F3	99%
CLARKSON STREET 13	12.47	13F4	101%
CLARKSON STREET 13	12.47	13F5	102%
CLARKSON STREET 13	12.47	13F7	103%
CLARKSON STREET 13	12.47	13F9	93%
ELMWOOD 7 - OUTDOOR	12.47	7F2	92%
ELMWOOD 7 - OUTDOOR	12.47	7F4	93%
POINT STREET 76	12.47	76F1	100%
POINT STREET 76	12.47	76F2	101%
POINT STREET 76	12.47	76F4	105%
POINT STREET 76	12.47	76F5	102%
POINT STREET 76	12.47	76F7	100%
POINT STREET 76	12.47	76F8	98%
ADMIRAL STREET 9	4.16	9J1	96%
ADMIRAL STREET 9	4.16	9J3	102%
EAST GEORGE ST 77	4.16	77J1	91%
EAST GEORGE ST 77	4.16	77J2	99%
EAST GEORGE ST 77	4.16	77J3	102%
EAST GEORGE ST 77	4.16	77J4	96%
GENEVA 71	4.16	71J5	93%
HUNTINGTON PARK 67	4.16	67J1	96%
KNIGHTSVILLE 66	4.16	66J1	97%
KNIGHTSVILLE 66	4.16	66J2	130%
KNIGHTSVILLE 66	4.16	66J3	94%
OLNEYVILLE 6	4.16	6J2	90%
OLNEYVILLE 6	4.16	6J7	91%
ROCHAMBEAU AVENUE 37	4.16	37J2	91%
ROCHAMBEAU AVENUE 37	4.16	37J3	98%
ROCHAMBEAU AVENUE 37	4.16	37J4	91%
ROCHAMBEAU AVENUE 37	4.16	37J5	95%
SPRAGUE STREET 36	4.16	36J1	93%
SPRAGUE STREET 36	4.16	36J2	97%
SPRAGUE STREET 36	4.16	36J5	90%

1. Items shown highlighted exceed summer normal rating

4.2 Thermal Loading – Contingency

In order to ensure that system performance does not deteriorate when changes are made to the distribution system, the MWh exposure for the worst case component failure is calculated for each feeder using the screening tool. The Distribution Planning Guide recommends that under contingency conditions the load at risk should not exceed 16 MWh on the distribution system. Any distribution feeder in the 2015 Annual Plan with a calculated value of 16 MWh or higher with the screening tool in the year 2030 was further analyzed. Calculations for the existing system are shown in Table 6. Thermal contingency loading was not considered a major factor in project sequencing.

Table 9.5.2 in Section 9.5 of the Appendix shows the summer contingency loading on the study area transformers.

Table 6 – Calculated MWh Load-at-Risk – Existing Configuration

Feeder	Calculated MWh Load-at-Risk 2030[1]
13F4	16.2
13F9	20.7
13F10	19.2
79F2	27.1
76F1	38.3
76F2	18.7
76F4	29.5
76F5	17.3
76F6	20.2
76F8	27.6
73F4	22.2
73F5	20.8
73F6	20.3

1. Items shown in red exceed MWh criteria

4.3 Voltage Performance

The sub-transmission and substation system was modeled with projected summer peak loads using the PSS/e load flow program for both normal and contingency operation. A model was created to include future system modifications. Sub-transmission and substation voltages are maintained to enable customer service voltages within regulatory and ANSI guidelines. The first step in this analysis is to apply the ANSI guidelines at the sub-transmission and substation levels. Voltages outside of the ANSI ranges found during this first step would be further studied to determine their impacts to the customer services. No voltage issues were found.

All 12.47 kV feeders within the study area have either bus regulation or individual feeder regulation. A CYME voltage map, for the year 2030, is shown in Figure 9.4.2 in Section 9.4 of the Appendix. Minor voltages issues were identified to emerge by 2030 in the existing configuration.

4.4 Asset Condition

The 11.5 kV and 4.16 kV stations, together with their supply and distribution circuits, mostly date back to the early 1920's and 1930's with most installations completed by the 1950's. Several of these stations are of the indoor type and were designed for standards applicable at the time of construction. Replacement equipment is typically not available for these stations and many parts have to be custom built when needed.

As the most economical way to address the substantial asset condition issues, the Providence Area Long Term Supply and Distribution Study, issued in May 2014, recommended expansion of the 12.47 kV system and retirement of the 11.5 kV and 4.16 kV indoor substations. An indoor substation priority order was included in that report and is and reproduced in Table 7. Table 8 shows the major equipment counts that need to be addressed. In addition to the major equipment, each station has clearance and fire suppression issues that further complicate direct replacement.

Table 7 – Indoor Substation Priority Score

Substation	Priority Score (Safety, Condition, Loading)
Dyer Street	1056
Admiral Street	959
South Street	862
Franklin Square	854
Olneyville	710
Harris Avenue 11.5 kV	515
Harris Avenue 4.16 kV	460
Sprague Street	406
Rochambeau Avenue	397

Table 8 – Indoor Substation Major Equipment Counts

Substation	Indoor Voltage	# Breakers	# Transformers	Indoor Voltage Regulators
Admiral Street	11.5-4.16kV	8-11.5, 7-4.16	2	0[1]
Harris Avenue	11-4.16kV	18-11.5, 12-4.16	2	0[1]
Olneyville	11.5-4.16kV	8-11.5, 12-4.16	3	0[1]
Rochambeau	4.16kV	8-4.16	2	0
Sprague Street	4.16kV	8-4.16	2	2-4.16 kV

1. Regulators were taken out of service due to condition

Admiral Street Substation

Admiral Street indoor station, originally constructed in 1930, has both 11.5 kV and 4.16 kV distribution voltages. There are four 11.5 kV circuits and four 4.16 kV circuits. Specific issues include:

- GE – FH203, 15 kV 500 & 1200 Amp Breakers – Obsolete, with no spare parts. After opening upon fault isolation, these breakers often must be serviced before returning to operation.
- Control Room Area / Station Wiring – Protection equipment is obsolete with no spare parts. The majority of the control wiring is asbestos covered.
- 11.5 kV Feeder Reactors – Deteriorated due to exposure and past animal contacts
- Fire Suppression System – Obsolete.

Asset pictures of Admiral Street indoor substation are shown in Section 9.6 of the Appendix.

Olneyville Substation

Olneyville indoor substation, initially constructed in 1924, has 11.5 kV supply and 4.16 kV distribution voltages. The remaining 11.5 kV switchgear supplies the 11.5/4.16 kV transformers as the former 11.5 kV distribution circuits have been previously eliminated. Specific issues include:

- GE “H” Type Oil Circuit Breakers – Obsolete, with no spare parts. These breakers have a growing tendency to fail upon operation in a violent manner.
- Control Room Area / Station Wiring – Protection equipment is obsolete with no spare parts. The majority of the control wiring is asbestos covered.
- Disconnects / Interlocks – The disconnects are arranged across the station floors with no interlocks. Operation of the disconnects requires a lesser approach distance with an orientation in front or below the operator. Gang operated disconnects consist of wooden rod insulation to live parts.

Asset pictures of Olneyville indoor substation are shown in Section 9.6 of the Appendix.

Harris Avenue Substation

Harris Avenue substation has both 11.5 kV and 4.16 kV switchgear located in a building and 23 kV switchgear located in an outdoor yard. The 23 kV is supplied from Admiral Street and Franklin Square substations. There are six 4.16 kV feeders and six 11.5 kV feeders at Harris Avenue. Specific issues include:

- GE “H” Type Oil Circuit Breakers – Obsolete, with no spare parts. These breakers have a growing tendency to fail upon operation in a violent manner.
- Control Room Area / Station Wiring – Protection equipment is obsolete with no spare parts. The majority of the control wiring is asbestos covered.

Sprague Street Substation

Sprague Street substation, constructed in 1951, is a 23/ 4.16 kV substation supplied by two 23 kV circuits: 2201 from South Street and 2203 from Elmwood Avenue. The 23 kV supply cables were originally installed in 1918 to supply Elmwood substation. Specific issues include:

- Interlocks – The disconnects are arranged across the station floors with no interlocks.
- Control Room Area / Station Wiring – Protection equipment is obsolete with no spare parts. The majority of the control wiring is asbestos covered.
- 4.16 kV Regulators - The feeder regulators are three phase units and are no longer available. The station layout is not suitable for installation of single phase regulators and parts have to be cannibalized from equipment retired from other stations to maintain feeder regulation.
- RTU/EMS – This station has no remote control or remote data acquisition. As a result of the condition of the existing control wiring, installation of EMS functionality would be cost prohibitive.

Rochambeau Avenue Substation

Rochambeau Avenue, constructed in 1946, is located across the street from residential structures and there have been repeated complaints about transformer noise. Rochambeau Avenue is supplied partly by a 23 kV circuit, 2248 from South Street, and partly by an 11.5 kV circuit, 1110 from Admiral Street. Specific issues include:

- Interlocks – The disconnects are arranged across the station floors with no interlocks.
- Control Room Area / Station Wiring – Protection equipment is obsolete with no spare parts. The majority of the control wiring is asbestos covered.
- RTU/EMS – This station has no remote control or remote data acquisition. As a result of the condition of the existing control wiring, installation of EMS functionality would be cost prohibitive.

Underground Cable

Asset issues also exist in the 11.5 kV and 23 kV underground system. Table 9.6.1 in Section 9.6 of the Appendix shows the underground cables with asset concerns impacted by the long term recommended plan. The long term plan avoids the direct replacement costs of these cable assets through proposed retirements.

4.5 Additional Analysis

In addition to asset issues, reliability performance, arc flash concerns, fault duty analysis, reactive compensation and protective coordination were analyzed. Results of this analysis are documented in this section.

4.5.1 Reliability Performance

The area reliability meets the overall existing reliability targets established for this area. As individual feeders in an area contribute to the overall area reliability, the frequency and duration reliability indices of individual feeders for the period 2013 – 2015 were examined to determine whether indices trends of feeders might be indicating emerging reliability issues.

Actual individual feeder performance for feeders that exceed at least one of the indices for overall area reliability for the years 2013 – 2015 are shown in Table 9.7.1 in Section 9.7 of the Appendix.

Although there are no performance indices established for individual feeders, feeders that exceed the company overall target values for the area are highlighted in Table 9.7.1. This reliability review was done to establish existing conditions and was not used to determine project sequencing.

From this table, it appears that reliability trends may be emerging on the 2J1 and 13F6 circuits. Further investigation, however, determined that the 2J1 indices were impacted by supply issues at the South Street Substation and were not due solely to feeder issues. Supply reliability for Dyer Street station should improve significantly following the ongoing South Street rebuild project. It was also found that the reliability statistics on the 13F6 feeder did not account for the auto-throw over switchgear installed at customer locations on this feeder resulting in higher duration (CKADI) values than actually occurred.

4.5.2 Arc Flash

Arc flash analysis has been previously conducted for the existing feeders within the study area. This analysis was required by OSHA rule 1910.269 to identify locations where an employee may be exposed to hazards from flames and electric arcs. Work practices were established for switching in each of the stations and the proper protective gear was made available at each location. Some of the locations requiring mitigating work practices and supplemental PPE will be eliminated upon plan implementation. Table 9.8.1 in Section 9.8 of the Appendix shows distribution substation equipment arc flash levels for stations with a Hazard Risk Category ("HRC") of 3 or more. These stations require workers to use 55 calorie per centimeter-squared ("cal/cm^2") protective equipment.

Work at all stations except for Elmwood requires the 55 cal/cm^2 protective suit at minimum approach distance ("MAD"). Work at Elmwood also requires a live line tool in addition to the protective suit.

4.5.3 Fault Duty/Short Circuit Availability

The ASPEN program was used to calculate fault currents at each substation bus for both three phase and single line to ground zero impedance faults. This was done for each bus voltage within a station for both the primary and backup sources where data was available for the backup source. These faults currents were then compared to the interrupting capability of the station breakers. There were a number of locations where the calculated fault current may exceed the interrupting ratings of the breakers. The results of this analysis are shown in Table 9.9.1 in Section 9.9 of the Appendix.

4.5.4 Reactive Compensation

Reactive loads on the feeders, without compensation, reduce the optimal performance of the system. ISO-NE conducts annual power factor surveys to ensure that each area is in compliance with applicable standards for both heavy and light load conditions.

Reactive load on the feeders is obtained from the Energy Management System ("EMS") data, where available, and estimated for feeders where reactive data is not measured. Feeders with reactive loads outside compliance ranges during either peak or off peak periods are compensated by either adding or removing capacitors or by adjusting their switching schedules as appropriate. The area does not presently violate the applicable standards.

New station design would include multistage capacitor banks to be used for reactive compensation of the power transformers. As loads are added to the system and system rearrangements are made, reactive compensation needs would be reviewed and capacitors added to or removed from feeders as necessary to maintain both system power factor compliance and feeder voltages.

A CYME reactive compensation review was conducted to establish existing conditions and was not used to determine project sequencing. A repeat analysis was done for 2030 following the system reconfiguration considered in the recommended plan.

4.5.5 Protection Coordination

A variety of devices are used to protect or isolate sections of a feeder during fault conditions. Typical protective devices in use are circuit breakers, circuit reclosers, line reclosers and fuses. In rearranging a distribution system particular care must be given to ensure that the coordination between protective devices is maintained. In some instances line reclosers settings may have to be adjusted or reclosers relocated or added as the feeder configuration changes.

Due to the significant reconfigurations recommended by the long range plan, an existing configuration coordination study is not necessary at this time.

Line reclosers can also be used to reduce load at risk as these can be switched remotely and reduce switching times during the customer restoration process after a contingency. Where new line reclosers are recommended, advanced controls will be utilized.

5. Plan Development

Plan development in this study is an implementation plan for the 15 year period 2016 – 2030 consistent with the conceptual plan recommended in the Providence Area Long Term Supply and Distribution Study dated May 2014.

The Providence Area Long Term Supply and Distribution Study assessed various options to resolve issues identified within the study area and compared the economics of several supply and distribution alternatives. The preferred option recommended the expansion of the 12.47 kV distribution system, conversion of the majority of 11.5 kV and 4.16 kV load to 12.47 kV and elimination of several 4.16 kV and 11.5 kV indoor and outdoor stations. The majority of the new 12.47 kV capacity in the recommended plan would be provided by new 115/12.47 kV stations at Admiral Street, Auburn and South Street.

A second study, the Central Rhode Island East Study, was carried out simultaneously with this study. The Central Rhode Island East Study area is adjacent to and includes part of this study area. There are therefore some overlapping issues between the two study areas and a coordinated effort was made to ensure that recommendations are consistent with the long term needs of both areas.

Admiral Street indoor station ranks high on the station priority list with asset concerns, and the northern section of the study area will be addressed first in this study. The 11.5 kV and 4.16 kV distribution load at Admiral Street will be converted to 12.47 kV and supplied by capacity on the new 13F10 feeder that was installed at Clarkson Street in 2016. A new 11 kV supply will be provided to Rochambeau Avenue substation from Admiral Street 23 kV station to replace the existing 11.5 kV supply. By prioritizing Admiral Street, the indoor station at this location can be demolished to prepare for the construction of a new 115/12.47 kV metal clad station on the site of the existing indoor substation. This new 12.47 kV station is crucial to enable the retirement of the other northern area assets and indoor stations.

Two options were evaluated to resupply Rochambeau Avenue substation. The preferred alternative is the installation of a new 23/11 kV transformer at Admiral Street to supply the existing 1110 circuit. This transformer will be supplied from the Admiral Street 23 kV station. The second alternative that was considered was converting the supply to Rochambeau Avenue to 23 kV and supplying a new 23 kV circuit directly from Admiral Street 23 kV station. The 11.5 kV supply cables to Rochambeau Avenue substation would be replaced. Both options require a new 23 kV breaker at Admiral Street to supply Rochambeau Avenue. The 23 kV bay presently supplying the #5 transformer and the 2237 circuit would be completed in both options by adding a new tie breaker.

The proposed 115/12.47 kV Admiral Street substation would be a breaker and one half design with two LTC transformers, metal clad switchgear with provisions for eight feeders and two multi-stage capacitor banks. The capacity provided would be used to supply the load converted to 12.47 kV at Geneva, Harris Avenue, Olneyville and Rochambeau Avenue substations. These stations would be retired after the conversions and transfer of load.

The asset issues at Knightsville substation and loading on the 4.16 kV feeders supplied by Knightsville will be addressed by installing a new 23/12.47 kV modular station and converting the load to 12.47 kV. The existing 23/4.16 kV station at Knightsville would be retired and removed.

After completion of the developments in the north section of the study area, a new 12.47 kV station would be built at Auburn. The preferred alternative is a 115/12.47 kV station with eight regulated feeders. Two transmission circuits, I-187 and J-188, would be extended from Sockanosset to Auburn along an existing right-of-way. The 12.47 kV capacity at Auburn will be used to convert 4.16 kV load at Auburn, Huntington Park, Lakewood and Sprague Street substations and allow these four stations to be retired. Load on the Elmwood 23/12.47 kV station will also be transferred to Auburn. The 23/12.47 kV station at Elmwood would be retained to provide 12.47 kV feeder backup for the period of time that the Elmwood 23 kV station remains in service. The development of a 115 kV station at Auburn provides an option to retire the 115/23 kV station at Sockanosset.

Alternatives to the 115 kV supply and the 115/12.47 kV station at Auburn is a smaller station at Auburn with four feeders supplied at either 23 kV or 35 kV from a rebuilt Sockanosset substation. The Elmwood 12.47 kV station would remain and be expanded to a four feeder station with two transformers and be supplied at either 23 kV or 35 kV, also from Sockanosset. Sockanosset substation would be rebuilt as either a 115/23 kV or 115/34.5 kV supply station. The load on Lakewood substation would be converted to 12.47 kV under both alternatives to resolve issues identified at Lakewood. The justification for the Lakewood substation retirement and removal is presented in the CRIE study.

On completion of the infrastructure development to address the asset concerns, several feeders were projected to violate the 16 MWh criteria in 2030, the end of the study period. Non-wires energy storage options were evaluated as alternatives at these locations; however, the costs were not found to be economic when compared to traditional wires solutions. New 12.47 kV feeders are proposed at Geneva, Knightsville and Lippitt Hill substations in 2030 to resolve these MWh violations. A review of feeder loads and non-wires alternatives should be re-evaluated prior to the construction of new 12.47 kV feeders.

5.1 Common Items

There are items that are common to all alternatives considered in the implementation plan. A description of the investment, the in-service year and estimated project costs are detailed below.

2019

Transfer the single customer on Olneyville 6J5 feeder to the 6J6 feeder and retire the 6J5 feeder.

Distribution – Capital $150,000 O&M $0 Removals $20,000

2020

Increase the capacity of the Clarkson Street 13F10 feeder by replacing overhead conductor on Hawkins Street.

Distribution – Capital $350,000 O&M $50,000 Removals $110,000

2021

Complete the 23 kV bay supplying the existing No.5 transformer and 2237 feeder at Admiral Street.

Rebuild the Admiral Street 4.16 kV and 11.5 kV overhead feeders for 12.47 kV operation. Rebuild portions of the Clarkson Street 13F2, and the Lippitt Hill 79F1 and 79F2 feeders to allow for reconfiguration of the 12.47 kV distribution system. Install new conduit on Charles Street to extend the Clarkson Street 13F2 feeder to the Main Post Office and convert the Post Office to 12.47 kV. Install a new riser on Brown St from the Lippitt Hill 79F2 feeder to increase the capacity of the feeder. Install new 15 kV class cable on North Main Street and reconfigure the 1171 circuit to retain an alternate supply to customers supplied by the feeder. Reroute the Clarkson Street 13F3 feeder to Corliss Street. Convert the customers supplied by the 11 kV and 4.16 kV feeders at Admiral Street to 12.47 kV and supply load from Clarkson Street and Lippitt Hill feeders. Retire the Admiral Street indoor station.

Proposed installations at Admiral Street 115/23 kV are shown in the partial one line in Figure 9.10.1 in Section 9.10 of Appendix.

Distribution	–	Capital	$7,580,000	O&M	$558,000	Removals	$1,877,000
Substation	–	Capital	$1,250,000	O&M	$5,000	Removals	$100,000

2022

Remove equipment from Admiral Street indoor station and demolish existing indoor substation building. Remove transformers supplying indoor station at Admiral Street and prepare site for new 115/12.47 kV station. Figure 9.10.2 in Section 9.10 of Appendix shows an aerial view of Admiral Street substation site with the indoor station location highlighted.

Install a new duct and manhole system for the feeder getaways from new Admiral Street station.

Convert load on the Olneyville 4.16 kV feeders 6J1, 6J3, 6J6 (partial) and 6J7 to 12.47 kV and supply from the Johnston 18F7 and 18F9 feeders.

Distribution	–	Capital	$7,390,000	O&M	$180,000	Removals	$905,000
Substation	–	Capital	$0	O&M	$0	Removals	$785,000

2023

Install a new 115/12.47 kV breaker and one half metal clad station at Admiral Street with 2 – circuit switchers, 2 – 33/44/55 MVA LTC transformers, 8 – feeder positions and 2 – 7.2 MVAr multistage capacitor banks. Tap the Q-143 and R-144 circuits in the substation yard to supply the transformers. A partial one-line proposed for Admiral Street substation is shown in Figure 9.10.3 in Section 9.10 of Appendix.

Install 6 – 12.47 kV 1000 kcmil Cu feeder getaways at Admiral Street. Extend two feeders underground to the Capital Center with a combination of 1000 kcmil Cu and 500 kcmil Cu cables. Rearrange the 12.47 kV distribution system and transfer load from Clarkson Street and Lippitt Hill substations to the new Admiral Street substation.

Install a 23/12.47 kV modular station at Knightsville and supply with the 2226 (preferred) and 2228 circuits (alternate) from Johnston substation. Rebuild the Knightsville feeders for 12.47 kV operation and supply from the new feeder position at Knightsville. Rebuild a portion of the Johnston 18F7 feeder on Cranston Street to facilitate feeder rearrangement.

A partial one line for the Knightsville substation is shown in Figure 9.10.4 in Section 9.10 of Appendix. Figure 9.10.5 in Section 9.10 of Appendix shows the results of the load flow with two modular feeders at Knightsville substation, the proposed ultimate layout for Plan 1.

Distribution	–	Capital	$9,782,000	O&M	$536,000	Removals	$1,150,000
Substation	–	Capital	$8,100,000	O&M	$1,000,000	Removals	$350,000
Transmission	–	Capital	$500,000	O&M	$0	Removals	$0

2024

Rebuild the Harris Avenue 11.5 kV feeders 1131, 1133, 1145 and 1147 and the Harris Avenue 4.16 kV feeders for 12.47 kV operation. Rebuild a portion of the Johnston 18F5 feeder on Harris Avenue and install several new load break switches to facilitate feeder rearrangement. Rebuild a portion of the Dyer Street 2J3 feeder on Westminster Street, between MH216 and MH221 for 12.47 kV and prepare to supply from Knight Street. Convert the Harris Avenue load, except for the hospitals, and convert 2J3 load on Westminster Street to 12.47 kV and supply the load from Admiral Street, Johnston and Point Street feeders.

Distribution	–	Capital	$7,341,000	O&M	$380,000	Removals	$1,306,000

2025

Extend the two underground cables supplying the Capital Center from Admiral Street to the VA Hospital and Roger Williams Hospital. Convert the two hospitals to 12.47 kV. Retire the Harris Avenue indoor and outdoor substations.

Rebuild a section of the Dyer St 2J3 feeder for 12.47 kV operation. Rebuild the 4.16 kV feeders at Geneva, Olneyville (6J2, 6J6 partial, and 6J8) and Rochambeau Avenue substations for 12.47 kV operation. Convert these 4.16 kV feeders and supply from Admiral Street, Clarkson Street, Johnston, Lippitt Hill and Point Street feeders. Install load break switches on the 13F2 and 13F9 feeders at Clarkson Street and the 79F2 feeder at Lippitt Hill to facilitate the feeder rearrangements. Retire Geneva, Olneyville and Rochambeau Avenue substations.

Rebuild sections of the 7F4 feeder at Elmwood substation and the 27F2 feeder at Pontiac substation and install a new load break on the Lincoln Avenue 72F6 feeder to facilitate feeder rearrangement. Rebuild the 2235 and 73J1 feeders with double circuit 477 kcmil between Elmwood Avenue and Mill Street. Rebuild the remainder of the common items for the Auburn 4.16 kV feeders for 12.47 kV (note: the 73J1, 73J3 and 73J5 feeders have non-common items that are not included as part of this rebuild).

Distribution	–	Capital	$24,481,000	O&M	$1,697,000	Removals	$6,569,000

2026

Demolish the 23/4.16 kV Auburn substation and prepare Auburn site for redevelopment. Remove equipment from Geneva, Harris Avenue, Olneyville, and Rochambeau Avenue substations and demolish buildings.

Remove the 23 kV and 11.5 kV supply cables to Harris Avenue, Olneyville and Rochambeau Avenue substations.

Distribution	–	Capital	$0	O&M	$0	Removals	$2,069,000
Substation	–	Capital	$0	O&M	$285,000	Removals	$2,195,000

2027

Rebuild sections of the Point Street 76F4 feeder. Convert a section of the Dyer Street 2J8 feeder on Cranston Street to 12.47 kV and supply from Point Street substation. Transfer a section of the 36J4 feeder at Sprague Street substation to the 2J5 feeder at Dyer Street substation to maintain an alternate supply to the Franklin Square station service transformer. Rebuild the Huntington Park feeder and remaining 4.16 kV feeders at Sprague Street for 12.47 kV and convert. Retire Huntington Park and Sprague Street substations.

Rebuild the Lakewood 4.16 kV feeders for 12.47 kV operation and convert load and supply from a 12.47 kV feeder at Auburn substation.

Convert 23 kV customers on the 2213 and 2235 circuits at Elmwood and Sockanosset substations to 12.47 kV and supply from existing 12.47 kV feeders.

Distribution	–	Capital	$10,250,000	O&M	$582,000	Removals	$2,721,000

2028

Remove equipment from Huntington Park and Sprague Street substations and demolish Sprague Street building. Retire and remove Lakewood substation. Remove the 23 kV circuit on the r-o-w between Mill Street and Warwick Avenue.

Distribution	–	Capital	$0	O&M	$0	Removals	$67,000
Substation	–	Capital	$0	O&M	$100,000	Removals	$1,560,000

5.2 Recommended Plan

The recommended plan presents the preferred alternatives for infrastructure development in the locations where more than one alternative was developed. In the plan, alternatives and their costs are grouped together by location to allow for substitution of alternatives into the preferred plan to develop alternative plans as necessary. Alternatives presented were evaluated either as part of this implementation study or as a result of work proposed in the Central Rhode Island East Study.

5.2.1 Supply to Rochambeau Avenue Substation

2021

Install a new 23/11 kV 7.5/9.375 MVA transformer, with zero phase shift, in the Admiral Street yard (see partial one line in Figure 9.10.1 in Appendix) and supply from the No. 5 transformer position. Extend the 1110 circuit from an existing manhole in the yard to this new transformer location. Replace several sections of the 1110 circuit between Admiral Street and Rochambeau Avenue substations as identified by the Rhode Island Cable Replacement program.

Distribution	–	Capital	$430,000	O&M	$0	Removals	$30,000
Substation	–	Capital	$1,250,000	O&M	$5,000	Removals	$20,000

5.2.2 Auburn Substation – 115 kV Option

2025

Rebuild Auburn 4.16 kV feeders below the existing 23 kV circuits on Elmwood Avenue and Wellington Avenue for 12.47 kV operation. Rebuild the 4.16 kV Auburn feeders 73J1 and 73J3, between Auburn substation and Elmwood Avenue to prepare for new Auburn getaways. Rebuild the non-common section of Auburn 73J5 feeder. Convert the 4.16 kV load and supply from existing 12.47 kV feeders.

Distribution	–	Capital	$3,387,000	O&M	$161,000	Removals	$787,000

2027

Extend the 115 kV transmission circuits I-187 and J-188, with 795 kcmil ACSR, from Sockanosset substation to the Auburn substation along an existing right-of-way. Remove the 23 kV circuit, 2235, from the right-of-way.

Note: One of these transmission lines will be initially energized at 23 kV to maintain supply to Elmwood 23/12.47 kV substation from Sockanosset. The second transmission line will be energized at 115 kV and extended into Auburn to energize the station initially with a single transformer. The second transmission line would then be disconnected from the 2235 and energized at 115 kV circuit to supply the second 115 kV transformer at Auburn after Elmwood 23/12.47 kV station is retired.

An aerial view with the route of the 115 kV extension is shown in Figure 9.10.6 in Section 9.10 of Appendix.

Install a new 115/12.47 kV breaker and one half low profile station at Auburn with 2 – circuit switchers, 2 – 55 MVA transformers, 8 – regulated feeder positions and 2 – 7.2 MVAr multistage capacitor banks. Supply the station from the I-187 and J-188 circuits. Install 8 – 12.47 kV feeder getaways at Auburn. A partial one-line for the proposed substation at Auburn is shown in Figure 9.10.7 in Section 9.10 of Appendix.

Install eight 12.47 kV getaways at Auburn substation. Rebuild the section of the 2235 between Auburn substation and Elmwood Avenue to become a new 12.47 kV getaway. Rearrange the 12.47 kV distribution system and transfer load from Elmwood, Point Street, and Pontiac substations to the Auburn substation. Retire Sockanosset 115/23 kV substation.

Distribution	–	Capital	$1,325,000	O&M	$8,000	Removals	$42,000
Substation	–	Capital	$8,315,000	O&M	$700,000	Removals	$350,000
Transmission	–	Capital	$6,500,000	O&M	$24,000	Removals	$308,000

2028

Remove Sockanosset substation.

Substation –	Capital	$0	O&M	$0	Removals	$1,500,000

Total cost of Auburn Redevelopment for years 2025 through 2028 – Recommended Plan

Distribution –	Capital	$4,237,000	O&M	$169,000	Removals	$829,000
Substation –	Capital	$8,315,000	O&M	$700,000	Removals	$1,850,000
Transmission –	Capital	$6,500,000	O&M	$24,000	Removals	$308,000

5.2.3 Other Infrastructure Development

2028

Remove the 2203 supply cable between St. Joseph Hospital and Sprague Street substation. Remove the 2201 supply cable between South Street and Sprague Street.

Distribution –	Capital	$0	O&M	$0	Removals	$628,000

2030

Install a new 23/12.47 kV modular feeder position at Geneva substation and supply from the Admiral Street 22 circuit (preferred) and from the Johnston 2211 circuit (alternate). Transfer load from Admiral Street and Clarkson Street to Geneva. A partial one line for Geneva substation is shown in Figure 9.10.8 in Section 9.10 of Appendix.

Install a second 23/12.47 kV modular feeder (Phase 2) at Knightsville substation. Transfer load to the new Knightsville feeder from Knightsville feeder 1, Johnston and Point Street feeders. The partial one line for Phase 2 is shown in Figure 9.10.4 in Section 9.10 of Appendix..

Install a third feeder position at Lippitt Hill substation. Convert a part of the East George 77J2 feeder to 12.47 kV. Rearrange the Lippitt Hill and Point Street feeders. A partial one line proposed for Lippitt Hill is shown in Figure 9.10.9 in Section 9.10 of Appendix.

The substation and distribution costs associated with the expansion of Geneva, Knightsville and Lippitt Hill substation are as follows:

Distribution –	Capital	$1,300,000	O&M	$115,000	Removals	$240,000
Substation –	Capital	$5,210,000	O&M	$310,000	Removals	$0

5.3 Alternative Plans

Several alternatives were developed to supply Rochambeau Avenue substation and for the new Auburn substation. Non-wires alternatives were also considered for resolution of MWh violations; however, they were not considered to be economically viable at this time. Prior to the station projects being initiated for 2030 completion to solve MWh violations (Geneva modular feeder, second modular feeder at Knightsville, third feeder at Lippitt Hill substation), non-wires alternatives should again be considered.

The alternative developed to supply Rochambeau Avenue substation is conversion of the supply voltage to 23 kV and installing a new 23 kV cable between Admiral Street and Rochambeau Avenue substations. The Rochambeau Avenue transformer has high side taps for both 11.5 kV and 23 kV. The 11.5 kV supply cables between Admiral Street and Rochambeau Avenue would be removed.

Two alternatives to the 115 kV supply to Auburn were evaluated and included as part of this study and coordinated with work carried out in the Central Rhode Island East study. In summary, supply voltages of 35 kV and 23 kV were considered as options for the Auburn 12.47 kV station. These lower supply voltages would result in a smaller 12.47 kV station at Auburn and expanding the 12.47 kV distribution station at Elmwood. Sockanosset substation would be rebuilt as either a 23 kV or 35 kV station to supply Auburn and Elmwood. New supply lines would be built from Sockanosset to supply both Auburn and Elmwood substations at either 35 kV or 23 kV. In addition to the 23 kV or 35 kV substation facilities required at Sockanosset for these options, substantial flood mitigation work would also be required.

5.3.1 Supply to Rochambeau Avenue Substation

2021

Install approximately 12,000 circuit feet of 25 kV cable, consisting of 4/0 Cu and 500 kcmil Cu conductor, from the Admiral Street transformer No. 5 feeder position to Rochambeau Avenue substation. Change taps on the No. 2 transformer at Rochambeau Avenue substation.

Distribution – Capital $890,000 O&M $10,000 Removals $556,000

5.3.2 Auburn Substation Option 1 – 23 kV supply

2025

Rebuild the 2235, 73J1 and 73J3 circuits between Auburn substation and Elmwood Avenue. Rebuild the remaining sections of the existing 23 kV circuits, 2213 and 2235, between Auburn substation and Elmwood substation with 795 ACSR. The 2235 will continue to supply Elmwood substation from a new line to be constructed between Sockanosset and Auburn. The second 23 kV supply to Elmwood would mainly follow the route of the existing 2213 circuit and connect to a second 23 kV circuit between Sockanosset and Auburn. Rebuild the Auburn 4.16 kV circuits below the 2213 and 2235 circuits on Wellington and Elmwood Avenues for 12.47 kV operation. Convert customers on the 4.16 kV circuits to 12.47 kV and supply from existing feeders. Rebuild a non-common section of the 73J5 west of highway and convert.

Distribution – Capital $3,757,000 O&M $223,000 Removals $907,000

2027

Install a new 115/23 kV Sockanosset substation with metal clad switchgear in a breaker and one half arrangement and containing 2 – circuit switchers, 2 – 55 MVA transformers, 6 –feeder positions and 2 – 10.4 MVAr multistage capacitor banks. Remove the existing substation. The new station would be installed above the flood plain. A partial one line for the proposed substation at Sockanosset is shown in Figure 9.11.1 in Section 9.11 of the Appendix.

Install four new 23 kV circuits between Sockanosset and Auburn substations, a distance of approximately 1.1 miles, with 795 kcmil ACSR and supply from four feeder positions from the new 115/23 kV Sockanosset substation. Terminate two of these circuits at Auburn substation to supply two 23/12.47 kV transformers. Connect the remaining two circuits to the rebuilt 23 kV circuits between Auburn and Elmwood substations. The proposed 23 kV construction between Sockanosset and Auburn is shown in Figure 9.11.2 in Section 9.11 of the Appendix..

Install a new 23/12.47 kV low profile station at Auburn with two 23/12.47 kV 24/32/40 MVA LTC transformers, six feeders and two multi-stage capacitor banks. Install four 12.47 kV cable getaways at Auburn and rearrange existing 12.47 kV distribution circuits. A partial one line of the proposed station at Auburn is shown in Figure 9.11.3 in Section 9.11 of the Appendix.

Remove the alternative supply, 2213, to the No. 2 transformer at Elmwood substation and add a second 23/12.47 kV 20/26.7/33 MVA transformer. Supply the second transformer from the second 23 kV line (following the route of the 2213 circuit) from Sockanosset substation. Add a fourth 12.47 kV regulated feeder at Elmwood substation. Add tie breakers in the 12.47 kV feeder bays and remove existing overhead bus tie. Install new feeder getaway to Narragansett Avenue. Rearrange the distribution feeders to accommodate the fourth feeder. The proposed installations at Elmwood for the 23/12.47 kV alternative are shown in the partial one line in Figure 9.11.4 in Section 9.11 of the Appendix.

Distribution	–	Capital	$6,952,000	O&M	$213,000	Removals	$829,000
Substation	–	Capital	$18,865,000	O&M	$850,000	Removals	$1,050,000

Total cost of Auburn – Option 1 for years 2025 through 2028 (23 kV supply):

Distribution	–	Capital	$10,709,000	O&M	$436,000	Removals	$1,736,000
Substation	–	Capital	$18,865,000	O&M	$850,000	Removals	$1,050,000

5.3.3 Auburn Substation Option 2 – 35 kV supply

2025

Rebuild sections of the existing 23 kV circuits, 2213 and 2235, between Auburn substation and Elmwood substation with 477 ACSR and insulated for 35 kV. These rebuilt circuits will provide two 35 kV supply circuits to Elmwood. One 35 kV supply circuit from Auburn to Elmwood will replace the existing 2235 circuit and the second 35 kV supply circuit would primarily follow the route of the existing 2213 circuit (but also includes part of the 2235 circuit east of Auburn). Both circuits between Auburn and Elmwood would connect to new 35 kV circuits between Sockanosset and Auburn. Rebuild the Auburn 4.16 kV circuits below the 2213 and 2235 circuits on Wellington and Elmwood Avenues for 12.47 kV operation and convert customers on both the 4.16 kV and 23 kV circuits to 12.47 kV and supply from existing feeders. Rebuild a non-common section of the 73J5 west of highway and convert.

Distribution	–	Capital	$3,582,000	O&M	$213,000	Removals	$857,000

<u>2027</u>

Install a new 115/35 kV Sockanosset substation with metal clad switchgear in a breaker and one half arrangement and containing 2 – circuit switchers, 2 – 55 MVA transformers, 6 –feeder positions and 2 – 10.4 MVAr multistage capacitor banks. Remove the existing substation. The new station would be installed above the flood plain. A partial one line of the proposed station at Sockanosset is shown in Figure 9.12.1 in Section 9.12 of the Appendix.

Install four new 35 kV circuits between Sockanosset and Auburn substations, a distance of approximately 1.1 miles, with 795 kcmil ACSR and supply from two feeder positions at a rebuilt 115/35 kV Sockanosset substation. Tap two of the circuits into Auburn substation to supply two 35/12.47 kV transformers. Connect the remaining two circuits to the new 35 kV circuits between Auburn and Elmwood substations. The proposed 35 kV construction between Sockanosset and Auburn is similar to the 23 kV option as shown in Figure 9.11.2 in Section 9.11 of the Appendix.

Install a new 35/12.47 kV low profile station at Auburn with two 35/12.47 kV 24/32/40 MVA LTC transformers, six feeders and two multi-stage capacitor banks. Install four 12.47 kV cable getaways at Auburn and rearrange existing 12.47 kV distribution circuits. A partial one line for the proposed substation at Auburn is shown in Figure 9.12.2 in Section 9.12 of the Appendix.

Remove the alternative supply, 2213, to the No. 2 transformer at Elmwood substation. Install a new 35/12.47 kV 24/32/40 MVA transformer in the No. 1 position and replace the existing No. 2 23/12.47 kV transformer with a 35/12.47 kV 24/32/40 MVA transformer. Supply the two transformers from two 35 kV circuits from Sockanosset substation. Add a fourth 12.47 kV regulated feeder at Elmwood substation. Add tie breakers in the 12.47 kV feeder bays and remove existing overhead bus tie. Install new feeder getaway to Narragansett Avenue. Rearrange the distribution feeders to accommodate the fourth feeder. The proposed installations at Elmwood for the 35/12.47 kV alternative are shown in the partial one line in Figure 9.12.3 Section 9.12 of the Appendix.

Distribution	–	Capital	$7,212,000	O&M	$225,000	Removals	$894,000
Substation	–	Capital	$20,413,000	O&M	$850,000	Removals	$1,050,000

Total cost of Auburn – Option 2 for years 2025 through 2028 (35 kV supply):

Distribution	–	Capital	$10,794,000	O&M	$438,000	Removals	$1,751,000
Substation	–	Capital	$20,413,000	O&M	$850,000	Removals	$1,050,000

5.3.4 Other Infrastructure Development

2028

Continue to supply Elmwood 23/12.47 kV station from 2213 circuit and retain a single feeder. Rearrange distribution and convert St. Joseph Hospital to 12.47 kV. Remove the portion of the 2203 circuit between Elmwood substation and St. Joseph Hospital.

Distribution – Capital $30,000 O&M $5,000 Removals $200,000

2030

Evaluate non-wires alternatives to Geneva modular feeder, the second modular feeder at Knightsville and the third feeder at Lippitt Hill.

5.3.5 Do Nothing

The Providence Area Long Term Supply and Distribution Study did not consider a do-nothing option as the asset issues could not be ignored. Taking no action would leave all problems identified in the Providence Area Long Term Supply and Distribution Study unaddressed.

6. Plan Considerations and Comparisons

6.1 Economic, Schedule, and Technical Comparisons

This study evaluated the economics of alternatives, where available, during the development of the implementation plan.

The alternatives to resupply Rochambeau Avenue substation were reduced to two viable alternatives after consultation with the operations group. Reuse of the existing 23/11.5 kV transformers at Admiral Street were rejected due to age and condition of the transformers. The capital cost of maintaining the 11.5 kV supply to Rochambeau Avenue exceeded the cost of converting to a 23 kV supply, however, maintaining the 11 kV supply is the preferred alternative. The 23/11 kV step down transformer will be available as a system spare when Rochambeau Avenue is retired in 2025. In addition, the duct and manhole system between Admiral Street and Rochambeau Avenue substations is a mix of square and round tile duct installed between 1915 and 1927 and fiber duct installed in 1947. There is significant risk that remedial duct work would be required with the 23 kV cable installation as difficulties have been previously experienced with both types of ducts. That could potentially result in significant cost increases for the 23 kV alternative.

The preferred plan recommends a 115 kV supply to Auburn and construction of a new115/12.47 kV substation to supply load presently supplied by Auburn, Elmwood and Lakewood substations. Elmwood, Lakewood and Sockanosset substations would be retired. The total cost of the preferred plan, including capital, O&M and removals was $39.7M. The alternative plans for Auburn comprised of either a 23 kV or 35 kV supply to Auburn, expanding Elmwood and rebuilding Sockanosset substation to remove it from the flood plain. Load at Lakewood would be converted in all alternatives as documented in the CRIE study. The total costs of these alternate plans for Auburn were $51.3M and $52.6M respectively for the 23 kV and 35 kV options. These alternatives and costs were developed jointly with the Central Rhode Island East study.

Although Admiral Street and Auburn projects are independent and technically can progress in parallel, the Auburn plan includes complex permitting associated with extension of the 115 kV system and was sequenced after the Admiral Street plan. The stations dependent on 12.47 kV capacity at Auburn (Huntington Park and Sprague Street indoor station) must remain in service until late in the study. The schedule of converting those stations may be advanced in some instances; however, that would require out of line resources to be made available.

After all conversions and load transfers have been completed, feeders exceeding the 16 MWh criteria in the Annual Plan screening tool were evaluated in detail. New capacity was installed to address confirmed violations.

6.2 Non-Wires Alternatives Considerations

Asset condition of the 5 – 4 kV and 2 – 11 kV indoor stations, together with the asset condition of their supply and distribution circuits, is the main driver in the Providence study area. In addition, there are 4 – 4 kV outdoor stations with asset condition issues that need to be addressed. Although there are significant costs to resolve these issues, the total load of

85 MVA supplied by these stations exceeds the capability of non-wires alternatives. Non wires alternatives were therefore not considered to address asset issues.

Existing and in-queue distributed generation ("DG") was gathered to determine loading impacts or benefits of these facilities. The DG list is shown Table 9.13.1 in Section 9.13 of the Appendix.

As can be seen from the table, there is one large (4.5 MW) wind generating source on Ernest Street, Providence. The remaining DG is scattered in small amounts throughout the study area and totals less than 1 megawatt. This scattered DG would not impact the loading analysis regardless of time of peak and peak reduction factors and was excluded from further analysis. A cursory review was done on the Ernest Street wind generators. This wind source is in the southeast corner of the study area on an isolated feeder. Enough data does not exist to determine the dependency of the wind resource during peak periods. This DG was also excluded from further analysis.

There are several locations where the projected MWh criteria could not be met without additional investments and non-wires alternatives were considered for some of these locations. The capacity required in 2030 to resolve the MWh violation on the Clarkson Street 13F5 feeder was estimated at 3.9 MVA and 2.3 MVA was required for the 13F4 feeder. The cost of a wires alternative to resolve the MWh violations, a new 12.47 kV feeder at Geneva, was estimated at approximately $2M. Battery storage was evaluated as an option to supply load during contingencies on these two feeders. Two substation sites owned by National Grid would be available to site battery storage facilities: one is the former Marieville substation, and the other, Geneva substation, will no longer be in use as a conventional substation by that point in time. The present estimated cost of the battery storage option at Geneva for the 13F4 feeder was $1.4M per hour of required capacity (for 5 hours of use the total cost is $7M) and at Marieville for the 13F5 was $3.6M per hour of required capacity (for 5 hours of use the total cost is $18M). In addition to the capital costs of these storage systems, additional O&M costs would also be required as with a wires alternative. The non-wires alternative is not recommended at this time. As these investments are required towards the end of the study period, non-wires options should be re-evaluated prior to the wires option being implemented in the event that the cost for non-wires alternatives are reduced.

6.3 Permitting, Licensing, Real Estate, and Environmental Considerations

Sites recommended for development of new substations are sites owned by National Grid and used for existing substations. Lower profile stations are proposed in the three locations where residential properties are located adjacent to the existing substations. Although it is possible that there may be some opposition from neighbors, it is not expected that there will be major issues to redevelop these sites. The aesthetics of the proposed stations are expected to improve over that of the existing stations and with adequate screening would improve these sites significantly.

The 115 kV line extensions from Sockanosset to Auburn will be constructed on an existing right-of-way that presently contains an existing 23 kV circuit. Permits and licensing will be required for the 115 kV circuits. There is an interstate highway, river crossing and wetlands along the route that will require permits from various agencies for both the 115 kV option and any of the lower voltage alternatives considered. As there are existing circuits on the right-of-way, it is anticipated that the construction permits for the new circuits should not be an issue utilizing best practices for these environments. Swamp mats and hay bales in the wet areas and near river banks will be utilized to minimize erosion and sediment and run off.

Development of Auburn as a 12.47 kV station will require the replacement of existing distribution circuits over an interstate highway and the Amtrak electrified tracks between Boston and New York. Standard guying practices for the structures carrying the circuits over the interstate highway is not feasible due to the locations of the crossings. Special construction procedures, using either laminated or steel poles, will be used for these crossings to provide a non-guyed alternative.

6.4 Planned Outage Considerations

The connection of the 115 kV supply into the new Admiral Street and Auburn substations will require outages on the Q-143, R-144, I-187 and J-188 circuits at various times. Transmission line outages would be coordinated with ISO-NE. All stations supplied by these circuits have dual supplies and no customers are expected to be impacted during the construction and commissioning of these stations.

Load on the 11 kV and 4.16 kV stations will be converted to 12.47 kV and transferred to other feeders prior to the stations being retired and demolished. There will be some customer impact during the conversion process. These conversions will be scheduled primarily in the second quarter of the year when temperatures are expected to be moderate and will be done at a time of day to pose the smallest possible inconvenience to customers.

6.5 Asset Physical Security Considerations

There have been intrusions and vandalism in National Grid substations. Consideration was given to the types of stations proposed in the various locations based on input from the operations department. A 12.47 kV metal clad substation, with completely enclosed switchgear, is proposed for the Admiral Street site. Low profile and modular stations are proposed for other locations; however, this will be evaluated through the design process where the security department will provide additional input.

6.6 Climate Resiliency

Development of the Auburn site with a 115/12.47 kV substation provides an opportunity to off load and retire the 115/23 kV Sockanosset substation. Sockanosset substation is located in a flood plain adjacent to the Pawtuxet River and was severely impacted during a flooding event in 2010. This resulted in major disruption to many of the customers supplied by Sockanosset. Plan1 eliminates the need for the flood mitigation work at Sockanosset.

7. Conclusions and Recommendations

This study recommends the common items and Plan 1 to implement the recommendations of the Providence Area Long Term Supply and Distribution Study, completed in May 2014. The projects are sequenced over the 2016 to 2030 period. This plan addresses the numerous issues in the lowest cost and timeliest manner possible. The spending forecast for Fiscal years 2016 – 2030 for Plan1, including the common items, is shown in section 9.14 of the Appendix.

7.1 Benefits of the Recommended Plan

Stations with over duty breakers are retired and many of the locations with special arc flash requirements would be eliminated. Similarly, several of the feeders with historical reliability performance concerns are eliminated. Issues on some of the remaining feeders are discussed in further detail in Section 7.1.5 below.

A CYME reactive compensation review was conducted on the distribution system configuration considered in the recommended plan. Capacitor installations are proposed to provide some capacity release and avoid reconductoring while improving overall power factor. A more detailed reactive compensation review will be conducted in future efforts as the plans are implemented.

7.1.1 Thermal Loading – Normal

The recommended plan addresses the projected feeder overloads as shown in Table 9.

Table 9 – Recommended Plan Feeder Loads for Year 2030

	Station	Feeder	% Summer Rating
12.47 kV	CLARKSON STREET 13	13F3	97%
	CLARKSON STREET 13	13F4	95%
	CLARKSON STREET 13	13F5	98%
	CLARKSON STREET 13	13F7	65%
	CLARKSON STREET 13	13F9	61%
	ELMWOOD 7 - OUTDOOR	7F2	Retired
	JOHNSTON 18	18F5	96%
	LIPPITT HILL 79	79F1	88%
	LIPPITT HILL 79	79F2	86%
	POINT STREET 76	76F2	99%
	POINT STREET 76	76F4	92%
	POINT STREET 76	76F5	98%
	POINT STREET 76	76F6	92%
	POINT STREET 76	76F7	80%
4.16 kV	ADMIRAL STREET 9	9J1	Retired
	EAST GEORGE ST 77	77J2	62%
	EAST GEORGE ST 77	77J3	Monitor
	GENEVA 71	71J1	Retired
	GENEVA 71	71J5	Retired
	KNIGHTSVILLE 66	66J1	Retired

The CYME loading map after recommended plan implementation is shown in Figure 9.4.3 in Section 9.4 of the Appendix.

The projected transformer loading (normal) after recommended plan implementation is shown in Table 9.5.3 in Section 9.5 of the Appendix.

Small scale distribution line work is required to address remaining overloaded circuit facilities as shown in Table 10.

Table 10 – Small Scale Distribution Line Work after Recommended Plan – 2030

Substation	**Feeder**	**Issue**	**Street Name & Pole No.**	**Comments**
Auburn	73F6	Overload	Legion Way – Pole 32 to Pole 10	Reconductor to 477 Al
			Auburn Street	Reconductor to 477 Al
			Rolfe St – Pole 6-50 to Pole 6	Reconductor to 477 Al
Johnston	18F7	Overload	Maplewood Dr – Pole 100-50 to Pole 54	Reconductor to 477 Al
			Laurel Hill Ave – Pole 38 to Pole 22	Reconductor to 477 Al
Clarkson St	13F10	Overload	Salina St - P24 to P5	Monitor

7.1.2 Thermal Loading – Contingency

The resulting contingency loading improvements for the recommended plan are shown in Table 11.

Table 11 – Calculated MWh Load-at-Risk – Recommended Plan

Feeder	Calculated MWh Load-at-Risk 2030[1]
13F4	10.4
13F9	9.3
13F10	7.4
79F2	7.9
76F1	10.1
76F2	16.4
76F4	27.2
76F5	17.3
76F6	20.2
76F8	27.6
73F4	11.6
73F5	11.0
73F6	6.3

1. Items shown in red exceed MWh criteria

The Point Street feeders 76F2 through 76F8 would require a major investment to provide the capacity to resolve the MWh violations on the feeders. As the worst case contingency element is the getaway cable and these are relatively new cables, it is felt that the risk of the contingency occurring is low. It is not proposed that any investments be made at the end of the study period to address this issue.

The projected transformer loading (contingency) after recommended plan implementation is shown in Table 9.5.4 in Section 9.5 of the Appendix.

7.1.3 Voltage Performance

The recommended plan addresses a number of potential emerging voltage issues. Minor distribution line work is suggested following the recommended plan to address other projected voltages issues in targeted areas as shown in Table 12. The CYME voltage map after recommended plan implementation is shown in Figure 9.4.4 in Section 9.4 of the Appendix.

Table 12 – Small Scale Distribution Line Work after Recommended Plan – 2030

Substation	Feeder	Issue	Street Name & Pole No.	Comments
Point St	76F2	Low voltage	Melrose St – Pole 33	Upgrade stepdown to 450 kVA
Point St	76F8	Low voltage	Verndale Ave – Pole 21	Upgrade stepdown to 100 kVA

7.1.4 Asset Condition

The recommended plan addresses all of the indoor substation asset issues at the Admiral Street, Olneyville, Harris Avenue, Sprague Street, and Rochambeau substations. It also addresses over 25 miles of underground cable asset issues through retirement. Figure 9.15.1 in Section 9.15 of the Appendix shows the resulting sub-transmission system.

7.1.5 Reliability Performance

Table 9.7.2 in section 9.7 of the Appendix shows the feeders remaining after the elimination of feeders at Elmwood, Harris Avenue, and Olneyville with potentially emerging reliability issues.

7.1.6 Arc Flash

A substantial improvement in the overall arc flash issues within the study area would be achieved by the recommended plan as shown in Table 9.8.2 in Section 9.8 of the Appendix.

7.1.7 Fault Duty/Short Circuit Availability

The recommended plan addresses a number of the study area breaker duty issues as shown in Table 9.9.2 in Section 9.9 of the Appendix.

7.1.8 Reactive Compensation

A detailed reactive compensation study was not conducted due to the substantial system rearrangement associated with the recommended plan. However, as part of a post-plan CYME review, capacitor installations and removals were identified to help with certain remaining loading and high/low voltage areas as shown in Table 9.15.1 in Section 9.15 of the Appendix.

7.1.9 Protection Coordination

Following the recommended plan reconfigurations, a CYME analysis was done to check for possible mis-coordination. Table 9.15.2 in Section 9.15 of the Appendix shows the additional protection changes following completion of the recommended plan.

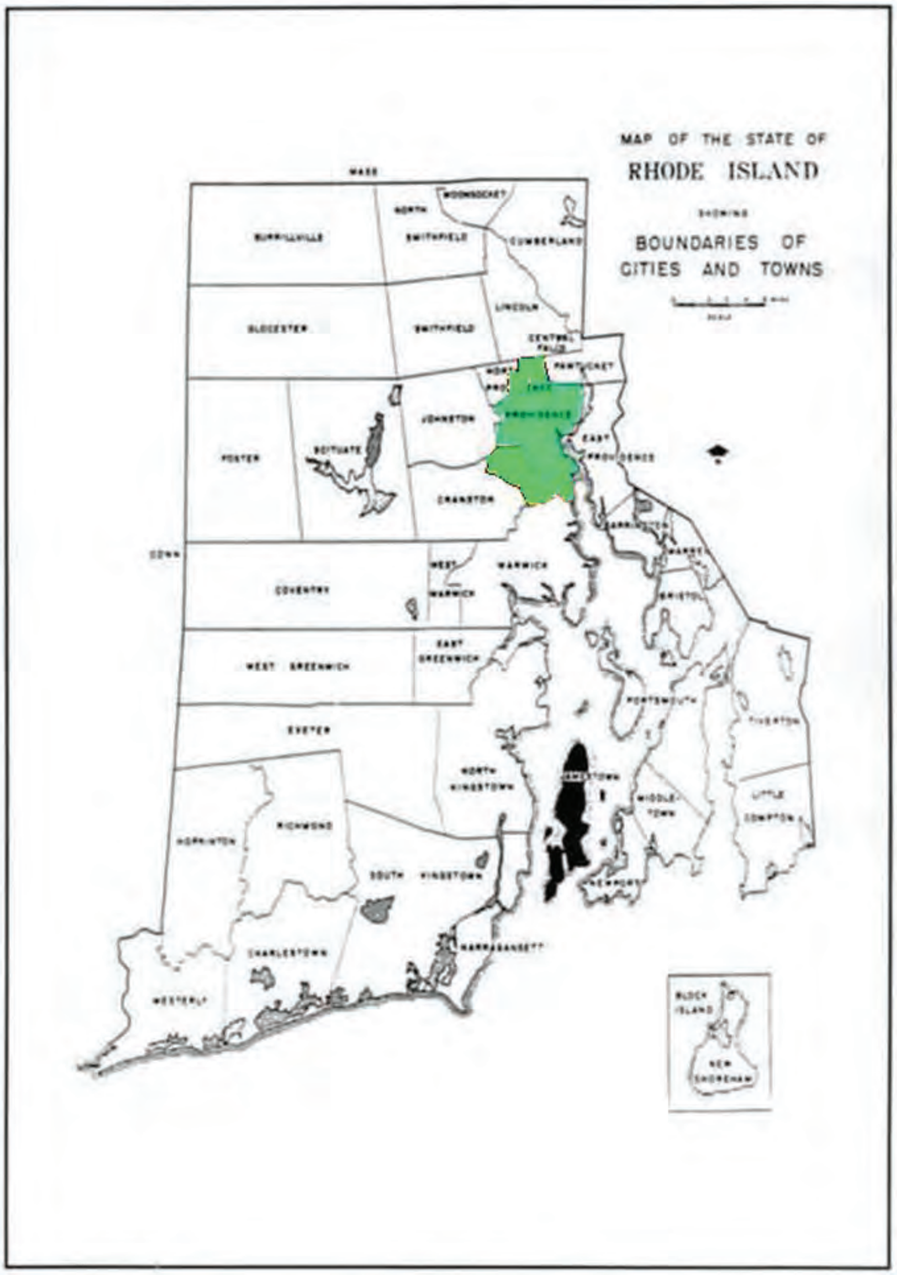
8. Factors Influencing Future Studies

Investments proposed in this study resolve a variety of asset and system issues. However, the complexity and duration of the solution will require further analysis and possible revision or augmentation in the future. The Point Street distribution system remains highly loaded at the end of the study period. Contingency loading issues, although of relatively low risk, remain in the Point Street station area. Higher load growth rates or concentrated growth in one area may exacerbate these two long term issues. It is recommended that the study be reviewed in approximately five years to re-evaluate non-wires alternatives as a solution to loading and reliability concerns that may develop. The non-wires solution could be compared against the next phase of the Providence Area Long Term Supply and Distribution Study which recommends new 115/12.47 kV capacity at South Street. During this future study it is suggested a detailed reactive compensation review be conducted.

9. Appendix

9.1 Geographic Scope

Figure 9.1.1 – Geographic Location of Study Area



9.2 Description of Study Boundary

Figure 9.2.1 – Boundaries of the Study Area and City of Providence

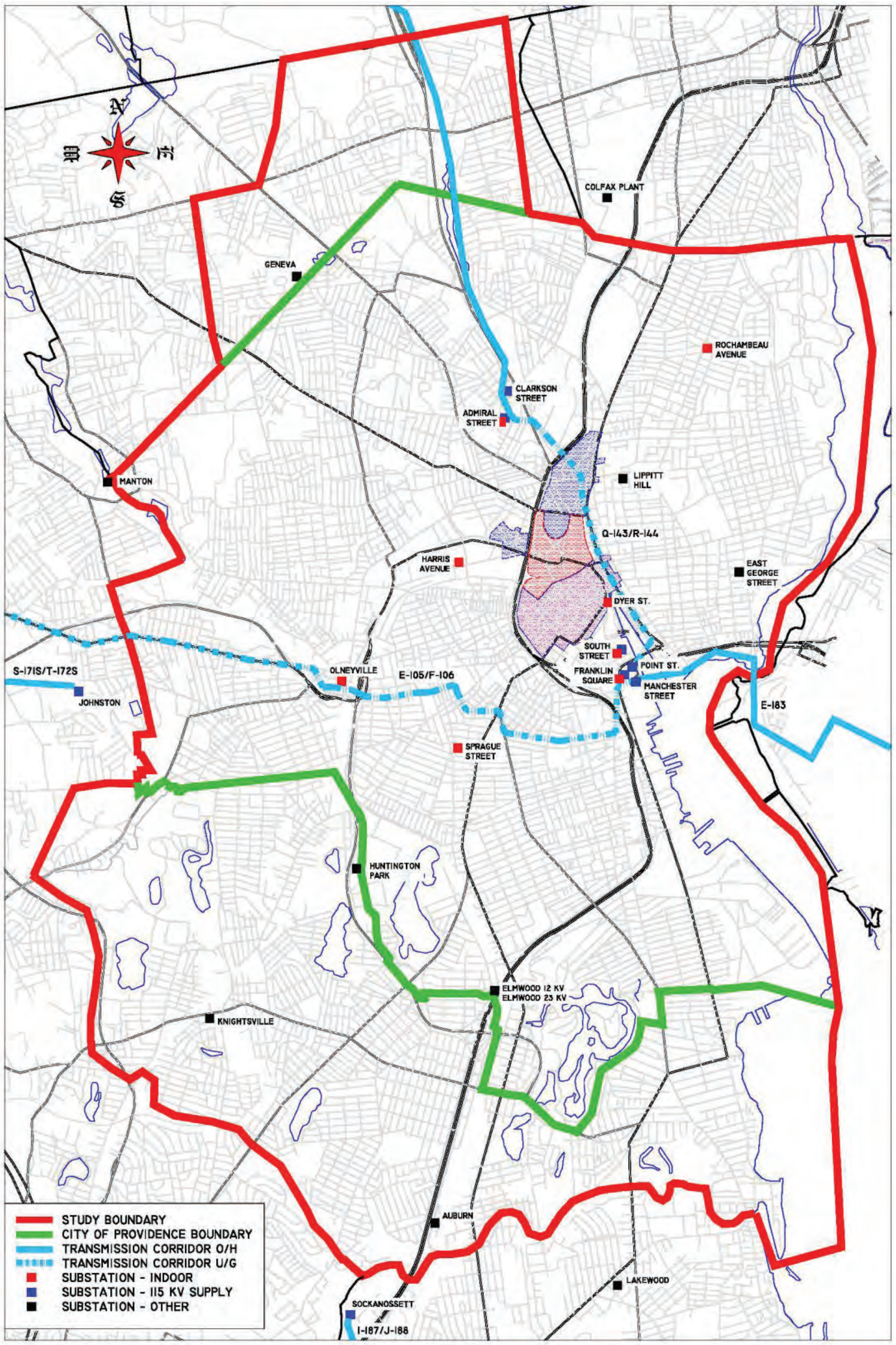
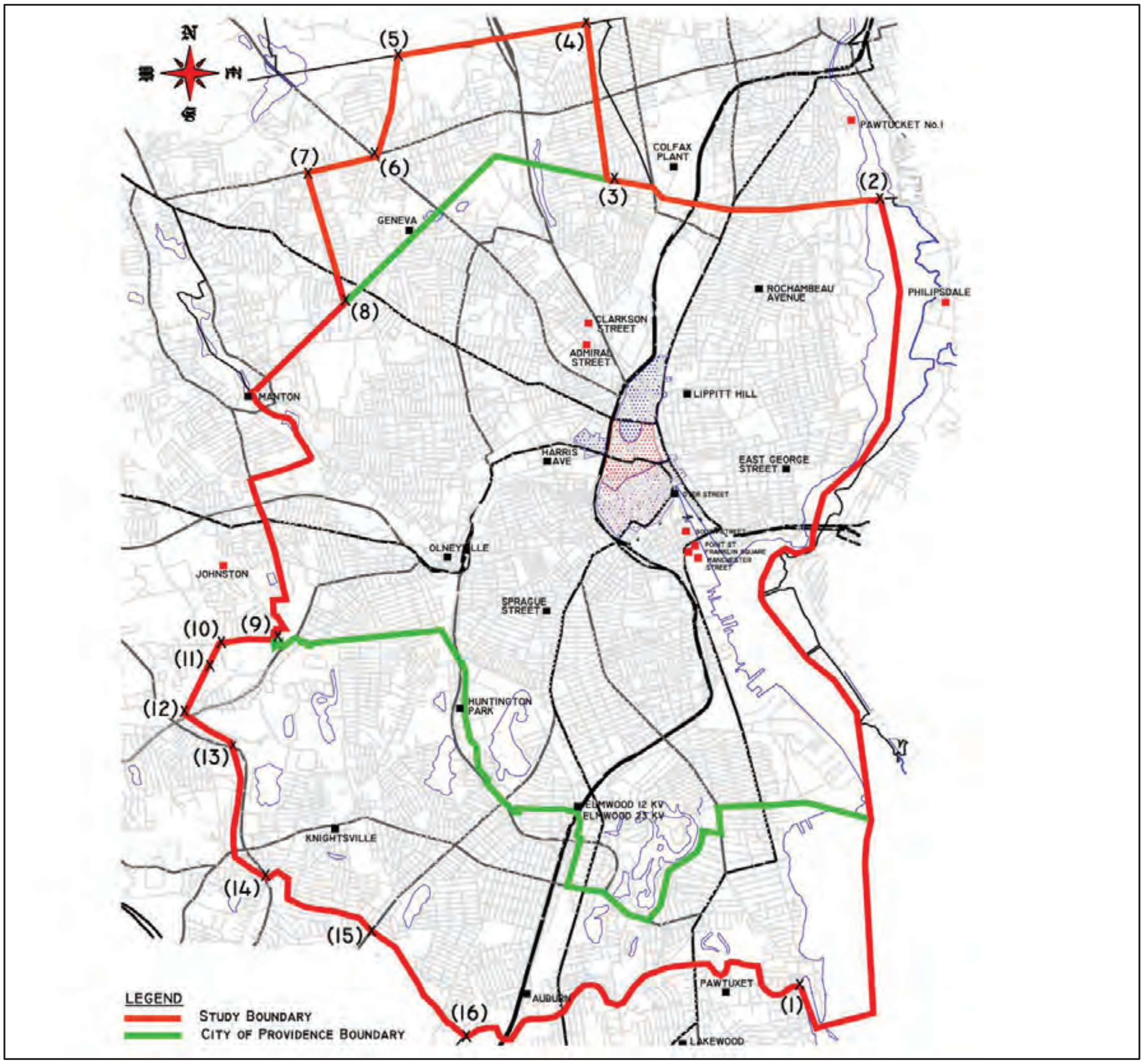


Figure 9.2.2 – Study Boundary with Land Marks



The study area is described as follows (refer to Figure 26 for location of the land marks):

Beginning at the point (1) where the Pawtuxet River enters the Providence River, the study area is bounded to the East by the Providence River and the Seekonk River and extends north to the Pawtucket City line (2);
Thence bounded to the north by the City of Pawtucket to a point where the City of Providence and the Town of North Providence boundary lines intersect (3);
Thence heads in a generally northerly direction bounded to the west by the City of Pawtucket to a point where the Town of North Providence and the Lincoln town lines intersect (4);
Thence heads in a westerly direction, bounded to the North by the Town of Lincoln to a point west of Angell Road (5);

Thence turns and heads in a generally southwesterly direction to the intersection of Mineral Spring Avenue and Douglas Avenue (6);
Thence follows Mineral Spring Avenue to Smithfield Avenue (7);
Thence heads in a generally southerly direction to the Providence town line (8).
Thence following the City of Providence town line to a the intersection with the City of Cranston town line (9);
Thence west into the Town of Johnston as far as the right-of-way corridor with the 2226 and 2228 circuits (10);
Thence heads in a southwest direction along the right-of-way to a point where the 23 kV circuits turn in southeast direction (11);
Thence continues in a straight line southwesterly to the intersection of Plainfield Pike with Fletcher Avenue (12);
Thence turns and heads in a generally southeasterly direction along Fletcher Avenue to its intersection with Route 5 (13);
Thence follows Route 5 to its junction with Wayland Ave (14);
Thence follows Wayland Ave to Cranston Street before heading south towards Sagamore Road, and along Sagamore Road to east to a point where the Pocasset River crosses Reservoir Avenue (15);
Thence following the Pocasset River to its junction with the Pawtuxet River (16);
Thence following the Pawtuxet River to the Providence River, the beginning point (1).

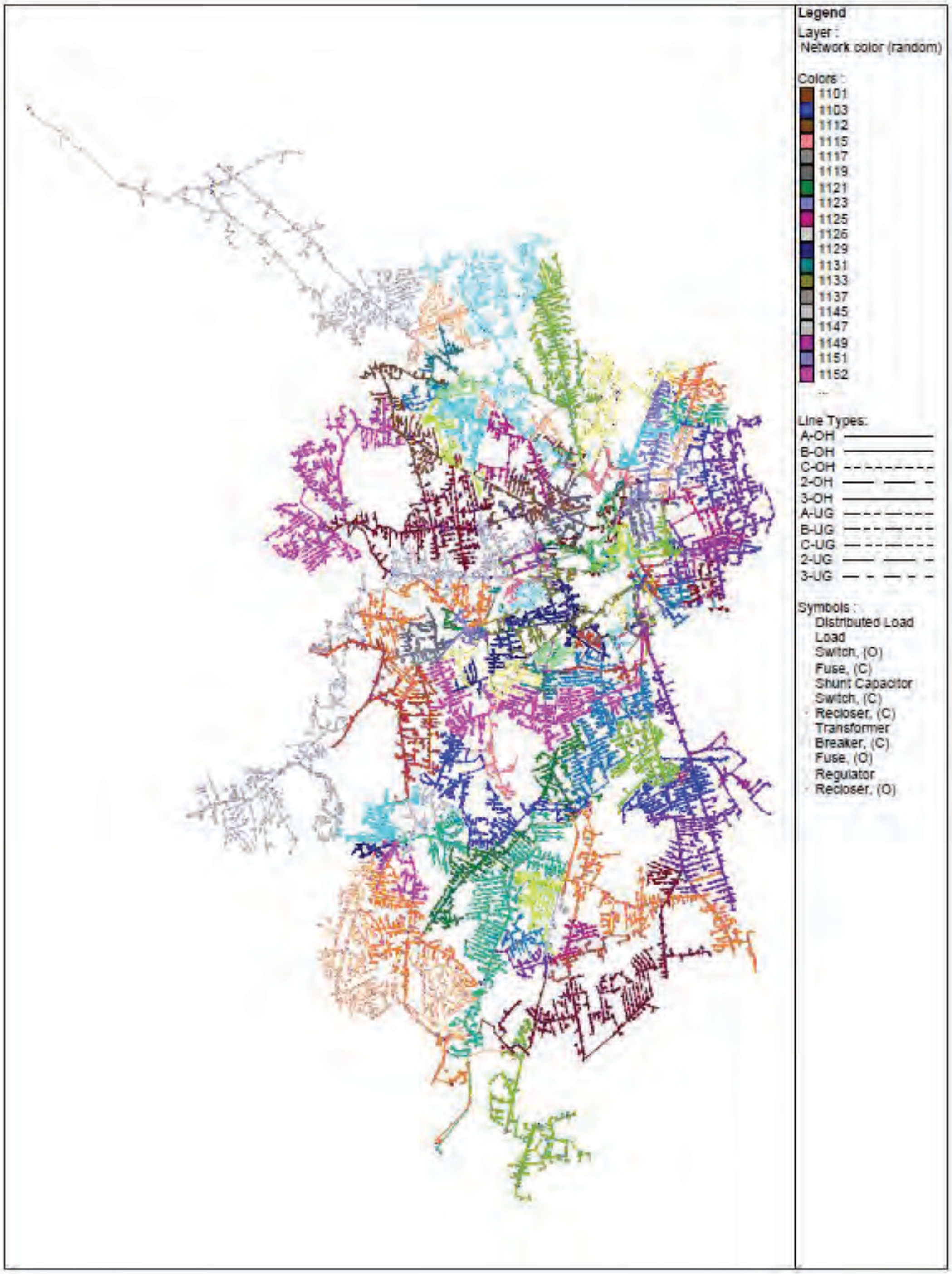
9.3 Existing Electrical System

Table 9.3.1 – Stations Supplying Study Area

Location	Sta ion	Year of Initial Construction	Indoor/Outdoor	Type (outdoor)	Supply Voltage	Number of Supply and Distribution Feeders by Voltage				
						4.16 kV	11.5 kV	12.47 kV	23 kV	35 kV
Inside Study Area	Admiral Street[1]	1930	Indoor & Outdoor	Low Profile	115 kV	4	4	-	4	-
	Auburn	1956	Outdoor	Steel Structure	23 kV	6	-	-	-	-
	Clarkson Street	1991	Outdoor	Low Profile	115 kV	-	-	10	-	-
	Dyer Street	1924	Indoor	-	11.5 kV	9	3	-	-	-
	East George	1970	Outdoor	Metalclad	23 kV	4	-	-	-	-
	Elmwood 23 kV	1929	Outdoor	Steel Structure	23 kV	-	-	-	4	-
	Elmwood 12.47 kV	1994	Outdoor	Low Profile	23 kV	-	-	3	-	-
	Franklin Square	1939	Indoor	-	115 kV	-	16	-	4	2
	Geneva	1953	Outdoor	Steel Structure	23 kV	5	-	-	-	-
	Harris Avenue	1929	Indoor & Outdoor	Steel Structure	23 kV	6	6	-	-	-
	Huntington Park	1967	Outdoor	Steel Structure	23 kV	1	-	-	-	-
	Knightsville	1952	Outdoor	Steel Structure	23 kV	4	-	-	-	-
	Lippitt Hill	1974	Outdoor	Metalclad	23 kV	-	-	2	-	-
	Olneyville	1924	Indoor	-	11.5 kV	7	-	-	-	-
	Point Street	2001	Outdoor	Low Profile	115 kV	-	-	8	-	-
	Rochambeau Avenue	1946	Indoor	-	23 kV & 11.5 kV	5	-	-	-	-
	South Street	1929	Indoor	-	115 kV	-	14	-	4	-
	Sprague Street	1951	Indoor	-	23 kV	4	-	-	-	-
Outside Study Area[2]	Farnum Pike	2006	Outdoor	Metalclad	115 kV	-	-	1	-	-
	Johnston	1955	Outdoor	Low Profile	115 kV	-	-	3	3	-
	Manton	1974	Outdoor	Low Profile	23 kV	-	-	1	-	-
	Pontiac	1975	Outdoor	Low Profile	115 kV	-	-	2	-	-
	Sockanosset	1973	Outdoor	Low Profile	115 kV	-	-	-	2	-
Total feeders						55	43	30	21	2

Figure 9.3.1 – Existing Layout of 11.5 kV, 23 kV and 35 kV Sub-transmission System

Figure 9.3.2 – Existing Layout of the Distribution System



9.4 CYME Radial Distribution Analysis Diagrams

Figure 9.4.1 – CYME – Base (Existing) Case – 2030 Loading

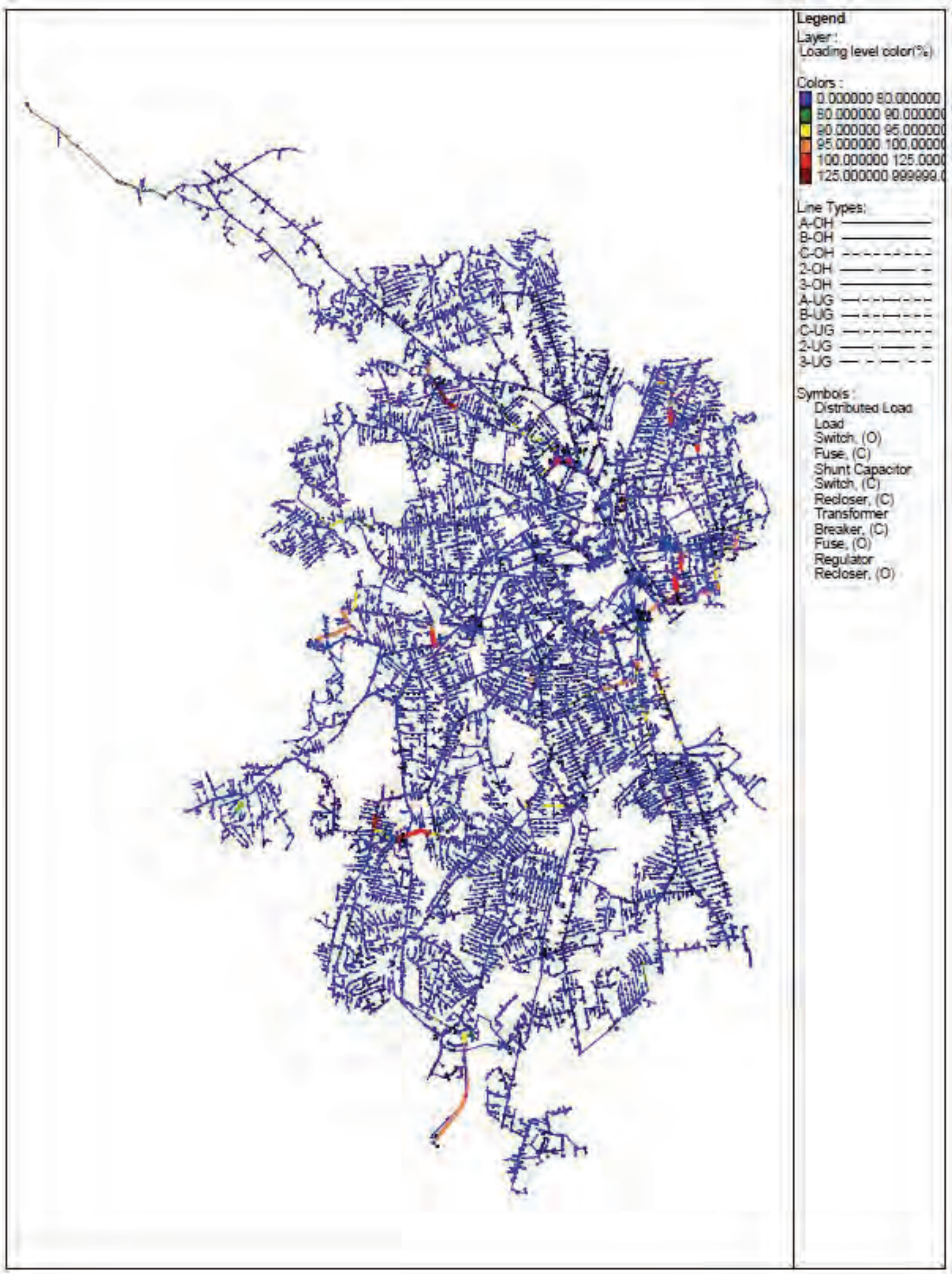


Figure 9.4.2 – CYME – Base (Existing) Case – 2030 Voltage

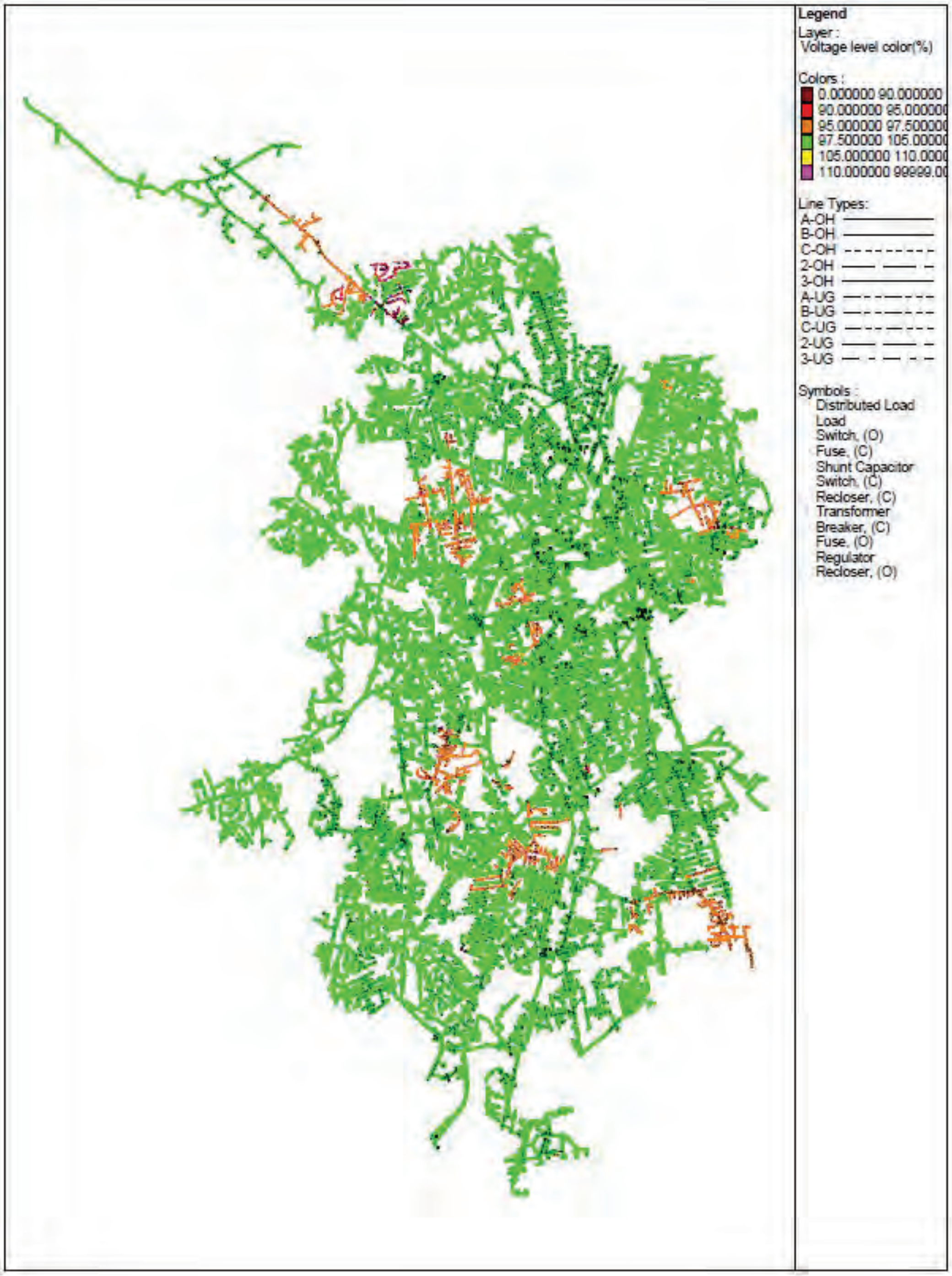


Figure 9.4.3 – CYME – Recommended Plan – 2030 Loading

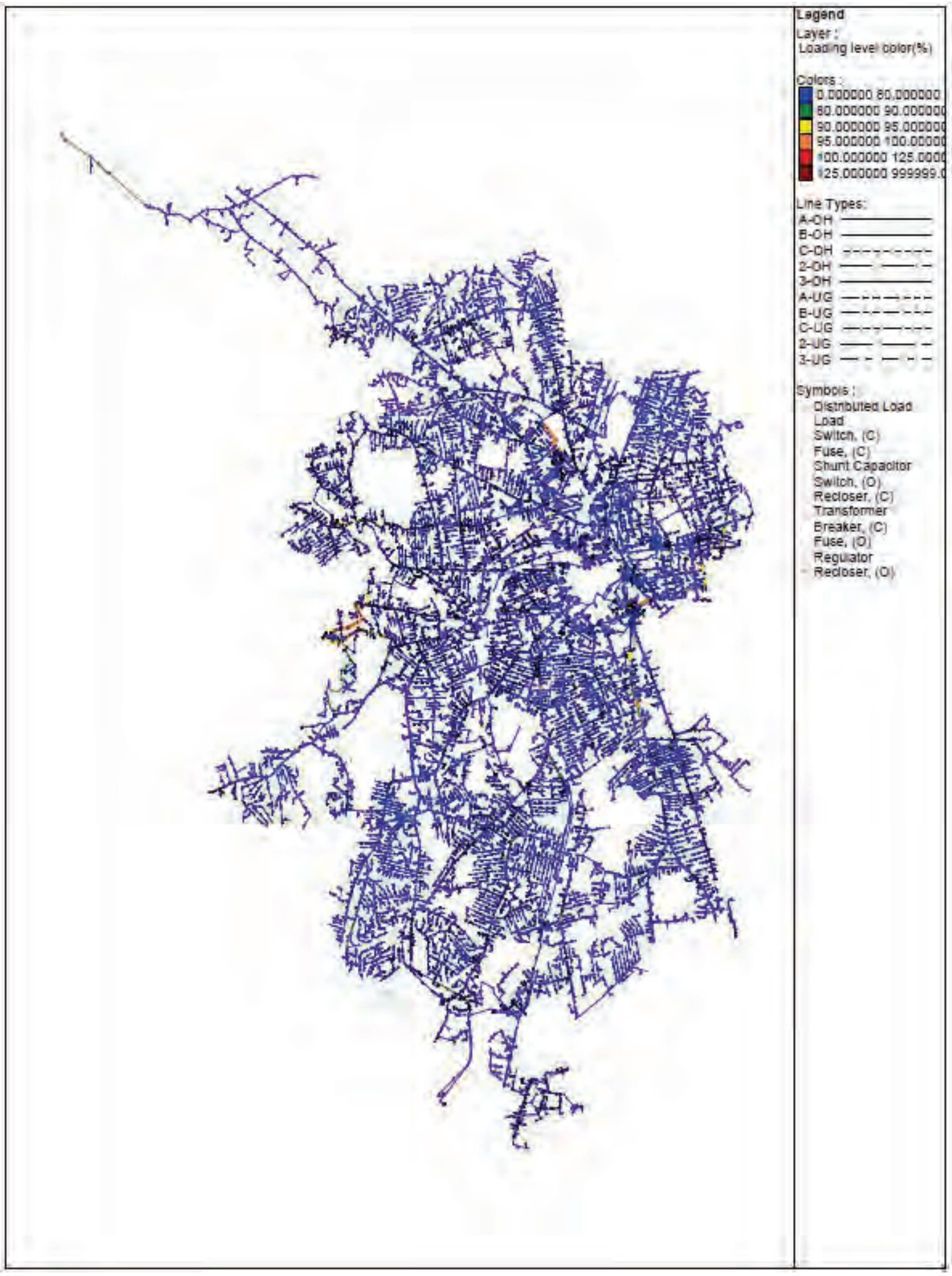
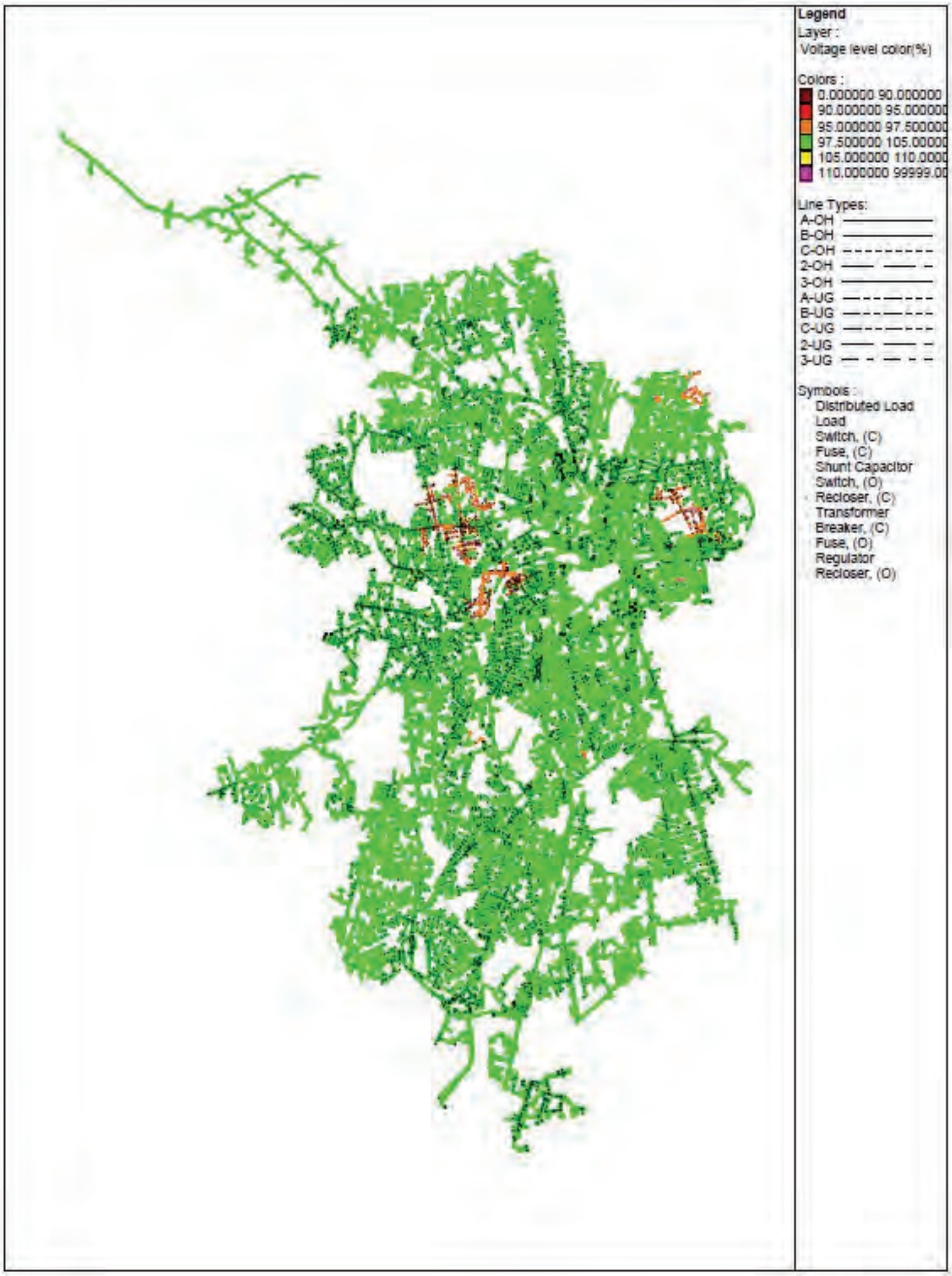


Figure 9.4.4 – CYME – Recommended Plan – 2030 Voltage



9.5 Transformer Loading Tables

Table 9.5.1 – Transformer Loading (Normal) for Existing System

Substation	Tranf. ID.	System Voltage (kV)		Rating (MVA)	Peak Load							
					2018		2022		2026		2030	
		From	To	SN	MVA	% SN	MVA	% SN	MVA	% SN	MVA	% SN
Admiral Street 9	T1	23	11/4.16	15	4.9	33%	5.0	33%	5.1	34%	5.2	35%
Admiral Street 9	T2	23	11/4.16	15	0.0	0%	0.0	0%	0.0	0%	0.0	0%
Franklin Square 11	3320	11.5	34.5	25.87	6.0	23%	6.0	23%	6.2	24%	6.3	24%
Franklin Square 11	3324	11.5	34.5	25.75	6.0	23%	6.0	23%	6.2	24%	6.3	24%
Admiral Street 9	T3	115	23	62.1	23.0	37%	23.3	38%	23.7	38%	24.2	39%
Admiral Street 9	T4	115	23	63	22.6	36%	22.9	36%	23.2	37%	23.7	38%
Franklin Square 11	2207	11.5	23	16.06	2.2	14%	2.3	14%	2.3	14%	2.4	15%
Franklin Square 11	2210	11.5	23	17.14	9.8	57%	10.0	58%	10.1	59%	10.4	61%
Franklin Square 11	2220	11.5	23	17.7	10.9	61%	11.0	62%	11.2	63%	11.5	65%
Franklin Square 11	2260	11.5	23	16.06	1.0	6%	1.0	6%	1.0	6%	1.1	7%
South Street 1	2201	11.5	23	7.5	3.5	47%	3.6	48%	3.7	49%	3.7	50%
South Street 1	2216	11.5	23	10	5.8	58%	5.9	59%	6.0	60%	6.2	62%
South Street 1	2248	11.5	23	12.81	8.4	65%	8.5	66%	8.7	68%	8.9	69%
South Street 1	24	11.5	23	9.1	4.8	53%	4.9	54%	5.0	55%	5.1	56%
Clarkson Street 13	T1	115	12.47	65.46	38.9	59%	39.5	60%	40.2	61%	41.1	63%
Clarkson Street 13	T2	115	12.47	65.16	33.1	51%	33.6	52%	34.2	53%	35.1	54%
Elmwood 7 (Outdoor)	T2	23	12.47	40.58	28.2	69%	28.6	70%	29.1	72%	29.8	73%
Lippitt Hill 79	T1	23	12.47	25.11	7.9	31%	8.0	32%	8.2	33%	8.4	33%
Lippitt Hill 79	T2	23	12.47	25.11	9.8	39%	10.0	40%	10.1	40%	10.4	41%
Point Street 76	T1	115	12.47	77	35.0	45%	35.5	46%	36.2	47%	37.0	48%
Point Street 76	T2	115	12.47	70.86	40.4	57%	41.1	58%	41.8	59%	42.8	60%
Franklin Square 11	T1	115	11.5	50.65	27.4	54%	27.8	55%	28.3	56%	29.0	57%
Franklin Square 11	T2	115	11.5	51.24	26.8	52%	27.3	53%	27.7	54%	28.4	55%
Franklin Square 11	T3	115	11.5	51.24	31.8	62%	32.2	63%	32.8	64%	33.6	66%
South Street 1	T1	115	11.5	66.34	33.9	51%	34.5	52%	35.1	53%	35.9	54%
South Street 1	T2	115	11.5	66.78	32.8	49%	33.3	50%	33.9	51%	34.7	52%
South Street 1	T3	115	11.5	72.69	27.4	38%	27.8	38%	28.3	39%	29.0	40%
Admiral Street 9	T5	23	4.16	15.13	6.3	42%	6.4	42%	6.5	43%	6.7	44%
Dyer St 2	T1	11.5	4.16	18.27	6.8	37%	6.9	38%	7.0	38%	7.2	39%
Dyer St 2	T2	11.5	4.16	18.25	6.8	37%	6.9	38%	7.0	38%	7.2	39%
East George St. 77	T1	23	4.16	12.59	4.9	39%	4.9	39%	5.0	40%	5.1	41%
East George St. 77	T2	23	4.16	12.59	4.8	38%	4.9	39%	5.0	40%	5.1	41%
Geneva 71	T1	23	4.16	11.54	4.4	38%	4.4	38%	4.5	39%	4.6	40%
Geneva 71	T2	23	4.16	11.85	4.4	37%	4.4	37%	4.5	38%	4.6	39%
Harris Avenue 12	T1	23	4.16	11.48	5.5	47%	5.5	48%	5.6	49%	5.8	50%
Harris Avenue 12	T2	23	4.16	9.06	1.6	18%	1.6	18%	1.7	18%	1.7	19%
Huntington Park 67	T1	23	4.16	3	1.8	59%	1.8	60%	1.8	61%	1.9	63%
Knightsville 66	T1	23	4.16	10.48	5.3	50%	5.4	51%	5.5	52%	5.6	53%
Knightsville 66	T2	23	4.16	10.48	5.3	50%	5.4	51%	5.5	52%	5.6	53%
Olneyville 6	T1	11.5	4.16	11.8	4.0	34%	4.1	34%	4.1	35%	4.2	36%
Olneyville 6	T3	11.5	4.16	11.8	4.0	34%	4.1	34%	4.1	35%	4.2	36%
Rochambeau Ave 37	T1	23	4.16	11.96	3.5	29%	3.6	30%	3.6	30%	3.7	31%
Rochambeau Ave 37	T2	11.5	4.16	11.02	5.9	54%	6.0	54%	6.1	55%	6.3	57%
Sprague St. 36	T1	23	4.16	10.58	3.5	33%	3.6	34%	3.7	35%	3.7	35%
Sprague St. 36	T2	23	4.16	10.79	3.5	33%	3.6	33%	3.7	34%	3.7	35%

Table 9.5.2 – Transformer Loading (Contingency) for Existing System

Substation	Tranf. ID.	System Voltage (kV)		Rating (MVA)	Peak Load								Worst Contingency
					2018		2022		2026		2030		
		From	To	SE	MVA	% SE	MVA	% SE	MVA	% SE	MVA	% SE	
Admiral Street 9	T1	23	11/4.16	15									No auto transfer
Franklin Square 11	3320	11 5	34.5	29.66									Modular
Franklin Square 11	3324	11 5	34.5	29 5									Modular
Admiral Street 9	T3	115	23	63.7	45.6	72%	46.2	73%	47.0	74%	48.0	75%	Loss of T4
Admiral Street 9	T4	115	23	64 9	45.6	70%	46.2	71%	47.0	72%	48.0	74%	Loss of T3
Franklin Square 11	2207	11 5	23	18.75									Modular
Franklin Square 11	2210	11 5	23	15.85									Modular
Franklin Square 11	2220	11 5	23	19 3									Modular
Franklin Square 11	2260	11 5	23	18.75									Modular
South Street 1	2201	11 5	23	7.5									Modular
South Street 1	2216	11 5	23	10									Modular
South Street 1	2248	11 5	23	14.33	14.3	100%	14.5	101%	14.8	103%	15.1	106%	Loss of Rocham T2
South Street 1	24	11 5	23	10.23	9.7	95%	9.8	96%	10.0	98%	10.3	100%	Loss of E Geoarge T1
Clarkson Street 13	T1	115	12.47	81.01	72.0	89%	73.1	90%	74.4	92%	76.2	94%	Loss of T2
Clarkson Street 13	T2	115	12.47	80.24	72.0	90%	73.1	91%	74.4	93%	76.2	95%	Loss of T1
Elmwood 7 (Outdoor)	T2	23	12.47	45.78									Single Transformer
Lippitt Hill 79	T1	23	12.47	27.54	17.7	64%	18.0	65%	18.3	67%	18.8	68%	Loss of T2
Lippitt Hill 79	T2	23	12.47	27.54	17.7	64%	18.0	65%	18.3	67%	18.8	68%	Loss of T1
Point Street 76	T1	115	12.47	89 8	75.4	84%	76.6	85%	78.0	87%	79.8	89%	Loss of T2
Point Street 76	T2	115	12.47	79.98	75.4	94%	76.6	96%	78.0	97%	79.8	100%	Loss of T1
Franklin Square 11	T1	115	11.5	61.04									Not considered in Study
Franklin Square 11	T2	115	11.5	56.69									Not considered in Study
Franklin Square 11	T3	115	11.5	56.69									Not considered in Study
South Street 1	T1	115	11.5	78.75									Not considered in Study
South Street 1	T2	115	11.5	77.14									Not considered in Study
South Street 1	T3	115	11.5	91.22									Not considered in Study
Admiral Street 9	T5	23	4.16	15.36									Single Transformer
Dyer St 2	T1	11 5	4.16	19.78	13.6	69%	13.8	70%	14.0	71%	14.4	73%	Loss of T2
Dyer St 2	T2	11 5	4.16	19.74	13.6	69%	13.8	70%	14.0	71%	14.4	73%	Loss of T1
East George St. 77	T1	23	4.16	15.27	9.7	63%	9.8	64%	10.0	66%	10.3	67%	Loss of T2
East George St. 77	T2	23	4.16	15.27	9.7	63%	9.8	64%	10.0	66%	10.3	67%	Loss of T1
Geneva 71	T1	23	4.16	14.19	8.7	61%	8.8	62%	9.0	63%	9.2	65%	Loss of T2
Geneva 71	T2	23	4.16	14.61	8.7	60%	8.8	61%	9.0	62%	9.2	63%	Loss of T1
Harris Avenue 12	T1	23	4.16	12.72	7.1	55%	7.2	56%	7.3	57%	7.5	59%	Loss of T2
Harris Avenue 12	T2	23	4.16	11.52	7.1	61%	7.2	62%	7.3	63%	7.5	65%	Loss of T1
Huntington Park 67	T1	23	4.16	3									Single Transformer
Knightsville 66	T1	23	4.16	11.02	10.6	96%	10.7	97%	10.9	99%	11.2	101%	Loss of T2
Knightsville 66	T2	23	4.16	11.02	10.6	96%	10.7	97%	10.9	99%	11.2	101%	Loss of T1
Olneyville 6	T1	11 5	4.16	13.02	8.0	61%	8.1	62%	8.3	64%	8.5	65%	Loss of T2
Olneyville 6	T3	11 5	4.16	13.02	8.0	61%	8.1	62%	8.3	64%	8.5	65%	Loss of T1
Rochambeau Ave 37	T1	23	4.16	13.12	9.4	72%	9.6	73%	9.7	74%	10.0	76%	Loss of T2
Rochambeau Ave 37	T2	11 5	4.16	13.04	9.4	72%	9.6	73%	9.7	75%	10.0	77%	Loss of T1
Sprague St. 36	T1	23	4.16	11.85	7.1	60%	7.2	61%	7.3	62%	7.5	63%	Loss of T2
Sprague St. 36	T2	23	4.16	12	7.1	59%	7.2	60%	7.3	61%	7.5	62%	Loss of T1

Table 9.5.3 – Transformer Loading (Normal) with Recommended Plan Improvements

Substation	Tranf. ID.	System Voltage (kV)		Rating (MVA)	Peak Loads								Comments
					2018		2022		2026		2030		
		From	To	SN	MVA	% SN	MVA	% SN	MVA	% SN	MVA	% SN	
Admiral Street 9	T1	23	11/4.16	15	4.9	33%	0.0	0%	0.0	0%	0.0	0%	Retired
Franklin Square 11	3320	11.5	34.5	25.87	6.0	23%	6.0	23%	6.2	24%	6.3	24%	
Franklin Square 11	3324	11.5	34.5	25.75	6.0	23%	6.0	23%	6.2	24%	6.3	24%	
Admiral Street 9	T3	115	23	62.1	23.0	37%	19.1	31%	12.0	19%	12.2	20%	
Admiral Street 9	T4	115	23	63	22.6	36%	18.7	30%	11.7	19%	12.0	19%	
Admiral Street 9 (New)	T7	115	12.47	65					24.4	38%	24.9	38%	
Admiral Street 9 (New)	T8	115	12.47	65					26.1	40%	26.1	40%	
Auburn 73 (New)	T1	115	12.47	65					33.0	51%	34.1	52%	
Auburn 73 (New)	T2	115	12.47	65					35.0	54%	36.2	56%	
Franklin Square 11	2207	11.5	23	16.06	2.2	14%	2.3	14%	2.3	14%	2.4	15%	
Franklin Square 11	2210	11.5	23	17.14	9.8	57%	10.0	58%	10.1	59%	10.4	61%	
Franklin Square 11	2220	11.5	23	17.7	10.9	61%	11.0	62%	11.2	63%	11.5	65%	
Franklin Square 11	2260	11.5	23	16.06	1.0	6%	1.0	6%	1.0	6%	1.1	7%	
South Street 1	2201	11.5	23	7.5	3.5	47%	3.6	48%	3.7	49%			Sprague St Retired
South Street 1	2216	11.5	23	10	5.8	58%	5.9	59%	6.0	60%	6.2	62%	
South Street 1	2248	11.5	23	12.81	8.4	65%	8.5	66%	5.0	39%	5.1	40%	
South Street 1	24	11.5	23	9.1	4.8	53%	4.9	54%	5.0	55%	5.1	56%	
Clarkson Street 13	T1	115	12.47	65.46	38.9	59%	39.9	61%	37.3	57%	38.2	58%	
Clarkson Street 13	T2	115	12.47	65.16	33.1	51%	41.7	64%	41.1	63%	42.0	65%	
Elmwood 7 (12.47 kV)	T2	23	12.47	40.58	28.2	69%	28.2	69%	28.6	71%			Retired
Lippitt Hill 79	T1	23	12.47	25.11	7.9	31%	8.9	35%	8.5	34%	8.7	35%	
Lippitt Hill 79	T2	23	12.47	25.11	9.8	39%	11.7	47%	11.5	46%	11.8	47%	
Point Street 76	T1	115	12.47	77	35.0	45%	35.5	46%	37.2	48%	36.1	47%	
Point Street 76	T2	115	12.47	70.86	40.4	57%	40.7	57%	41.4	58%	41.4	58%	
Franklin Square 11	T1	115	11.5	50.65	27.4	54%	27.8	55%	28.3	56%	29.0	57%	
Franklin Square 11	T2	115	11.5	51.24	26.8	52%	27.3	53%	27.7	54%	28.4	55%	
Franklin Square 11	T3	115	11.5	51.24	31.8	62%	32.2	63%	32.8	64%	33.6	66%	
South Street 1	T1	115	11.5	66.34	33.9	51%	34.5	52%	35.1	53%	35.9	54%	
South Street 1	T2	115	11.5	66.78	32.8	49%	33.3	50%	33.9	51%	34.7	52%	
South Street 1	T3	115	11.5	72.69	27.4	38%	27.8	38%	28.3	39%	29.0	40%	
Admiral Street 9	T5	23	4.16	15.13	6.3	42%							Retired
Dyer St 2	T1	11.5	4.16	18.27	6.8	37%	6.9	38%	6.6	36%	7.1	39%	
Dyer St 2	T2	11.5	4.16	18.25	6.8	37%	6.9	38%	6.6	36%	7.1	39%	
East George St. 77	T1	23	4.16	12.59	4.9	39%	4.9	39%	5.0	40%	5.1	41%	
East George St. 77	T2	23	4.16	12.59	4.8	38%	4.9	39%	5.0	40%	5.1	41%	
Geneva 71	T1	23	4.16	11.54	4.4	38%	4.4	38%					Retired
Geneva 71	T2	23	4.16	11.85	4.4	37%	4.4	37%					Retired
Harris Avenue 12	T1	23	4.16	11.48	5.5	47%	5.5	48%					Retired
Harris Avenue 12	T2	23	4.16	9.06	1.6	18%	1.6	18%					Retired
Huntington Park 67	T1	23	4.16	3	1.8	59%	1.8	60%	1.8	61%			Retired
Knightsville 66	T1	23	4.16	10.48	5.3	50%	5.4	51%					Retired
Knightsville 66	T2	23	4.16	10.48	5.3	50%	5.4	51%					Retired
Olneyville 6	T1	11.5	4.16	11.8	4.0	34%	1.9	16%					Retired
Olneyville 6	T3	11.5	4.16	11.8	4.0	34%	1.9	16%					Retired
Rochambeau Ave 37	T1	23	4.16	11.96	3.5	29%	3.6	30%					Retired
Rochambeau Ave 37	T2	11.5	4.16	11.02	5.9	54%	6.0	54%					Retired
Sprague St. 36	T1	23	4.16	10.58	3.5	33%	3.6	34%	3.7	35%			Retired
Sprague St. 36	T2	23	4.16	10.79	3.5	33%	3.6	33%	3.7	34%			Retired

Table 9.5.4 – Transformer Loading (Contingency) with Recommended Plan Improvements

Substation	Tranf. ID.	System Voltage (kV)		Rating (MVA)	Peak Load								Worst Contingency
					2018		2022		2026		2030		
		From	To	SE	MVA	% SE	MVA	% SE	MVA	% SE	MVA	% SE	
Admiral Street 9	T1	23	11/4.16	15									No auto transfer
Franklin Square 11	3320	11.5	34.5	29 66									Modular
Franklin Square 11	3324	11.5	34.5	29.5									Modular
Admiral Street 9	T3	115	23	63.7	45.6	72%	37.8	59%	23.7	37%	24.2	38%	Loss of T4
Admiral Street 9	T4	115	23	64.9	45.6	70%	37.8	58%	23.7	37%	24.2	37%	Loss of T3
Admiral Street 9 (New)	T7	115	12.47	80					50.6	63%	51.5	64%	Loss of T8
Admiral Street 9 (New)	T8	115	12.47	80					50.6	63%	51.5	64%	Loss of T7
Auburn 73 (New)	T1	115	12.47	80					68.1	85%	70.3	88%	Loss of T2
Auburn 73 (New)	T2	115	12.47	80					68.1	85%	70.3	88%	Loss of T1
Franklin Square 11	2207	11.5	23	18.75									Modular
Franklin Square 11	2210	11.5	23	15 85									Modular
Franklin Square 11	2220	11.5	23	19.3									Modular
Franklin Square 11	2260	11.5	23	18.75									Modular
South Street 1	2201	11.5	23	7 5									Modular
South Street 1	2216	11.5	23	10									Modular
South Street 1	2248	11.5	23	14 33	14.3	100%	14.5	101%	5.0	35%	5.1	36%	Rochambeau retired
South Street 1	24	11.5	23	10 23	9.7	95%	9.8	96%	10.0	98%	10.3	100%	Loss of E Geoarge T1
Clarkson Street 13	T1	115	12.47	81 01	72.0	89%	81.5	101%	78.3	97%	80.2	99%	Loss of T2
Clarkson Street 13	T2	115	12.47	80 24	72.0	90%	81.5	102%	78.3	98%	80.2	100%	Loss of T1
Elmwood 7 (Outdoor)	T2	23	12.47	45.78									Single Transformer
Lippitt Hill 79	T1	23	12.47	27 54	17.7	64%	20.6	75%	20.0	73%	20.5	75%	Loss of T2
Lippitt Hill 79	T2	23	12.47	27 54	17.7	64%	20.6	75%	20.0	73%	20.5	75%	Loss of T1
Point Street 76	T1	115	12.47	89.8	75.4	84%	76.2	85%	78.6	88%	77.5	86%	Loss of T2
Point Street 76	T2	115	12.47	79 98	75.4	94%	76.2	95%	78.6	98%	77.5	97%	Loss of T1
Franklin Square 11	T1	115	11.5	61 04									Not considered in study
Franklin Square 11	T2	115	11.5	56 69									Not considered in study
Franklin Square 11	T3	115	11.5	56 69									Not considered in study
South Street 1	T1	115	11.5	78.75									Not considered in study
South Street 1	T2	115	11.5	77.14									Not considered in study
South Street 1	T3	115	11.5	91 22									Not considered in study
Admiral Street 9	T5	23	4.16	15 36									Single Transformer
Dyer St 2	T1	11.5	4.16	19.78	13.6	69%	13.8	70%	13.3	67%	14.2	72%	Loss of T2
Dyer St 2	T2	11.5	4.16	19.74	13.6	69%	13.8	70%	13.3	67%	14.2	72%	Loss of T1
East George St. 77	T1	23	4.16	15 27	9.7	63%	9.8	64%	10.0	66%	10.3	67%	Loss of T2
East George St. 77	T2	23	4.16	15 27	9.7	63%	9.8	64%	10.0	66%	10.3	67%	Loss of T1
Geneva 71	T1	23	4.16	14.19	8.7	61%	8.8	62%	0.0	0%	0.0	0%	Retired
Geneva 71	T2	23	4.16	14 61	8.7	60%	8.8	61%	0.0	0%	0.0	0%	Retired
Harris Avenue 12	T1	23	4.16	12.72	7.1	55%	7.2	56%	0.0	0%	0.0	0%	Retired
Harris Avenue 12	T2	23	4.16	11 52	7.1	61%	7.2	62%	0.0	0%	0.0	0%	Retired
Huntington Park 67	T1	23	4.16	3									Retired
Knightsville 66	T1	23	4.16	11 02	10.6	96%	10.7	97%					Retired
Knightsville 66	T2	23	4.16	11 02	10.6	96%	10.7	97%					Retired
Olneyville 6	T1	11.5	4.16	13 02	8.0	61%	3.7	29%					Retired
Olneyville 6	T3	11.5	4.16	13 02	8.0	61%	3.7	29%					Retired
Rochambeau Ave 37	T1	23	4.16	13.12	9.4	72%	9.6	73%					Retired
Rochambeau Ave 37	T2	11.5	4.16	13 04	9.4	72%	9.6	73%					Retired
Sprague St. 36	T1	23	4.16	11 85	7.1	60%	7.2	61%	7.3	62%			Retired
Sprague St. 36	T2	23	4.16	12	7.1	59%	7.2	60%	7.3	61%			Retired

9.6 Asset Condition

Figure 9.6.1 – Fire Suppression System – Admiral St Substation

Figure 9.6.2 – 4.16 kV Voltage Regulators – Admiral St Substation

Figure 9.6.3 – General Electric "H" Oil Circuit Breakers (1930) – Olneyville Substation

Table 9.6.1 - Underground Cable Asset Issues

Terminal Station 1	Terminal Station 2	Age Group	Line Number	Total Miles	Paper & Lead Miles
SOUTH STREET	Distribution Load	50+ Years	1171	3.18	0.86
HARRIS AVENUE	Distribution Load	50+ Years	1131	2.53	2.07
HARRIS AVENUE	Distribution Load	50+ Years	1145	0.06	0.00
HARRIS AVENUE	Distribution Load	50+ Years	1147	2.22	1.22
HARRIS AVENUE	Distribution Load	50+ Years	1137	1.65	0.64
ADMIRAL STREET	Distribution Load	50+ Years	1119	0.85	0.47
ADMIRAL STREET	Distribution Load	50+ Years	1115	0.40	0.37
ADMIRAL STREET	Distribution Load	50+ Years	1117	0.58	0.52
HARRIS AVENUE	Distribution Load	50+ Years	1133	0.46	0.22
HARRIS AVENUE	Distribution Load	50+ Years	1129	1.58	1.43
ADMIRAL STREET	ROCHAMBEAU	50+ Years	1110	4.29	4.29
ELMWOOD	SPRAGUE STREET	50+ Years	2203	2.62	0.58
FRANKLIN SQUARE	HARRIS AVENUE / OLNEYVILLE	50+ Years	1130	2.76	2.76
SOUTH STREET	HARRIS AVENUE	50+ Years	1114	1.54	1.54
FRANKLIN SQUARE	OLNEYVILLE	50+ Years	1132	3.75	3.70
SOUTH STREET	SPRAGUE STREET	50+ Years	2201	2.78	2.78
FRANKLIN SQUARE	HARRIS AVENUE	50+ Years	2207	2.37	0.30
ADMIRAL STREET	HARRIS AVENUE	50+ Years	2252	1.57	1.57
FRANKLIN SQUARE	HARRIS AVENUE	50+ Years	1120	1.60	1.60
TOTAL				**36.79**	**26.92**

9.7 Reliability Performance

Table 9.7.1 – Historic Reliability Indices – Study Area Feeders[1]

Substation	Voltage (kV)	Feeder	CKAIFI			CKAIDI		
			2015	2014	2013	2015	2014	2013
CLARKSON STREET 13	12.47	53-13F1	0.916	1.984	0.659	38.580	6.409	38.858
CLARKSON STREET 13	12.47	53-13F2	0.494	1.108	0.068	25.404	67.970	4.498
CLARKSON STREET 13	12.47	53-13F3	1.077	1.107	0.309	115.327	149.534	20.500
CLARKSON STREET 13	12.47	53-13F4	0.632	2.400	0.295	41.717	144.238	22.790
CLARKSON STREET 13	12.47	53-13F6	0.640	2.280	0.885	100.912	162.640	328.769
CLARKSON STREET 13	12.47	53-13F8	0.089	0.000	0.400	61.956	0.000	278.800
ELMWOOD 7 - OUTDOOR	12.47	53-7F1	1.024	0.498	2.253	64.045	15.774	134.576
ELMWOOD 7 - OUTDOOR	12.47	53-7F2	1.062	1.668	1.066	69.843	90.164	62.921
ELMWOOD 7 - OUTDOOR	12.47	53-7F4	1.411	0.204	1.572	75.356	10.840	80.304
POINT STREET 76	12.47	53-76F7	0.267	0.341	1.085	9.913	29.796	19.703
POINT STREET 76	12.47	53-76F8	0.285	0.168	0.023	12.303	9.468	3.015
DYER STREET 2	11.5	53-1103	0.612	1.016	0.000	84.641	86.815	0.000
FRANKLIN SQUARE 11	11.5	53-1125	0.600	0.000	0.938	43.573	0.000	98.125
FRANKLIN SQUARE 11	11.5	53-1149	1.358	1.000	0.417	135.213	22.625	137.917
HARRIS AVENUE 12	11.5	53-1131	1.508	1.917	2.923	113.277	200.744	159.385
HARRIS AVENUE 12	11.5	53-1133	0.800	0.000	1.000	353.500	0.000	316.000
HARRIS AVENUE 12	11.5	53-1137	0.360	0.000	1.000	133.800	0.000	569.000
SOUTH STREET 1	11.5	53-1101	1.023	1.988	1.000	115.943	190.047	45.700
SOUTH STREET 1	11.5	53-1171	0.440	0.000	1.182	65.640	0.000	228.818
ADMIRAL STREET 9	4.16	53-9J1	0.867	0.042	3.190	63.485	2.947	241.128
ADMIRAL STREET 9	4.16	53-9J2	0.873	0.000	1.368	77.615	0.000	125.449
ADMIRAL STREET 9	4.16	53-9J3	0.291	0.333	1.077	28.126	29.575	110.214
ADMIRAL STREET 9	4.16	53-9J5	0.352	0.000	1.201	34.360	0.000	118.655
DYER STREET 2	4.16	53-2J1	1.600	1.052	1.907	160.445	101.028	211.576
DYER STREET 2	4.16	53-2J2	0.354	1.000	0.000	39.330	101.000	0.000
DYER STREET 2	4.16	53-2J3	0.598	0.993	0.989	71.900	100.249	132.918
DYER STREET 2	4.16	53-2J4	0.388	1.008	0.000	43.923	102.103	0.000
DYER STREET 2	4.16	53-2J5	0.600	0.976	0.000	61.825	98.595	0.000
DYER STREET 2	4.16	53-2J7	1.052	2.948	0.000	81.790	152.359	0.000
DYER STREET 2	4.16	53-2J8	0.598	0.996	0.000	88.613	100.616	0.000
DYER STREET 2	4.16	53-2J9	0.496	1.261	0.085	67.007	204.948	5.085
DYER STREET 2	4.16	53-2J10	0.594	0.966	0.000	74.680	98.558	0.000
EAST GEORGE ST 77	4.16	53-77J4	0.503	0.199	0.080	70.200	129.403	3.379
GENEVA 71	4.16	53-71J4	0.243	0.027	1.061	16.689	2.233	59.684
GENEVA 71	4.16	53-71J5	0.442	0.105	1.083	29.762	9.122	81.444
HARRIS AVENUE 12	4.16	53-12J5	0.540	0.919	0.373	58.561	113.274	103.847
HARRIS AVENUE 12	4.16	53-12J6	0.463	0.040	0.000	154.082	4.200	0.000
HUNTINGTON PARK 67	4.16	53-67J1	1.208	2.005	0.000	121.347	102.136	0.000
KNIGHTSVILLE 66	4.16	53-66J5	0.107	0.000	0.135	25.984	0.000	79.089
OLNEYVILLE 6	4.16	53-6J3	0.515	0.000	0.067	68.791	0.000	107.667
OLNEYVILLE 6	4.16	53-6J5	0.000	0.090	0.993	0.030	9.792	228.153
OLNEYVILLE 6	4.16	53-6J6	0.832	1.000	1.155	105.813	86.688	163.515
OLNEYVILLE 6	4.16	53-6J7	0.496	0.007	1.156	47.232	0.459	27.399
OLNEYVILLE 6	4.16	53-6J8	3.415	0.000	0.000	436.271	0.000	0.000
ROCHAMBEAU AVENUE 37	4.16	53-37J2	0.402	2.012	0.000	21.439	107.327	0.000
ROCHAMBEAU AVENUE 37	4.16	53-37J3	0.481	1.156	0.132	38.201	86.132	3.210
ROCHAMBEAU AVENUE 37	4.16	53-37J5	1.225	3.064	0.000	93.456	303.723	0.000
SPRAGUE STREET 36	4.16	53-36J4	0.582	1.000	0.813	93.817	84.482	151.593
SPRAGUE STREET 36	4.16	53-36J5	0.240	1.043	0.041	23.703	102.184	4.785
FARNUM PIKE 23	12.47	53-23F6	0.632	0.622	0.580	53.724	92.945	39.918
JOHNSTON 18	12.47	53-18F7	0.865	0.017	1.497	41.699	2.251	27.213
PONTIAC 27	12.47	53-27F1	0.442	0.690	0.123	18.942	75.135	9.649
PONTIAC 27	12.47	53-27F2	2.172	0.076	0.000	178.535	40.682	0.000
AUBURN 73	4.16	53-73J4	1.171	0.122	2.000	177.138	19.634	714.698

1. Values in red exceed the overall frequency and duration targets for RI.

Table 9.7.2 – Reliability Indices of Circuits after Implementing Recommended Plan[1, 2]

Substation	Voltage (kV)	Feeder	CKAIFI			CKAIDI		
			2015	2014	2013	2015	2014	2013
CLARKSON STREET 13	12.47	53-13F1	0.916	1.984	0.659	38.580	6.409	38.858
CLARKSON STREET 13	12.47	53-13F2	0.494	1.108	0.068	25.404	67.970	4.498
CLARKSON STREET 13	12.47	53-13F3	1.077	1.107	0.309	115.327	149.534	20.500
CLARKSON STREET 13	12.47	53-13F4	0.632	2.400	0.295	41.717	144.238	22.790
CLARKSON STREET 13	12.47	53-13F6	0.640	2.280	0.885	100.912	162.640	328.769
CLARKSON STREET 13	12.47	53-13F8	0.089	0.000	0.400	61.956	0.000	278.800
~~ELMWOOD 7 - OUTDOOR~~	~~12.47~~	~~53-7F1~~	~~1.024~~	~~0.498~~	~~2.253~~	~~64.045~~	~~15.774~~	~~134.576~~
~~ELMWOOD 7 - OUTDOOR~~	~~12.47~~	~~53-7F2~~	~~1.062~~	~~1.668~~	~~1.066~~	~~69.843~~	~~90.164~~	~~62.921~~
~~ELMWOOD 7 - OUTDOOR~~	~~12.47~~	~~53-7F4~~	~~1.411~~	~~0.204~~	~~1.572~~	~~75.356~~	~~10.840~~	~~80.304~~
POINT STREET 76	12.47	53-76F7	0.267	0.341	1.085	9.913	29.796	19.703
POINT STREET 76	12.47	53-76F8	0.285	0.168	0.023	12.303	9.468	3.015
~~DYER STREET 2~~	~~11.5~~	~~53-1103~~	~~0.612~~	~~1.016~~	~~0.000~~	~~84.641~~	~~86.815~~	~~0.000~~
FRANKLIN SQUARE 11	11.5	53-1125	0.600	0.000	0.938	43.573	0.000	98.125
FRANKLIN SQUARE 11	11.5	53-1149	1.358	1.000	0.417	135.213	22.625	137.917
~~HARRIS AVENUE 12~~	~~11.5~~	~~53-1131~~	~~1.508~~	~~1.917~~	~~2.923~~	~~113.277~~	~~200.744~~	~~159.385~~
~~HARRIS AVENUE 12~~	~~11.5~~	~~53-1133~~	~~0.800~~	~~0.000~~	~~1.000~~	~~353.500~~	~~0.000~~	~~316.000~~
~~HARRIS AVENUE 12~~	~~11.5~~	~~53-1137~~	~~0.360~~	~~0.000~~	~~1.000~~	~~133.800~~	~~0.000~~	~~569.000~~
SOUTH STREET 1	11.5	53-1101	1.023	1.988	1.000	115.943	190.047	45.700
SOUTH STREET 1	11.5	53-1171	0.440	0.000	1.182	65.640	0.000	228.818
~~ADMIRAL STREET 9~~	~~4.16~~	~~53-9J1~~	~~0.867~~	~~0.042~~	~~3.190~~	~~63.485~~	~~2.947~~	~~241.128~~
~~ADMIRAL STREET 9~~	~~4.16~~	~~53-9J2~~	~~0.873~~	~~0.000~~	~~1.368~~	~~77.615~~	~~0.000~~	~~125.449~~
~~ADMIRAL STREET 9~~	~~4.16~~	~~53-9J3~~	~~0.291~~	~~0.333~~	~~1.077~~	~~28.126~~	~~29.575~~	~~110.214~~
~~ADMIRAL STREET 9~~	~~4.16~~	~~53-9J5~~	~~0.352~~	~~0.000~~	~~1.201~~	~~34.360~~	~~0.000~~	~~118.655~~
DYER STREET 2	4.16	53-2J1	1.600	1.052	1.907	160.445	101.028	211.576
DYER STREET 2	4.16	53-2J2	0.354	1.000	0.000	39.330	101.000	0.000
DYER STREET 2	4.16	53-2J3	0.598	0.993	0.989	71.900	100.249	132.918
DYER STREET 2	4.16	53-2J4	0.388	1.008	0.000	43.923	102.103	0.000
DYER STREET 2	4.16	53-2J5	0.600	0.976	0.000	61.825	98.595	0.000
DYER STREET 2	4.16	53-2J7	1.052	2.948	0.000	81.790	152.359	0.000
DYER STREET 2	4.16	53-2J8	0.598	0.996	0.000	88.613	100.616	0.000
DYER STREET 2	4.16	53-2J9	0.496	1.261	0.085	67.007	204.948	5.085
DYER STREET 2	4.16	53-2J10	0.594	0.966	0.000	74.680	98.558	0.000
EAST GEORGE ST 77	4.16	53-77J4	0.503	0.199	0.080	70.200	129.403	3.379
~~GENEVA 71~~	~~4.16~~	~~53-71J4~~	~~0.243~~	~~0.027~~	~~1.061~~	~~16.689~~	~~2.233~~	~~59.684~~
~~GENEVA 71~~	~~4.16~~	~~53-71J5~~	~~0.442~~	~~0.105~~	~~1.083~~	~~29.762~~	~~9.122~~	~~81.444~~
~~HARRIS AVENUE 12~~	~~4.16~~	~~53-12J5~~	~~0.540~~	~~0.919~~	~~0.373~~	~~58.561~~	~~113.274~~	~~103.847~~
~~HARRIS AVENUE 12~~	~~4.16~~	~~53-12J6~~	~~0.463~~	~~0.040~~	~~0.000~~	~~154.082~~	~~4.200~~	~~0.000~~
~~HUNTINGTON PARK 67~~	~~4.16~~	~~53-67J1~~	~~1.208~~	~~2.005~~	~~0.000~~	~~121.347~~	~~102.136~~	~~0.000~~
~~KNIGHTSVILLE 66~~	~~4.16~~	~~53-66J5~~	~~0.107~~	~~0.000~~	~~0.135~~	~~25.984~~	~~0.000~~	~~79.089~~
~~OLNEYVILLE 6~~	~~4.16~~	~~53-6J3~~	~~0.515~~	~~0.000~~	~~0.067~~	~~68.791~~	~~0.000~~	~~107.667~~
~~OLNEYVILLE 6~~	~~4.16~~	~~53-6J5~~	~~0.000~~	~~0.090~~	~~0.993~~	~~0.030~~	~~9.792~~	~~228.153~~
~~OLNEYVILLE 6~~	~~4.16~~	~~53-6J6~~	~~0.832~~	~~1.000~~	~~1.155~~	~~105.813~~	~~86.688~~	~~163.515~~
~~OLNEYVILLE 6~~	~~4.16~~	~~53-6J7~~	~~0.496~~	~~0.007~~	~~1.156~~	~~47.232~~	~~0.459~~	~~27.399~~
~~OLNEYVILLE 6~~	~~4.16~~	~~53-6J8~~	~~3.415~~	~~0.000~~	~~0.000~~	~~436.271~~	~~0.000~~	~~0.000~~
~~ROCHAMBEAU AVENUE 37~~	~~4.16~~	~~53-37J2~~	~~0.402~~	~~2.012~~	~~0.000~~	~~21.439~~	~~107.327~~	~~0.000~~
~~ROCHAMBEAU AVENUE 37~~	~~4.16~~	~~53-37J3~~	~~0.481~~	~~1.156~~	~~0.132~~	~~38.201~~	~~86.132~~	~~3.210~~
~~ROCHAMBEAU AVENUE 37~~	~~4.16~~	~~53-37J5~~	~~1.225~~	~~3.064~~	~~0.000~~	~~93.456~~	~~303.723~~	~~0.000~~
~~SPRAGUE STREET 36~~	~~4.16~~	~~53-36J4~~	~~0.582~~	~~1.000~~	~~0.813~~	~~93.817~~	~~84.482~~	~~151.593~~
~~SPRAGUE STREET 36~~	~~4.16~~	~~53-36J5~~	~~0.240~~	~~1.043~~	~~0.041~~	~~23.703~~	~~102.184~~	~~4.785~~
FARNUM PIKE 23	12.47	53-23F6	0.632	0.622	0.580	53.724	92.945	39.918
JOHNSTON 18	12.47	53-18F7	0.865	0.017	1.497	41.699	2.251	27.213
PONTIAC 27	12.47	53-27F1	0.442	0.690	0.123	18.942	75.135	9.649
PONTIAC 27	12.47	53-27F2	2.172	0.076	0.000	178.535	40.682	0.000

Notes to Table 9.7.2:

1. Values shown in red exceed the overall frequency and duration targets for RI.
2. Items shown with strikethrough are eliminated after implementing the preferred plan.

9.8 Arc Flash

Table 9.8.1 – Existing Substation Arc Flash Levels

Substation	Bus Voltage (kV)	HRC Level	55 cal/cm^2 Boundary (in)
Admiral Street 9	4.16	3	*
Admiral Street 9	11.5	3	*
Admiral Street 9	23	3	*
East George St 77	4.16	3	*
East George St 77	23	3	*
Elmwood	23	>4	33
Franklin Square	11.5	3	*
Harris Avenue 12	4.16	>4	*
Harris Avenue 12	11.5	3	*
Huntington Park 67	23	3	*
Lippitt Hill 79	12.47	3	*
Lippitt Hill 79	23	3	*
Olneyville 6	11.5	4	*
Olneyville 6	4.16	4	*
Sprague St 36	4.16	3	*

Table 9.8.2 – Substation Arc Flash Levels – Recommended Plan[1]

Substation	Bus Voltage (kV)	HRC Level	55 cal/cm^2 Boundary (in)
~~Admiral Street 9~~	~~4.16~~	~~3~~	~~*~~
~~Admiral Street 9~~	~~11.5~~	~~3~~	~~*~~
~~Admiral Street 9~~	~~23~~	~~3~~	~~*~~
East George St 77	4.16	3	*
East George St 77	23	3	*
Elmwood	23	>4	33
Franklin Square	11.5	3	*
~~Harris Avenue 12~~	~~4.16~~	~~>4~~	~~*~~
~~Harris Avenue 12~~	~~11.5~~	~~3~~	~~*~~
~~Huntington Park 67~~	~~23~~	~~3~~	~~*~~
Lippitt Hill 79	12.47	3	*
Lippitt Hill 79	23	3	*
~~Olneyville 6~~	~~11.5~~	4	~~*~~
~~Olneyville 6~~	~~4.16~~	4	~~*~~
~~Sprague St Total~~	~~4.16~~	~~3~~	~~*~~

1. Items shown with strikethrough are eliminated after implementing the preferred plan.

* The current Minimum Approach Distance (“MAD”) is sufficient

9.9 Fault Duty Analysis

Table 9.9.1 – Breaker Duty Analysis – Existing System

Station	Breaker	Rating (A)	Interrupt. Amp at Rated kV	Rated kV	IR >Fault Duty 3Ø/LG
Admiral St	1T4	2000	6,000	15	NO/NO[1]
Admiral St	2T4	2000	6,000	15	NO/NO[1]
Auburn	73J1	600	10,000	14.4	NO/NO[1]
Auburn	73J2	600	10,000	14.4	NO/NO[1]
Auburn	73J3	600	10,000	14.4	NO/NO[1]
Auburn	73J4	600	10,000	14.4	NO/NO[1]
Auburn	73J5	600	8,900	15.5	NO/NO[1]
Auburn	73J6	600	8,900	14.4	NO/NO[1]
Auburn	1-2	600	8,900	14.4	NO/NO[1]
Auburn	3-4	600	8,900	14.4	NO/NO[1]
Auburn	5-6	600	8,900	14.4	NO/NO[1]
Clarkson St	C2	1200	20,000	15.5	NO/NO
Geneva	71J1	600	4,000	14.4	NO/NO
Geneva	71J2	600	4,000	14.4	NO/NO
Geneva	71J3	600	4,000	14.4	NO/NO
Geneva	71J4	600	4,000	14.4	NO/NO
Geneva	71J5	600	8,900	14.4	NO/NO[1]
Geneva	71J6	600	8,900	14.4	NO/NO[1]
Geneva	1-2	600	8,900	14.4	NO/NO[1]
Geneva	3-4	600	8,900	14.4	NO/NO[1]
Geneva	5-6	600	8,900	14.4	NO/NO[1]
Harris Ave 4kV	12J6	600	6,300	13.8	NO/NO[1]
Harris Ave 4kV	12J7	600	6,300	13.8	NO/NO[1]
Harris Ave 4kV	IS4	1200	10,000	13.8	NO/NO[1]
Knightsville	66J1	600	7,000	14.4	NO/NO[1]
Knightsville	66J2	600	7,000	14.4	NO/NO[1]
Knightsville	66J3	600	7,000	14.4	NO/NO[1]
Knightsville	66J4	600	7,000	14.4	NO/NO[1]
Knightsville	66J5	600	10,000	14.4	NO/NO[1]
Knightsville	1-2	600	7,000	14.4	NO/NO[1]
Knightsville	3-4	600	7,000	14.4	NO/NO[1]
Knightsville	5-6	600	10,000	14.4	NO/NO[1]
Lippitt Hill	1TR	560	8,000	27	NO/YES
Lippitt Hill	2TR	560	8,000	38	NO/YES

Table 9.9.1 – Breaker Duty Analysis – Existing System (cont.)

Station	Breaker	Rating (A)	Interrupt. Amp at Rated kV	Rated kV	IR >Fault Duty 3Ø/LG
Olneyville	1121	500	13,000	15	NO/YES
Olneyville	1130	500	13,000	15	NO/YES
Olneyville	1134	500	13,000	15	NO/YES
Olneyville	1T11	500	13,000	15	NO/YES
Olneyville	2T11	500	13,000	15	NO/YES
Olneyville	3T11	500	13,000	15	NO/YES
Olneyville	6J1	600	6,000	15	NO/NO[1]
Olneyville	6J2	600	6,000	15	NO/NO[1]
Olneyville	6J3	600	6,000	15	NO/NO[1]
Olneyville	6J5	600	6,000	15	NO/NO[1]
Olneyville	6J6	600	6,000	15	NO/NO[1]
Olneyville	6J7	600	6,000	15	NO/NO[1]
Olneyville	6J8	600	6,000	15	NO/NO[1]
Olneyville	1T4	1600	8,000	7.5	NO/NO[1]
Olneyville	2T4	2000	2,300	25	NO/NO[1]
Olneyville	3T4	1200	4,000	15	NO/NO[1]
Rochambeau Ave	37J1	600	6,700	15	NO/NO[1]
Rochambeau Ave	37J2	600	6,700	15	NO/NO[1]
Rochambeau Ave	37J3	600	8,000	7.2	NO/NO[1]
Rochambeau Ave	37J4	600	8,000	7.2	NO/NO[1]
Sprague Street	36J1	1200	7,000	13.8	NO/NO[1]
Sprague Street	36J2	1200	7,000	13.8	NO/NO[1]
Sprague Street	36J3	1200	7,000	13.8	NO/NO[1]
Sprague Street	36J4	1200	7,000	13.8	NO/NO[1]
Sprague Street	36J5	1200	7,000	13.8	NO/NO[1]
Sprague Street	12	1200	7,000	13.8	NO/NO[1]
Sprague Street	34	1200	7,000	13.8	NO/NO[1]
Sprague Street	56	1200	7,000	13.8	NO/NO[1]

1 - K factor could not be determined. Maximum historical value for breaker class used.

Table 9.9.2 – Breaker Duty Analysis – Recommended Plan[2]

Station	Breaker	Rating (A)	Interrupt. Amp at Rated kV	Rated kV	IR > Fault Duty 3Ø/LG
~~Admiral St~~	~~1T4~~	~~2000~~	~~6,000~~	~~15~~	~~NO/NO[1]~~
~~Admiral St~~	~~2T4~~	~~2000~~	~~6,000~~	~~15~~	~~NO/NO[1]~~
~~Auburn~~	~~73J1~~	~~600~~	~~10,000~~	~~14.4~~	~~NO/NO[1]~~
~~Auburn~~	~~73J2~~	~~600~~	~~10,000~~	~~14.4~~	~~NO/NO[1]~~
~~Auburn~~	~~73J3~~	~~600~~	~~10,000~~	~~14.4~~	~~NO/NO[1]~~
~~Auburn~~	~~73J4~~	~~600~~	~~10,000~~	~~14.4~~	~~NO/NO[1]~~
~~Auburn~~	~~73J5~~	~~600~~	~~8,900~~	~~15.5~~	~~NO/NO[1]~~
~~Auburn~~	~~73J6~~	~~600~~	~~8,900~~	~~14.4~~	~~NO/NO[1]~~
~~Auburn~~	~~1-2~~	~~600~~	~~8,900~~	~~14.4~~	~~NO/NO[1]~~
~~Auburn~~	~~3-4~~	~~600~~	~~8,900~~	~~14.4~~	~~NO/NO[1]~~
~~Auburn~~	~~5-6~~	~~600~~	~~8,900~~	~~14.4~~	~~NO/NO[1]~~
Clarkson St	C2	1200	20,000	15.5	NO/NO
~~Geneva~~	~~71J1~~	~~600~~	~~4,000~~	~~14.4~~	~~NO/NO~~
~~Geneva~~	~~71J2~~	~~600~~	~~4,000~~	~~14.4~~	~~NO/NO~~
~~Geneva~~	~~71J3~~	~~600~~	~~4,000~~	~~14.4~~	~~NO/NO~~
~~Geneva~~	~~71J4~~	~~600~~	~~4,000~~	~~14.4~~	~~NO/NO~~
~~Geneva~~	~~71J5~~	~~600~~	~~8,900~~	~~14.4~~	~~NO/NO[1]~~
~~Geneva~~	~~71J6~~	~~600~~	~~8,900~~	~~14.4~~	~~NO/NO[1]~~
~~Geneva~~	~~1-2~~	~~600~~	~~8,900~~	~~14.4~~	~~NO/NO[1]~~
~~Geneva~~	~~3-4~~	~~600~~	~~8,900~~	~~14.4~~	~~NO/NO[1]~~
~~Geneva~~	~~5-6~~	~~600~~	~~8,900~~	~~14.4~~	~~NO/NO[1]~~
~~Harris Ave 4kV~~	~~12J6~~	~~600~~	~~6,300~~	~~13.8~~	~~NO/NO[1]~~
~~Harris Ave 4kV~~	~~12J7~~	~~600~~	~~6,300~~	~~13.8~~	~~NO/NO[1]~~
~~Harris Ave 4kV~~	~~IS4~~	~~1200~~	~~10,000~~	~~13.8~~	~~NO/NO[1]~~
~~Knightsville~~	~~66J1~~	~~600~~	~~7,000~~	~~14.4~~	~~NO/NO[1]~~
~~Knightsville~~	~~66J2~~	~~600~~	~~7,000~~	~~14.4~~	~~NO/NO[1]~~
~~Knightsville~~	~~66J3~~	~~600~~	~~7,000~~	~~14.4~~	~~NO/NO[1]~~
~~Knightsville~~	~~66J4~~	~~600~~	~~7,000~~	~~14.4~~	~~NO/NO[1]~~
~~Knightsville~~	~~66J5~~	~~600~~	~~10,000~~	~~14.4~~	~~NO/NO[1]~~
~~Knightsville~~	~~1-2~~	~~600~~	~~7,000~~	~~14.4~~	~~NO/NO[1]~~
~~Knightsville~~	~~3-4~~	~~600~~	~~7,000~~	~~14.4~~	~~NO/NO[1]~~
~~Knightsville~~	~~5-6~~	~~600~~	~~10,000~~	~~14.4~~	~~NO/NO[1]~~
Lippitt Hill	1TR	560	8,000	27	NO/YES
Lippitt Hill	2TR	560	8,000	38	NO/YES

1 – K factor could not be determined. Maximum historical value for breaker class used.
2 – Items shown with strikethrough are eliminated after implementing the preferred plan.

Table 9.9.2 – Breaker Duty Analysis – Recommended Plan[2] (cont.)

Station	Breaker	Rating (A)	Interrupt. Amp at Rated kV	Rated kV	IR >Fault Duty 3Ø/LG
~~Olneyville~~	~~1121~~	~~500~~	~~13,000~~	~~15~~	~~NO/YES~~
~~Olneyville~~	~~1130~~	~~500~~	~~13,000~~	~~15~~	~~NO/YES~~
~~Olneyville~~	~~1134~~	~~500~~	~~13,000~~	~~15~~	~~NO/YES~~
~~Olneyville~~	~~1T11~~	~~500~~	~~13,000~~	~~15~~	~~NO/YES~~
~~Olneyville~~	~~2T11~~	~~500~~	~~13,000~~	~~15~~	~~NO/YES~~
~~Olneyville~~	~~3T11~~	~~500~~	~~13,000~~	~~15~~	~~NO/YES~~
~~Olneyville~~	~~6J1~~	~~600~~	~~6,000~~	~~15~~	~~NO/NO[1]~~
~~Olneyville~~	~~6J2~~	~~600~~	~~6,000~~	~~15~~	~~NO/NO[1]~~
~~Olneyville~~	~~6J3~~	~~600~~	~~6,000~~	~~15~~	~~NO/NO[1]~~
~~Olneyville~~	~~6J5~~	~~600~~	~~6,000~~	~~15~~	~~NO/NO[1]~~
~~Olneyville~~	~~6J6~~	~~600~~	~~6,000~~	~~15~~	~~NO/NO[1]~~
~~Olneyville~~	~~6J7~~	~~600~~	~~6,000~~	~~15~~	~~NO/NO[1]~~
~~Olneyville~~	~~6J8~~	~~600~~	~~6,000~~	~~15~~	~~NO/NO[1]~~
~~Olneyville~~	~~1T4~~	~~1600~~	~~8,000~~	~~7.5~~	~~NO/NO[1]~~
~~Olneyville~~	~~2T4~~	~~2000~~	~~2,300~~	~~25~~	~~NO/NO[1]~~
~~Olneyville~~	~~3T4~~	~~1200~~	~~4,000~~	~~15~~	~~NO/NO[1]~~
~~Rochambeau Ave~~	~~37J1~~	~~600~~	~~6,700~~	~~15~~	~~NO/NO[1]~~
~~Rochambeau Ave~~	~~37J2~~	~~600~~	~~6,700~~	~~15~~	~~NO/NO[1]~~
~~Rochambeau Ave~~	~~37J3~~	~~600~~	~~8,000~~	~~7.2~~	~~NO/NO[1]~~
~~Rochambeau Ave~~	~~37J4~~	~~600~~	~~8,000~~	~~7.2~~	~~NO/NO[1]~~
~~Sprague Street~~	~~36J1~~	~~1200~~	~~7,000~~	~~13.8~~	~~NO/NO[1]~~
~~Sprague Street~~	~~36J2~~	~~1200~~	~~7,000~~	~~13.8~~	~~NO/NO[1]~~
~~Sprague Street~~	~~36J3~~	~~1200~~	~~7,000~~	~~13.8~~	~~NO/NO[1]~~
~~Sprague Street~~	~~36J4~~	~~1200~~	~~7,000~~	~~13.8~~	~~NO/NO[1]~~
~~Sprague Street~~	~~36J5~~	~~1200~~	~~7,000~~	~~13.8~~	~~NO/NO[1]~~
~~Sprague Street~~	~~12~~	~~1200~~	~~7,000~~	~~13.8~~	~~NO/NO[1]~~
~~Sprague Street~~	~~34~~	~~1200~~	~~7,000~~	~~13.8~~	~~NO/NO[1]~~
~~Sprague Street~~	~~56~~	~~1200~~	~~7,000~~	~~13.8~~	~~NO/NO[1]~~

1 – K factor could not be determined. Maximum historical value for breaker class used.
2 – Items shown with strikethrough are eliminated after implementing the preferred plan.

9.10 Recommended Plan One-Lines and Other Diagrams

Figure 9.10.1 – Proposed Partial One Line for Admiral Street 23 kV

[redacted]

Figure 9.10.2 – Aerial view of Admiral Street Substation

Figure 9.10.3 – Proposed Partial One Line of 115/12.47 kV Metal Clad Station at Admiral Street

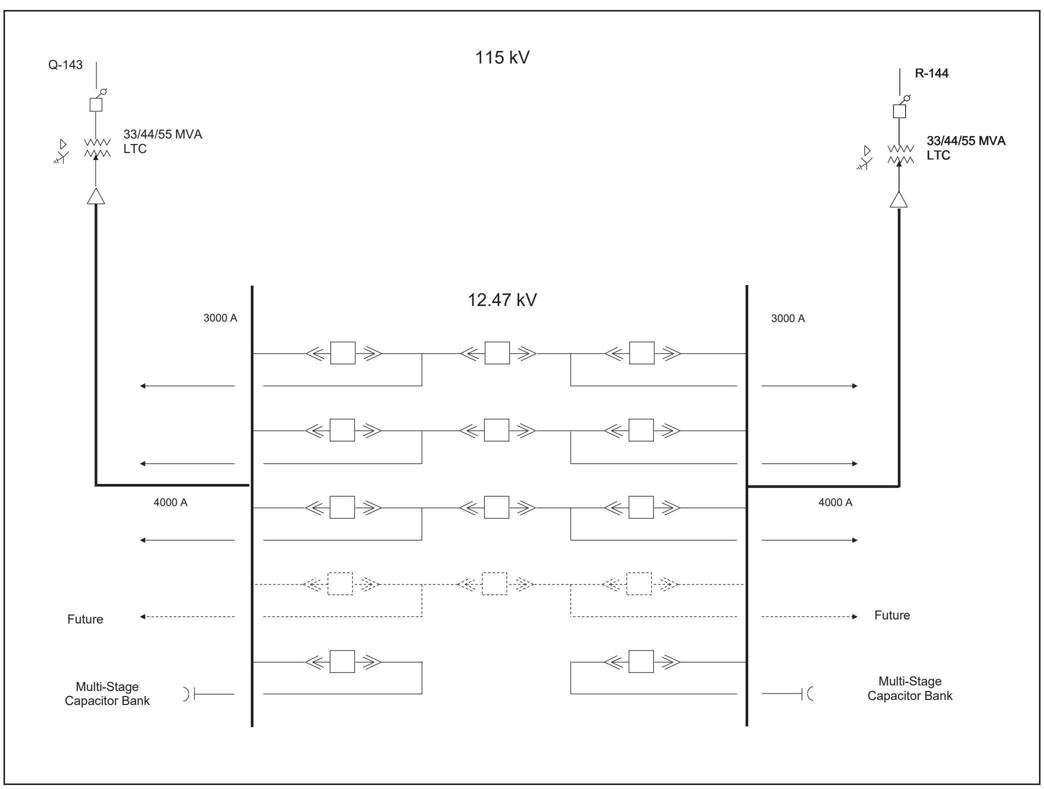


Figure 9.10.4 – Partial One Line for Knightsville Substation showing Ultimate Layout

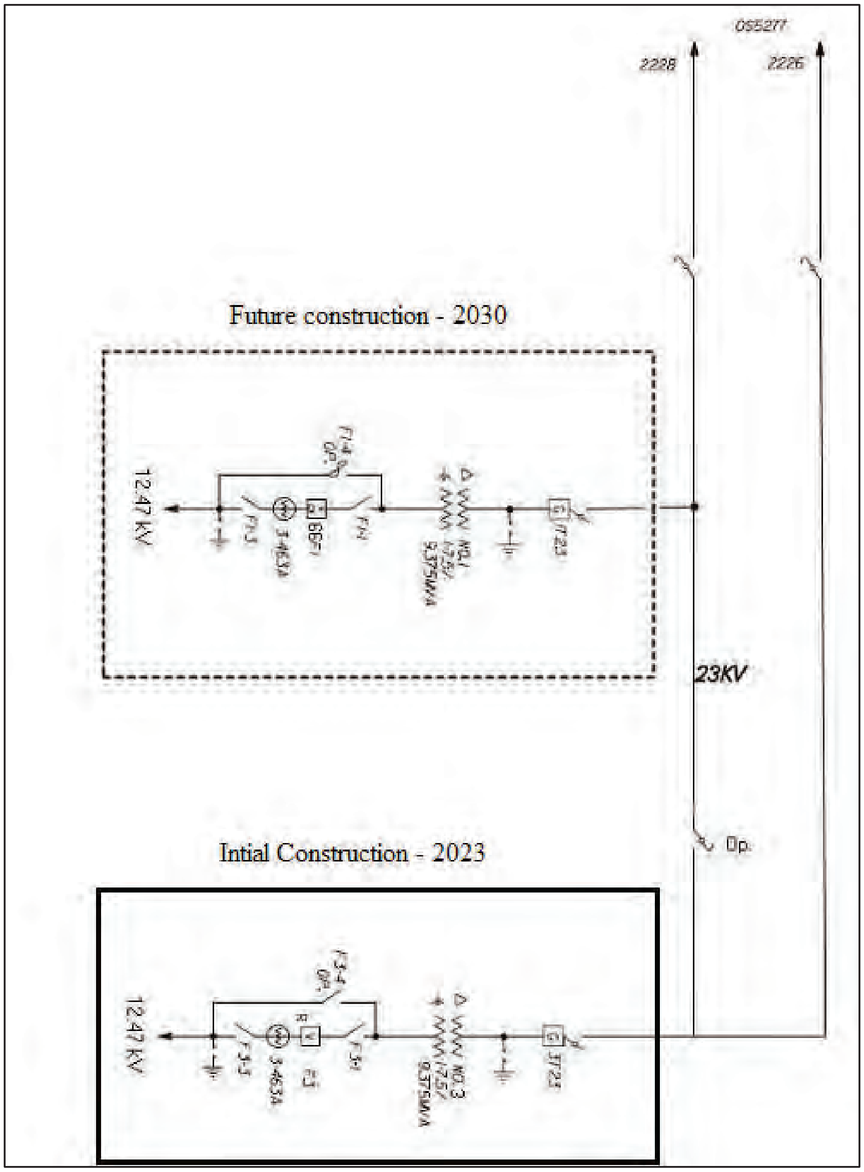


Figure 9.10.5 – PSSE Base Case with Proposed Modifications at Knightsville Substation

[redacted]

Figure 9.10.6 – Aerial View Showing 115 kV Route from Sockanosset to Auburn

Figure 9.10.7 – Proposed Partial One-line for Auburn 115/12.47 kV Substation

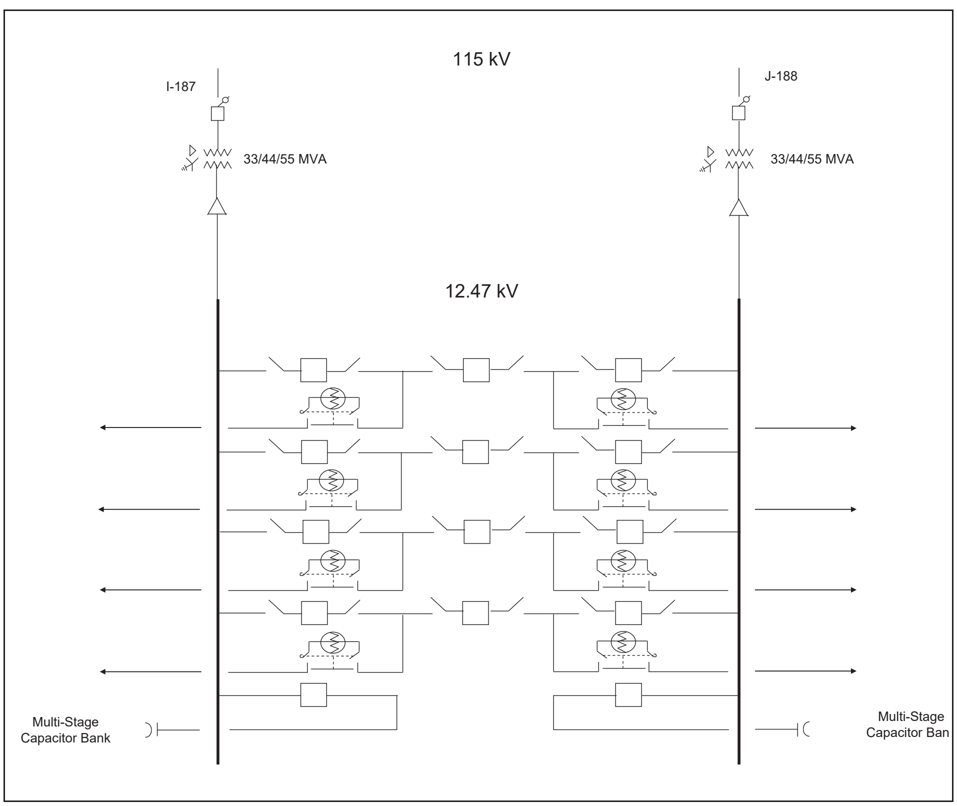


Figure 9.10.8 – Proposed Partial One Line for Geneva Substation

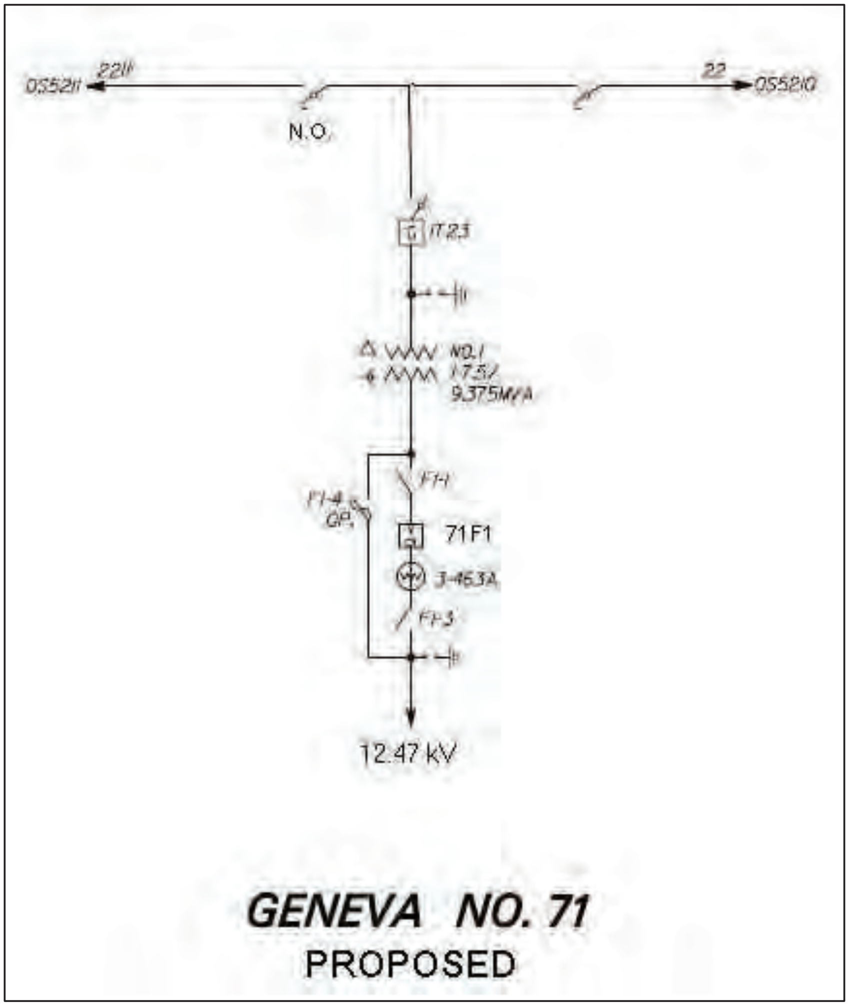
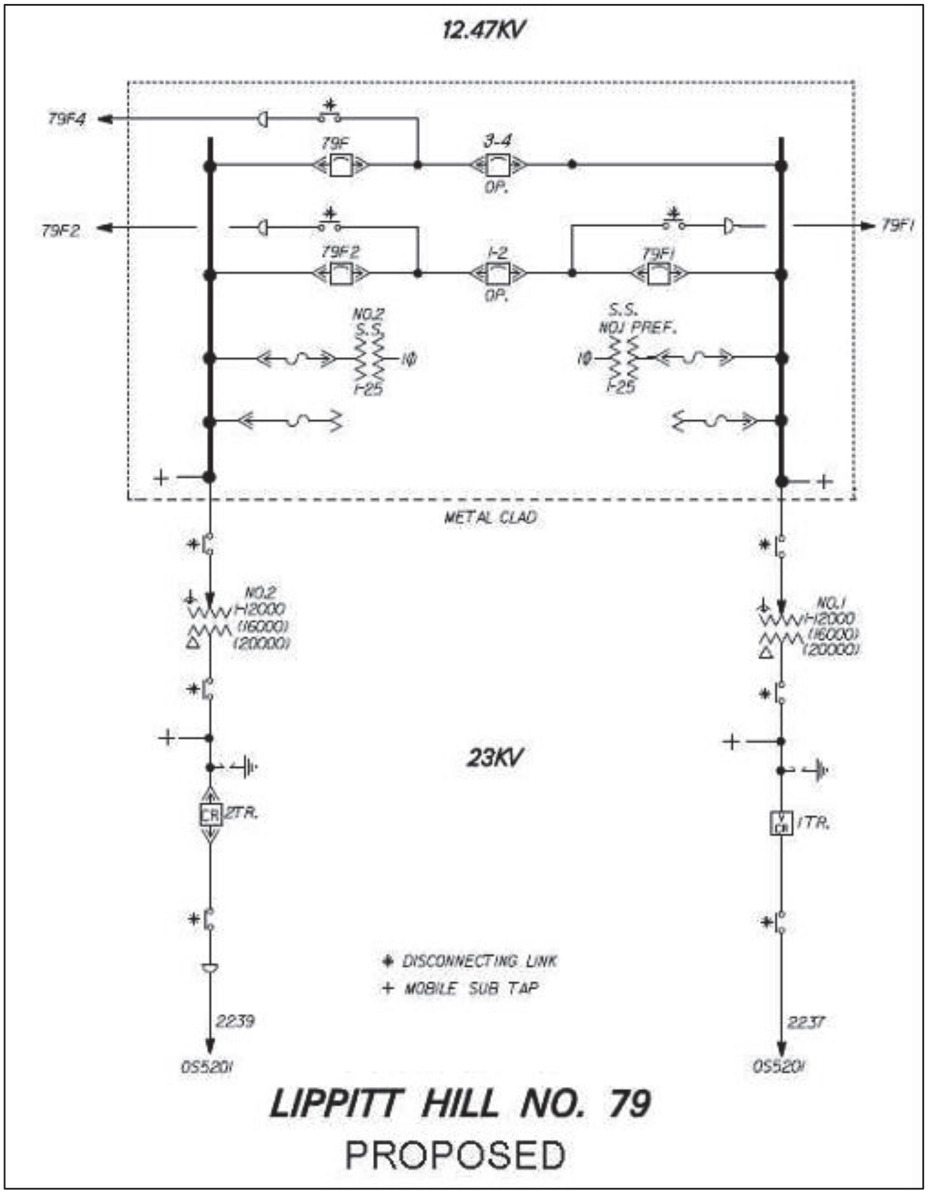


Figure 9.10.9 – Proposed Partial One Line for Lippitt Hill Substation



9.11 Auburn Option 1 One-Lines and Other Diagrams

Figure 9.11.1 – Proposed Partial One Line for 115/23 kV station at Sockanosset

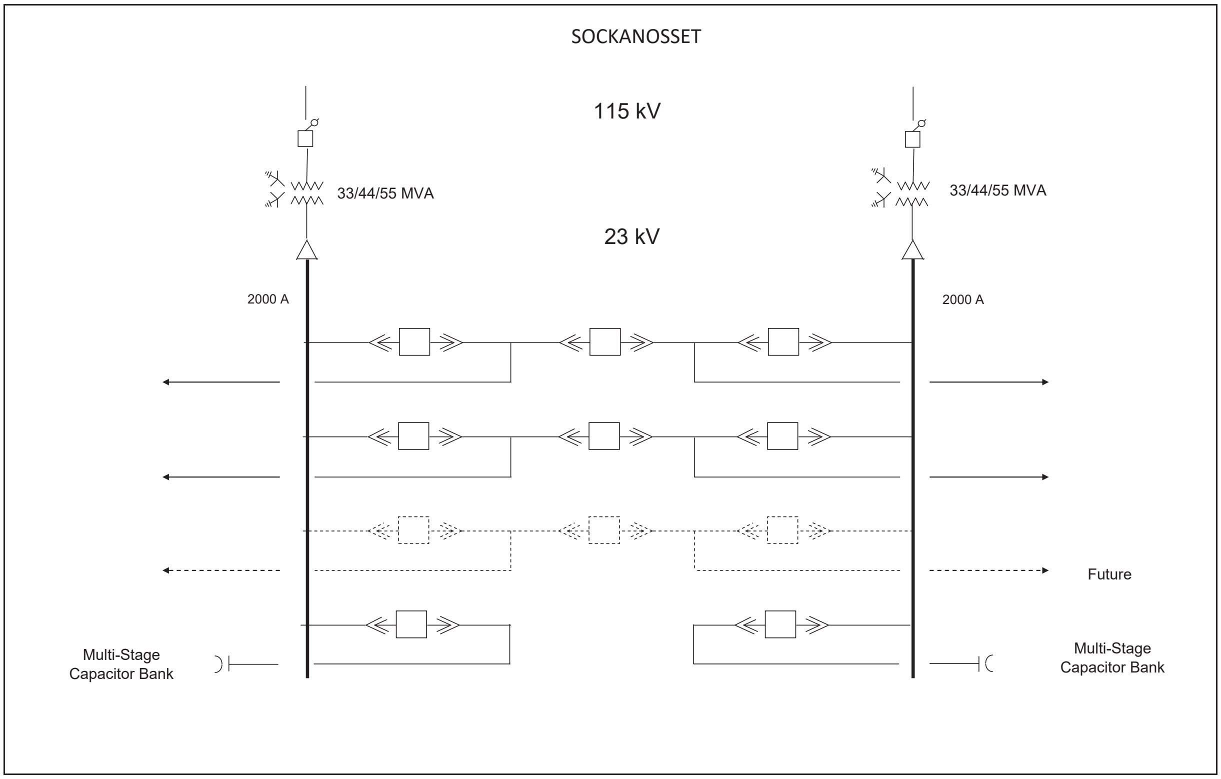


Figure 9.11.2 – Proposed 23 kV circuits between Sockanosset and Auburn Substations

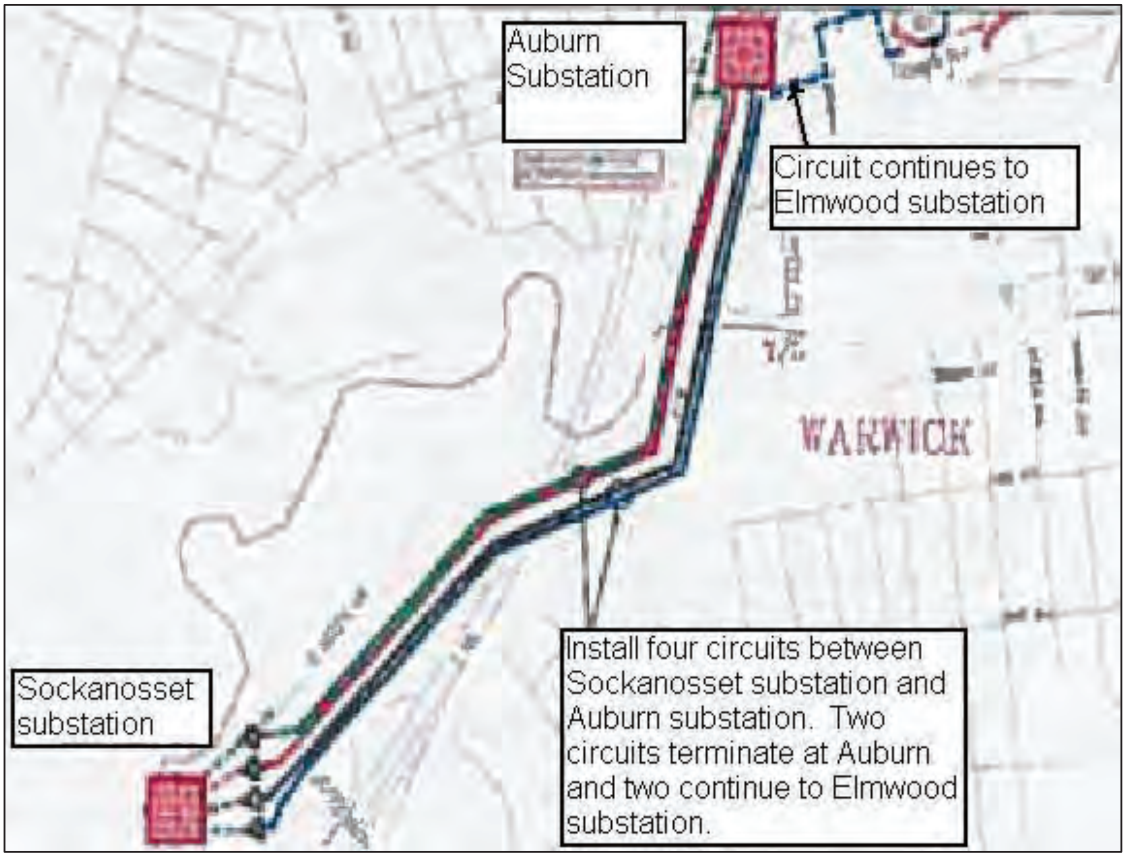


Figure 9.11.3 – Proposed Partial One Line for 23/12.47 kV Substation at Auburn

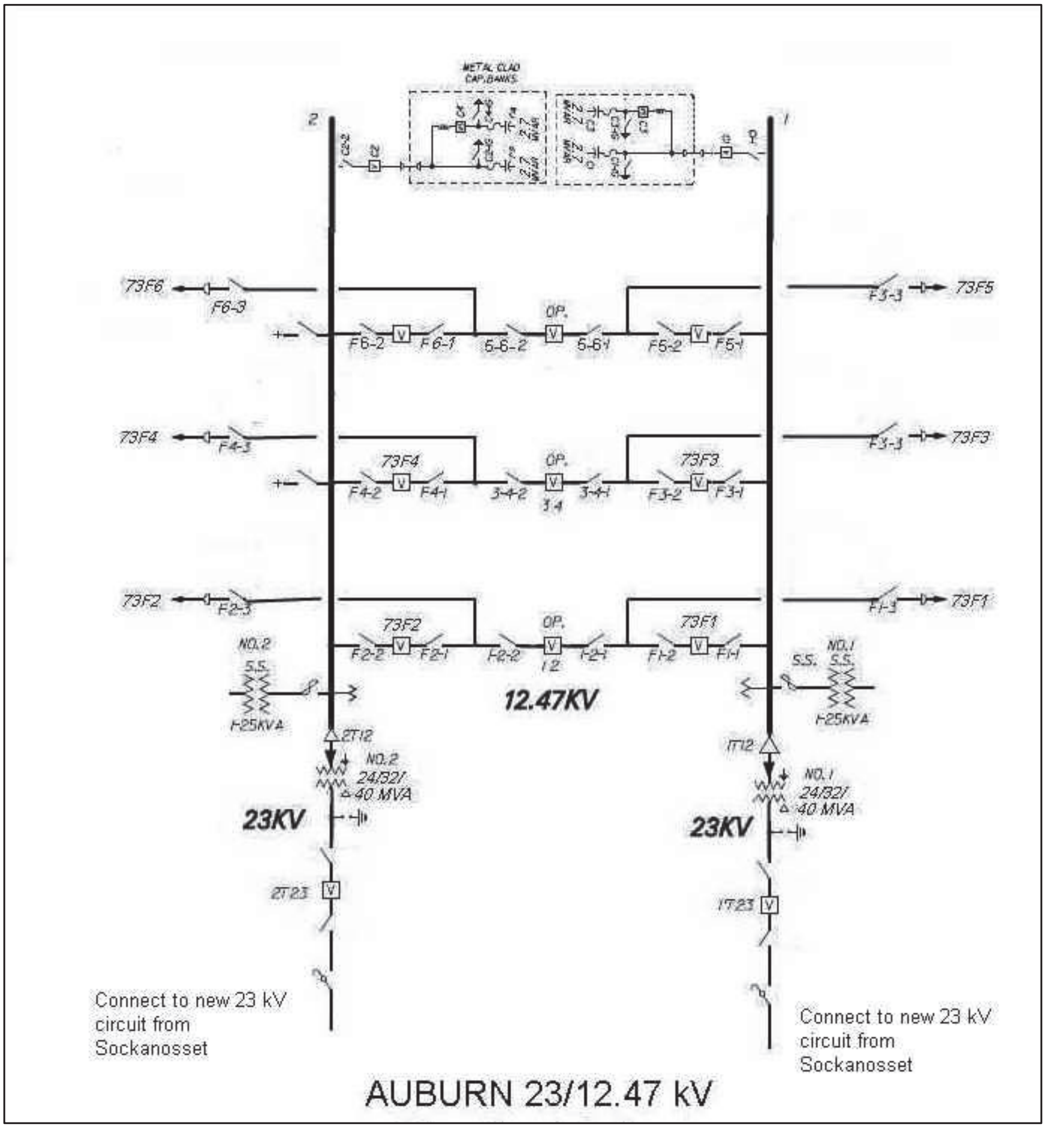
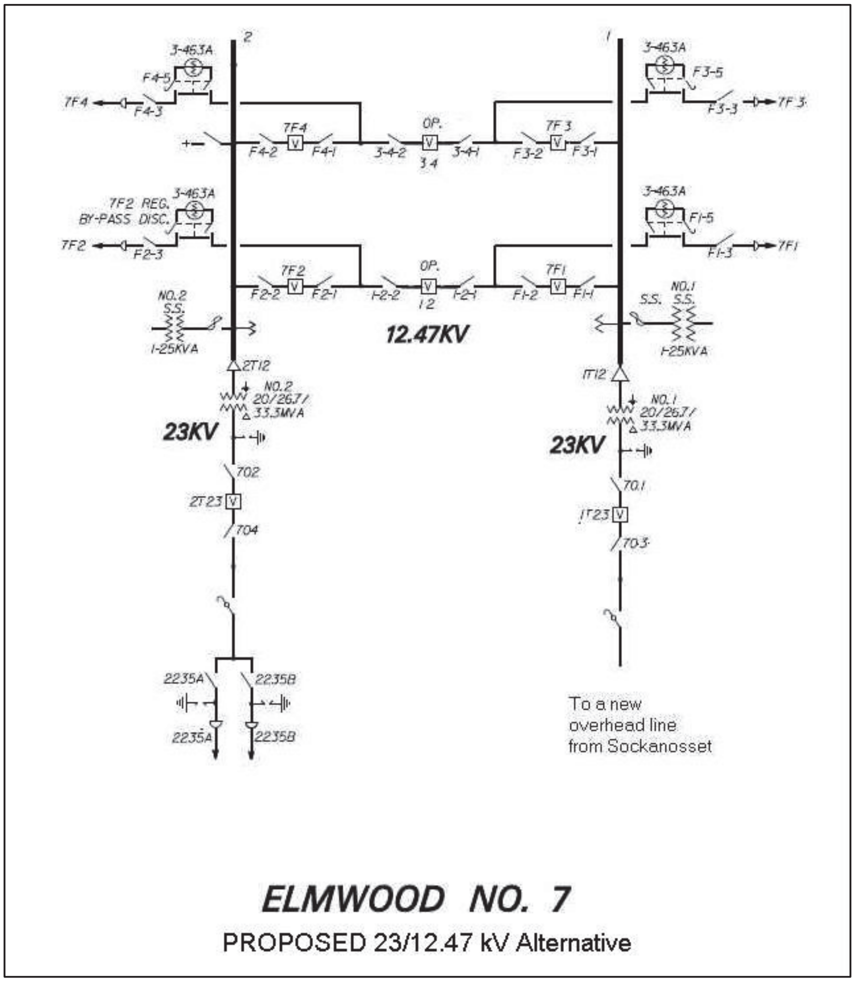


Figure 9.11.4 – Proposed Partial One Line for Elmwood 23/12.47 kV Substation



9.12 Auburn Option 2 One-Lines and Other Diagrams

Figure 9.12.1 – Proposed Partial One Line for 115/35 kV Substation at Sockanosset

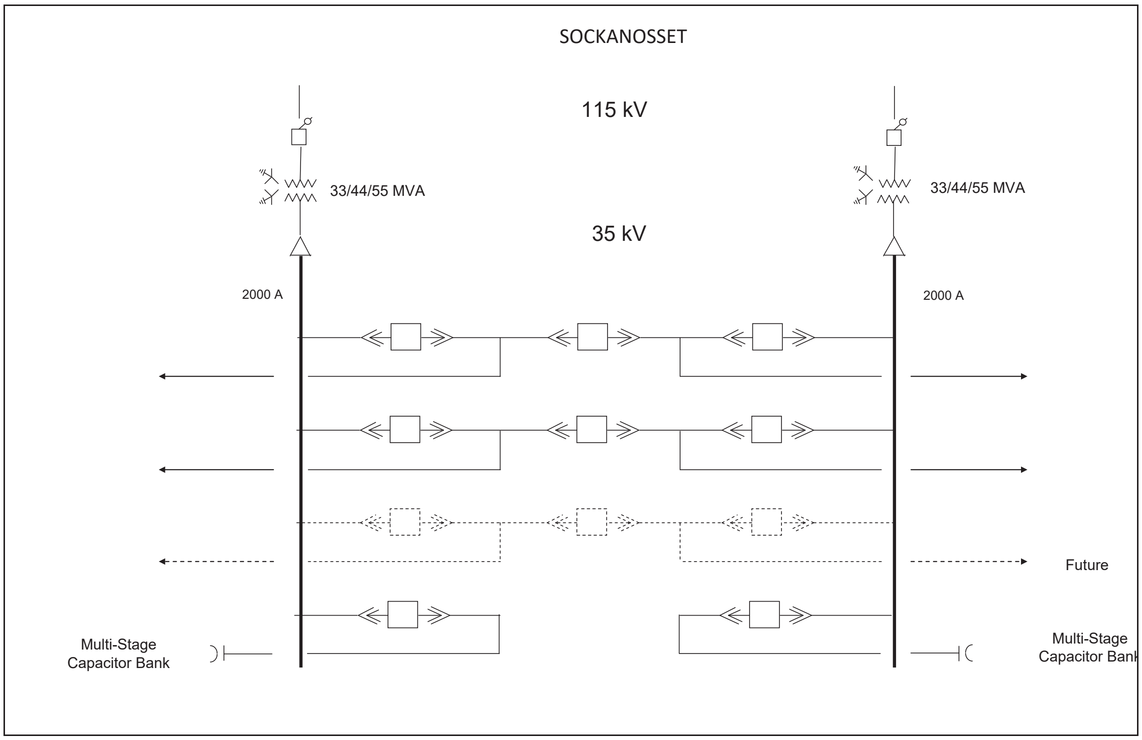


Figure 9.12.2 – Proposed Partial One Line for 35/12.47 kV Substation at Auburn

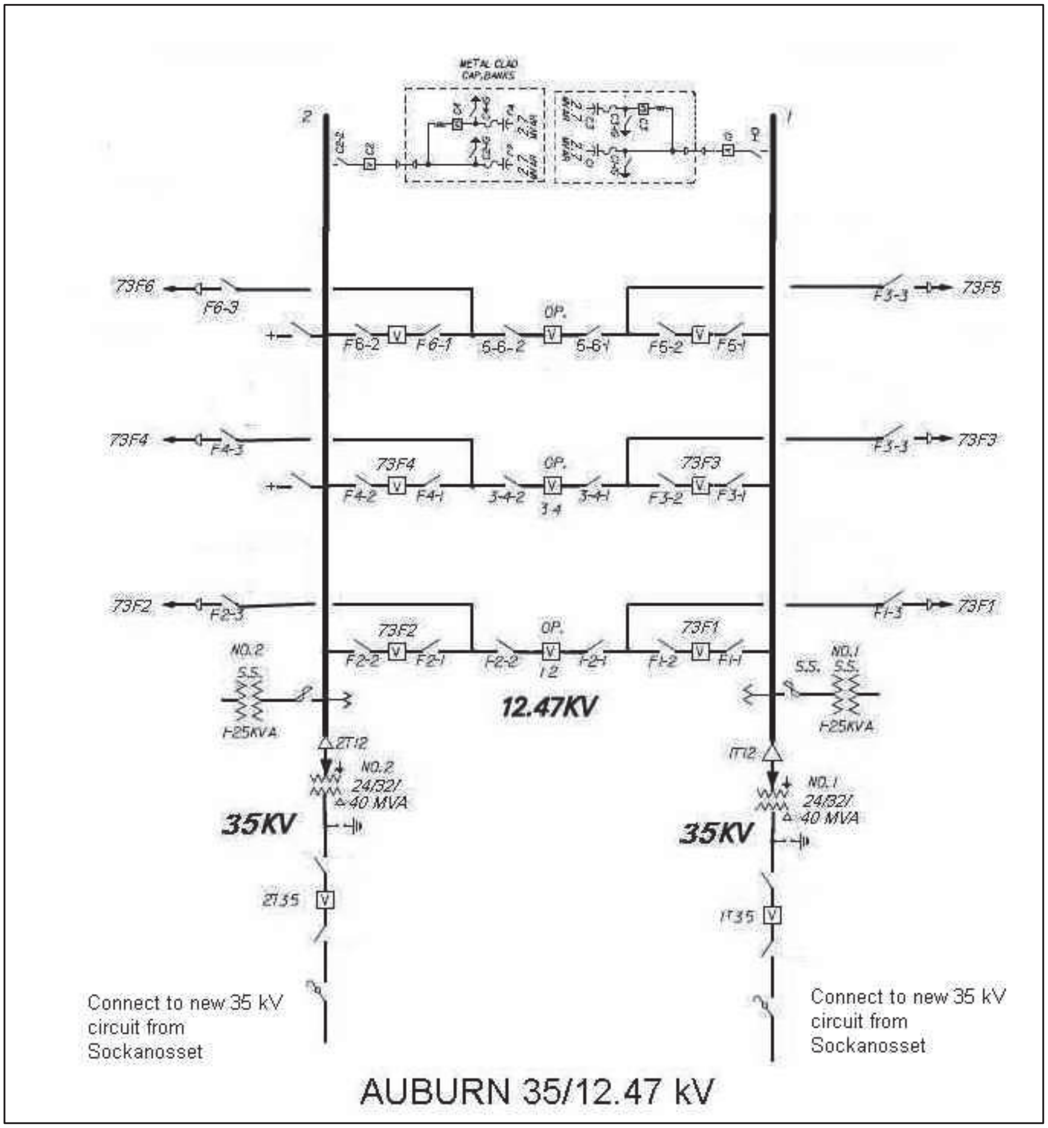
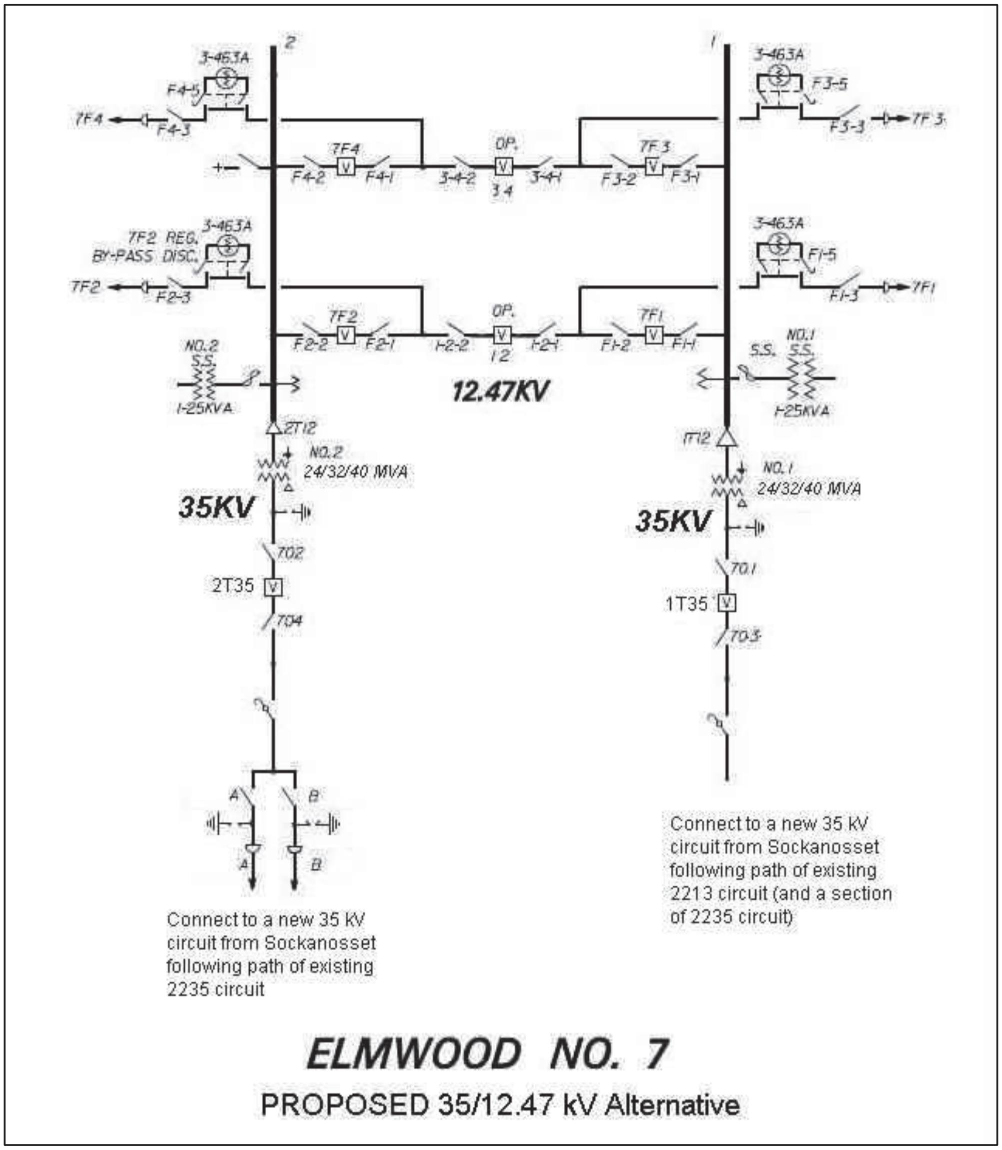


Figure 9.12.3 – Proposed Partial One Line for Elmwood 35/12.47 kV Substation



9.13 Distributed Generation

Table 9.13.1 – Existing Distributed Generation in the Study Area

Street Name	Suffix	City/Town	State	Feeder #	Name Plate Rating kW	Fuel Type	DG Type
BROOK	ST	PROVIDENCE	RI	53-2J1	50	solar	Inverter Based - PV
DIKE	ST	PROVIDENCE	RI	53-6J6	6	solar	Inverter Based - PV
HARRISON	ST	PROVIDENCE	RI	53-6J5	5	solar	Inverter Based - PV
COURTLAND	ST	PROVIDENCE	RI	53-76F5	5	solar	Inverter Based - PV
FEDERAL	ST	PROVIDENCE	RI	53-12J4	3	solar	Inverter Based - PV
HAMMOND	ST	PROVIDENCE	RI	53-6J5	5	solar	Inverter Based - PV
KNIGHT	ST	PROVIDENCE	RI	53-12J4	5	solar	Inverter Based - PV
WESTMINSTER	ST	PROVIDENCE	RI	53-76F5	5	solar	Inverter Based - PV
DUPONT	DR	PROVIDENCE	RI	53-2228	320	solar	Inverter Based - PV
MARSHALL	ST	PROVIDENCE	RI	53-76F5	3	Solar	Inverter Based - PV
SYCAMORE	ST	PROVIDENCE	RI	53-76F5	3	Solar	Inverter Based - PV
WESTMINSTER	ST	PROVIDENCE	RI	53-76F5	4	Solar	Inverter Based - PV
FOUNTAIN	ST	PROVIDENCE	RI	53-76F5	5	Solar	Inverter Based - PV
ERNEST	ST	PROVIDENCE	RI	53-76F8	4500	Wind	Inverter Based - Wind
HENDRICK	ST	PROVIDENCE	RI	53-18F5	1	Solar	Inverter Based - PV
WESTMINSTER	ST	PROVIDENCE	RI	53-76F5	2	Solar	Inverter Based - PV
DEXTER	ST	PROVIDENCE	RI	53-6J5	2	Solar	Inverter Based - PV
UPTON	AVE	PROVIDENCE	RI	53-37J2	5	Solar	Inverter Based - PV
HARRIS	AVE	PROVIDENCE	RI	53-18F5	7	Solar	Inverter Based - PV
TELL	ST	PROVIDENCE	RI	53-12J4	4	Solar	Inverter Based - PV
CARPENTER	ST	PROVIDENCE	RI	53-76F5	4	Solar	Inverter Based - PV
ERNEST	ST	PROVIDENCE	RI	53-76F7	0	Solar	Inverter Based - PV
GANO	ST	PROVIDENCE	RI	53-77J1	1	Solar	Inverter Based - PV
HAMLIN	ST	PROVIDENCE	RI	53-7F1	1	Solar	Inverter Based - PV
FIFTH	ST	PROVIDENCE	RI	53-37J5	4	Solar	Inverter Based - PV
HAMMOND	ST	PROVIDENCE	RI	53-6J5	3	Solar	Inverter Based - PV
WYNDHAM	AVE	PROVIDENCE	RI	53-13F2	3	Solar	Inverter Based - PV
HAMMOND	ST	PROVIDENCE	RI	53-6J5	4	Solar	Inverter Based - PV
ALMY	ST	PROVIDENCE	RI	53-76F5	3	Solar	Inverter Based - PV
OAK	ST	PROVIDENCE	RI	53-76F5	3	Solar	Inverter Based - PV
THAYER	ST	PROVIDENCE	RI	53-1103	56	Solar	Inverter Based - PV
VINCENT	ST	PROVIDENCE	RI	53-9J1	6	Solar	Inverter Based - PV
WASHINGTON	ST	PROVIDENCE	RI	53-76F5	4	Solar	Inverter Based - PV
HARKNESS	ST	PROVIDENCE	RI	53-76F5	0	Solar	Inverter Based - PV
SOMERSET	ST	PROVIDENCE	RI	53-76F2	42	Solar	Inverter Based - PV
EDDY	ST	PROVIDENCE	RI	53-76F6	75	Solar	Inverter Based - PV
HAMMOND	ST	PROVIDENCE	RI	53-6J5	4	Solar	Inverter Based - PV
CHACE	AVE	PROVIDENCE	RI	53-13F3	4	Solar	Inverter Based - PV
JENCKES	ST	PROVIDENCE	RI	53-9J3	5	Solar	Inverter Based - PV
DEXTER	ST	PROVIDENCE	RI	53-6J5	2	Solar	Inverter Based - PV
BRIGHTON	ST	PROVIDENCE	RI	53-2J3	3	Solar	Inverter Based - PV
ANGELL	ST	PROVIDENCE	RI	53-77J4	15	Solar	Inverter Based - PV
LLOYD	AVE	PROVIDENCE	RI	53-76F1	5	Solar	Inverter Based - PV
WOONASQUATUCKET	AVE	NORTH PROVIDENCE	RI	53-50J1	3	Solar	Inverter Based - PV

Street Name	Suffix	City/Town	State	Feeder #	Name Plate Rating kW	Fuel Type	DG Type
WASHINGTON	ST	PROVIDENCE	RI	53-2J3	4	Solar	Inverter Based - PV
ORCHARD	AVE	PROVIDENCE	RI	53-76F1	45	Solar	Inverter Based - PV
BROOK-FARM	RD	NORTH PROVIDENCE	RI	53-13F9	10	Solar	Inverter Based - PV
VEAZIE	ST	PROVIDENCE	RI	53-13F4	42	Solar	Inverter Based - PV
VEAZIE	ST	PROVIDENCE	RI	53-13F4	42	Solar	Inverter Based - PV
MALVERN	ST	PROVIDENCE	RI	53-13F5	8	Solar	Inverter Based - PV
HOPE	ST	PROVIDENCE	RI	53-37J4	5	Solar	Inverter Based - PV
ROCHAMBEAU	AVE	PROVIDENCE	RI	53-37J5	3	Solar	Inverter Based - PV
PARADE	ST	PROVIDENCE	RI	53-6J8	6	Solar	Inverter Based - PV
BROAD	ST	PROVIDENCE	RI	53-76F7	10	Solar	Inverter Based - PV
APRIL	CT	PROVIDENCE	RI	53-71J5	8	Solar	Inverter Based - PV
LLOYD	AVE	PROVIDENCE	RI	53-76F1	5	Solar	Inverter Based - PV
PLEASANT-VALLEY	PKWY	PROVIDENCE	RI	53-18F5	4	Solar	Inverter Based - PV
BOYLSTON	AVE	PROVIDENCE	RI	53-77J2	2	Solar	Inverter Based - PV
Total kW					**5382**		
Total kW Less Ernest St					**882**		

9.14 Project Spending by Fiscal Year

Table 9.14.1 – Distribution and Substation Capital Spending Plan by Fiscal Year

Distribution and Substation Capital Spending Plan
($000)

	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030
Clarkson Street 13 F10 –Hawkins Street	$140	$210										
Olneyville – transfer customer from 6J5 feeder to 6J6	$150											
Admiral Street - convert 4.16 kV to 12.47 kV	$916	$1,832	$1,832									
Admiral Street – convert 11 kV to 12.47 kV (Phase 1)	$294	$588	$588									
Admiral Street – convert 11 kV to 12.47 kV (Phase 2)	$86	$172	$172									
Clarkson Street (assoc. with Admiral Street)	$276	$552	$552									
Lippitt Hill (assoc. with Admiral Street)	$30	$60	$60									
Admiral Street – Install breaker in 23 kV bay	$125	$250	$750	$125								
Admiral Street – Install 23/11 kV transformer	$125	$250	$750	$125								
Olneyville – Convert 4.16 kV to 12.47 kV (Phase 1)		$592	$1,184	$1,184								
Admiral Street - Install man hole & duct system		$886	$1,772	$1,772								
Admiral Street – Install new 115/12.47 kV substation			$680	$1,360	$4,080	$680						

Distribution and Substation Capital Spending Plan (cont'd)
($000)

	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030
Admiral Street – 12.47 kV getaways			$654	$1,308	$1,308							
Knightsville – Install modular 23/12.47 kV feeder			$130	$260	$780	$130						
Knightsville –convert 4.16 kV to 12.47 kV			$1,276	$2,552	$2,552							
Johnston 18F7 (assoc. with Knightsville)			$26	$53	$53							
Harris Avenue – convert 4.16 kV to 12.47 kV				$1,049	$2,098	$2,098						
Harris Avenue – convert 11 kV to 12.47 kV (Phase 1)				$400	$800	$800						
Johnston 18F5 (assoc. with Harris Avenue)				$20	$39	$39						
Olneyville – Convert 4.16 kV to 12.47 kV (Phase 2)					$690	$1.380	$1,380					
Dyer Street – Convert 2J8 partial (assoc with Olneyville)					$198	$396	$396					
Harris Avenue – convert 11 kV to 12.47 kV (Phase 2)					$483	$966	$966					
Geneva - convert 4.16 kV to 12.47 kV					$1.031	$2,062	$2,062					
Clarkson Street rebuilds (associated with Geneva)					$14	$28	$28					

Distribution and Substation Capital Spending Plan (cont'd)
($000)

	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030
Aubum - convert 41.6 kV to 12.47 kV (common items)					$1,060	$2,120	$2,120					
Aubum - convert 41.6 kV to 2.47 kV (non common items – Plan 1)					$677	$1,354	$1,354					
Elmwood rebuilds (associated with Aubum)					$152	$304	$304					
Pontiac rebuilds (associated with Aubum)					$136	$272	$272					
Lincoln Avenue rebuilds (associated with Auburn)					$4	$8	$8					
Rochambeau Ave - convert 4.16 kV to 12.47 kV					$1,121	$2,241	$2,241					
Lippitt Hill rebuilds (associated with Rochambeau Avenue)					$8	$15	$15					
Aubum – Install new 115/12.47 kV substation							$832	$1,663	$4,989	$832		
Aubum – install 12.47 kV getaways							$265	$530	$530			
23 kV circuits (2213 & 2235) – convert to 12.47 kV							$102	$204	$204			
Sprague Street - convert 4.16 kV to 12.47 kV							$806	$1,612	$1,612			
Point Street rebuilds (associated with Sprague Street)							$80	$159	$159			

Distribution and Substation Capital Spending Plan (cont'd)
($000)

	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030
Dyer Street - convert 2J3 partial (associated with Sprague St.)							$50	$100	$100			
Huntington Park - convert 4.16 kV to 12.47 kV							$194	$387	$387			
Lakewood – Convert 4.16 kV to 12.47 kV							$818	$1,638	$1,638			
Knightsville – Install second 23/12.47 kV modular feeder										$135	$270	$810
Geneva – Install 23/12.47 kV modular feeder										$340	$680	$2,040
Install getaways at Geneva, Knightsville and Lippitt Hill subs										$90	$180	$180
Lippitt Hill – Install 3rd 12.47 kV feeder and tie breaker											$46	$368
East George – Convert 77J2 feeder (partial) to 12.47 kV										$170	$340	$340
Totals	$2,142	$5,392	$10,426	$10,208	$17,284	$14,893	$14,295	$6,293	$9,619	$1,567	$1,516	$3,738

Spending by fiscal year is based on the in-service date, the construction time line and the historical spending pattern for similar projects.

Table 23 – Transmission Capital Spending Plan by Fiscal Year

Transmission Capital Spending Plan
($000)

	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030
Admiral Street - Install 115 kV circuit switchers			$50	$100	$300	$50						
Extend the I-187 and J-188 circuits from Sockanosset to Auburn						$150	$450	$2,850	$2,550			
Auburn - Install 115 kV circuit switchers							$50	$100	$300	$50		
Totals			$50	$100	$300	$200	$500	$2,950	$2,850	$50		

Spending by fiscal year is based on the in-service date, the construction time line and the historical spending pattern for similar projects.

9.15 Miscelleneous

Figure 9.15.1 – Proposed Layout of 11.5 kV, 23 kV and 35 kV Sub-transmission System

Table 9.15.1 – Reactive Compensation after Recommended Plan - 2030

Substation	**Feeder**	**Issue**	**Street Name & Pole No.**	**Comments**
Johnston	18F7	Reactive compensation	Maplewood Dr - near Pole 11	Install 600 kVAr Cap Bank
			Plainfield St – near Pole 134	Install 600 kVAr Cap Bank
			Magnolia St - near Pole 24	Install 600 kVAr Cap Bank
Point St	76F1	Reactive compensation	Sessions St – near Pole 17	Remove/Disable Cap Bank
Clarkson St	13F2	Reactive compensation	Chace Ave - near Pole 10	Remove/Disable Cap Bank
Point St	76F8	Reactive compensation	Allens Ave - near Pole 369	Remove/Disable Cap Bank
Johnston	18F9	Reactive compensation	Springsfield St - near Pole 6	Remove/Disable Cap Bank
Clarkson St	13F2	Reactive compensation	Silver Spring St – near Pole 17	Remove/Disable Cap Bank
Clarkson St	13F5	Reactive compensation	Charles St – near Pole 1153	Remove/Disable Cap Bank

Table 9.15.2 – Protective Device Changes after Recommended Plan - 2030

Substation	Feeder	Section ID	Street Name & Pole No.	Comments
Clarkson St	13F4	275449853	Junction of Douglas Ave and Stansbury St - Pole 171	Change to 40 K-Link fuse
Clarkson St	13F4	195906756	Ivan St - Pole 8	Change to 40 K-Link fuse
Clarkson St	13F4	275511561	Ivan St - Pole 7	Change to 25 K-Link fuse
Clarkson St	13F4	275511665	Ivan St - Pole 7	Change to 25 K-Link fuse
Johnston	18F10	275550367	Ipswich St - Pole 8	Change to 40 K-Link fuse
Johnston	18F5	275235515	Tell St - Pole 7-50	Change to 25 K-Link fuse
Johnston	18F5	275478669	Mongenais St - Pole 9168	Change to 40 K-Link fuse
Farnum Pike	23F6	275516270	Brookfarm Rd - Pole 7	Change to 40 K-Link fuse
Pontiac	27F1	275392515	New London Ave - Pole 5	Change to 25 K-Link fuse
Dyer St	2J5	275503745	Crary St - Pole 23	Change to 40 K-Link fuse
Manton	69F3	197157003	Manton Ave - Pole 191	Change to 100 K-Link fuse
New Auburn Sub	73F4	200662652	Benedict St - Pole 16	Change to 65 K-Link fuse
New Auburn Sub	73F4	275244389	Benedict St - Pole 20	Change to 40 K-Link fuse
New Auburn Sub	73F5	275475602	Access Rd - Pole 32	Change to 100 K-Link fuse
New Auburn Sub	73F6	275438818	Fay St - Pole 210	Change to 40 K-Link fuse
New Auburn Sub	73F7	275402228	Park Ave - Pole 29	Change to 65 K-Link fuse
New Auburn Sub	73F7	275399903	Hodsell St - Pole 6	Change to 30 K-Link fuse
Point St	76F1	275497879	Angell St - Pole 99	Change to 100 K-Link fuse
Point St	76F2	200663664	Oxford St - Pole 35	Change to 100 K-Link fuse
Point St	76F4	42972796	Updike St - Pole 46	Change to 100 K-Link fuse
Point St	76F4	275458077	Ford St - Pole 22	Change to 100 K-Link fuse
Point St	76F5	275456632	Hayward St - Pole 39	Change to 200 K-Link fuse
Point St	76F6	275494962	Chapman St - Pole 210	Change to 65 K-Link fuse
Point St	76F8	200659863	Ernst St - Pole 20-50	Change recloser ground curve to 165
Point St	76F8	275442452	Carolina Ave - Pole 16	Change to 10 K-Link fuse
Point St	76F8	275223303	Georgia Ave - Pole 23	Change to 15 K-Link fuse
Point St	76F8	239436045	Baker St - Pole 5	Change to 25 K-Link fuse
East George	77J1	275248963	Seekonk St - Pole 6	Change to 40 K-Link fuse
East George	77J3	275234442	Governor St - Pole 20-1	Change to 40 K-Link fuse
Lincoln Ave	72F1	275741953	Pavilion Ave - Pole 11-5	Change to 65 K-Link fuse

9.16 Distribution Planning Criteria

nationalgrid

Distribution Planning Guide

Rev. 1

Approved by: ______________________ **Date:** 2/15/11

Patrick Hogan, Sr. VP
Distribution Asset Management
National Grid USA Service Company

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
0	10/14/2009	Initial draft	Curt J. Dahl Manager, T&D Planning LI John F. Duffy, Jr. Distribution Planning	Patrick Hogan Sr. Vice President Distribution Asset Management
1	2/15/2011	Final approved document	Max F. Huyck Network Asset Planning Jeffery H. Smith Distribution Asset Strategy	

Distribution Planning Criteria Strategy
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Strategy Statement

This document describes the National Grid Electric Distribution Planning Criteria that will be applied by the Distribution Planning Department in future distribution studies. These criteria are applicable to the New England (NE) and upstate New York (UPNY) areas of National Grid.

The electric distribution system on Long Island, NY shall continue to follow the LIPA Transmission and Distribution Planning Criteria.

For normal loading conditions, all types of facilities are to remain within their normal ratings at all times. For N-1 contingency situations it is expected that load shall be returned to service within 24 hours via system reconfiguration through switching, the installation of temporary equipment such as mobile transformers or generators, or by the repair of a failed device. Where practical, switching flexibility should be integrated into the system design to minimize the duration of customer outages following an N-1 contingency to meet reliability objectives. The following shall guide contingency planning on the distribution system:

1.) For the loss of a power transformer or substation bus fault that disrupts distribution load, the following planning criterion applies:

- The initial load increase at the remaining transformers within the area must not exceed either the summer or winter STE rating or 200% of nameplate.
- Load will need to be transferred or shed in a reasonable number of steps to reduce loading to the summer or winter LTE level within 15 minutes.
- Load on remaining transformers will be reduced to the summer or winter normal limit within 24 hours.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 10MW.
- Repairs or the installation of mobile equipment are expected to require 24 hour implementation.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.) For the loss of a sub-transmission supply line, the following planning criteria apply:

- The initial load increase at the remaining sub-transmission supply lines within the area must not exceed the summer or winter LTE rating.
- Every effort must be made to return the failed sub-transmission line to service within 12 hours.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 20MW combined, considering all substations served via the supply line.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a single line fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

3.) For the loss of a distribution feeder, the following planning criteria apply:

- Feeders shall tie to neighboring feeders as much as practical as the flexibility to reconfigure feeders has a positive reliability impact for a wide range of possible contingencies.
- Following a contingency, all adjoining tie feeders can be loaded to their maximum thermal emergency or LTE rating.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload adjoining feeders.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 16MWHrs of load is at risk at peak load periods for a single feeder fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

Application of these criteria will result in somewhat less load at risk than previous criteria in either New York or New England which generally limited load at risk to between 20 and 28 MW pending the installation of a mobile device. Therefore it is expected that the Load Relief budgets will increase from historic levels for a given load growth rate. The capital cost associated with meeting the existing and proposed criteria for both normal and N-1 contingency conditions in New England and upstate New York are shown in Table 1:

Table 1 - Comparison of Capital Costs between Existing and New Criteria

Criteria	Present Value ($ Millions)	15 Year Annualized ($ Millions)
Existing NE/NY Criteria	$800	$80
New Criteria	$1,250	$130

The new criteria may result in an increase in capital requirements up to $50M/year over the existing criteria for the 15-year period studied.

Based on the results of the sample areas (expanded to the overall system) the following approximate quantities of additional facilities may be required over the next 15years.

Transformers (at existing or new substations)	180
Sub-Transmission Lines	46
Distribution Feeders	319

The new criteria will be applied to new installations and/or significant rebuilds initially. This is a long-term strategy and it is expected to take the full 15 year horizon to achieve compliance with existing facilities system-wide.

Performance targets for the adoption of the new planning criteria are:

- Quantification of equipment (sub-transmission lines, transformers, feeders) with load at risk forecast above the guidelines above.
- Identifying high load at risk areas and as part of annual summer preparedness and communicate monitoring plans for the Regional Control Centers.

- Developing project recommendations to eliminate or significantly reduce load at risk areas based on MWHr metrics, reliability performance and mitigation costs.

This policy shall be reviewed and revised as often as needed to reflect any major standards or criteria changes. It is recommended that a 2-3 year review cycle be performed.

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
0	10/14/2009	Initial draft	Curt J. Dahl Manager, T&D Planning LI John F. Duffy, Jr. Distribution Planning Max F. Huyck Network Asset Planning Jeffery H. Smith Distribution Asset Strategy	Patrick Hogan Sr. Vice President Distribution Asset Management
1	2/15/2011	Final approved document		

Strategy Justification

1.0 Purpose and Scope

This document describes the National Grid Electric Distribution Planning Criteria that will be applied by the Distribution Planning Department in future distribution studies. These criteria are applicable to the New England (NE) and upstate New York (UPNY) areas of National Grid.

A map showing National Grid electric service territory within New England and upstate New York is attached in Appendix A.

The electric distribution system on Long Island, NY shall continue to follow the LIPA Transmission and Distribution Planning Criteria.

This policy shall be reviewed and revised as often as needed to reflect any major standards or criteria changes. It is recommended that a 2-3 year review cycle be performed.

2.0 Strategy Description

2.1 Description of Distribution System

The distribution system of National Grid is comprised of all lines and equipment operated at a voltage below 69kV in New England and below 115kV in New York. The components of the distribution system are distribution substations, sub-transmission lines, and distribution circuits or feeders.

2.1.1 Distribution substations

The distribution substations within National Grid are a mixture of stations with one, two, and three or more transformers. The distribution substations step down voltage to a distribution or sub-transmission level. In Upstate New York approximately 70% of the substations have either a single source or a single transformer. In New England 40% of the substations have a single source and/or transformer.

A typical substation involves a 115/13 kV, 25-40 MVA rated transformer with either a load tap changer built into the transformer or individual voltage regulators applied to the feeders. In many locations, two or three transformers are within one substation and will interconnect via bus tie breakers. Many of the distribution substations supplied by the 115kV circuits also include one or more capacitor banks for reactive support.

National Grid maintains approximately 680 distribution substations containing approximately 1,530 power transformers. The total number of distribution substations, transformers, circuit miles of overhead and underground within NE and UPNY is listed in Distribution Line Overarching Strategy paper dated July 2008.

2.1.2 Sub-Transmission systems

The sub-transmission system within National Grid is designed to provide adequate capacity between transmission sources and load centers at reasonable cost and with minimal impact on the environment. The National Grid sub-transmission system provides supply to distribution substations as well as large three phase customers. It consists of those parts of the system that are neither bulk transmission nor distribution. The typical voltages for the sub-transmission system include 46, 34, and 23 kilovolts. In New York, the sub-transmission also includes the 69 kV.

Sub-transmission systems may be designed in a closed or open loop system originating from transmission substations, and generally providing a redundant supply for distribution substations. In other cases, a single radial sub-transmission supply line may serve load. The substations served from a sub-transmission line will serve approximately 10-40 MW of load depending on the voltage.

Generally, the sub-transmission system is presently designed with conductors ranging from 336.4 ACSR (UPNY) to 795 kcmil AAC (NE) overhead conductor and from 500 to 2000 kcmil copper underground conductor. However, most of the sub-transmission lines are older designs and built with smaller wire such as 2/0 AWG copper installed along right-of-ways or on public streets.

There are approximately 930 sub-transmission lines in New England and upstate New York within National Grid.

2.1.3 Distribution Feeders

Distribution feeders originate at circuit breakers connected within the distribution substations. Feeders are generally comprised of 477 or 336 kcmil aluminum mainline overhead conductors and 1/0 AWG aluminum branch line conductors. Some feeders have underground getaway cables exiting from the substation with 500 to 1000 kcmil aluminum or copper conductor. Feeders are designed in a radial configuration. The feeder mainline will typically have several normal open tie points to one or more adjacent feeders for backup. Protection for faults on the feeders consists of relays at the circuit breaker, automatic circuit reclosers at points on the mainline, and fuses on the branch circuits.

The National Grid Primary distribution system in New England and upstate New York is comprised of approximately 3,770 feeders.

2.1.4 Secondary Networks

Low voltage secondary networks have historically been employed in several urban areas to maximize the reliability for the customers in these areas. They typically have a 120/208V class secondary system that is connected as a grid with many downtown customers connected. Most of the secondary networks have from 4-10 supply feeders. The low voltage secondary network supply feeders will typically have 10-30 network transformers connecting into the secondary grid.

Spot secondary networks are used in areas to serve specific large loads in urban areas. Some of these are served at 120/208V, while others are served at 277/480V. Typically, 2-3 supply feeders are used to serve the spot networks.

2.2 Distribution Planning Criteria

2.2.1 General Items impacting the Distribution Planning Criteria

2.2.1.1 Load Forecasting

The load forecast used by Distribution Planning for New England and New York will be based on a regional econometric regression model that considers historic loading, weather conditions, various economic indicators. The forecast is adjusted for known spot load additions and DSM forecasts. Presently, distribution planning is based on a forecast that considers loading during extreme weather conditions such that those weather conditions are expected to occur once in 20 years. Separate models are used for NE and UPNY.

2.2.1.2 Equipment Ratings

Distribution Planning maintains equipment ratings for New England and New York. The summer and winter normal and summer and winter long time emergency (LTE) ratings will be used. The major equipment ratings to be used by Distribution Planning relate to transformers, overhead lines, and underground cables. The normal and LTE rating limits for these items may be applied for the time associated with each rating. Generally, the durations for emergency loading are as listed below in Table 2. System operators must be aware of the limiting factor involved in any contingency:

Table 2 - Equipment Rating Durations

Equipment		Normal	LTE	STE
Transformer		Continuous	24 hour	15 Min
Overhead Line		Continuous	24 hour	N/A
Underground Cable		Continuous	24 hour	N/A

There is also a short time emergency rating which may be determined for substation transformers, in no instance should this rating exceed 200% of nameplate rating. In addition to the items in the above table, ratings are reviewed for switches, circuit breakers, voltage regulators, and instrument transformers.

2.2.1.3 Planning Study Areas

A planning study area within National Grid is a grouping of distribution substations, feeders, transformers, and sub-transmission lines within a specific geographic area that are interconnected and can be studied as a group. Some areas are totally independent, while others will have points of interconnection with other study areas. A listing of the planning study areas that exist in NE and UPNY to be used by Distribution Planning are presented in Appendix B.

2.2.1.4 Load Flows

Distribution planning studies will utilize the PSS/e load flow program for the study of the sub-transmission lines and networks. The distribution feeder load flow analyses will be done using the Cymedist feeder analysis software program.

2.2.1.5 Distribution Analysis Alternatives

When performing distribution system analyses, Distribution Planning shall consider both traditional capacity enhancements as well as alternatives for "Non-Wires" customer load management alternatives where appropriate. The factors below could impact capacity planning analysis

a. Distributed Generation
b. Controllable Load Curtailment
c. Energy Storage devices
d. Demand Side Management

e. Distribution Automation
f. Smart Grid solutions

2.2.2 Distribution Substation Transformer Planning Criteria

2.2.2.1 Normal transformer load planning criteria

A substation transformer will not be loaded above its Normal rating during non-contingency operating periods.

2.2.2.2 Contingency N-1 substation transformer planning criteria

For an N-1 contingency condition that would involve the loss of a power transformer or substation bus, the following planning criteria apply:

- The initial load increase at the remaining transformers within the area must not exceed either the summer or winter STE rating or 200% of nameplate.
- Load will need to be transferred or shed in a reasonable number of steps to reduce loading to the summer or winter LTE level within 15 minutes.
- Substations will be designed to allow the installation of a mobile transformer within a maximum of 24 hours for a failed transformer.
- Load on remaining transformers will be reduced to the summer or winter normal limit within 24 hours.
- Feeder ties within the area can be utilized to their emergency limits. Cascading of load between feeders and substations may be needed to reduce loading to normal limits within the time frames required.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 10MW.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.2.2.3 Automatic transfer of load

Many locations with two or more transformers at a substation utilize automatic bus transfers. In some stations, one bus tie breaker is used, while in other substations a breaker and half design is utilized and there may be several feeder bus tie breakers. Based on the loading limitations in Section 2.2.2.2, it may be necessary to block the automatic transfer on either the main bus tie or one of the feeder bus tie breakers to avoid exceeding the STE limit during an N-1 contingency. Cases where automatic restoration are disabled will be documented and communicated with Regional Control Centers as part of an annual summer preparedness review. Recommendations to add capacity to the area will be evaluated and prioritized based load at risk, reliability and cost with other Load Relief alternatives.

When available, the use of the Energy Management System (EMS) control shall be implemented as needed to block automatic transfer. During an N-1 contingency, the System Operator will be required to maintain the loading on transformers as specified in Section 2.2.2.2.

2.2.2.4 Substation reactive support criteria

Reactive compensation shall be required for substations in the form of station capacitor banks or static VAR compensators. These should be sized to offset the reactive losses of the transformers at full load. Two or three stage capacitor banks may be needed for larger transformers to manage power factor and to limit voltage fluctuations.

2.2.2.5 Impact of planned maintenance

Capacity in all areas should allow the off loading of any distribution substation transformer for planned maintenance during the off peak months without exceeding the normal ratings of the other area equipment. However, in areas of the system with limited feeder ties, it may be more economical to allow the installation of a mobile transformer for maintenance.

2.2.3 Distribution Sub-transmission Planning Criteria

2.2.3.1 Normal sub-transmission load planning criteria

A sub-transmission supply line will not be loaded above its normal rating during non-contingency operating periods.

2.2.3.2 Contingency N-1 sub-transmission planning criteria

For an N-1 contingency condition that would involve the loss of a sub-transmission supply line, the following planning criteria apply:

- The initial load increase at the remaining sub-transmission supply lines within the area must not exceed the summer or winter LTE rating.
- Load on the remaining sub-transmission line will need to be reduced to normal levels within 24 hours.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload a sub-transmission line.
- Every effort must be made to return the failed sub-transmission line to service within 12 hours.
- The limit of load at risk for the loss of any sub-transmission line will be 20MW.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 20MW combined, considering all substations served via the supply line.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a single line fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.2.3.3 Automatic line transfer systems

Auto transfer of load on the sub-transmission may be employed, but may not exceed the emergency (LTE) ratings of the remaining supply lines. When available, EMS control of sub-transmission lines will be utilized to block auto transfers and avoid overloading of lines as needed.

2.2.3.4 Sub-transmission reactive support criteria

Reactive compensation for sub-transmission lines shall be required in the form of station and distribution capacitor banks.

2.2.4 Distribution Feeder Planning Criteria

2.2.4.1 Normal feeder load planning criteria

A distribution feeder circuit will not be loaded above its normal rating during non-contingency operating periods.

2.2.4.2 Contingency N-1 feeder planning criteria

For an N-1 contingency condition that would involve the loss of a distribution feeder, the following planning criteria apply:

- Feeders shall tie to neighboring feeders as much as practical as the flexibility to reconfigure feeders has a positive reliability impact for a wide range of possible contingencies.
- Following a contingency, all adjoining tie feeders can be loaded to their maximum thermal emergency or LTE rating.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload adjoining feeders.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 16MWHrs of load is at risk at peak load periods for a single feeder fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.2.4.3 Automatic transfers on feeders

In some cases, it will be necessary to adjust a feeder rating to below normal summer or winter thermal rating due to automatic backup or Second Feeder Service commitments to certain customers.

2.2.4.4 Feeder reactive support criteria

Reactive compensation for feeders should be installed to provide additional capacity, improve voltage regulation and meet external power factor standards where applicable. A mixture of fixed and switched capacitor banks may be used as needed. All feeders in a planning area shall have proper reactive compensation prior to any requests for other load relief infrastructure improvements.

2.2.4.5 Feeder load balance criteria

Distribution Planning studies are based on three phase average loading. Load balance between the three phases on any feeder is assumed to be within a reasonable level.

Distribution feeder load balance shall require correction of the load imbalance for either of the following cases:

- Any feeder with the calculated neutral current exceeding 30% of the feeder ground relay pickup setting.

- Any feeder exceeding 100A between the high and low phase amps.

2.2.5 Network criteria

Secondary network criteria and loading limitations are defined in the National Grid distribution standards. The criteria are different for NE and UPNY based on the history of how various networks evolved.

2.2.6 Voltage criteria

2.2.6.1 Allowable Voltage Range at Service Point for Distribution Customers

The normal and emergency voltage to all customers shall be in line with limits specified by state regulators and within the limits of ANSI C84.1

These upper and lower voltage limits for each state in the service territory are listed in Table 3 below:

Table 3 - Voltage Requirements by State

State	Upper	Nominal	Lower
Massachusetts	126	120	114
New Hampshire	126	120	114
New York	123	120	114
Rhode Island	123	120	113

The values in Table 3 are in line with the National Grid Overhead Construction Standards.

Voltage on the sub-transmission and primary feeders is determined by many factors including:
- Primary mainline conductor sizes
- Distance of lines
- Reactive compensation

Voltage on the feeders is controlled by the station load tap changer or station regulators on feeders, the application of distribution capacitor banks, and the application of pole or padmounted line regulators. Voltage regulation of the feeders and supply lines must be adequate to ensure the voltage requirements in Table 3 above are maintained.

2.3 Residual risk and project prioritization

2.3.1 Residual risk after compliance with new criteria

The goal of the new planning criteria is to maintain the performance of the electric distribution system. Generally, after compliance with the new criteria, the residual risk for the worst case will be 10 MW of load out for 24 hours for a substation transformer failure or 20 MW out for 12 hours for an overhead supply line failure.

2.3.2 Methodology to prioritize capital projects

Prioritization of capital projects utilizes scoring system that considers the consequence of not completing the project and the probability that the consequences will be realized. A risk score between 1 and 49 is developed utilizing a 7x7 scoring matrix.

3.0 Risks/Benefits

The principal impacts of the planning criteria are reliability performance, customer service and efficiency. Due to the extended time frame for strategy compliance, the impact of the strategy will not be initially visible at the system level. These benefits will be most apparent in those areas where it has been implemented.

3.1 Safety & Environmental

Safety and environmental factors are not principal drivers of the planning strategy. However, the planning criteria will ensure equipment loading is maintained within accepted ratings reducing the risk of premature equipment failure that could result in environmental and public safety concerns.

3.2 Reliability

The planning criteria will provide operating flexibility to facilitate the restoration of customer outages following an N-1 contingency event. With an expected long implementation schedule, the impact will not be initially visible at the system level but will be significant in the areas where the criteria have been implemented. A long range reliability improvement of 11.4 minutes in SAIDI and 0.073 in SAIFI on a system basis is forecasted if the strategy is implemented over a 15 year planning horizon. Additionally, lower feeder loading will support future distribution automation to further improve reliability.

3.3 Customer/Regulatory/Reputation

The customer benefit associated with planning criteria is significant. Improved system reliability and lower equipment loading provide greater flexibility in serving both existing and new customers.

3.4 Efficiency

The planning strategy provides a consistent approach for feeder/substation and study area loading analysis across NE and UPNY. All studies being conducted under one criterion will create a consistent reference for ranking projects as part of the business planning process.

4.0 Estimated Costs

The estimated costs to adopt the new planning criteria are summarized as follows:

The capital cost associated with meeting the existing and proposed criteria for both normal and N-1 contingency conditions in New England and upstate New York are shown in Table 4:

Table 4 - Comparison of Capital Costs between Existing and New Criteria

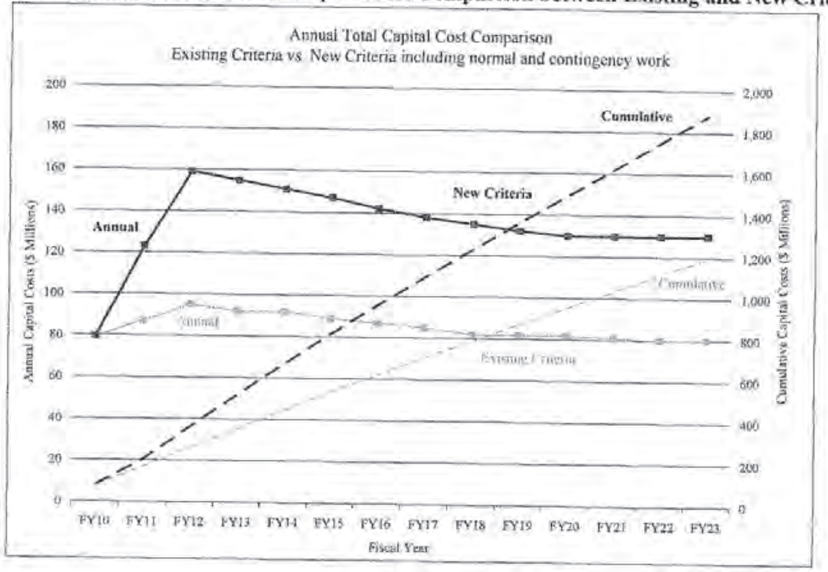
Criteria	Present Value ($ Millions)	15 Year Annualized ($ Millions)
Existing NE/NY Criteria	$800	$80
New Criteria	$1,250	$130

The new criteria may result in increased in capital costs of $50M/year in the Load Relief budget category compared to previous criteria for the 15-year period studied.

Based on an analysis of normal loading issues, it is projected that capital work associated with normal loading will remain at present levels or slightly higher for several years and then ramp down as contingency projects will tend to drive the load relief spending.

These combined normal and contingency capital costs are shown in Figure 1 below:

Figure 1 - Annual and Cumulative Capital Cost Comparison between Existing and New Criteria



5.0 Implementation

Based on the results of the sample areas (expanded to the overall system) the following approximate quantities of additional facilities are forecasted to be required over the next 15 years in NE and UPNY.

Transformers (at existing or new substations)	180
Sub-Transmission Lines	46
Distribution Feeders	319

The new criteria will be applied to new installations and/or significant rebuilds initially. This is a long term strategy and it is expected to take many years to implement system-wide.

6.0 Data Requirements

The data sources required for the proper execution of the planning strategy include:

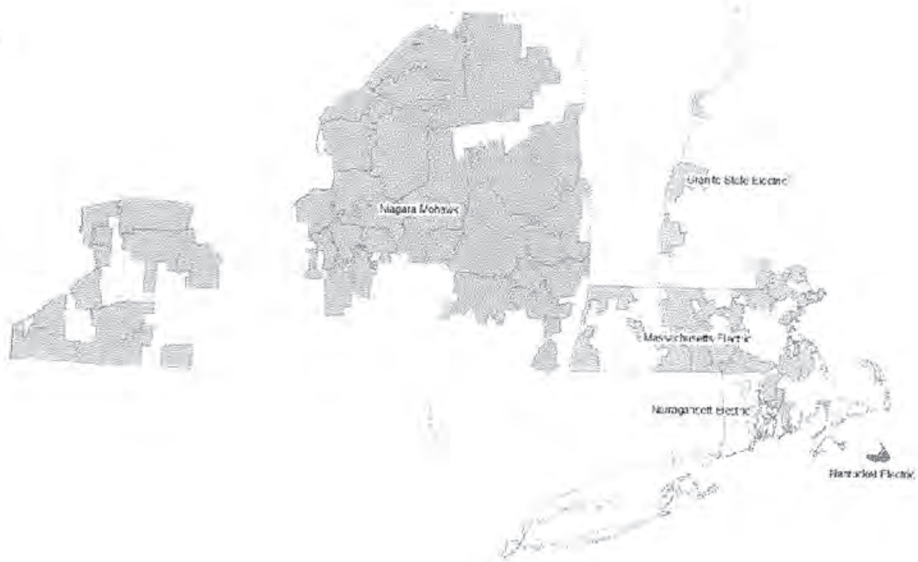
6.1 Planning Tools:

Cymedist (Cyme) – for radial feeder load flow and voltage analysis
Smallworld GIS – to support Cyme analysis
PSS/e – for network load flow analysis
FeedPro - for equipment loading and ratings
EMS and PI or ERS access in NE and UPNY

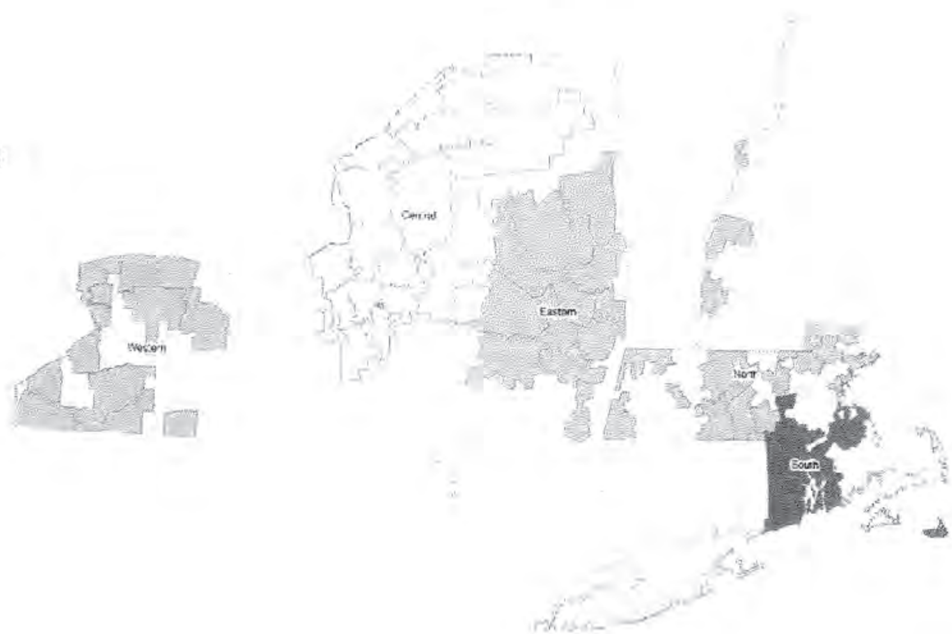
Appendix A – Service Territory Maps

Maps of Electric Distribution Service Territories for five companies and five divisions:

Companies

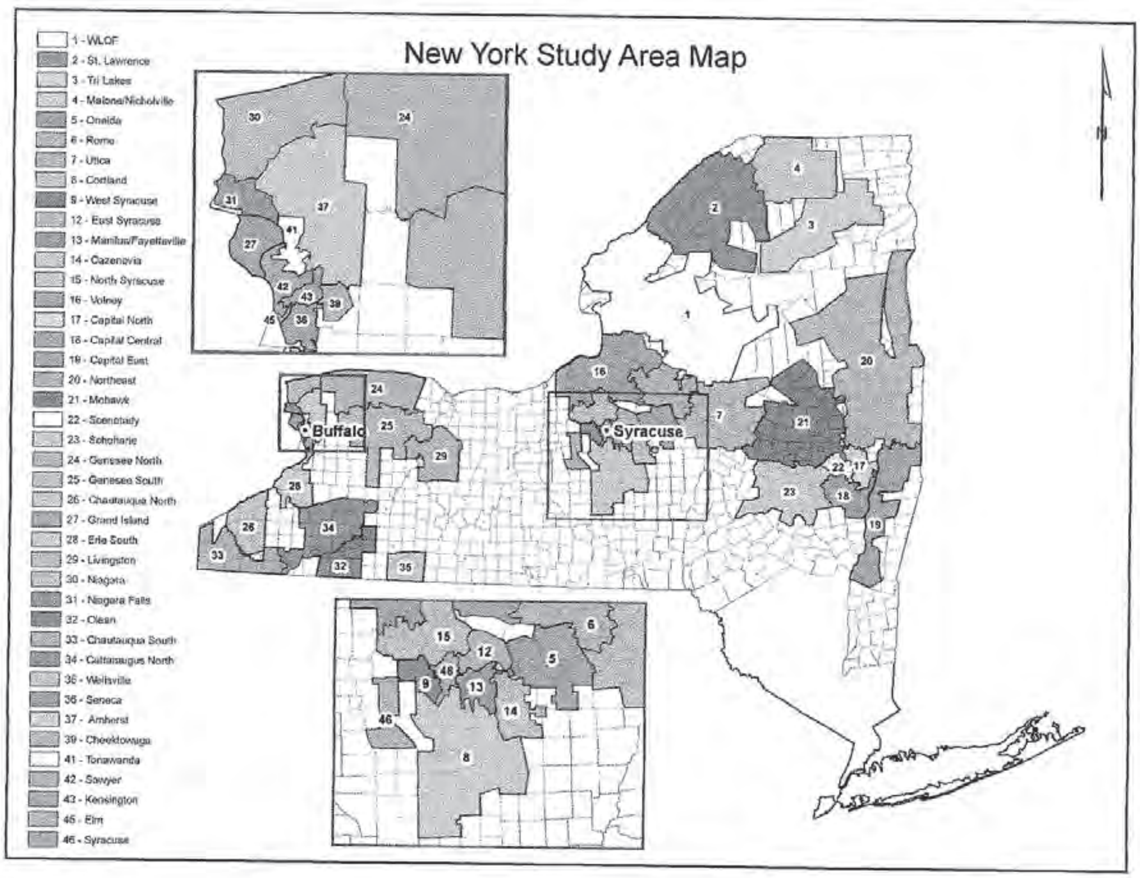


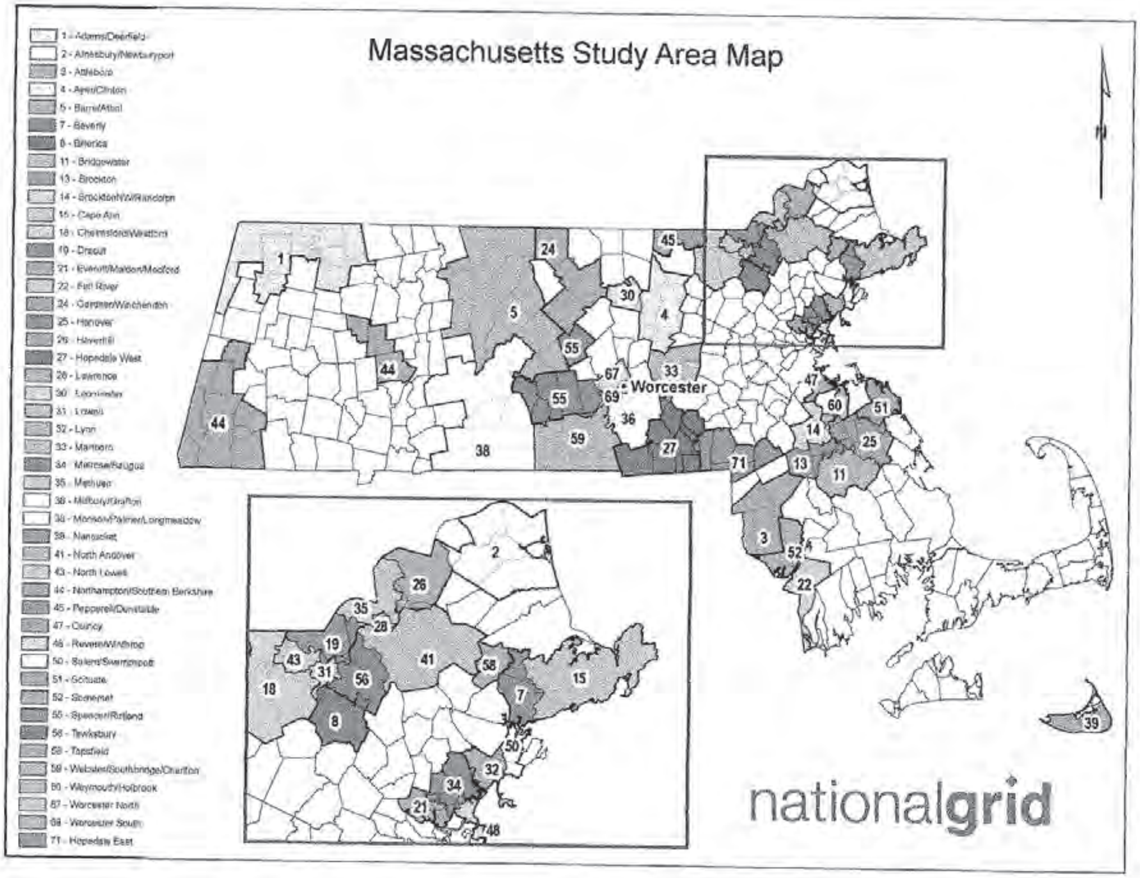
Divisions

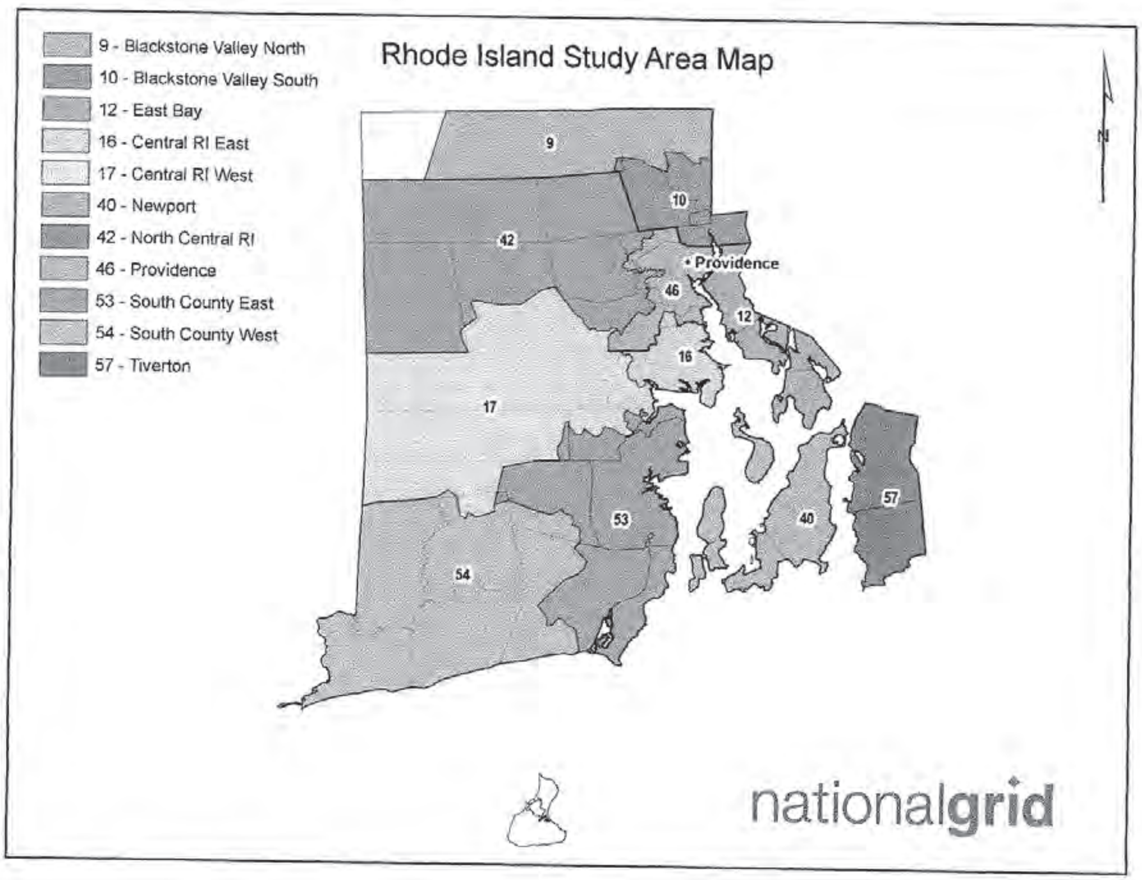


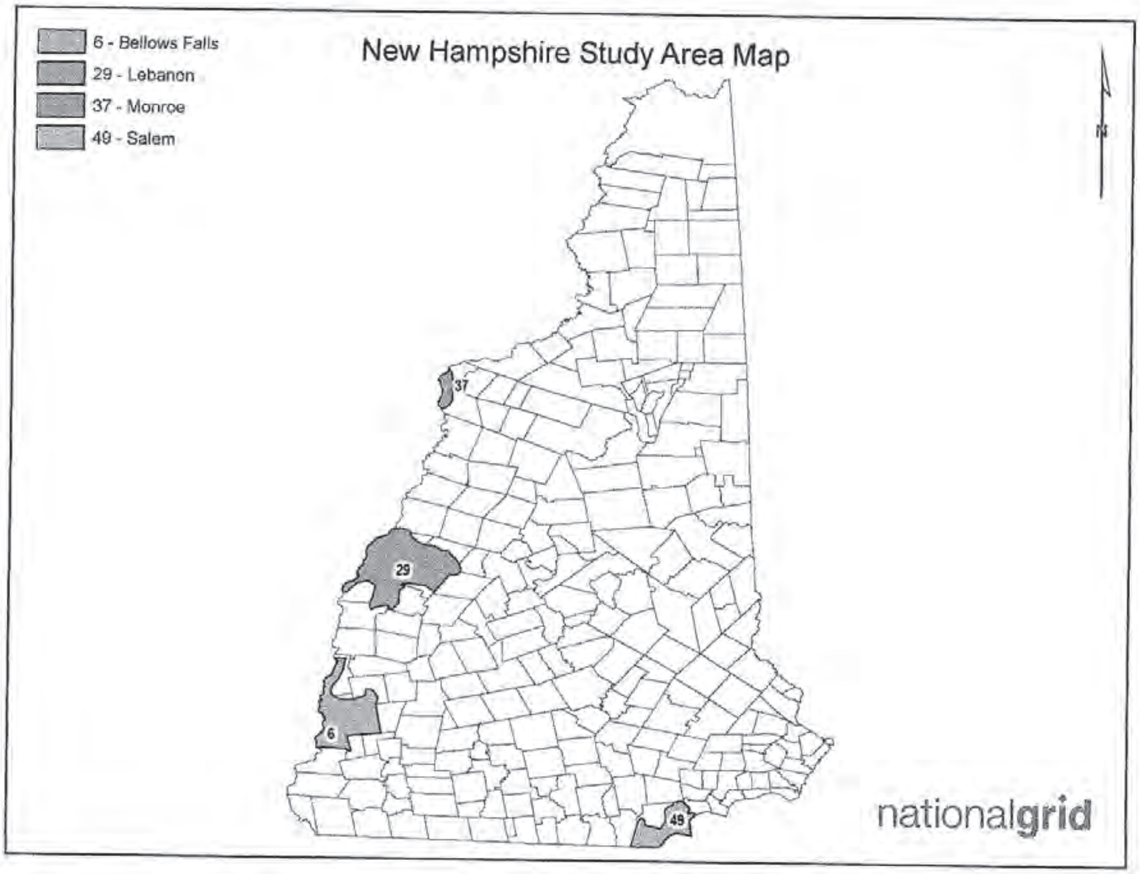
Appendix B - Distribution Planning Study Areas

To foster the annual capacity planning assessment, the distribution system across UNY and NE has been segmented into Planning Study Areas as shown in the following figures.




Massachusetts Study Area Map
2 - Amesbury/Newburyport
5 - Barre/Athol
7 - Beverly
11 - Bridgewater
13 - Brockton
15 - Cape Ann
27 - Hopedale West
32 - Lynn
35 - Methuen
41 - North Andover
43 - North Lowell
45 - Pepperell/Dunstable
47 - Quincy
52 - Somerset
56 - Tewksbury
58 - Topsfield
59 - Webster/Southbridge/Charlton
60 - Weymouth/Holbrook
67 - Worcester North
68 - Worcester South
71 - Hopedale East
Worcester


Rhode Island Study Area Map
9 - Blackstone Valley North
10 - Blackstone Valley South
12 - East Bay
16 - Central RI East
17 - Central RI West
40 - Newport
42 - North Central RI
46 - Providence
53 - South County East
54 - South County West
57 - Tiverton
9
10
42
Providence
46
12
16
17
53
40
57
54
N
nationalgrid


6 - Bellows Falls
29 - Lebanon
37 - Monroe
49 - Salem
New Hampshire Study Area Map
37
29
6
49
N
nationalgrid

9.17 Distribution Planning Study Process

Distribution Planning Study Process

1. Introduction

In order to maintain a consistent approach to distribution planning, it is necessary that uniform planning criteria be followed and that there is well executed coordination among stakeholder departments/groups. This document has been prepared to provide guidance on the performance and expected work product of distribution area planning studies.

2. Purpose

This document details the Distribution Planning and Asset Management study process for system planners, the functions that support them, and the stakeholders reliant on their work product. It is expected that execution of a well defined study process will result in timely delivery of infrastructure development recommendations having thoroughly defined project scopes that satisfy the needs and expectations of all stakeholders (especially customers). In addition, it enhances the organization's ability to meet its obligation to provide safe, reliable, and efficient electric service for customers at reasonable costs.

3. Applicability

All personnel within Distribution Planning and Asset Management when assigned to work on:

- Area Studies
- Program Studies (initial or modification)
- Complex Customer Service Requirements Studies – Typically, large services requests, generally 8MW or greater and/or greater than 5MW with requirements for service redundancy

Members of departments that support the study process and associated work product development should be trained in and/or aware of this process.

4. Process

Distribution planning studies will typically be assigned to central planning engineers in the Distribution Planning and Asset Management group by their department manager. Assignment of a study to other engineers in the Distribution Planning and Asset Management group (ex: field engineers) is also possible.

The prioritization of area planning studies to be executed and the engineering analysis conducted within an area study is supported by the Annual Planning Screening Process. This process is a recurring annual effort which aides in the identification of thermal system performance concerns. As part of this effort, the following is recorded or estimated:
Area (feeder, substation, and supply line) summer* peak loads (date, time, and value) both coincident and non-coincident with the system peak load.
System summer peak load (date, time, and value).

*In areas that are winter peaking and winter limited, winter peak load data will be collected.

Distribution Planning Engineers are responsible for assembling, screening, and recording of facility peak loads. Peak load data will be stored in FeedPro and the annual planning screening spreadsheets. Load forecasts will be applied to facility peak loads and recorded in the annual planning spreadsheets.

As already noted, the Annual Planning Screening Process work product facilitates the prioritization of area studies to be conducted. Once a decision has been made to execute a specific area study, the assigned engineer will bring the effort through the following major milestones:

- Scoping Activities
- Initial System Assessment
- Study Kickoff
- Detailed System Assessment / Engineering Analysis
- Plan Development and Project Estimating
- Identification of Recommended Plan
- Technical Review
- Documentation
- Sanctioning

Further detail on each of these milestones follows:

4.1. Scoping

The study engineer starts by preparing to execute the study. All area distribution studies will require the same basic preparation steps. The engineer will:

- Gather the most recent version of the Distribution Planning Guidelines ("DPG")
  - Upon consultation with the manager, gather any other emerging guidelines that have not been formally incorporated into the DPG (ex: grid modernization or volt-var optimization guidelines).
- Gather equipment rating data, settings data, specifications data, etc.
- Gather the most recent Distribution Standards including, but not limited to:
  - Overhead conductor ratings (section 6.0)
  - Generic underground cable ratings (section 35.14)
  - Latest recloser controls (pages 12-338 to 12-340)
  - Latest capacitor controls (pages 15-335 to 15-336, 15-404 to 15-405)
  - Latest sensor controls (page 15-600)
  - Storm Hardening (section 4.0)
- Define the electrical scope (lines and substations to be studied)
- Define the geographic scope (towns and portions or towns to be included in study)
- Building/correcting/updating system models in CYME, PSS/e, ASPEN
- Gather the latest forecast and review/refine the area/facility load and expected load growth from the present to the study's horizon year (typically 15 years)
- Gather service territory maps
- Gather large commercial and industrial customer load data[1]
- Gather or request asset condition reports[2]
- Identify all infrastructure development limitations (ex: river, highway, state forest, etc)
- Gather documentation of existing system performance concerns (ex: thermal, reliability, voltage, reactive support, arc flash, fault duty, etc.)[3]
- Gather recently completed area projects or ongoing area projects within the work plan. This will set the base year and base configuration.[4]

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[1] Consult with Customer and Community
[2] Consult with Substation O&M Services
[3] At a minimum, include annual plan screening information. Consult with area engineering and operations experts as time allows.

- Gather existing and in-queue distributed generation or distributed energy resources
- Gather state information or policies regarding distribution planning or distributed energy resources

The engineer will then develop a scope that details the study area boundaries and concerns. The study scope will be reviewed by their respective manager. The manager must approve the study scope before next steps are executed.

The final scoping activity is to request study team members. The study engineer will request formal team members from the following departments, via Study Engineering Request form.

- Transmission Planning
- Transmission Line Engineering
- Substation Engineering
- Protection Engineering (Relay, Communications, and Controls and Integration)

The following additional departments may be expected to provide input during various stages of the study and will be included in study meetings as required:

- Substation O&M Services Operations
- Transmission Control Center and/or Regional Control Center
- Project and Program Management
- Community and Customer Management
- Distribution Design
- Safety
- Environmental
- Legal
- Real Estate

All study contributors will be provided proper accounting to charge their time in support of the study. Once a study team is formed, the study engineer will schedule the study kickoff meeting.

4.2. Initial System Assessment

Study area initial system assessment consists of a quick analysis of facilities and system performance within the identified study geographic and electric scope. As part of the assessment, the study engineer will conduct the following:

- Existing and in-queue distributed generation and distributed energy resources
- A review for compliance with Planning Guidelines:
  - Thermal (load vs. capability) issues using the annual planning screening spreadsheet, CYME, and PSS/e
  - Voltage – using CYME, PSS/e
  - Reactive Support
- Asset condition assessments and consideration of active asset programs including, but not limited to:

[4] For example a study starting in year X may set a base year of X+3 if substantial system modification will be completed in year X+3.

  - Breaker Replacement
  - EMS
  - Metal Clad Substations
  - Indoor Substations
  - Underground Cable
  - Distribution Line Inspection & Maintenance
- Screening review of arc flash and fault duty data
- Screening review of CKAIDI and CKAIFI reliability indices[5] against state targets or average values

Initial system assessment is completed when the planner has enough information to consult with the wider group of subject matter experts and internal departments at the study kickoff. A careful balance of analysis to ensure study timeline efficiency is required. Too little analysis leaves the planner unable to lead a robust discussion during the kickoff meeting to gather those asset, operational, and construction complexities that help refine issues and generate comprehensive alternatives. Too much analysis may lead to rework by the planner should new information result from the kickoff. It is preferable that high level alternative concepts are developed during Initial System Assessment simply to generate discussion. Never should alternatives be fully developed or considered final within this step. Throughout the Initial System Assessment, it is expected that informal and regular consultations will be required with Transmission Planning, Distribution Design, Substation Engineering, Transmission Line Engineering, Substation O&M Services, and/or Operations.

4.3. Study Kickoff

The study kickoff is a meeting held to inform the larger stakeholder group that an area study is underway and to solicit inputs from those with knowledge of the system infrastructure in the area under review.

The study engineer will invite the following groups/representatives to the Kickoff meeting:

- Community & Customer Management
- Operations:
  - Distribution Line (OH & UG) Supervisors
  - Substation O&M Supervisors
  - Distribution Design
- Substation O & M Services
- System Control Center
- Project Management
- Program Management (Substation and Line)
- Distribution Engineering and Asset Management
  - Field Engineer
  - Field Engineering Manager
- Transmission Engineering and Asset Management
  - Transmission Planning Engineer
  - Transmission Asset Management Engineer
- Transmission Line Engineering
- Substation Engineering
- Protection Engineering
- Resource Planning
  - Short Term Resource Planning

[5] 5 year reliability data is preferred. 3 year data may be used to avoid years of significant major storm activity or significant system reconfiguration.

   - Long Term Resource Planning
- Product Energy Services (NWA)
- IT/ IS

The study engineer will present the following:
- Proposed study electrical and geographic scope
- Recent area studies and infrastructure development projects impacting the area
- Study area load and initial understanding of load growth expected in the area
- Known concerns in the area
- Using one-lines, possible infrastructure development plans for discussion
- Using area maps, possible distributed energy resource ideas fro discussion
- Study schedule and the names of representatives of departments assigned to support it

Upon completion of this presentation, the study engineer will open the meeting for group discussion. Specific input that the study engineer is looking for includes:

- Acceptance of electrical and geographic boundaries
- Operational concerns, examples:
   - Switching flexibility
   - Restoration areas of concern (ex: rights-of-way, direct buried cables)
- Asset condition concerns not already identified
- Safety by Design
- System performance concerns not already identified, examples:
   - Reliability
   - Voltage
   - Loading
- Details on any significant near term load additions in the area not already identified
- Details on any significant distributed energy resources in the area not already identified
- Details on potential alternative ideas or concerns, examples:
   - Locations that should/could be considered for new substation development
   - Substation expansion opportunities
   - Feeder routing (new feeders and feeder ties)
   - Local issues that might impact infrastructure development options, examples
      1. Local regulations requiring underground vs. overhead construction
      2. Status of community relationships with the Company
- Details on any distributed energy resource opportunities that should be considered

Representatives assigned from all groups are expected to support the study throughout the entire process and document any concerns their department may have along the way.

All individuals invited to the kick off meeting should be asked to forward the meeting notice to any other individuals they would like to have take part in the meeting.

It is expected that the study engineer will prepare minutes of this meeting. Minutes will be shared with all those invited to participate in the meeting.

4.4. Detailed System Assessment / Engineering Analysis

The study engineer will utilize input received at the study kickoff meeting in subsequent detailed analysis and comprehensive plan development. All area distribution studies will require the same basic analysis steps.

The study engineer should look to optimize existing system performance and identify any common infrastructure development needs of the area prior to engaging in the detailed analysis associated with finalizing the development of alternative plans. Simple no-cost or low-cost system adjustments such as switching or load balancing can be progressed immediately by the planner and do not need to be formally included in the study report. Instead the study base case should be adjusted to include these simple changes.

The study engineer should:

- Conduct system fault studies, associated protective device coordination, and breaker capability reviews
- Conduct incident energy calculations (arc flash)
- Conduct system thermal assessments
- Conduct system loss studies
- Conduct system reliability assessments
- Conduct system voltage performance evaluation
- Analyze Distributed Energy Resources (DER) impacts

Typical Analysis tools:

- PSS/e load flow software for analysis of:
  - Supply system (transmission and sub-transmission)
  - Network system
- CYME and other radial distribution feeder analysis software
- CYME, ASPEN, and other protective device coordination software including short circuit analysis
- ArcPro for Arc Flash analysis
- GIS systems
- Annual Planning Screening Spreadsheets
- Equipment ratings programs
- Cascade and other asset information systems

Note that the presentation of results and defense of recommendations is significantly enhanced by the functionality of these tools (particularly load flow and radial distribution feeder analysis software). These tools will strengthen response to questions posed during the review of recommendations. These tools enable quick evaluation of "what if" questions that could otherwise cause unacceptable delays in study delivery.

4.5. Plan Development and Project Estimating

Once the engineering analysis is performed, the study engineer develops and refines alternative infrastructure development and non-wires alternative plans and updates associated plan one-lines. The plans should be technically comparable to the furthest extent possible. Infrastructure and non-wires alternatives can be combined to create comparable plans.

The following team members/departments will provide a feasibility review of these one-lines:

- Field Engineer
- Substation Engineer
- Transmission Line Engineer
- Distribution Design Engineer
- Operations
- Transmission Planning

OPTIONAL - It is suggested the planner gather all internal stakeholders[6] at a Plan Development meeting to review and gain acceptance of the various plans immediately prior to requesting estimates. It is important that the various engineering functions understand the interrelationship between their individual portions of the comprehensive plans. Without this review, it is often difficult for the engineering functions to understand the segmented nature of estimate requests.[7]

As the one-lines and plans are modified with this cross functional input, engineering analysis will be refined as needed to accommodate for any scope changes. Once the plans and one-lines are completed, the study engineer will request study estimates from the respective team members (substation engineer, transmission line engineer, and distribution design engineer) for all alternative plans.[8]

It is expected that estimates will be returned within 8-12 weeks of the request date. Estimators will use primary equipment scope and known field conditions along with recent costs for comparable projects to develop estimates. Field visits are not required, but are encouraged especially if constructability or future system maintenance (ex. R/W accessibility) is a concern. Estimates are expected to be suitable for plan comparison/selection and enable initial partial sanction of more detailed engineering activities. Substation and transmission line conceptual engineering reports and estimates may be requested if they can be completed within the 8-12 weeks. Distribution line estimates can be completed by the planner using the Company's Success Enterprise estimating tool and can be considered at a conceptual level of accuracy.

Note: When considering alternate locations for a new substation. The site where a new substation will be constructed should be selected by the sponsor with input from the project team. Where alternate sites are required for regulatory reasons or are desirable for other reasons, those alternate sites should also be selected by the sponsor. In addition to the engineering requests, sites should be assessed for other flaws that could warrant them unsuitable for use. These "due diligence" assessments for potentially "fatal flaws" should be performed by the following departments and reported to the sponsor: Environmental, Real Estate, Legal (Siting), Project Management, and Construction or Operations.

While estimates are under development, the planner should organize and document the technical benefits and issue resolution of each alternative. The planner has discretion to the level of analysis for alternatives that are expected to be economically non-competitive.

Once the study estimates are returned, the study engineer will review and finalize the identified plans. Study team members will be asked to note their agreement with the scope of projects estimated.

[6] Similar to the kickoff meeting invite list
[7] For example a substation request that asks for a common item such as a capacitor bank to be estimated separately from a feeder position which may be an alternative plan.
[8] Requests should be well documented with clearly defined one-line scope diagrams, using

4.6. Identification of Recommended Plan

As part of this phase, the study engineer reviews the various alternatives with costs, identifies, and finalizes a recommended plan. Once the recommended plan is identified, the study engineer completes (with team member assistance as required):

- Economic comparison of plans
- Technical comparison of plans if not equivalent
- Performance of an environmental and safety review of recommended plan
- Identification of the system outages required to implement the recommended plan
- Statement or summary of alignment with Climate Resiliency standards[9]
- If not formally evaluated as a criteria, strategy, or program within the study, include a statement or summary of alignment with potential or pending Grid Modernization concepts.[10]
- Review of the recommended plan project implementation schedule[11]

The planner should summarize recommended plan risks to the furthest extent possible. For example, permitting or site acquisition delay risks could be noted with the system issues that may result. Potential mitigation concepts, including acceptance of risk, can be described. This is not intended to be an exhaustive review and it is noted that significant internal department consultation and support is necessary. Instead, this risk analysis is only intended to help or guide future efforts.

Once all this analysis is completed and documented, the study engineer updates the project team members on the final recommended plan.

4.7. Technical Review

This meeting will be held once the planner has completed the majority of the study analysis and after an internal review in Distribution Planning and Asset Management has been completed, but prior to the formal study document approval process.

The primary purpose of this meeting is to give those who will be asked to approve the area study report an opportunity to hear a presentation and ask their own questions on the overall study effort. It is expected that this meeting will facilitate the study report approval process that will in most instances follow soon after.

The presentation will provide a description of the issue identification efforts and a comparison of all plans, including estimated costs, describing the advantages and disadvantages of each.

The planner will cover the following topics in presentation format during the meeting. The presentation will be split (between Distribution Planning and Transmission Planning) if study responsibility is split.

- Study scope (electric system one-lines and map of area)
- Study area load and load growth
- Additional study assumptions
- System performance concerns identified (existing and predicted)
- Plans considered to address concerns with detailed description of the scope of proposed projects, time and cost required to implement, technical differences, as well as unresolved stakeholder concerns

[9] All recommendation should be built to the latest storm hardening and substation flood mitigation standards
[10] For example, use of latest controls that prevent near term obsolescence
[11] Consult with Long Term Resource Planning for implementation schedule and cash flow assistance.

- Plan recommended to address concerns with detailed description of the scope of proposed projects, time, and cost required to implement

Meeting participants are expected to constructively challenge study assumptions and analysis (ex. load growth assumptions, load flow models, equipment ratings, interpretation of planning criteria in determining violations, etc.) and the plans developed to address area concerns. If a specific project's scope of work is in question (ex. asset condition concerns not addressed) and can not be resolved in this meeting, the Study engineer will set up subsequent meetings with the project team for more detailed discussion and problem resolution.

The following groups/representatives are part of the Technical Review meeting governance:
- Asset Management (NY or NE), including:
  - Vice President Asset Management
  - Director Distribution Planning and Asset Management
  - Manager of Asset Management
  - Director of Transmission Planning and Asset Management
  - Manger of Transmission Planning
- Electrical Systems Engineering, including:
  - Vice President of Electrical Systems Engineering
  - Director of Substation Engineering Design
  - Director of Protection Engineering
  - Director of Transmission Line Engineering
- Operations (NY or NE), including:
  - Vice President of Operations
  - Director of Distribution Design
  - Director of Overhead Lines
  - Director and Manager of Substation O&M
- Dispatch and Control, including:
  - Vice President of Control Center Operations
- Jurisdictional Leadership, including:
  - Jurisdictional President
  - Community and Customer Management, Director
- Representatives assigned from all groups that are supporting the study (attendance required)

4.8. Documentation

The area study report is the primary documentation delivered upon completion of the area study. This report becomes a source document for many other forms and reports (used both internally and externally). As such, the importance of form and order in reports be as consistent as possible.

In order to properly complete the report template, the study engineer will need to have done the work necessary to prepare the following general report sections:
- <u>Executive summary</u>, including:
  - Explanation of why the study was done and the major concerns/needs for the area
  - A brief description of the alternatives considered
  - A brief description of the recommended plan
  - Reasons for the recommendation
  - Cost and cash flow of the recommended plan
- <u>Introduction</u>, including:
  - Purpose statement
  - Problem statement

- Background, including:
  - A statement on all items gathered in Section 4.1
  - Versions or dates of guidelines, standards, forecasts, databases, screening work, and software used
- Problem/Issue Identification, including:
  - A summary of all analysis done in Sections 4.2 and 4.4
- Plan Development, including:
  - A summary of all efforts done in Section 4.5
- Description of recommended plan, including:
  - A summary of the comparative analysis and conclusions made during Section 4.6
  - A clear summary of the sequencing of projects, project dependencies, proposed cash flow, and risks.
- Conclusion and factors affecting future studies
- Appendices, including but not limited to:
  - Geographic study area maps
  - One-line diagrams for stations, sub-transmission systems, and circuit tie maps - base case and recommended plan
  - Feeder rating sheets
  - Existing and in-queue Distributed Generation tables
  - Annual Plan screening tables – base case and recommended plan
  - CYME, PSSE, and Aspen screens and tabular exports - base case and recommended plan
  - Strategy or program tabular details including criticality rankings
  - Arc flash tables - base case and recommended plan
  - Reliability indices tables
  - Fault duty analysis tables - base case and recommended plan
  - Estimate data

Appendix A and B of this document provide a detailed outline of area study and program study report content respectively.

Study reports will be issued following the Study Results presentation (and resolution of any issues it raised). The report will be electronically issued with a cover letter to the following individuals for approval:

- Respective Manager of Distribution Asset Management
- Respective Director of Distribution Planning and Asset Management
- Vice President Asset Management

The study report will be electronically stored on Distribution Planning and Asset Management's SharePoint site.

It is expected that the Customer and Community Management group will communicate the recommended plan with external stakeholders as appropriate. Consultation with jurisdictional leader for approval of the external communication plans is required.

4.9. Sanctioning

Per the National Grid US Sanctioning Committee (USSC) Procedure, all investments must receive proper Delegation of Authority (DOA). The National Grid US Sanctioning Committee procedure and document templates can be found on the Investment Planning website.

It is expected that the study engineer will, upon study approval, seek initial sanction of any recommended projects having forecasted spending within the next three fiscal years. Long Term Resource Planning will track and schedule initial sanctioning activities for all projects that will be initiated beyond the first two full fiscal years from study completion.

5. Appendix A

Study Report Table of Contents

1. Executive Summary
2. Introduction
- **2.1 Purpose**
- **2.2 Problem**

3. Background
- **3.1 Scope**
  - **3.1.1 Geographic Scope**
  - **3.1.2 Electrical Scope**
- **3.2 Area Load and Load Forecast**
- **3.3 Active Projects**
- **3.4 Limitations on Infrastructure Development**
- **3.5 Assumptions & Guidelines**
- **3.6 Spot Loads**
- **3.7 Existing and In-queue Distributed Generation**
- **3.8 State Policies or Programs**

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- **4.1 Thermal Loading**
- **4.2 Voltage Performance**
- **4.3 Asset Condition**
- **4.4 Additional Analysis**
  - **4.4.1 Reliability Performance**
  - **4.4.2 Arc Flash**
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  - **4.4.5 Protective Coordination**

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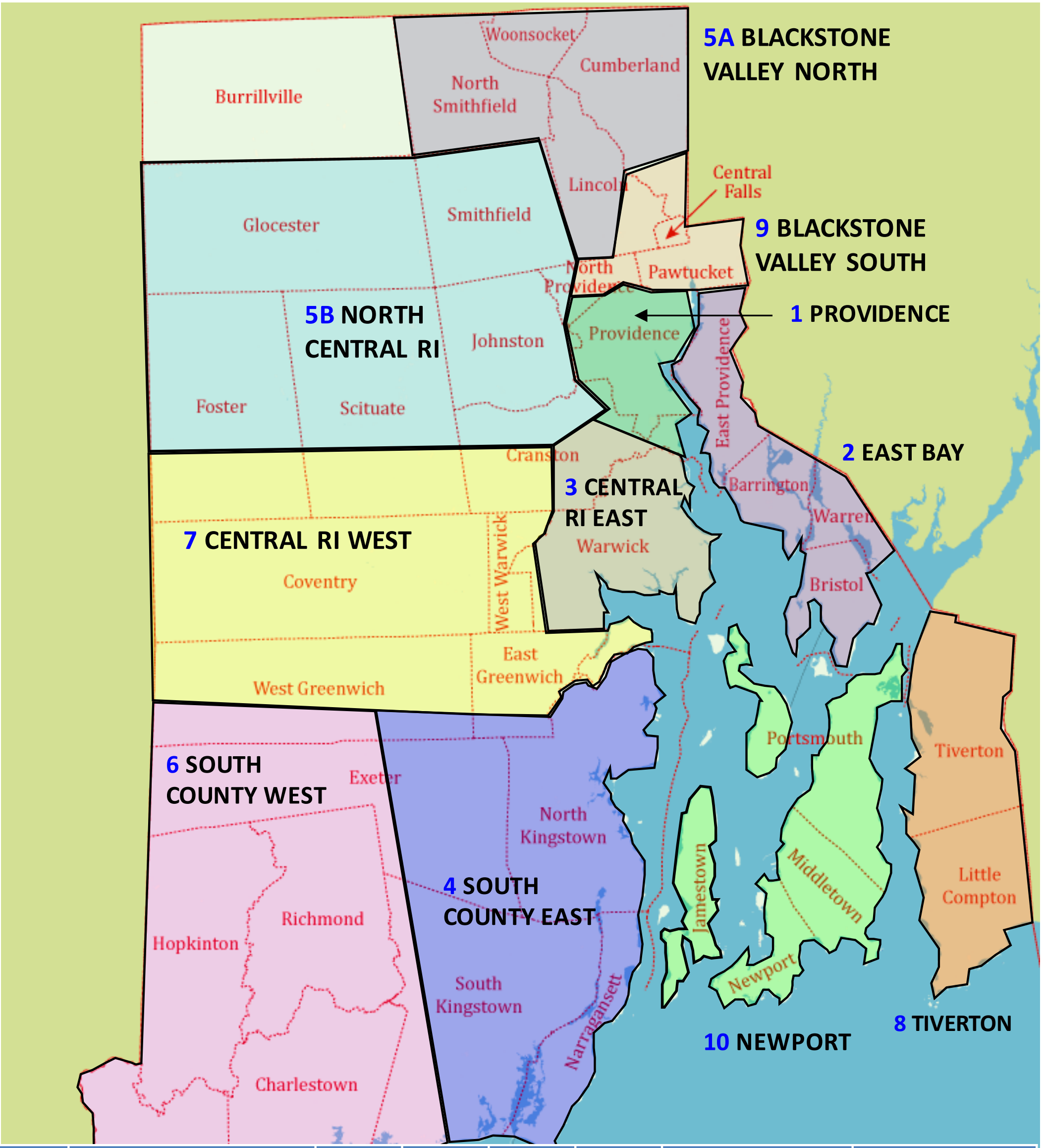
- **5.1 Common Items**
- **5.2 Plan – 1**
- **5.3 Alternative Plans**
  - **5.3.1 Plan – 2**
  - **5.3.2 Plan – 3**
  - **5.3.3 Do Nothing**

6. Plan Considerations and Comparisons
- **6.1 Economic, Schedule, and Technical Comparisons**
- **6.2 Permitting, Licensing, Real Estate, and Environmental Considerations**
- **6.3 Planned Outage Considerations**
- **6.4 Asset Physical Security Considerations**
- **6.5 Climate Resiliency**
- **6.6 Grid Modernization**

7. Conclusions and Recommendations
8. Factors Influencing Futures Studies
9. Appendix

Appendix B

Program Report Table of Contents



Rank	Study Area	Load (MVA)	% State Load	# Feeders	# Stations	Annual Planning Review % Complete	Area Planning Study % Complete
1	Providence	358	19%	95	17	100%	100%
2	East Bay	147	8%	22	7	100%	100%
3	Central Rhode Island East	204	11%	37	9	100%	100%
4	South County East	159	9%	22	9	100%	100%
5A	Blackstone Valley North	139	8%	27	6	100%	85%
5B	North Central Rhode Island	269	15%	35	10	100%	85%
6	South County West	98	5%	14	5	100%	40%
7	Central Rhode Island West	167	9%	33	11	100%	40%
8	Tiverton	28	2%	4	1	100%	40%
9	Blackstone Valley South	171	9%	54	11	100%	10%
10	Newport	105	6%	42	12	100%	0%
	Totals	1845	100%	385	98	100%	70%[i]

[i] Percent complete based on total state load studied.

1 PROVIDENCE
Concerns:
-Asset condition concerns.
-Capacity to supply load growth in an urban environment.
Resolutions:
-Long Term Study complete.
- Study completed May 2017.

2 EAST BAY
Concerns:
-Normal and contingency capacity issues.
-Asset condition concerns.
Resolutions:
-Study completed August 2015.

3 CENTRAL RI EAST
Concerns:
-Normal and contingency capacity issues.
-Long term capacity plan needed to supply eastern Warwick.
-Flood risk at Sockanosett (pending solution in Providence study).
-Contingency issues at Kilvert St. (solution in progress).
Resolutions:
-On-going Kilvert St substation project will address contingency issues.
-Study completed February 2017.

4 SOUTH COUNTY EAST
Concerns:
-Potential feeder MWh violations.
-Potential MWh violations at Tower Hill.
Resolutions:
-Solutions outlined in recently completed study (2018) will address issues in area.

5A BLACKSTONE VALLEY NORTH (Northwest RI)
Concerns:
-Contingency MWHR violation on the Nasonville issues.
-Asset Condition concerns at Centerdale and Greenville.
-Municipal Electric Stakeholder.
Resolutions:
- On-going study to resolve issues.

5B NORTH CENTRAL RI (Northwest RI)
Concerns:
-Normal and contingency capacity issues.
-Asset condition concerns.
Resolutions:
-Conducted in concert with Blackstone Valley North Study.
- On-going study to resolve issues.

6 SOUTH COUNTY WEST
Concerns:
-Contingency capacity issues.
-Flooding concerns at Westerly Substation.
-Westerly Substation islanded in terms of phasing from surrounding area.
-Voltage concerns & reliability issues on feeders supplying Hopkinton and Richmond area.
Resolutions:
-Recently completed Chase Hill Substation has assisted in addressing capacity issues.
-On-going area study to outline and identify solutions to resolve remaining issues.

7 CENTRAL RI WEST
Concerns:
-Contingency capacity issues Divisions Street.
-Asset condition concerns at Arctic. (resolved, substation retired)
-Contingency issues at Kent County. (resolved)
-Asset, flood risk, & environmental concerns at Hunt River. (resolved, substation retired)
-Asset condition issues at several other sub transmission supplied stations, such as Anthony and Coventry.
Resolutions:
-Completed New London Ave substation project has addressed asset condition concerns at Arctic.
-Completed Kent County substation project has addressed contingency issues and Hunt River issues.
-On-going area study to outline and identify solutions to resolve remaining issues.

8 TIVERTON
Concerns:
-Feeders exceeding 90% of thermal rating.
-Contingency capacity issues on transformer and feeder level.
-Reliability issues due to bare open wire construction in heavily treed areas of Little Compton.
Resolutions:
-On-going area study to outline and identify solutions to resolve remaining issues.

9 BLACKSTONE VALLEY SOUTH
Concerns:
-Asset condition concerns at Pawtucket No 1 Indoor substation. (solution in progress)
-Asset condition concerns at Pawtucket No 2 Indoor substation.
-Normal and contingency capacity issues at Pawtucket No 1. (pending solution)
Resolutions:
-On-going Southeast substation project will address all asset and capacity issues at Pawtucket No 1.
-Additional concerns to be reviewed during the study include asset condition and capacity issues at Pawtucket No. 2 indoor substation.

10 NEWPORT
Concerns:
-Normal and contingency capacity issues. (solution in progress)
-Asset condition concerns at Vernon & Bailey Brook. (solution in progress)
-Subtransmission capacity concerns. (solution in progress)
Resolutions:
-On-going area reconfiguration and new substations (Newport and rebuilt Jepson) should address most issues in area.
-Any remaining concerns will be reviewed in a to be kicked off area study after existing conversion and rebuild is complete.

This document has been redacted for Critical Energy Infrastructure Information (CEII). 11/01/2019

South County East Area Study

Jack P. Vaz, PE

March 2018

Reviewed by: ______________________________ Date: ____________________
Elton Prifti, Distribution Planning & Asset Manager – New England, Electric Asset Management

Approved by: ______________________________ Date: ____________________
Alan LaBarre, Director, Distribution Planning and Asset Management, NE, Electric Asset Management

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LEGEND	
Al	Aluminum wire or cable
ARP	Asset Replacement Program
Cal/cm^2	Calories/square centimeter
Capex	Capital expenditure (budget expenditure type)
CKAIFI	Circuit Average Interruption Frequency Index
CKAIDI	Circuit Average Interruption Duration Index
Cu	Copper wire or cable
DPG	Distribution Planning Guide rev 1, dated February 2011
EMS	Energy Management System
GIS	Geographic Information System
ISO	Independent System Operator
kV	Kilovolts
LTC	Load Tap Changer
MVA	Megavolt Ampere
MVAR	Megavolt Ampere Reactive
MW	Megawatts
MWh	Megawatt hour
MOV	Metal-Oxide Varistor
NE	New England
Opex	Operations/Maintenance expenditure (budget expenditure type)
PEX	Process Excellence
PT	Potential Transformer
RAPR	Remote Access Pulse Recorder
RI	Rhode Island
PUC	Public Utility Commission
SN	Summer Normal Rating of Equipment
SE	Summer Emergency Rating of Equipment

1. Executive Summary

A comprehensive study of the South County East area was performed to identify existing and potential future distribution system performance concerns. System evaluation included comparison of equipment loading to thermal limits, contingency response capability, voltage performance, breaker operating capability, arc flash, reactive compensation performance, asset condition, and safety and environmental issues. The recommendations provide a comprehensive solution to address all the known system performance concerns in the study area thru 2031.

This study was conducted using the latest methods resulting from a Process Excellence ("PEX") review of project sponsorship. Engineering, Design, Project Estimating, Operations, Resource Planning, Project Management, Permitting, Licensing, Community and Customer Management, Transmission Planning, and other internal departments were consulted during initial study scoping as well as throughout problem identification and solution development. Such consultation was gathered at an investment grade or high level to explore feasibility of the alternatives and gather economic data sufficient to make investment decisions.

Common to all plans is a recommendation for a non-wires solution to be explored in detail to address various feeder overloads and to compare it to a wires solution. Both the wires solution and the non-wires option is documented in section 5.2 of this report. The investments have been developed at a town level to offer maximum flexibility in implementing either a wires solution or a non-wires solution to address the projected overloads. A cash flow will be established once the non-wires solution is developed and compared to the wires solution.

The recommended plan is to build a new 115/12.47 kV substation at the existing Lafayette substation site consisting of a single 115/12.47 kV 24/32/40 MVA transformer, (4) regulated feeders, and (1) 7.2 MVAr station capacitor bank. The preferred arrangement of the station is open air, low profile, with a breaker-and-one-half design. The cost of the recommended plan is \$19.53M. The estimated spending forecast is shown in Table 1 below.

Table 1 – Estimated Forecasted Spending – Recommended Plan (\$M)

	TOTAL	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28
Capex	14.20	0.14	0.71	2.84	4.26	4.26	1.99	0.00		
Opex	0.13	0.00	0.01	0.03	0.04	0.04	0.02	0.00		
Removal	5.20	0.00	0.02	0.08	0.12	0.60	0.54	3.84		
Total	19.53	0.15	0.74	2.94	4.42	4.90	2.54	3.84		

The recommended plan, combined with the common items, provides a comprehensive solution to address all the known system concerns existing and anticipated in the study area thru 2031.

2. Introduction

2.1 Purpose

A comprehensive study of the South County East area was performed to identify existing and potential future distribution system performance concerns. System evaluation included comparison of equipment loading to thermal limits, contingency response capability, voltage performance, breaker operating capability, arc flash, reactive compensation performance, asset condition, and safety and environmental issues. The recommendations provide a comprehensive solution to address all the known system performance concerns in the study area thru 2031.

2.2 Problem

A study's initial system assessment is typically based on the needs identified through the Annual Planning process. The latest Annual Planning review showed a variety of normal and contingency capacity issues in the South County East area. Furthermore, informal asset condition reviews and inspection results indicated there may be growing asset condition concerns. This study is being performed to recommend prudent and comprehensive solutions to provide adequate, reliable and economic service to the customers in this area.

3. Background

3.1 Scope

3.1.1 Geographic Scope

The South County East study area consists of the towns of North Kingstown, South Kingstown, Narragansett and sections of East and West Greenwich, Exeter, Richmond and Charlestown. The study area is shown geographically in Appendix 9.1.

3.1.2 Electrical Scope

The South County East area is supplied by 115 kV transmission lines from Kent County substation in Rhode Island (G-185S & L-190) and from the Northeast Utilities (NU) Montville substation in Connecticut (1870 & 1870N) and by five 34.5 kV sub-transmission lines (3302, 3307, 3308, 3312 and 84T3). Two 115/12.47 kV substations (Old Baptist and Tower Hill) supply approximately 14,300 customers and 71 MW of peak load.

West Kingston is a 115/34.5 kV station. It has two non-regulated 34.5 kV supply lines which supply URI and supply Peacedale, Wakefield and Bonnet substations. These lines also interconnect a 30 MW offshore wind farm and supply Block Island Power Company (BIPCo). The station supplies approximately 17,280 customers and 67 MW of peak load.

Davisville is a 115/34.5 kV station with four voltage regulated 34.5 kV supply lines. These lines supply Quonset substation and supply industrial customers. The station supplies approximately 1,600 customers and a peak load of 30 MW.

The Kent County 115/34.5 kV station also supplies load in the South County East area. It is the normal supply to Lafayette substation which has two regulated modular feeders. Lafayette supplies approximately 3,635 customers with a peak load of 16 MW of load.

3.2 Area Load and Load Forecast

The study area has approximately 36,800 customers and a peak electrical demand of 184 MW. The study area is summer peaking and summer limited. This study used the most recent forecast developed by National Grid, the "2017 New England Electric Peak Forecast". It utilized the 95/5 extreme weather scenario case. Table 3.2.1 shows the forecasted load growth rate for the study area from 2017 to 2031.

TABLE 3.2.1 – Forecasted Load Growth Rate from 2017 to 2031 for Study Area

2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
-0.3%	0.1%	0.2%	0.5%	0.6%	0.6%	0.6%	0.6%	0.6%	0.7%	0.7%	0.7%	0.7%	0.7%

Spot loads have been considered in this study to account for the proposed expansion at Electric Boat (EB) and Toray Plastics America (Toray). This study assumed a total of 28.8 MW of new spot loads as follows:

- EB has requested National Grid supply approximately 16 MW of new load. This expansion is projected to occur over the next ten years. The new load will be supplied from either the 12.47kV distribution system or the 34.5kV sub-transmission system.
- Toray is also planning a major expansion and is projecting 12.8 MW of new spot loads. This expansion will be supplied from the 34.5kV sub-transmission system.

The projected peak electrical demand by year 2031, or the end of the study horizon period, is approximately 216 MW. This projected peak demand was adjusted to account for existing and pending distributed generation totaling approximately 66 MW. The study assumed 39 MW of this generation would be available during peak loading conditions to reduce demand on the system. Section 5.1 has an analysis on how area DG was used in plan development and to adjust the projected peak area load.

3.3 Active Projects

There are two substation projects presently active in this study area, Quonset Substation expansion and Davisville EMS expansion. Quonset substation is being expanded to provide capacity to supply the proposed expansion at EB and to mitigate MWh exposure and unserved load risk. EMS is being installed at Davisville which the supply station to the Quonset area.

There is an active project to refurbish the 3307 and 3308 sub-transmission supply lines from West Kingston. These lines we originally built in the 1960's. A large portion of the structures, especially on the mainline, are original construction and inspection results indicated that nearly 60% of these mainline structures are exhibiting significant deterioration and pose a risk of failure. In addition to supplying the University of Rhode Island and National Grid substations, these lines supply the off-shore wind farm and the Block Island Power Company (BIPCo). Both of these lines are FERC-T assets.

3.4 Limitations on Infrastructure Development

Most of the load in the study area is supplied from a highly utilized 34.5 kV sub-transmission system that needs relief. Of the 184 MW of peak load in the study area, approximately 113 MW is supplied from the 34.5 kV system. There are three main supplies to this 34.5 kV system:

- Kent County substation supplies Lafayette substation and two industrial customers with a single 34.5 kV line. The bulk of the 3312 line equipment was installed in the 1930's and consists of mostly small wire. Any expansion of this system will require a complete refurbishment of this line and replacement of the small wire.

- West Kingston substation is loaded to its maximum capability. Loading on both the transformers and supply lines exceeds SE ratings for an n-1 contingency. It will be challenging and costly to increase the capacity of this station beyond what it is today.

- Davisville substation is also loaded to its maximum capability. Loading on both transformers is projected to exceed the SE ratings for an n-1 contingency. Any expansion at Davisville will required a major upgrade to the station.

Outside of expanding the 34.5 kV system, the only other system expansion potential would be new stations supplied from the 115 kV transmission system.

3.5 Assumptions & Guidelines

The current Distribution Planning Guide rev 1, February 2011 ("DPG") was used in performing this study. The guide describes the normal and contingency analysis, as well as considerations for safety, the environment, reliability, reactive compensation, load balance, voltage, and efficiency, used in National Grid's distribution planning studies.

The Distribution Planning & Asset Management department uses the Siemens PTI PSS/e loadflow program to analyze the transmission and sub-transmission system. This is the same program used by ISO NE and the National Grid Transmission Planning department.

The CYMdist 5.04 Revision 5.0 program was used to analyze radial three-phase unbalanced systems (distribution feeders). Databases were extracted from the GE-SmallWorld GIS System into a Microsoft Access format. The arc flash module of this program was used for relevant arc flash analysis.

The ASPEN OneLiner program was used to determine short circuit duty values at all substations. This is the same program used by National Grid Protection Engineering for all short circuit and relay coordination studies.

4. Problem Identification

4.1 Thermal Loading

4.1.1 Normal Configuration - Thermal Loading

Feeders: Loading on distribution line sections of each feeder was analyzed using the CYMdist software. Three feeders are projected to be loaded above SN limits during the study horizon period (42F1, 59F3, and 17F2). Additionally, sections on the Lafayette 30F2 feeder are also projected to be loaded above SN limits. Appendix 9.3 shows the loading on area feeders and the CYME analysis is shown in Appendix 9.4

Transformers: Loading on the Bonnet T2 transformer is projected to be loaded above SN limits during the study horizon period. There are no other projected transformer normal configuration overloads within the study period. Appendix 9.3 shows the loading on the area transformers.

Supply Lines: There are no projected supply line normal configuration overloads within the study area for the analysis period.

4.1.2 Contingency Configuration - Thermal Loading

Feeders: A contingency analysis was performed for all feeders in the study area. This analysis calculates a MWh 'exposure' or risk assuming a worst case component failure during summer peak (extreme weather) loading conditions. The assumptions made for this analysis were:

- A one-hour response time before performing the first switching step and 30-minutes to execute each additional switching step.
- Assumes a failed component can be repaired within four hours. Some feeders have underground cable getaways which may require a longer repair time. Because this exposure is small, a cable failure was not assumed in the analysis.
- Some feeders are double circuited on the same pole plant. Because this exposure is small, a failure involving two feeders was not assumed in the analysis.
- The MWh calculations utilize the summer emergency ratings of the feeders.

Five feeders were calculated to have a MWh "exposure" in excess of the Distribution Planning Criteria. Appendix 9.3 shows the MWh exposure for each feeder in the study area.

Transformers: A contingency analysis was performed for all station power transformers in the study area. This analysis calculates a MWh 'exposure' or risk assuming a worst case component failure during summer peak (extreme weather) loading conditions. Appendix 9.3 shows the loading on the area transformers.

By 2031, the Davisville substation transformers are projected to be loaded to approximately 115% of their SE rating for an n-1 contingency. Although this loading is not a violation of the DPG, it is noted here as a risk of un-served load for loss of either transformer or supply line.

By 2031, the West Kingston T1 transformer is projected to be loaded to 130% of its SE rating. Loss of the T2 transformer requires the company to drop the offshore wind farm from operation until the transformer is restored to normal operation or replaced. This is noted here as a risk of un-served load and the potential to have an extended outage to the windfarm.

Tower Hill is a single transformer station with four 12.47 kV feeders and approximately 36 MW of load. For loss of the station transformer, there is approximately 19 MW of unserved load exposure during peak load conditions (or 495 MWh of exposure). The unserved load exposure exceeds the recommendations in the DPG.

Supply Lines: A contingency analysis was performed for all supply lines in the study area. This analysis calculates a MWh 'exposure' or risk assuming a worst case component failure during summer peak loading conditions.

By 2031, the loss of either the 3307 or 3308 supply lines from West Kingston would result in the remaining supply line exceeding its SE rating. However, this projected overload is not a violation of the DPG, but it is noted here only as a potential risk of un-served load.

4.2 Voltage Performance

The DPG recommends that customer service voltages be maintained to meet ANSI 84.1 guidelines. ANSI 84.1 requires that service voltages be maintained between 0.95 and 1.05 per unit during normal loading conditions and between 0.90 and 1.05 per unit during contingency loading conditions. The ability to adjust transformer tap settings combined with voltage regulation equipment allows the supply system to vary greater than the required service voltage range. However for study purposes, the supply system was screened for potential issues using the ANSI 84.1 ranges.

The PSS/e load flow program was used to model the electrical system down to the 34.5 kV sub-transmission level including step-down transformers to the distribution feeder level. See Appendix 9.3 for loadflow diagrams. No voltage violations we identified in this PSS/e analysis. Moreover, there is no history of known voltage violations in this area.

The CYME program models all three phases of each distribution feeder for its entire length starting at the substation. Voltages at all points should be maintained between the range of 0.95 to 1.05 per unit, or from 114 volts to 126 volts on a 120 volt base. Minor violations were identified which can be mitigated using a combination of feeder balancing, line upgrades, or a non-wires solution. See Appendix 9.4 for CYME diagrams.

4.3 Asset Condition

Transformers: Substation O&M services department performed asset condition assessments for each substation in the study area. No transformers were identified as having any asset condition concerns during the study period.

Supply Lines: There are two 34.5 kV supply lines in the area built in the 1930's (Davisville 84T3 & Kent County 3312). A condition assessment was performed on these lines with support from local operations and distribution design. Large portions of these lines are installed in rights-of-way (ROW) with limited access or thru backyards with restricted access. The ROW contains wetlands and water crossings. It is challenging for the company to maintain these lines due to wetland impacts and restrictive backyard construction. A visual inspection of the lines identified significant deterioration on the pole plant and associated equipment. Table 4.3.1 has the pole data for both of these lines which was obtained from company records.

Table 4.3.1 – 84T3 Line and 3312 Line Pole Data

84T3 Line		
# of Poles	Age Range	% of Total
48	0 to 40	19%
101	40 to 60	39%
110	60 plus	42%
259	Total	100%

3312 Line		
# of Poles	Age Range	% of Total
89	0 to 40	35%
52	40 to 60	21%
110	60 plus	44%
251	Total	100%

4.4 Reliability Performance

A reliability review was conducted to check feeder indices against system targets. For calendar year 2016, the CKAIFI target was 1.05 and CKAIDI target was 71.9 minutes. CKAIFI or "Circuit Average Interruption Frequency Index" means the total number of customer interruptions divided by the total number of customers connected to the circuit, expressed in average number of interruptions per year. CKAIDI or "Circuit Average Interruption Duration Index" is defined as the total minutes of customer interruptions for a circuit divided by the total number of customers connected to the circuit, expressed in minutes per year. Table 4.4.1 below lists the three year CKAIFI and CKAIDI reliability data for all the feeders in the study area.

TABLE 4.4.1 – Study Area Reliability Indices

STATION	FEEDER	2013		2014		2015		AVERAGE	
		CKAIFI	CKAIDI	CKAIFI	CKAIDI	CKAIFI	CKAIDI	CKAIFI	CKAIDI
Bonnet	42F1	0.32	16	0.10	16	0.14	17	0.19	16
Lafayette	30F1	0.33	29	2.09	156	2.89	108	1.77	98
Lafayette	30F2	1.45	194	1.34	150	3.78	341	2.19	228
Old Baptist	46F1	1.28	52	1.68	59	1.40	150	1.46	87
Old Baptist	46F2	1.25	186	0.12	15	0.34	47	0.57	83
Old Baptist	46F3	0.10	16	1.02	4	2.64	289	1.25	103
Old Baptist	46F4	1.30	165	0.13	27	0.06	11	0.50	68
Peacedale	59F1	1.04	173	2.27	195	0.34	40	1.22	136
Peacedale	59F2	0.09	42	3.13	201	0.15	14	1.12	86
Peacedale	59F3	1.18	118	2.11	152	0.67	77	1.32	116
Peacedale	59F4	0.93	187	2.13	149	0.05	4	1.03	113
Quonset	83F1	0.00	0	1.00	235	0.00	0	0.33	78
Quonset	83F2	0.01	0	1.03	47	0.07	2	0.37	16
Quonset	83F3	0.00	0	1.00	109	0.00	0	0.33	36
Tower Hill	88F1	0.82	72	2.21	101	0.71	87	1.25	87
Tower Hill	88F2	0.92	77	1.21	82	1.05	104	1.06	88
Tower Hill	88F3	0.99	85	1.93	84	0.26	32	1.06	67
Wakefield	17F1	1.20	51	1.14	108	0.95	158	1.10	106
Wakefield	17F2	0.12	14	1.08	98	0.88	109	0.70	73
Wakefield	17F3	0.04	5	1.07	69	0.23	10	0.45	28

Over the last three years the 3312 line has experienced a number of outages. Generally, an outage on the 3312 line resulted in an outage on the under-built 12.47kV circuit. As documented in section 4.3, a visual inspection has identified significant deterioration on the pole plant and associated equipment on this line. Table 4.4.2 shows the IDS outage data.

TABLE 4.4.2 – 3312 Supply line Outage Data

Substation	Feeder	Time Off	Time On	Duration	Cust. Int.	Cust. Hrs.	CMI
Date: 02/07/2014		Classification: Sub-Transmission - Insulator Failure on 3312 Line					
Lafayette 30	56-30F1	11:17	12:44	01H 27M	1562	2265	135,900
Lafayette 30	56-30F2	11:17	12:44	01H 27M	2216	3213	192,780
	56-3312	11:17	13:20	02H 02M	1	2	120
Hunt River 40	56-40F1	11:17	12:59	01H 42M	849	1443	86,580
Hunt River 40	56-40F1	11:17	16:15	04H 57M	178	881	52,860
Hunt River 40	56-40F1	11:17	18:28	07H 10M	3	22	1,320
					4809	7826	469,560
Date: 06/23/2015		Classification: Sub-Transmission - Tree Fell on 3312 Line					
Lafayette 30	56-30F1	20:01	20:56	00H 54M	1335	1202	72,120
Lafayette 30	56-30F2	20:01	20:56	00H 54M	594	535	32,100
	56-3312	20:01	21:30	01H 28M	1	1	60
Old Baptist Rd 46	56-46F3	17:46	21:12	03H 25M	767	2621	157,260
Old Baptist Rd 46	56-46F3	20:01	20:59	00H 57M	56	53	3,180
Old Baptist Rd 46	56-46F3	20:01	22:50	02H 48M	1111	3111	186,660
					3864	7523	451,380
Date: 11/19/2015		Classification: Sub-Transmission - Tree Fell on 3312 Line					
Lafayette 30	56-30F1	13:20	13:40	00H 20M	1336	445	26,700
Lafayette 30	56-30F2	13:20	13:40	00H 20M	1801	600	36,000
	56-3312	13:20	13:53	00H 33M	1	1	60
					3138	1046	62,760
TOTALS					11,811		983,700

4.4.1 Arc Flash

Refer to Appendix 9.5.

4.4.2 Fault Duty/Short Circuit Availability

The ASPEN program was used to calculate single phase to ground and three phase short circuit current values at each area substation. These short circuit current values were compared to the station breaker interrupting capabilities. The table in Appendix 9.6 summarizes the results of this analysis. There were no short circuit current values in access of breaker interrupting capabilities identified by this analysis.

4.4.3 Reactive Compensation

Refer to Appendix 9.12.

5. Plan Development

5.1 Consideration of Distributed Generation in Plan Development

The impact of existing and planned distributed generation ("DG") installations was considered in the plan formation. Appendix 9.11 lists the existing and proposed DG within the study area. This study makes several assumptions on DG availability during peak hours to avoid infrastructure upgrades. The assumptions are as follows:

- Offshore Wind Generation: A 30 MW offshore wind farm has been recently placed in service (December 2016). A review was performed to correlate wind farm generation to wind availability. Wind data was obtained from weather underground for summer 2016 and generation data was obtained for the days the wind farm has been in operation. Wind data was used to project potential wind farm generation during summer peak loading periods. Based on the results of this review, this study assumes 15 MW of wind generation will be available during summer peak loading periods.

- Combined Heat/Power Natural Gas Generation: This area has a total of 20.5 MW of Combined Heat/Power (CHP) natural gas generation. A review was performed to correlate CHP generation to summer peak loading periods. This review concluded that CHP generation operates near nameplate capability with minimal downtime. Based on the results of this review, the study assumes 20.5 MW of CHP generation will be available during summer peak loading periods.

- Solar Generation: This area has approximately 13 MW of pending solar generation. A review was performed using a company owned solar site to correlate solar generation to summer peak loading periods. Weather data obtained from weather underground was utilized for this analysis. Based on this review, the study assumes that approximately 25% of solar generation will be available during summer peak loading periods.

West Kingston Supply: The 34.5 kV supply system from West Kingston substation is highly utilized. To defer infrastructure improvements, this study assumes 17 MW (37 MW total) of DG will be available during summer peak periods which defers the need for major system improvements in this system.

Davisville Supply: The 34.5 kV supply system from Davisville substation is highly utilized. To defer infrastructure improvements, the study assumes approximately 21 MW (24 MW total) of DG will be available during summer peak periods which defers the need for major system improvements in this system.

5.2 Common Items

This area has a number of projected feeder overloads during the study horizon period. To address these overloads both a wires solution and a non-wires option was developed. The investments were developed at a town level to offer maximum flexibility in implementing either a wires solution or a non-wires solution. The recommendation in this study is to further develop the non-wires option. Once the cost and feasibility of the non-wires option is better defined it can be compared against the wires solution. An economic decision can be made at that time as to the most prudent option to implement. A cash flow can be established once the anticipated non-wires costs are defined.

Town of Narragansett: Narragansett is supplied mostly by (4) 12.47 kV distribution feeders. Two feeders, 42F1 and 17F2, are projected to be loaded above SN ratings and lack feeder ties with capacity to reduce loading below ratings. Either more capacity is required or load must be reduced in this area. Two options were developed to address these projected overloads.

Wires Option – This option upgrades the Wakefield 17F2 feeder and modifies the 17F3 feeder. Investment would increase feeder capacity and provide additional switching flexibility to relieve the heavily loaded facilities. The estimated cost of this option is:

Description	Capex ($M)	Opex ($M)	Removal ($M)
17F2 Feeder Upgrade	$1.5900	$0.0000	$0.1700
17F3 Feeder Relief	$0.5700	$0.0000	$0.1300
TOTAL	$2.1600	$0.0000	$0.3000

Non-Wires Option – For this option to be comparable to the wires option, the load in the Town of Narragansett needs to be reduced by 3.0 MW (or 7%) from 43.4 MW to 40.4 MW.

The tables below show the projected loading on the existing system assuming no investments, the projected loading for the wires option, and the projected loading for the non-wires option.

TABLE 5.2.1 - Projected Feeder Loading (No Investments)

Substation	Feeder	SN Rating (Amps)	Projected Loading (No Investments)							
			2021		2022		2024		2030	
			Amps	%SN	Amps	%SN	Amps	%SN	Amps	%SN
BONNET	42F1	525	519	99%	522	99%	529	101%	550	105%
WAKEFIELD	17F1	602	475	79%	478	79%	483	80%	503	84%
WAKEFIELD	17F2	510	512	100%	515	101%	521	102%	542	106%
WAKEFIELD	17F3	597	491	82%	494	83%	500	84%	520	87%
TOTAL (MW)			43.1		43.4		43.9		45.7	

TABLE 5.2.2 - Projected Feeder Loading (Wires Option)

Substation	Feeder	SN Rating (Amps)	Projected Loading (Wires Option)							
			2021		2022		2024		2030	
			Amps	%SN	Amps	%SN	Amps	%SN	Amps	%SN
BONNET	42F1	525	519	99%	482	92%	488	93%	508	97%
WAKEFIELD	17F1	602	475	79%	478	79%	483	80%	503	84%
WAKEFIELD	17F2	600	512	100%	515	86%	521	87%	542	90%
WAKEFIELD	17F3	597	491	82%	534	89%	540	91%	562	94%
TOTAL (MW)			43.1		43.4		43.9		45.7	

TABLE 5.2.3 - Projected Feeder Loading (Non- Wires Option)

Substation	Feeder	SN Rating (Amps)	Projected Loading (Non-Wires Option)							
			2021		2022		2024		2030	
			Amps	%SN	Amps	%SN	Amps	%SN	Amps	%SN
BONNET	42F1	525	519	99%	486	93%	492	94%	512	97%
WAKEFIELD	17F1	602	475	79%	444	74%	450	75%	468	78%
WAKEFIELD	17F2	510	512	100%	479	94%	485	95%	505	99%
WAKEFIELD	17F3	597	491	82%	460	77%	465	78%	484	81%
TOTAL (MW)			43.1		40.4		40.9		42.5	

Narragansett 42F1 NWA

Result of NWA RFP

The Company issued an RFP for the Narragansett 42F1 NWA opportunity in calendar year 2018 and evaluated the submitted bid proposals from third-party solution providers in calendar year 2019. Please see Appendix 9.15 for the Narragansett 42F1 NWA RFP document, which also details the technical and area information for the Narragansett 42F1 NWA opportunity.

All NWA solution bid proposals submitted to National Grid for this opportunity did not pass evaluation for a feasible solution.

Next Steps

As the timing for the NWA need is not until 2024, the window of opportunity for sourcing a potential NWA solution is still open.

The Company will proceed with investigating alternate solution pathways, which may include: refining the parameters of the need, re-engineering the RFP, a Company-sourced proposal, a Company-owned solution, or a partial NWA. The Company is still actively seeking potential NWA solutions for this opportunity.

Narragansett 17F2 NWA

Result of NWA RFP

The Company issued an RFP for the Narragansett 17F2 NWA opportunity in calendar year 2018 and evaluated the submitted bid proposals from third-party solution providers in calendar year 2019. Please see Appendix 9.16 for the Narragansett 17F2 NWA RFP document, which also details the technical and area information for the Narragansett 17F2 NWA opportunity.

All NWA solution bid proposals submitted to National Grid for this opportunity did not pass evaluation for a feasible solution.

Next Steps

The need timing for this NWA opportunity is 2021. Therefore, the window of opportunity for sourcing a potential NWA solution is closed. Third-party solution providers, on average, require twelve to eighteen months lead time from the in-service date.

The Company will proceed with the wires option for the Narragansett 17F2 system need.

Town of South Kingston: The western half of South Kingston is supplied by (3) 12.47 kV distribution feeders. Two feeders, 59F3 and 68F2, are projected to be loaded above SN ratings and lack feeder ties with capacity to reduce loading below ratings. Either new feeder ties must be created or load must be reduced in the western half of the town. Two options were developed to address these projected overloads.

Wires Option: This option establishes a new feeder tie between the 68F5 and the 59F3 feeders. This new tie provides switching flexibility to relieve both the 59F3 and the 68F2 feeders. The estimated cost of this option is:

Description	Capex ($M)	Opex ($M)	Removal ($M)
59F3 Feeder Relief	$1.7400	$0.0300	$0.3800

Non-Wires Option: For this option to be comparable to the wires option, load in the western section of the Town would need to be reduced by 2 MW (or 8%) from 26.1 MW to 24.1 MW.

The tables below show the projected loading on the existing system assuming no investments, the projected loading for the wires option, and the projected loading for the non-wires option.

TABLE 5.2.4 - Projected Feeder Loading (No Investments)

Substation	Feeder	SN Rating (Amps)	Projected Loading (No Investments)							
			2022		2023		2024		2030	
			Amps	%SN	Amps	%SN	Amps	%SN	Amps	%SN
PEACEDALE	59F3	492	484	98%	487	99%	490	100%	510	104%
KENYON	68F2	511	512	100%	515	101%	518	101%	542	106%
KENYON	68F5	612	206	34%	208	34%	209	34%	219	36%
TOTAL (MW)			26.0		26.1		26.3		27.5	

TABLE 5.2.5 - Projected Feeder Loading (Wires Option)

Substation	Feeder	SN Rating (Amps)	Projected Loading (Wires Option)							
			2022		2023		2024		2030	
			Amps	%SN	Amps	%SN	Amps	%SN	Amps	%SN
PEACEDALE	59F3	492	484	98%	444	90%	447	91%	465	95%
KENYON	68F2	511	512	100%	465	91%	468	92%	490	96%
KENYON	68F5	612	206	34%	301	49%	303	49%	317	52%
TOTAL (MW)			26.0		26.1		26.3		27.5	

TABLE 5.2.6 - Projected Feeder Loading (Non-Wires Option)

Substation	Feeder		Projected Loading (Non-Wires Option)			
			2022	2023	2024	2030

		SN Rating (Amps)	Amps	%SN	Amps	%SN	Amps	%SN	Amps	%SN
PEACEDALE	59F3	492	484	98%	449	91%	451	92%	470	95%
KENYON	68F2	511	512	100%	474	93%	477	93%	499	98%
KENYON	68F5	612	206	34%	191	31%	192	31%	201	33%
TOTAL (MW)			26.0		24.1		24.2		25.3	

South Kingstown NWA

Result of NWA RFP
The Company issued an RFP for the South Kingstown NWA opportunity in calendar year 2019 and evaluated the submitted bid proposals from third-party solution providers in calendar year 2019. Please see Appendix 9.17 for the South Kingstown NWA RFP document, which also details the technical and area information for the South Kingstown NWA opportunity.

All NWA solution bid proposals submitted to National Grid for this opportunity did not pass evaluation for a feasible solution.

Next Steps
As the timing for the NWA need is not until 2022, the window of opportunity for sourcing a potential NWA solution is still open.

The Company will proceed with investigating alternate solution pathways, which may include: refining the parameters of the need, re-engineering the RFP, a Company-sourced proposal, a Company-owned solution, or a partial NWA. The Company is still actively seeking potential NWA solutions for this opportunity.

Town of Exeter: The eastern section of Exeter is supplied by the Lafayette 30F2 feeder. Sections of this feeder are projected to be loaded above SN ratings with the limit being 4/0 aluminum conductor. This feeder has no feeder ties that would enable reducing loading below the rating of the 4/0 aluminum. Either the 4/0 Al needs to be upgraded or load must be reduced in the eastern half of the town. Two options were developed to address these projected overloads.

Wires Option: This option replaces the 4/0 bare aluminum wire with 477 aluminum spacer cable to resolve projected overload and provide superior tree resistance. The estimated cost of this option is:

Description	Capex ($M)	Opex ($M)	Removal ($M)
30F2 Feeder Upgrade	$1.1500	$0.0200	$0.2800

Non-Wires Option: For this option to be comparable to the wires option, the load on the feeder would have to be reduced by approximately 0.7 MW.

The final component of the common items is to establish a feeder tie between the Lafayette 30F2 feeder and the Hopkins Hill 63F6 feeder. This feeder tie would provide an alternate supply to approximately 6 MW of load in western Exeter. The estimate cost of this tie is $0.75M ($0.61M capex, $0M opex, $0.14M removal). The recommendation is to defer this investment until a non-wires option is explored for western Exeter and a comprehensive solution is developed.

5.3 Plan – 1

This plan recommends a new 115/12.47 kV substation at the existing Lafayette substation site consisting of a single 115/12.47 kV 24/32/40 MVA transformer, four regulated feeders, and one 7.2 MVAr station capacitor bank consisting of two 3.6 MVAr stages. The preferred arrangement of the station is open air, low profile, with a breaker-and-one-half design. The station shall be built with 3V0 protection to accommodate existing and proposed distributed generation in the area. The proposed one line for this station is shown in Appendix 9.9.

Install a tap from the G-185S (115 kV) line to supply the station. Install two motor operated, remotely controlled, SCADA enabled, load break switches at the tap position. The proposed one line for this tap is shown in Appendix 9.9.

A manhole and ductline system will be installed for the feeder getaways out to city streets. The feeders will follow existing overhead routes and generally utilize existing overhead infrastructure. The new feeders will provide capacity to convert Anvil international and Bostich to 12.47 kV and allow for the retirement of the 34.5kV system that supplies Lafayette. The retirement of the 34.5kV supply to Lafayette address the asset condition concerns and mitigates the access issues associated with the right-of-way.

The final component of this plan is to remove the existing 34.5/12.47 kV station at Lafayette once the new station is in-service. The proposed mainline distribution for Plan 1 is shown in Appendix 9.9. The investments and expenses for Plan 1 are detailed in Table 5.3 below.

TABLE 5.3 - Estimated Investments and Expenses for Plan 1

Investment Description ($M)	Capex	Opex	Removal	Total
Lafayette Substation (T-Line)	$1.250	$0.030	$0.070	$1.350
Lafayette Substation (T-Sub)	$1.370	$0.000	$0.000	$1.370
Lafayette Substation (D-Sub)	$8.780	$0.000	$0.000	$8.780
Lafayette Substation (D-Line)	$2.800	$0.100	$0.320	$3.220
3312 ROW Removals (T-Line)	$0.000	$0.000	$2.173	$2.173
84T3 ROW Removals (D-Line)	$0.000	$0.000	$2.633	$2.633
Plan 1 (T-Spend)	$2.620	$0.030	$2.243	$4.893
Plan 1 (D-Spend)	$11.580	$0.100	$2.953	$14.633

Total PLAN 1 Spend	$14.200	$0.130	$5.196	$19.526

5.4 Alternative Plans

5.4.1 Plan – 2

The major component of this plan is a new 115/12.47 kV substation in Quonset to be built on a green field site and the refurbishment of the 34.5kV supply system to Lafayette substation. The substation site will have to be acquired from either the Quonset Development Corporation (QDC) or some other private party. The proposed substation would consist of a single 115/12.47 kV 24/32/40 MVA LTC transformer and three feeders. Refer to Appendix 9.10 for a detailed analysis of Plan 2. The estimate cost of Plan 2 is $36.600M.

5.4.2 Plan – 3

The major component of this plan is to expand Old Baptist substation by installing a third bay, two additional feeders, and station capacitor banks. This plan would also refurbish the 34.5kV supply to Lafayette substation. Refer to Appendix 9.11 for a detailed analysis of Plan 3. The estimate cost of Plan 3 is $25.700M

5.4.3 Do Nothing

Taking no action would leave all the problems mentioned in Section 4 unaddressed. Violations of the Distribution Planning Criteria would continue to exist and worsen as time goes by, adversely affecting customer service and reliability performance.

6. Plan Considerations and Comparisons

6.1 Economic, Schedule, and Technical Comparisons

The estimated investments and expenses for the three Plans are shown in Table 6.1 below. The economic comparisons exclude the cost of common items.

TABLE 6.1 – Estimated Investments and Expenses for Plan 1, Plan 2, and Plan 3

$M	PLAN 1				PLAN 2				PLAN 3			
	Capex	Opex	Removal	Total	Capex	Opex	Removal	Total	Capex	Opex	Removal	Total
T-Line	$1.25	$0.03	$2.24	$3.52	$9.38	$0.24	$0.68	$10.30	$7.35	$0.20	$0.55	$8.10
T-Sub	$1.37	$0.00	$0.00	$1.37	$1.95	$0.00	$0.00	$1.95	$0.00	$0.00	$0.00	$0.00
D-Sub	$8.78	$0.00	$0.00	$8.78	$10.10	$0.00	$0.00	$10.10	$4.40	$0.00	$0.10	$4.50
D-Line	$2.80	$0.10	$2.95	$5.85	$13.71	$0.02	$0.52	$14.25	$12.63	$0.03	$0.44	$13.10
T-Spend	$2.62	$0.03	$2.24	$4.89	$11.33	$0.24	$0.68	$12.25	$7.35	$0.20	$0.55	$8.10
D-Spend	$11.58	$0.10	$2.95	$14.63	$23.81	$0.02	$0.52	$24.35	$17.03	$0.03	$0.54	$17.60
Total Spend	$14.20	$0.13	$5.20	$19.53	$35.14	$0.26	$1.20	$36.60	$24.38	$0.23	$1.09	$25.70

Plan 1 is the most economical plan, is the most reliable, and has the lowest losses. It eliminates a large portion of the 34.5 kV supply system installed in difficult to access right-of-way, along highly congested roadways, and thru backyards with restricted access. It adds new distribution capacity supplied from a robust 115 kV system. A summary of key factors used in plan selection are shown in the Plan Comparison Matrix below.

Plan Comparison Matrix

KEY FACTOR	PLAN 1	PLAN 2	PLAN 3
Initial Cost	√	×	×
Reliability	√	×	×
Losses	√	×	×
Maintenance Costs	√	×	×
Climate Resiliency	√	×	×
Future Expansion Flexibility	√	×	×

6.2 Non-Wires Alternatives Considerations

Where an issue has been identified, a Non-Wires Alternative may be considered as an option to defer a transmission, sub-transmission, or distribution wires solution for a period of time. Considering Non-Wires Alternatives to every wires solution is not practical given the low cost of a large volume of potential wires solutions, the magnitude of load relief required in certain situations, the time to acquire Non-Wires Alternatives (and verify their availability) or instances where the issue is poor operating condition of the asset. As a result, Non-wires Alternatives are generally screened against the following four guidelines:

- A wires solution will likely be more than $1M.
- If load reduction is necessary, it should be less than 20 percent of the total load in the area of the defined need.
- Start of construction is at least 36 months in the future.
- The need is not based on Asset Condition.

Where practical, a non-wires solution was considered for each wires alternative. A full description of the potential non-wires solutions can be found in section 5.2.

6.3 Permitting, Licensing, Real Estate, and Environmental Considerations

Refer to Appendix 9.14.

6.4 Planned Outage Considerations

All three plans involve work on 115kV supplied stations. Plan 1 and Plan 2 requires a tap from a 115 kV transmission line. Any 115kV line outages need to be coordinated with ISO-NE.

Plan 2 and Plan 3 require refurbishment of two 34.5 kV sub-transmission lines. It is anticipated that line outages can be obtained during this refurbishment to avoid the challenges and expense of live line construction. Some outage restrictions should be anticipated during peak load conditions.

All three plans require distribution system upgrades. These will be routine upgrades with no special outage considerations required.

6.5 Asset Physical Security Considerations

National Grid Security department will be consulted during the design process for the new substations. Recommendations for improved security at existing area substations will also be solicited and incorporated.

6.6 Climate Resiliency

Plan 1 eliminates an extensive sub-transmission system installed on roadways and in rights-of-way. Large sections of the right-of-way have wetlands and potentially sensitive vegetation. Plan 1 has the least environmental impact.

Plans 2 and Plan 3 require the refurbishment of an extensive sub-transmission system installed both on city streets and rights-of-way. Large sections of the right-of-way have wetlands and potentially sensitive vegetation. Plan 2 and Plan 3 would have the most impact on the environment and be the least climate resiliency.

6.7 Grid Modernization

All recommended equipment will be installed with the latest standard control and communication equipment or with provisions for pending control and communication standards. New substations will be built with facilities to accommodate the possible future installation of feeder distributed generation such as CCVTs, bi-directional regulators, protective relaying, conduits, etc. All new stations will be built with 3V0 to allow for the interconnection of existing and future distributed generation.

All recommended distribution line reclosers and capacitors will be installed with the latest sensors, controls and communication capabilities per standards:
12-338 – 15kV loop scheme recloser with PTs
12-340 – 15kV loop scheme wiring
15-335 – 15kV advanced capacitor with 3 phase sensing and antennae
15-336 – 35kV (23kV) advanced capacitor with single phase sensing and no antennae

6.8 System Loss Analysis

The recommended plan installs new distribution capacity supplied directly from the 115 kV transmission system. The voltage is stepped down from 115 kV to 12.47 kV thru a single level of transformation. This approach results in the lowest losses.

Plan 2 and Plan 3 require two levels of transformation at Lafayatte substation. First, the voltage would be stepped down from 115 kV to 34.5 kV (at Kent County and Davisville) and then from

34.5 kV to 12.47 kV (at Lafayette). Plan 2 and Plan 3 would have higher losses as compared to Plan 1.

6.9 Recommended Plan Spending Forecast

Tables 6.9.1, 6.9.2, and 6.9.3 show the recommended plan capital, expense and removal spending forecasts.

TABLE 6.9.1 – Capital Spending Forecast

Description	TOTAL	FY21	FY22	FY23	FY24	FY25	FY26	FY27
Lafayette Substation (T-Line)	1.25	0.01	0.06	0.25	0.38	0.38	0.18	
Lafayette Substation (T-Sub)	1.37	0.01	0.07	0.27	0.41	0.41	0.19	
Lafayette Substation (D-Sub)	8.78	0.09	0.44	1.76	2.63	2.63	1.23	
Lafayette Substation (D-Line)	2.80	0.03	0.14	0.56	0.84	0.84	0.39	
3312 ROW Removals (T-Line)	0.00							
84T3 ROW Removals (D-Line)	0.00							
Plan 1 (T-Spend)	2.62	0.03	0.13	0.52	0.79	0.79	0.37	
Plan 1 (D-Spend)	11.58	0.12	0.58	2.32	3.47	3.47	1.62	
TOTAL	$14.20	$0.14	$0.71	$2.84	$4.26	$4.26	$1.99	

TABLE 6.9.2 – Expense Spending Forecast

Description	TOTAL	FY21	FY22	FY23	FY24	FY25	FY26	FY27
Lafayette Substation (T-Line)	0.03	0.00	0.00	0.01	0.01	0.01	0.00	
Lafayette Substation (T-Sub)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Lafayette Substation (D-Sub)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Lafayette Substation (D-Line)	0.10	0.00	0.01	0.02	0.03	0.03	0.01	
3312 ROW Removals (T-Line)	0.00							
84T3 ROW Removals (D-Line)	0.00							
Plan 1 (T-Spend)	0.03	0.00	0.00	0.01	0.01	0.01	0.00	
Plan 1 (D-Spend)	0.10	0.00	0.01	0.02	0.03	0.03	0.01	
TOTAL	$0.13	$0.00	$0.01	$0.03	$0.04	$0.04	$0.02	

TABLE 6.9.3 – Removals Spending Forecast

Description	TOTAL	FY21	FY22	FY23	FY24	FY25	FY26	FY27
Lafayette Substation (T-Line)	0.07	0.00	0.00	0.01	0.02	0.02	0.01	
Lafayette Substation (T-Sub)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Lafayette Substation (D-Sub)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Lafayette Substation (D-Line)	0.32	0.00	0.02	0.06	0.10	0.10	0.04	
3312 ROW Removals (T-Line)	2.17					0.22	0.22	1.74
84T3 ROW Removals (D-Line)	2.63					0.26	0.26	2.11
Plan 1 (T-Spend)	0.07	0.00	0.00	0.01	0.02	0.24	0.23	1.74
Plan 1 (D-Spend)	0.32	0.00	0.02	0.06	0.10	0.36	0.31	2.11

TOTAL	$0.39	$0.00	$0.02	$0.08	$0.12	$0.60	$0.54	$3.84

7. Conclusions and Recommendations

Three plans were develop to provide a comprehensive solution for the area thru the year 2031. All plans address asset condition, safety, and reliability concerns. Moreover, all plans address thermal loading concerns, add capacity to supply new load growth, and addresses all distribution planning criteria violations. Plan 1 is recommended for implementation since it provides a comprehensive solution to address all the concerns in the study area at least cost.

8. Factors Influencing Futures Studies

Unexpected significant load growth or distributed generation penetration is one factor that could affect future studies. This area has experienced large scale Distributed Generation (DG) developments and continues to be a target for large scale DG projects. Any DG project that exceeds the capacity of existing facilities may require infrastructure improvements to be able to interconnect to the National Grid system.

9. Appendix

9.1 Area Maps

FIGURE 9.1.1 – STUDY AREA

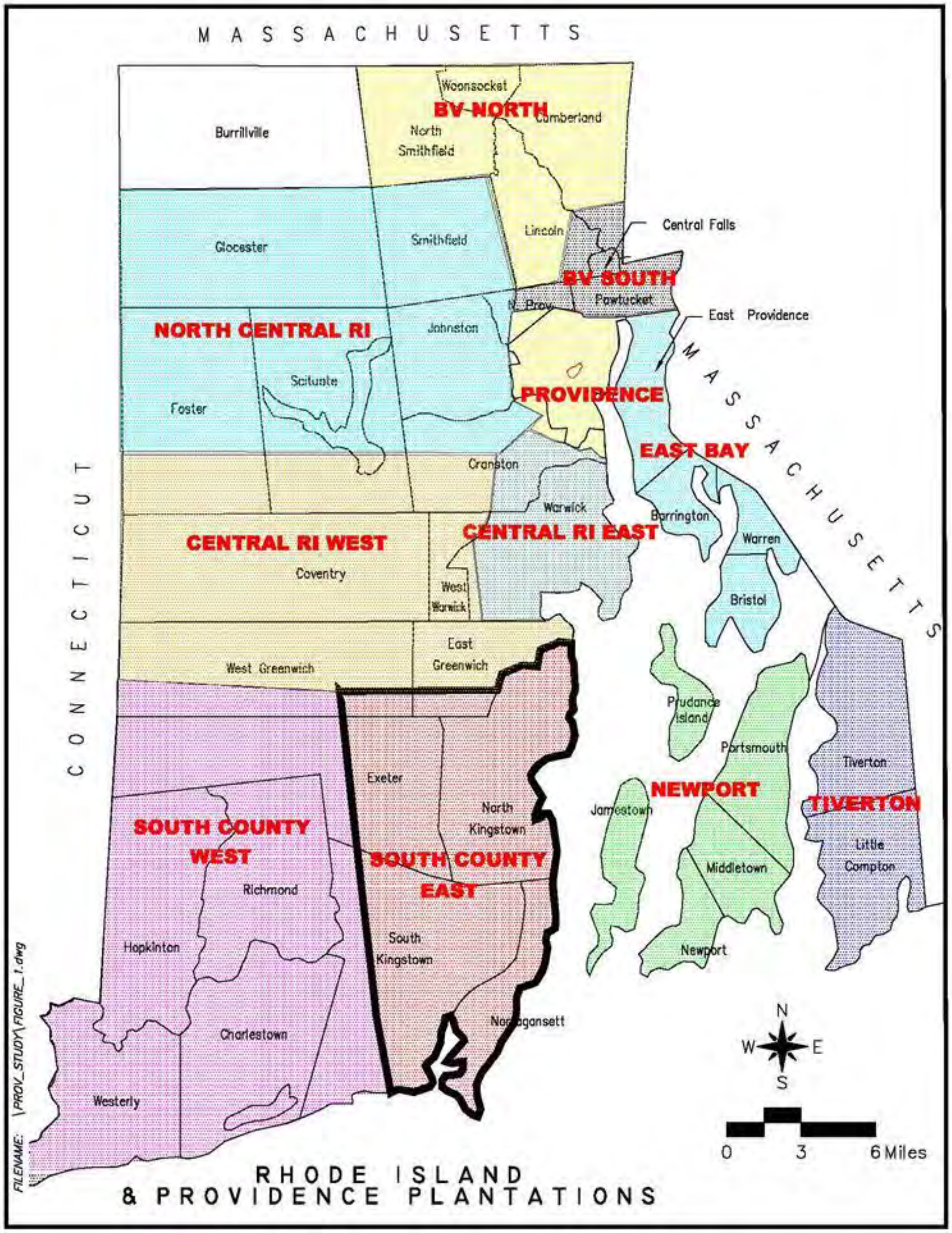
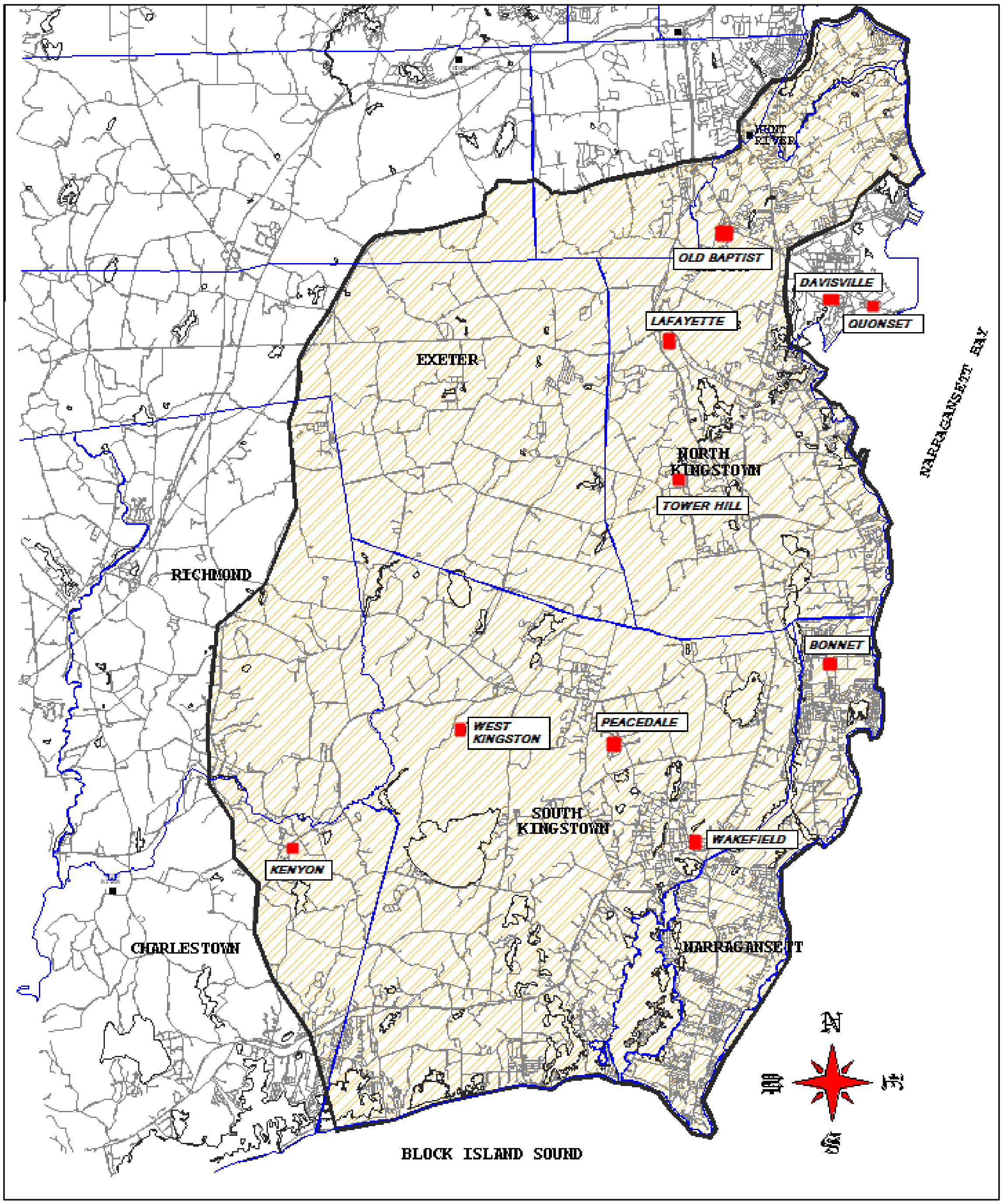


FIGURE 9.1.2 – STUDY AREA SUBSTATIONS



9.2 One Line Diagrams

[redacted]

FIGURE 9.2.2 – 34.5kV SUPPLY SYSTEM ONE-LINE DIAGRAM (NORTH)

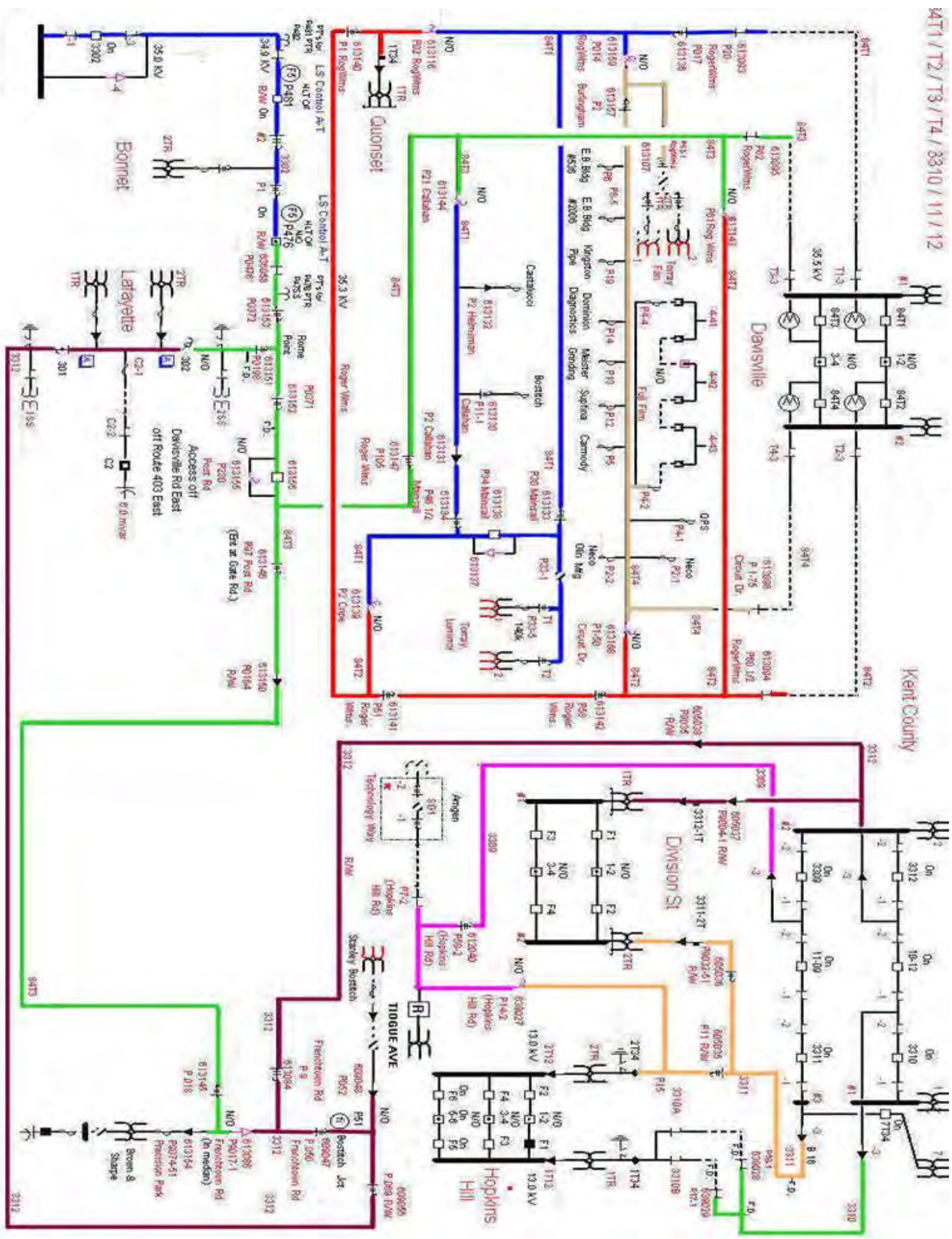


FIGURE 9.2.3 – 34.5kV SUPPLY SYSTEM ONE-LINE DIAGRAM (SOUTH)

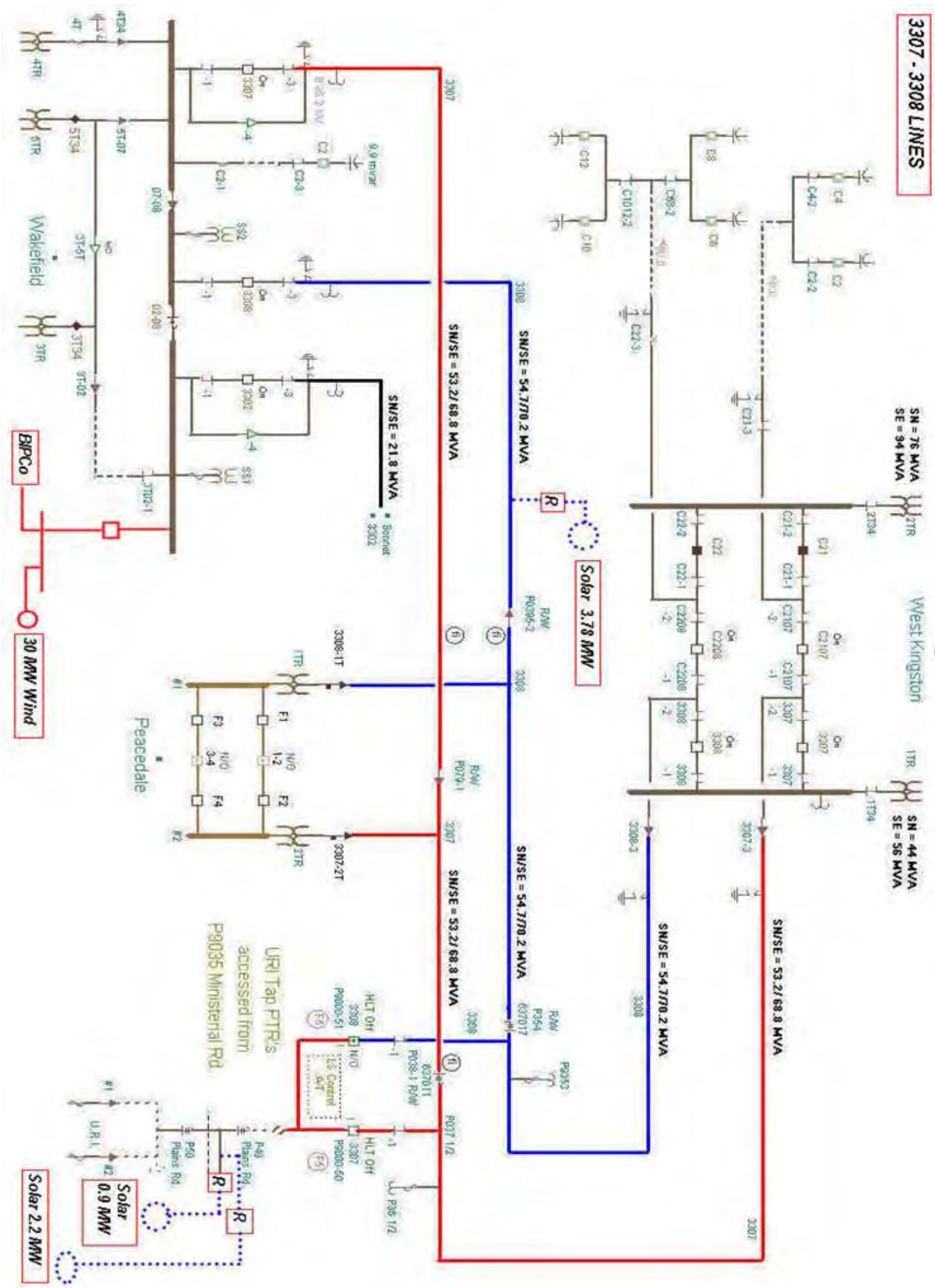
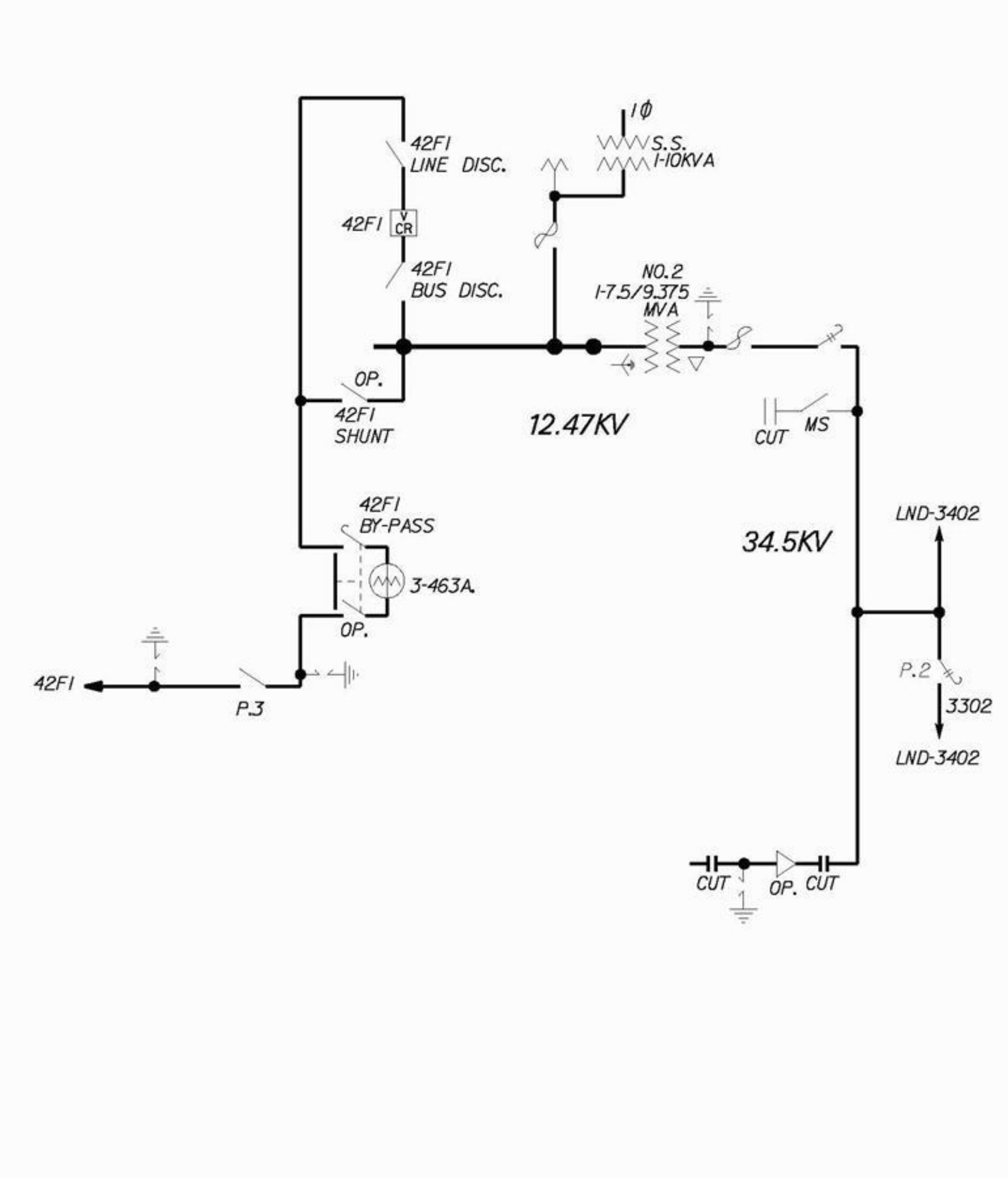
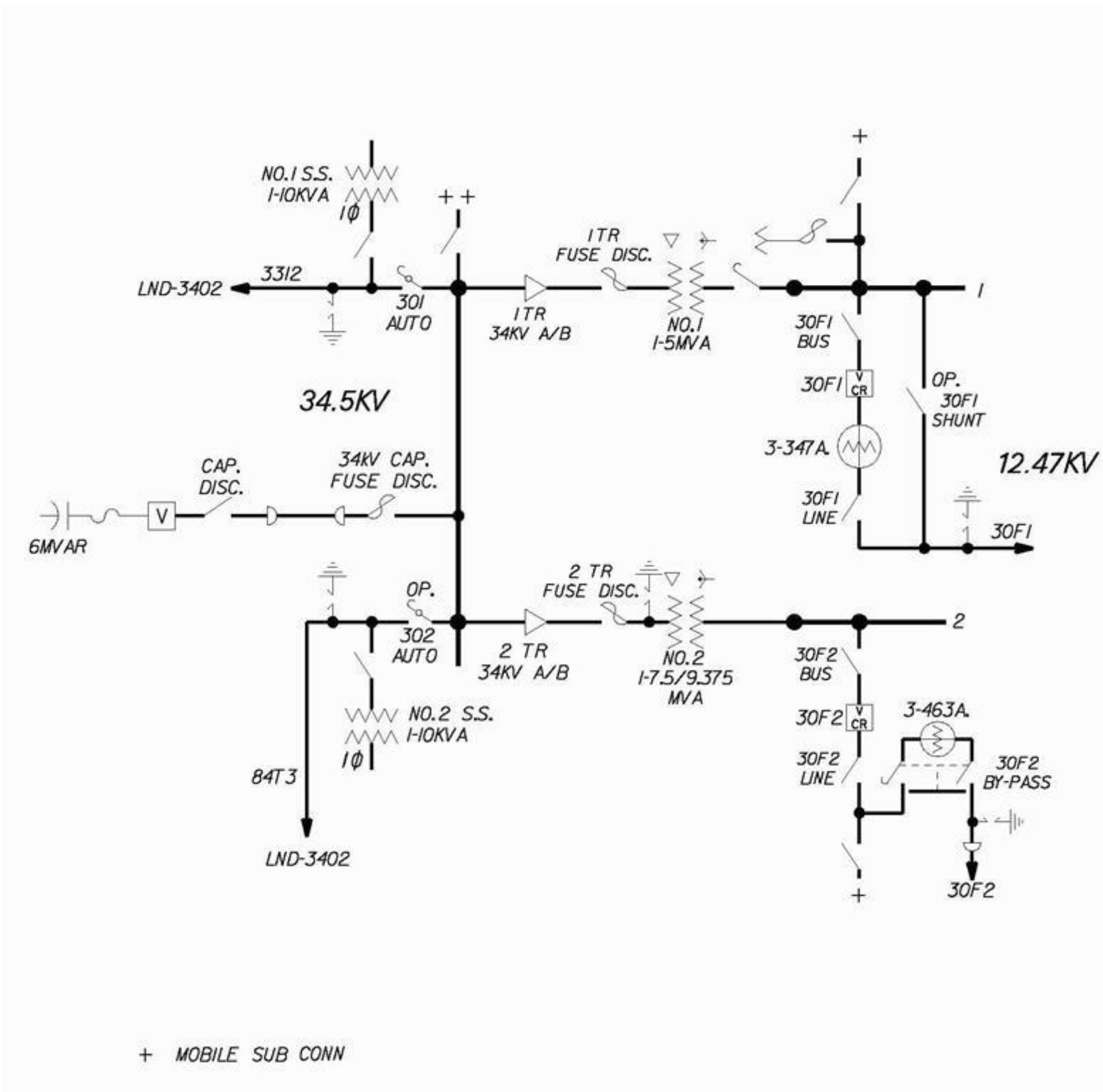


FIGURE 9.2.4 – BONNET SUBSTATION ONE-LINE DIAGRAM



[redacted]

FIGURE 9.2.6 – LAFAYETTE SUBSTATION ONE-LINE DIAGRAM



[redacted]

FIGURE 9.2.8 – PEACEDALE SUBSTATION ONE-LINE DIAGRAM

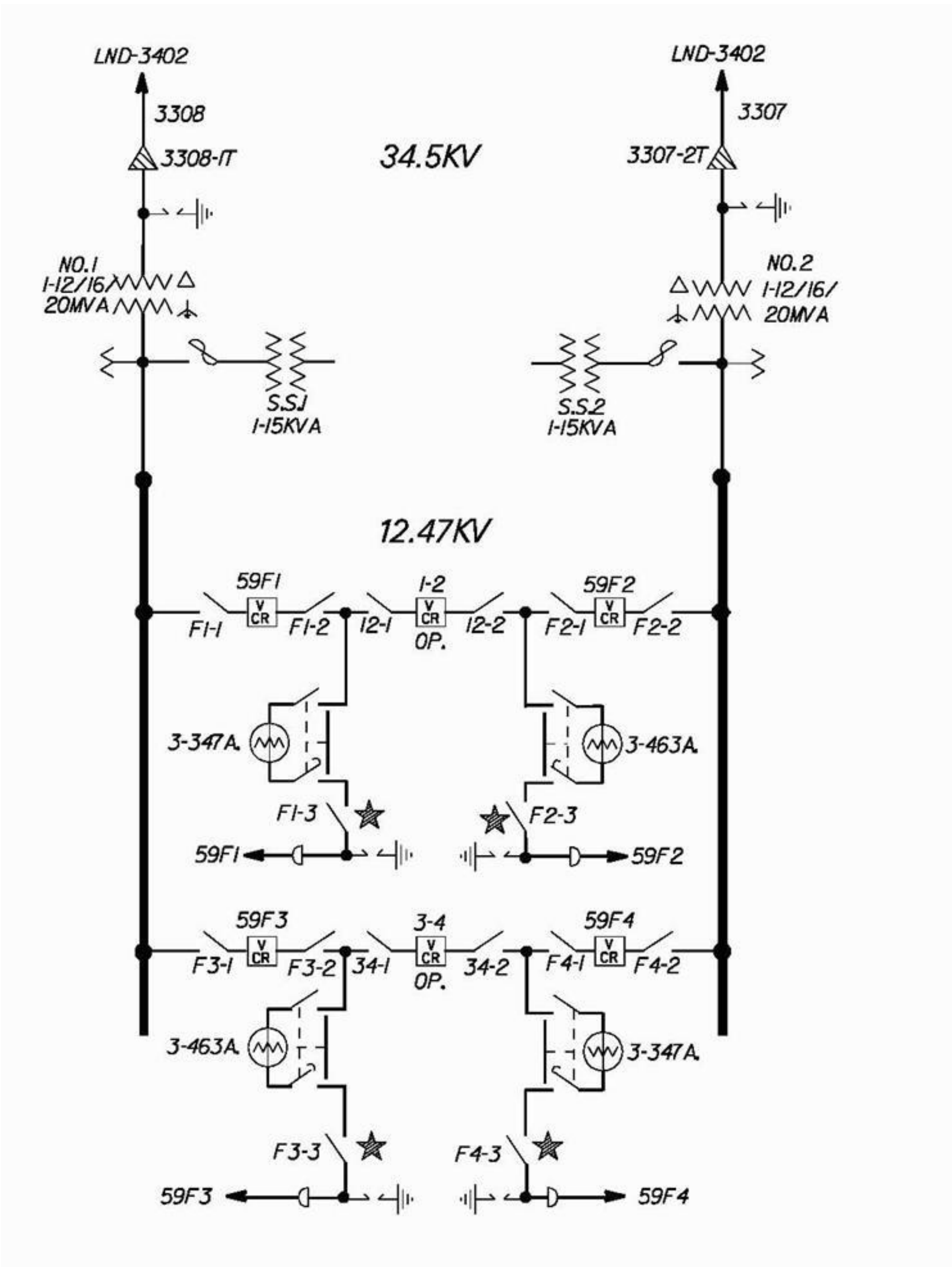
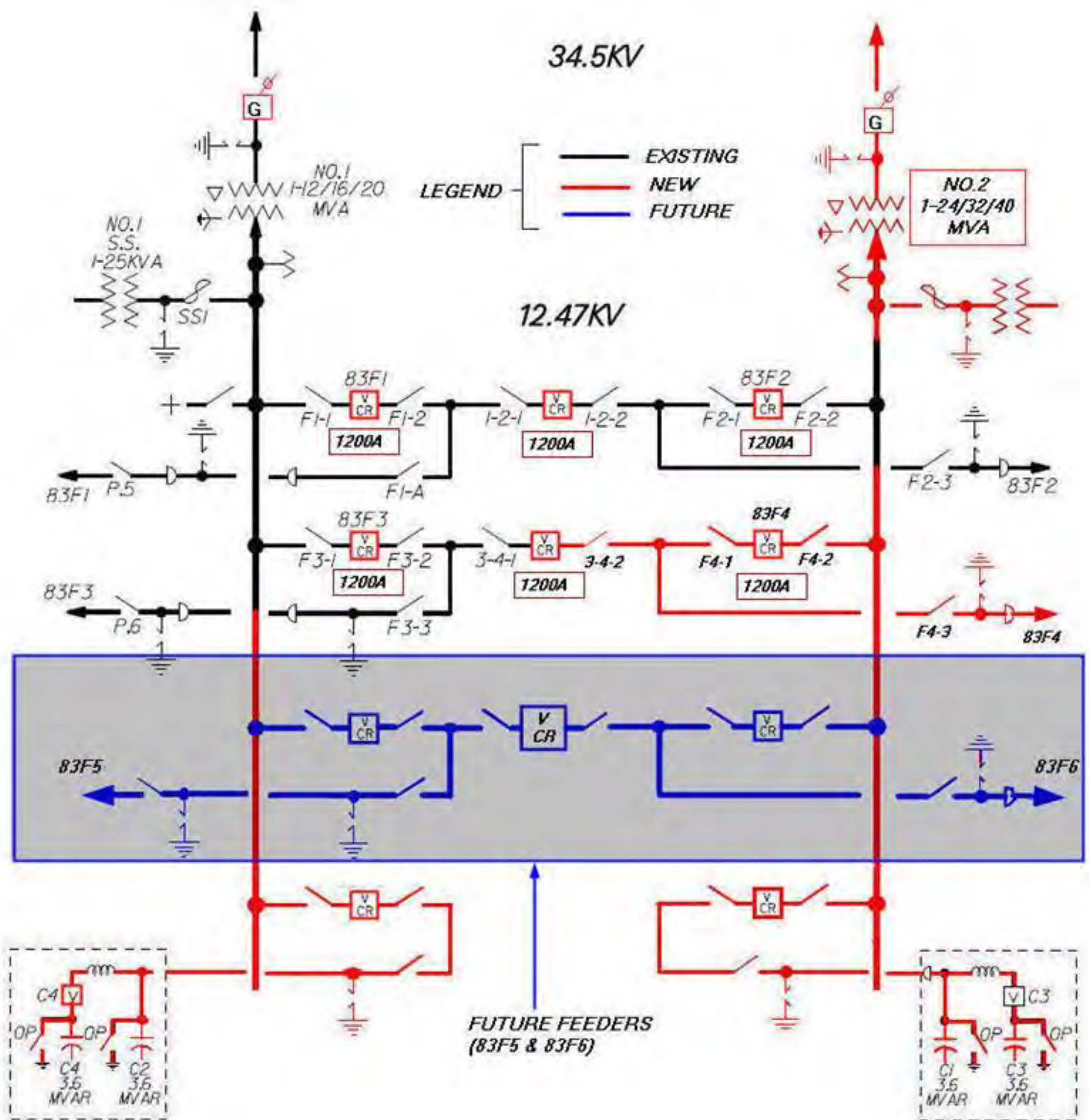
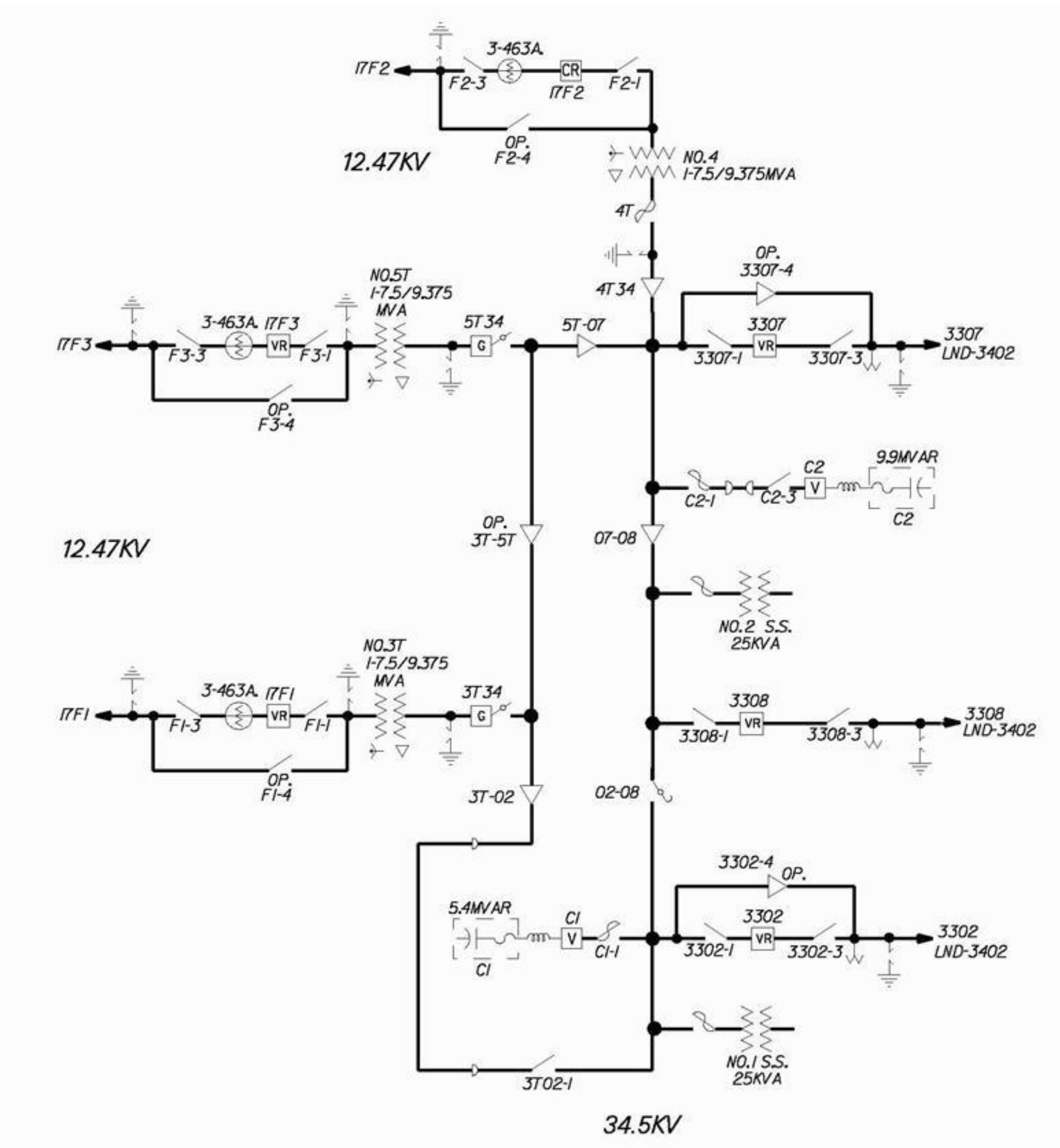


FIGURE 9.2.9 – QUONSET SUBSTATION ONE-LINE DIAGRAM



[redacted]

FIGURE 9.2.11 - WAKEFIELD SUBSTATION ONE-LINE DIAGRAM



[redacted]

9.3 Loading Tables

TABLE 9.3.1 – Feeder Loading Before Improvements

Substation	Feeder	SN Rating (Amps)	Projected Load 2018 Amps	2018 %SN	2022 Amps	2022 %SN	2026 Amps	2026 %SN	2030 Amps	2030 %SN
BONNET 42	42F1	525	515	98%	522	99%	535	102%	550	105%
LAFAYETTE 30	30F1	350	261	75%	265	76%	271	78%	279	80%
LAFAYETTE 30	30F2	530	457	86%	464	88%	475	90%	489	92%
OLD BAPTIST ROAD 46	46F1	530	422	80%	427	81%	438	83%	450	85%
OLD BAPTIST ROAD 46	46F2	530	376	71%	381	72%	390	74%	401	76%
OLD BAPTIST ROAD 46	46F3	565	362	64%	368	65%	376	67%	387	69%
OLD BAPTIST ROAD 46	46F4	594	478	80%	484	82%	496	84%	510	86%
PEACEDALE 59	59F1	409	165	40%	167	41%	171	42%	176	43%
PEACEDALE 59	59F2	492	326	66%	331	67%	339	69%	349	71%
PEACEDALE 59	59F3	492	478	97%	484	98%	496	101%	510	104%
PEACEDALE 59	59F4	492	190	39%	193	39%	197	40%	203	41%
QUONSET 83	83F1	645	115	18%	343	53%	351	54%	408	63%
QUONSET 83	83F2	490	121	25%	199	41%	260	53%	315	64%
QUONSET 83	83F3	645	329	51%	334	52%	342	53%	352	55%
WAKEFIELD 17	17F1	602	471	78%	478	79%	489	81%	503	84%
WAKEFIELD 17	17F2	510	508	100%	515	101%	527	103%	542	106%
WAKEFIELD 17	17F3	597	487	82%	494	83%	506	85%	520	87%
TOWER HILL 88	88F1	530	387	73%	392	74%	402	76%	413	78%
TOWER HILL 88	88F3	550	443	81%	449	82%	460	84%	473	86%
TOWER HILL 88	88F5	530	410	77%	416	78%	426	80%	438	83%
TOWER HILL 88	88F7	530	404	76%	410	77%	420	79%	432	81%
QUONSET 83	83F4	600	283	47%	287	48%	294	49%	302	50%

TABLE 9.3.2 - Feeder MWh “Exposure” Before Improvements

Substation	Feeder	Un-Served (MW)	MWHr Exposure
BONNET	42F1	4.99	28.4
LAFAYETTE	30F1	0.00	6.4
LAFAYETTE	30F2	2.59	19.5
OLD BAPTIST RD	46F1	1.80	15.9
OLD BAPTIST RD	46F2	1.53	13.6
OLD BAPTIST RD	46F3	0.00	11.2
OLD BAPTIST RD	46F4	0.00	13.8
PEACEDALE	59F1	0.00	3.6
PEACEDALE	59F2	0.00	7.7
PEACEDALE	59F3	0.00	12.8
PEACEDALE	59F4	0.00	4.3
QUONSET	83F1	0.00	3.6
QUONSET	83F2	0.00	6.6
QUONSET	83F3	0.00	7.1
WAKEFIELD	17F1	7.70	34.6
WAKEFIELD	17F2	3.00	24.1
WAKEFIELD	17F3	0.00	14.0
TOWER HILL	88F1	0.00	11.4
TOWER HILL	88F3	0.00	11.6
TOWER HILL	88F5	3.88	20.5
TOWER HILL	88F7	0.00	10.6

TABLE 9.3.3 – Transformer Normal Loading Before Improvements

Substation	Tranf. ID.	Rating (MVA)		Projected Load							
				2018		2022		2026		2030	
		SN	SE	MVA	% SN	MVA	% SN	MVA	% SN	MVA	% SN
BONNET 42	2	11.3	12.2	11.1	98%	11.3	100%	11.6	102%	11.9	105%
DAVISVILLE 84	1	45.3	52.1	12.3	27%	23.6	52%	24.7	54%	26.3	58%
DAVISVILLE 84	2A	45.1	51.8	22.8	50%	29.2	65%	31.0	69%	32.9	73%
LAFAYETTE 30	1	7.6	8.6	5.6	74%	5.7	75%	5.9	77%	6.0	79%
LAFAYETTE 30	2	12.3	13.2	9.9	80%	10.0	81%	10.3	83%	10.6	86%
OLD BAPTIST ROAD 46	1	48.7	54.4	16.9	35%	17.2	35%	17.6	36%	18.1	37%
OLD BAPTIST ROAD 46	2	48.9	51.9	18.4	38%	18.7	38%	19.1	39%	19.7	40%
PEACEDALE 59	1	24.2	27.2	13.9	57%	14.1	58%	14.4	60%	14.8	61%
PEACEDALE 59	2	24.2	27.2	11.2	46%	11.3	47%	11.6	48%	11.9	49%
QUONSET 83	1	25.6	26.7	9.6	37%	14.6	57%	15.0	58%	16.4	64%
WAKEFIELD 17	3	12.9	13.5	10.2	79%	10.3	80%	10.6	82%	10.9	84%
WAKEFIELD 17	4	12.9	13.5	11.0	85%	11.1	86%	11.4	88%	11.7	91%
WAKEFIELD 17	5	12.9	13.5	10.5	82%	10.7	83%	10.9	85%	11.2	87%
WEST KINGSTON 62	1	43.9	55.7	25.4	58%	25.8	59%	26.5	60%	27.4	62%
WEST KINGSTON 62	2	75.8	93.5	41.9	55%	42.5	56%	43.5	57%	44.7	59%
TOWER HILL 88	1	51	60	35.5	70%	36.0	71%	36.9	72%	37.9	74%
QUONSET 83	2	50	50	8.7	17%	10.5	21%	12.0	24%	13.3	27%
BIPCO	1	10	11.5	4.8	48%	4.9	49%	5.0	50%	5.1	51%

TABLE 9.3.4 – Transformer Contingency Loading Before Improvements

Substation	Tranf. ID.	Rating (MVA)		Contingency Loading							
				2018		2022		2026		2030	
		SN	SE	MVA	% SE	MVA	% SE	MVA	% SE	MVA	% SE
BONNET 42	2	11.30	12.20	0.0	0%	0.0	0%	0.0	0%	0.0	0%
DAVISVILLE 84	1	45.30	52.10	35.1	67%	52.8	101%	55.7	107%	59.2	114%
DAVISVILLE 84	2A	45.10	51.80	35.1	68%	52.8	102%	55.7	108%	59.2	114%
LAFAYETTE 30	1	7.60	8.60	0.0	0%	0.0	0%	0.0	0%	0.0	0%
LAFAYETTE 30	2	12.30	13.20	0.0	0%	0.0	0%	0.0	0%	0.0	0%
OLD BAPTIST ROAD 46	1	48.70	54.40	35.4	65%	35.9	66%	36.7	68%	37.8	69%
OLD BAPTIST ROAD 46	2	48.90	51.90	35.4	68%	35.9	69%	36.7	71%	37.8	73%
PEACEDALE 59	1	24.20	27.20	25.0	92%	25.4	93%	26.0	96%	26.7	98%
PEACEDALE 59	2	24.20	27.20	25.0	92%	25.4	93%	26.0	96%	26.7	98%
QUONSET 83	1	25.60	26.70	18.3	69%	25.1	94%	25.7	96%	26.4	99%
WAKEFIELD 17	3	12.90	13.50	0.0	0%	0.0	0%	0.0	0%	0.0	0%
WAKEFIELD 17	4	12.90	13.50	0.0	0%	0.0	0%	0.0	0%	0.0	0%
WAKEFIELD 17	5	12.90	13.50	0.0	0%	0.0	0%	0.0	0%	0.0	0%
WEST KINGSTON 62	1	43.90	55.70	67.3	121%	68.3	123%	70.0	126%	72.1	129%
WEST KINGSTON 62	2	75.80	93.50	67.3	72%	68.3	73%	70.0	75%	72.1	77%
TOWER HILL 88	1	51.00	60.00	0.0	0%	0.0	0%	0.0	0%	0.0	0%
QUONSET 83	2	50.00	50.00	18.3	37%	25.1	50%	25.7	43%	26.4	44%
BIPCO	1	10.00	11.50	0.0	0%	0.0	0%	0.0	0%	0.0	0%

TABLE 9.3.5 – Feeder Loading After Improvements

Substation	Feeder	SN Rating (Amps)	Projected Load 2025 Amps	2025 %SN	2026 Amps	2026 %SN	2030 Amps	2030 %SN	Comments
BONNET 42	42F1	525	435	83%	438	83%	450	86%	
LAFAYETTE 30	30F1	350	270	77%	0	0%	0	0%	Projected retirement 2026
LAFAYETTE 30	30F2	530	472	89%	0	0%	0	0%	Projected retirement 2026
OLD BAPTIST ROAD 46	46F1	530	435	82%	338	64%	347	66%	
OLD BAPTIST ROAD 46	46F2	530	388	73%	390	74%	401	76%	
OLD BAPTIST ROAD 46	46F3	565	374	66%	421	75%	433	77%	
OLD BAPTIST ROAD 46	46F4	594	493	83%	376	63%	387	65%	
PEACEDALE 59	59F1	409	170	42%	171	42%	176	43%	
PEACEDALE 59	59F2	492	337	69%	339	69%	349	71%	
PEACEDALE 59	59F3	492	378	77%	380	77%	391	80%	
PEACEDALE 59	59F4	492	380	77%	383	78%	393	80%	
QUONSET 83	83F1	645	349	54%	351	54%	408	63%	
QUONSET 83	83F2	490	259	53%	260	53%	315	64%	
QUONSET 83	83F3	645	340	53%	342	53%	352	55%	
WAKEFIELD 17	17F1	602	486	81%	489	81%	503	84%	
WAKEFIELD 17	17F2	602	524	87%	527	88%	542	90%	
WAKEFIELD 17	17F3	597	415	70%	418	70%	430	72%	
TOWER HILL 88	88F1	530	399	75%	402	76%	413	78%	
TOWER HILL 88	88F3	550	458	83%	460	84%	473	86%	
TOWER HILL 88	88F5	530	423	80%	426	80%	438	83%	
TOWER HILL 88	88F7	530	417	79%	420	79%	432	81%	
QUONSET 83	83F4	600	292	49%	139	23%	143	24%	
LAFAYETTE 30	30F1N	530			355	67%	365	69%	Projected in-service 2026
LAFAYETTE 30	30F2N	425			269	63%	277	65%	Projected in-service 2026
LAFAYETTE 30	30F3N	600			172	29%	177	30%	Projected in-service 2026
LAFAYETTE 30	30F4N	600			280	47%	288	48%	Projected in-service 2026

TABLE 9.3.6 – Transformer Normal Loading After Improvements

Substation	Tranf. ID.	Rating (MVA)		Projected Load						Comments
				2025		2026		2030		
		SN	SE	MVA	% SN	MVA	% SN	MVA	% SN	
BONNET 42	2	11.3	12.2	9.4	83%	9.5	84%	9.7	86%	
DAVISVILLE 84	1	45.3	52.1	24.5	54%	24.7	54%	26.3	58%	
DAVISVILLE 84	2A	45.1	51.8	30.8	68%	27.9	62%	29.6	66%	
LAFAYETTE 30	1	7.6	8.6	5.8	77%	0.0	0%	0.0	0%	Projected retirement 2026
LAFAYETTE 30	2	12.3	13.2	10.2	83%	0.0	0%	0.0	0%	Projected retirement 2026
OLD BAPTIST ROAD 46	1	48.7	54.4	17.5	36%	16.4	34%	16.9	35%	
OLD BAPTIST ROAD 46	2	48.9	51.9	19.0	39%	16.6	34%	17.0	35%	
PEACEDALE 59	1	24.2	27.2	11.8	49%	11.9	49%	12.2	51%	
PEACEDALE 59	2	24.2	27.2	15.5	64%	15.6	64%	16.0	66%	
QUONSET 83	1	25.6	26.7	14.9	58%	15.0	58%	16.4	64%	
WAKEFIELD 17	3	12.9	13.5	10.5	81%	10.6	82%	10.9	84%	
WAKEFIELD 17	4	12.9	13.5	11.3	88%	11.4	88%	11.7	91%	
WAKEFIELD 17	5	12.9	13.5	9.0	70%	9.0	70%	9.3	72%	
WEST KINGSTON 62	1	43.9	55.7	25.4	58%	25.5	58%	26.3	60%	
WEST KINGSTON 62	2	75.8	93.5	41.8	55%	42.1	55%	43.3	57%	
TOWER HILL 88	1	51	60	36.7	72%	36.9	72%	37.9	74%	
QUONSET 83	2	50	60	11.9	24%	8.6	17%	9.9	20%	
BIPCO	1	10	11.5	4.9	49%	5.0	50%	5.1	51%	
LAFAYETTE 30	T1	50	60			23.2	46%	23.9	48%	Projected in-service 2026

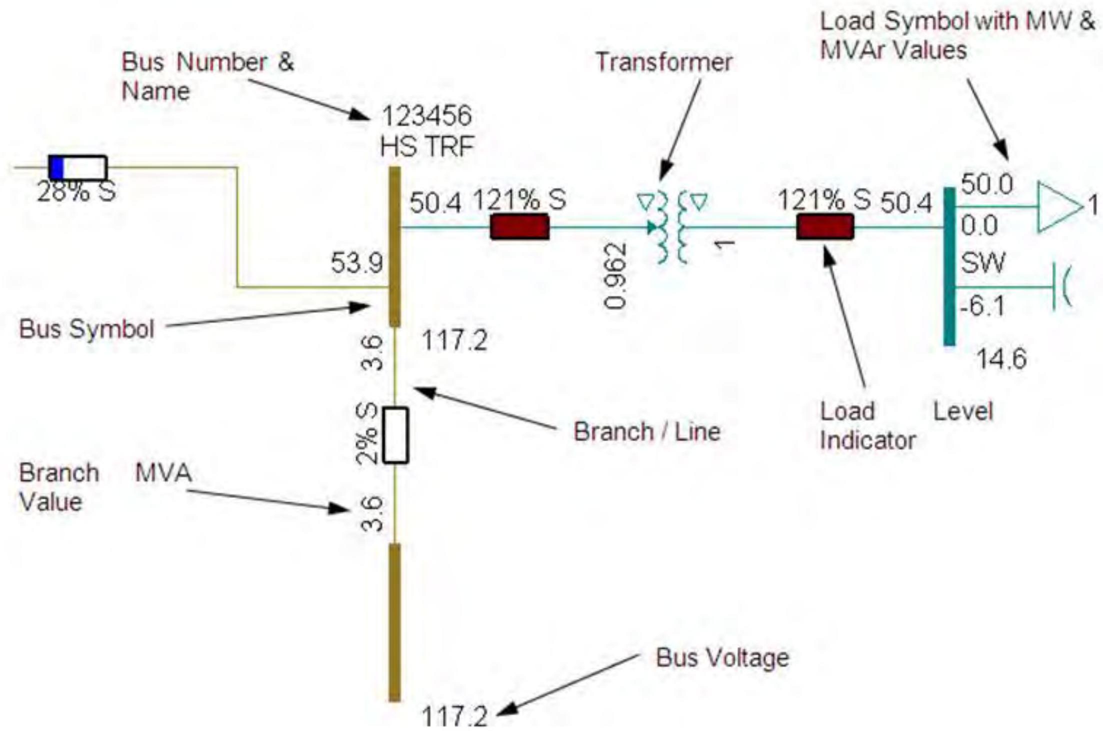
TABLE 9.3.7 – Transformer Contingency Loading After Improvements

Substation	Tranf. ID.	Rating (MVA)		Contingency Loading						
				2025		2026		2030		
		SN	SE	MVA	% SE	MVA	% SE	MVA	% SE	Remarks
BONNET 42	2	11.30	12.20	0.0	0%	0.0	0%	0.0	0%	
DAVISVILLE 84	1	45.30	52.10	55.4	106%	52.6	101%	56.0	107%	
DAVISVILLE 84	2A	45.10	51.80	55.4	107%	52.6	101%	56.0	108%	
LAFAYETTE 30	1	7.60	8.60	0.0	0%	0.0	0%	0.0	0%	Projected retirement 2026
LAFAYETTE 30	2	12.30	13.20	0.0	0%	0.0	0%	0.0	0%	Projected retirement 2026
OLD BAPTIST ROAD 46	1	48.70	54.40	36.5	67%	32.9	61%	33.9	62%	
OLD BAPTIST ROAD 46	2	48.90	51.90	36.5	70%	32.9	63%	33.9	65%	
PEACEDALE 59	1	24.20	27.20	27.3	100%	27.5	101%	28.3	104%	
PEACEDALE 59	2	24.20	27.20	27.3	100%	27.5	101%	28.3	104%	
QUONSET 83	1	25.60	26.70	25.6	96%	25.7	96%	26.4	99%	
WAKEFIELD 17	3	12.90	13.50	0.0	0%	0.0	0%	0.0	0%	
WAKEFIELD 17	4	12.90	13.50	0.0	0%	0.0	0%	0.0	0%	
WAKEFIELD 17	5	12.90	13.50	0.0	0%	0.0	0%	0.0	0%	
WEST KINGSTON 62	1	43.90	55.70	67.2	121%	67.6	121%	69.6	125%	
WEST KINGSTON 62	2	75.80	93.50	67.2	72%	67.6	72%	69.6	74%	
TOWER HILL 88	1	51.00	60.00	0.0	0%	0.0	0%	0.0	0%	
QUONSET 83	2	50.00	60.00	25.6	43%	25.7	43%	26.4	44%	
BIPCO	1	10.00	11.50	0.0	0%	0.0	0%	0.0	0%	
LAFAYETTE 30	T1	50	60	0.0	0%	0.0	0%	0.0	0%	Projected in-service 2026

9.4 Loadflow Diagrams

This section contains the electrical one-line loadflow diagrams. The diagrams show transformer and sub-transmission power flows throughout the study area. Included below are notes and guides to assist the review of these diagrams.

General Layout



LEGEND
Green = 5kV Class Equipment
Blue-Gray = 15kV Class Equipment
Aqua = 25kV Class Equipment
Tan = 35kV Class Equipment
Salmon = 46kV Class Equipment
Green = 69kV Class Equipment
Brown = 115kV Class Equipment

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9.5 CYME Radial Distribution Analysis Diagrams

Figure 9.5.1 – CYME Existing Configuration – Circuit Arrangement

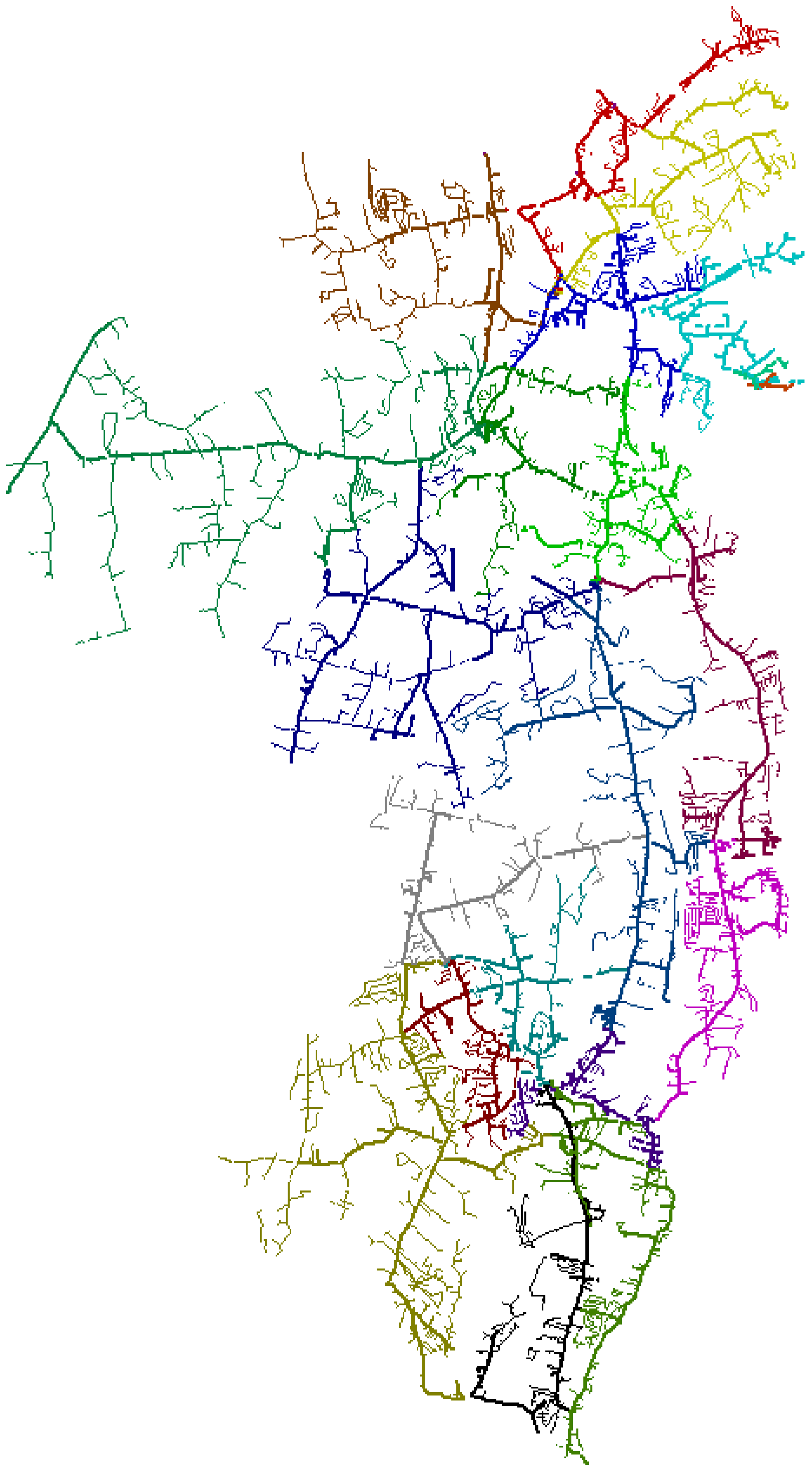


Figure 9.5.2 – CYME Existing Configuration – Loading Analysis

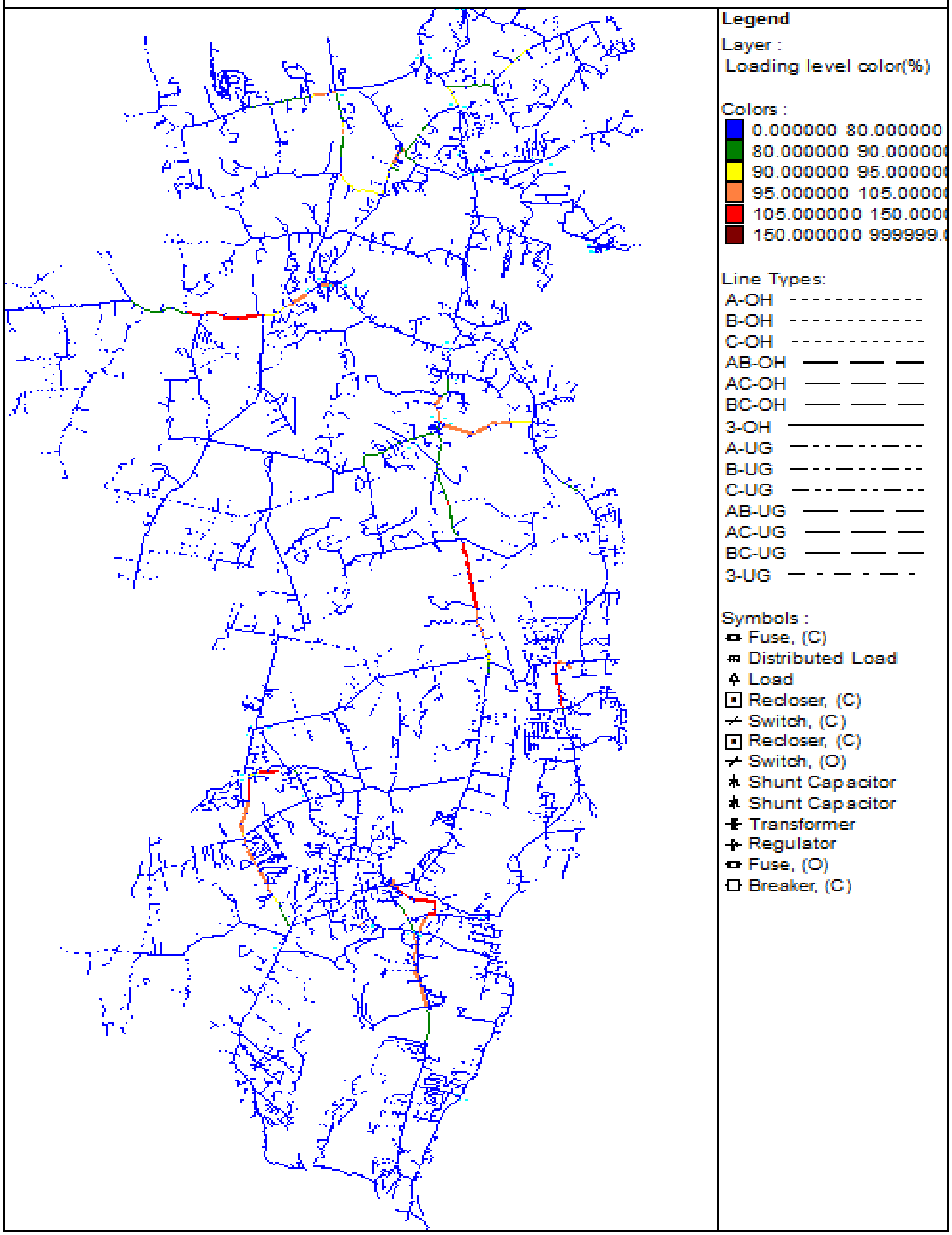
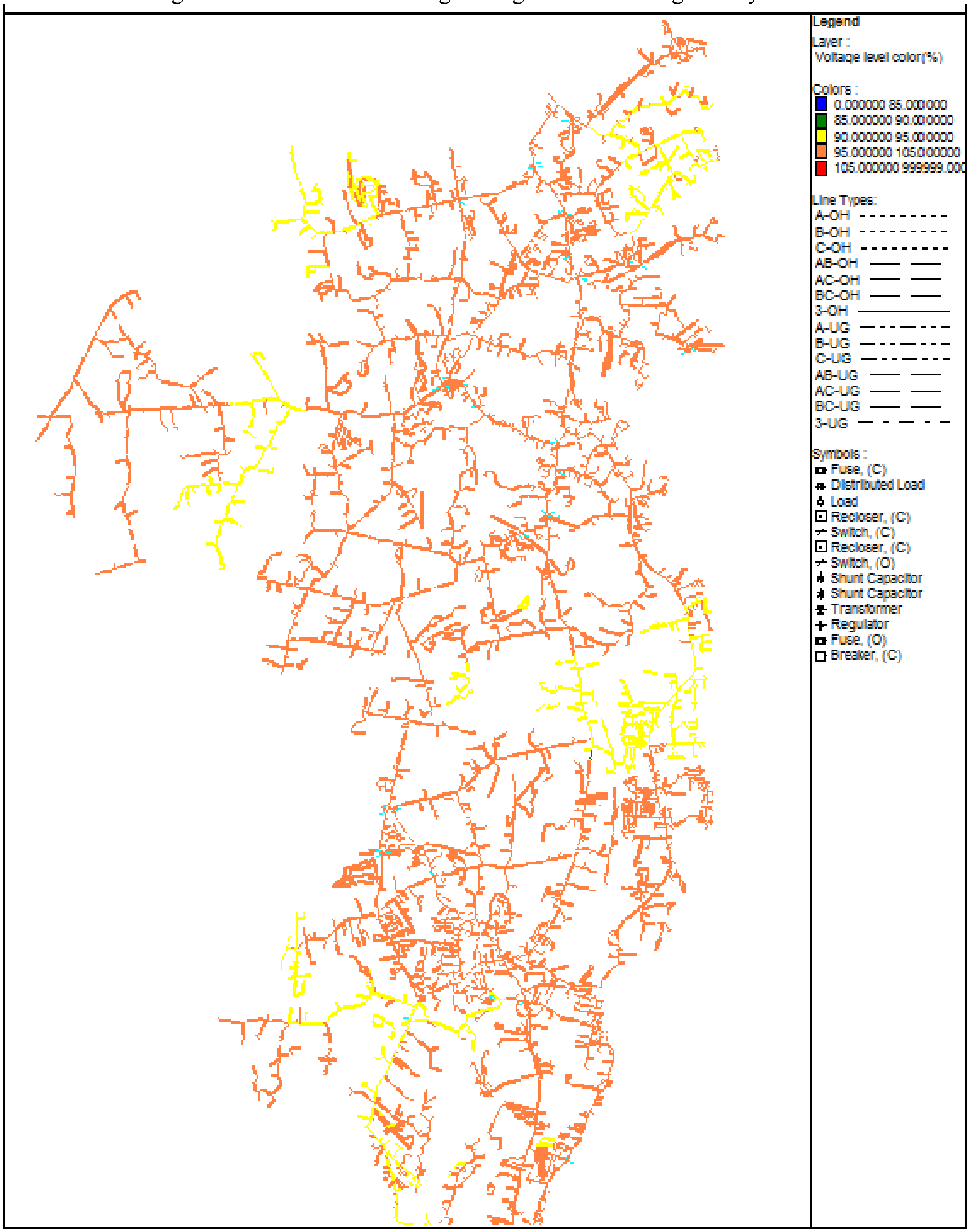


Figure 9.5.3 – CYME Existing Configuration – Voltage Analysis



9.6 Arc Flash Analysis

On April 1, 2014, the United States Department of Labor's Occupational Safety and Health Administration ("OSHA") issued final rule 1910.269 requiring the employer to assess the workplace to identify employees exposed to hazards from flames or electric arcs. Rule 1910.269 proposed compliance dates of January 1, 2015 and April 1, 2015 for completion of the hazard assessment and implementation of the assessment results respectively. As the industry adjusted to these new requirements and calculation methods, the dates were adjusted to March 31, 2015 and August 31, 2015.

A review using CYME fault current analysis and protection coordination values with ArcPro incident energy calculations provided an analysis in compliance with OSHA requirements. Table 9.6.1 shows the results of this analysis with no study area feeders indicating incident energies above 8 calories per centimeter squared (cal/cm^2).

TABLE 9.6.1 – Arc Flash Analysis (Existing System)

Substation	Feeder	Voltage kV	L-G Fault		Incident Energy (cal/cm2)
			Amps	Relay Time (Sec)	
BONNET	49_56_42F1	12.47	3,406	0.4095	1.29
LAFAYETTE	49_56_30F1	12.47	2,904	0.4427	1.16
LAFAYETTE	49_56_30F2	12.47	4,154	0.2300	1.00
OLD BAPTIST RD	49_56_46F1	12.47	6,440	0.3216	2.06
OLD BAPTIST RD	49_56_46F2	12.47	6,939	0.2627	2.13
OLD BAPTIST RD	49_56_46F3	12.47	5,796	0.4512	2.81
OLD BAPTIST RD	49_56_46F4	12.47	6,767	0.3304	2.22
PEACEDALE	49_56_59F1	12.47	6,137	0.3059	1.84
PEACEDALE	49_56_59F2	12.47	6,162	0.3137	1.85
PEACEDALE	49_56_59F3	12.47	6,192	0.2669	1.54
PEACEDALE	49_56_59F4	12.47	6,132	0.2693	1.52
QUONSET	49_56_83F1	12.47	4,517	0.4700	2.10
QUONSET	49_56_83F2	12.47	5,529	0.3600	2.10
QUONSET	49_56_83F3	12.47	4,516	0.4700	2.10
QUONSET	49_56_83F4	12.47	5,497	0.3600	2.10
TOWER HILL	49_56_88F1	12.47	6,029	0.2291	1.53
TOWER HILL	49_56_88F3	12.47	6,058	0.2508	1.68
TOWER HILL	49_56_88F5	12.47	6,000	0.2752	1.34
TOWER HILL	49_56_88F7	12.47	6,019	0.3277	2.23
WAKEFIELD	49_56_17F1	12.47	4,186	0.3638	1.49
WAKEFIELD	49_56_17F2	12.47	4,260	0.2941	1.17
WAKEFIELD	49_56_17F3	12.47	4,337	0.4581	1.97

9.7 Fault Duty Analysis

The ASPEN program was used to calculate single phase to ground and three phase short circuit current values at each area substation. These short circuit current values were compared to the station breaker interrupting capabilities. No fault current exceeds the interrupting capability of the breakers. The table in Appendix 9.7.1 summarizes the results of this analysis.

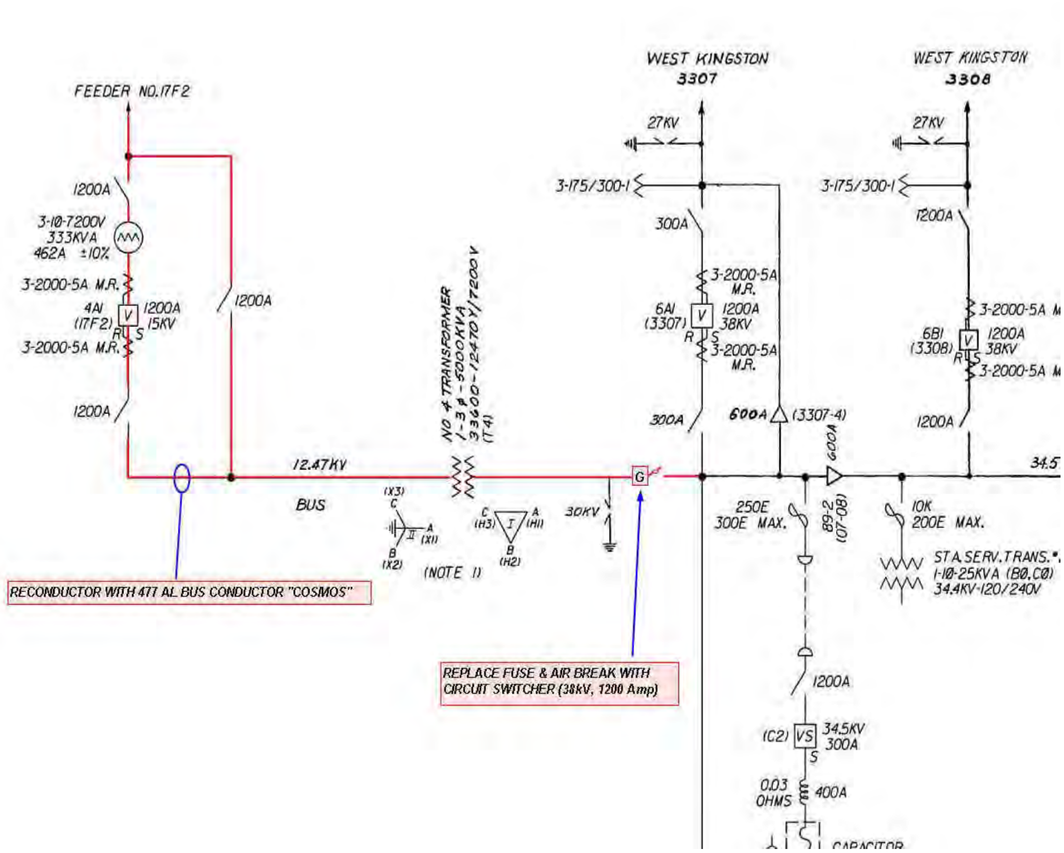
Figure 9.7.1 – Breaker Duty Analysis

Loaction	Position	Class	Rated IC (Amps)	1-Phase Fault (Amps)
Davisville	84T1	38kV	25,000	3,627
Davisville	84T2	38kV	25,000	3,210
Davisville	84T3	38kV	25,000	3,627
Davisville	84T4	38kV	25,000	3,210
Davisville	1-2 VCB	38kV	34,500	3,627
Davisville	3-4 TIE	38kV	25,000	3,627
Wakefield	3302 VCB	38kV	20,000	2,522
Wakefield	3308 VCB	38kV	20,000	2,522
Wakefield	3307 VCB	38kV	20,000	2,522
West Kingston	3307 OCB	38kV	22,000	7,901
West Kingston	3308 OCB	38kV	22,000	7,901
West Kingston	C21 OCB	38kV	22,000	7,901
West Kingston	C22 OCB	38kV	22,000	7,901
West Kingston	C2107 OCB	38kV	22,000	7,901
West Kingston	C2208 OCB	38kV	22,000	7,901
Bonnet	42F1 VCR	15kV	12,000	3,641
Lafayette	30F1 VCR	15kV	12,000	4,170
Lafayette	30F2 VCR	15kV	12,000	4,170
Old Baptist Rd	46F1 VCB	15kV	20,000	7,277
Old Baptist Rd	46F2 VCB	15kV	20,000	7,277
Old Baptist Rd	46F4 VCB	15kV	20,000	7,277
Old Baptist Rd	46F3 VCB	15kV	20,000	7,277
Old Baptist Rd	1-2 TIE VCB	15kV	20,000	7,277
Old Baptist Rd	3-4 TIE VCB	15kV	20,000	7,277
Peacedale	59F2 VCR	15kV	12,000	6,467
Peacedale	59F1 VCR	15kV	12,000	6,467
Peacedale	1-2 VCR	15kV	12,000	6,467
Peacedale	59F3 VCR	15kV	12,000	6,467
Peacedale	59F4 VCR	15kV	12,000	6,467
Peacedale	3-4 VCR	15kV	12,000	6,467
Quonset	83F1	15kV	12,000	3,773
Quonset	83F2	15kV	12,000	3,773
Quonset	83F3	15kV	12,000	3,773
Tower Hill	F1 VCB	15kV	20,000	8,277
Tower Hill	F3 VCB	15kV	20,000	8,277
Tower Hill	F5 VCB	15kV	20,000	8,277
Tower Hill	F7 VCB	15kV	20,000	8,277
Tower Hill	BT12 VCB	15kV	20,000	8,277
Tower Hill	C1 VCB	15kV	20,000	8,277

Tower Hill	1T12 VCB	15kV	20,000	8,277
Wakefield	17F2 VCB	15kV	20,000	4,420
Wakefield	17F1 VCB	15kV	20,000	3,215
Wakefield	17F3 VCB	15kV	20,000	4,459

9.8 Plan Development – Common Items

FIGURE 9.8.1 – WAKEFIELD SUBSTATION ONE-LINE DIAGRAM (COMMON ITEM)



9.9 Plan Development – Plan 1

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FIGURE 9.9.3 – PROPOSED 34.5 kV SUPPLY SYSTEM (PLAN 1)

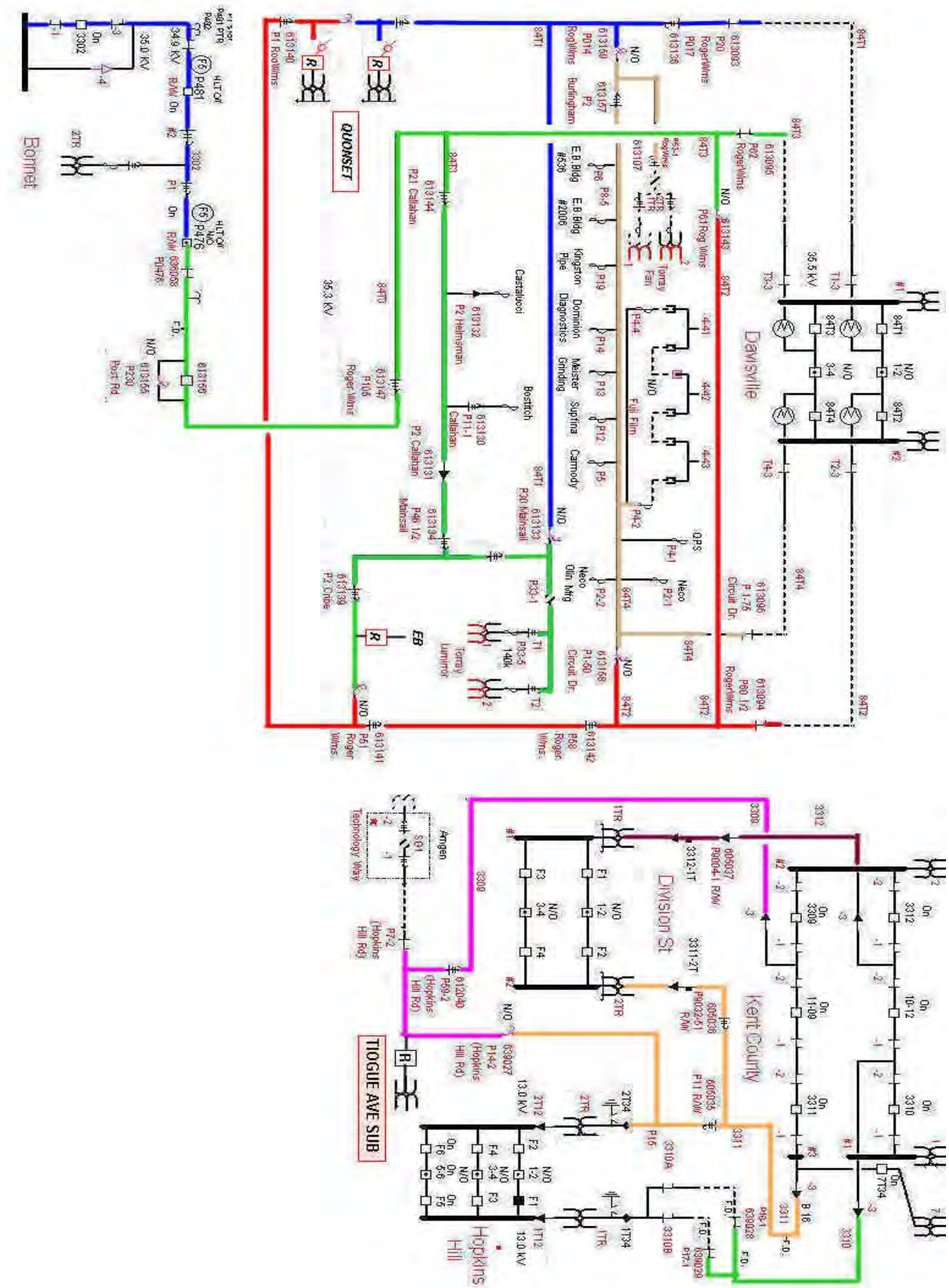
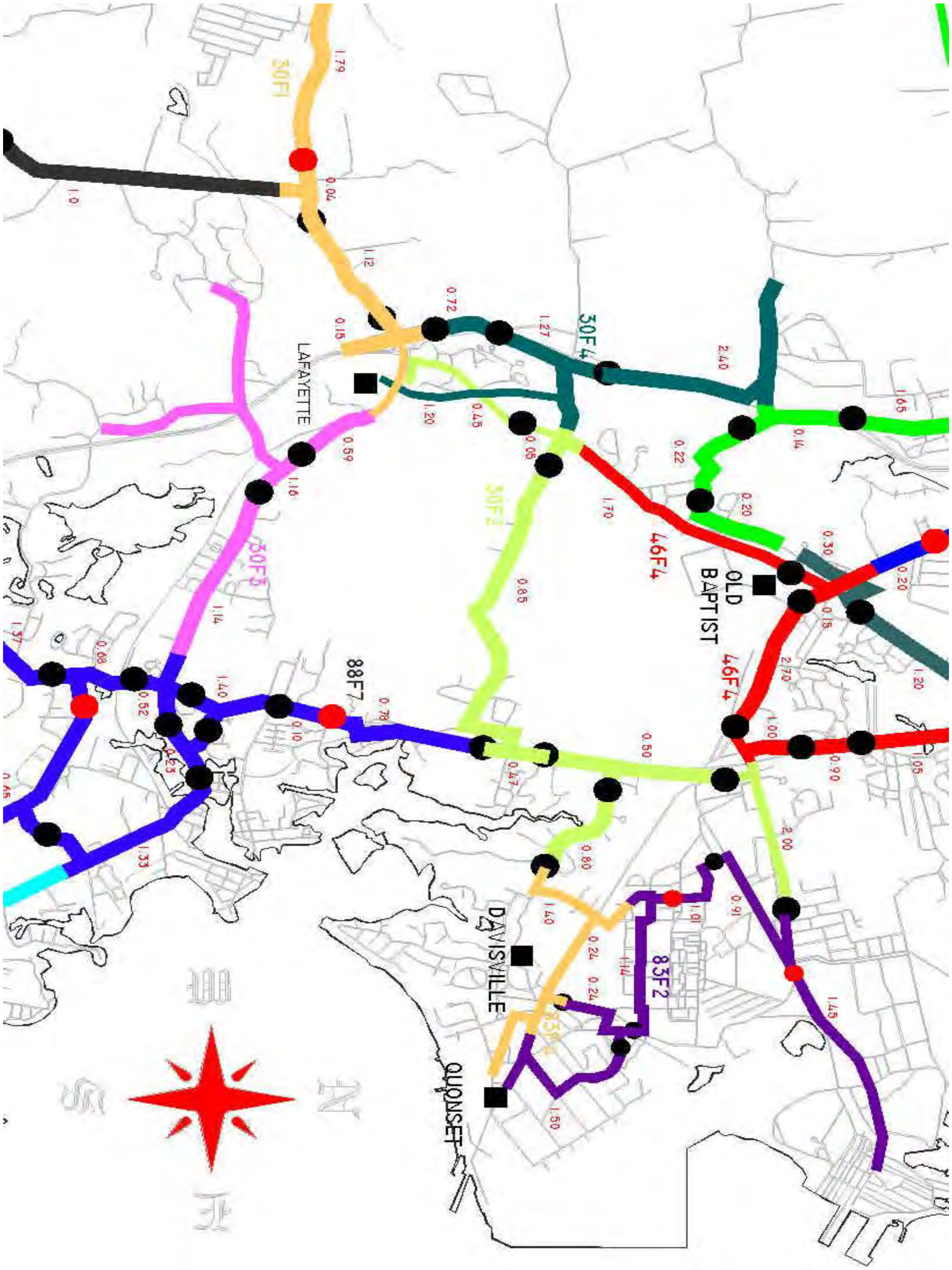


FIGURE 9.9.4 – PROPOSED MAINLINE DISTRIBUTION (PLAN 1)



9.10 Plan Development – Plan 2

This plan recommends a new 115/12.47 kV substation in Quonset to be built on a green field site. A site will have to be acquired by Quonset Development Corporation (QDC) or some other private party. The proposed substation would consist of a single 115/12.47 kV 24/32/40 MVA LTC transformer, three feeder positions, and one 7.2 MVAr station capacitor bank consisting of two 3.6 MVAr stages. The preferred arrangement of the station is a metal-clad straight bus design. Extend the G-185S (115 kV) line to supply the station. Install a motor operated, remotely controlled, SCADA enabled, load break switch at the tap position.

A manhole and ductline system will be built for the feeder getaways out to city streets. The feeders will general follow existing overhead routes. The existing overhead system will be modified to accommodate the three new feeders. This plan requires approximately 1-mile of new overhead construction.

This plan maintains an extensive 34.5kV transmission system. Both the 3312 line and the 84T3 line will be refurbished to maintain a safe and reliable supply to Lafayette substation. Because of the anticipated wetland challenges along with restrictive backyard construction, it is recommended that the lines be refurbished to include all items needed within the next 20-30 years. Outage restrictions may require line refurbishment outside of peak loading periods.

Opportunities were reviewed and high level estimates developed to relocate portions of the 3312 and 84T3 lines to the roadway where practical and where the right-of-way has significant wetland challenges or backyard construction with restricted access. These costs are not included in Plan 2 costs but are documented here as additional costs to relocate sections of these lines to the roadway. If plan 2 was to be selected for implementation, relocation of these lines to the roadway should be further investigated to provide reasonable access to maintain these lines. Because Plan 2 is not recommended, it was not fiscally prudent to further develop the relocation of these lines.

Description	Cap	O&M	Rem	Total
Relocate section of 84T3 line to Lafayette to roadway	$3.9022	$0.0582	$0.8054	$4.7658
Relocate section of 84T3 line section to Anvil to roadway	$2.0162	$0.0000	$0.2542	$2.2704
Relocate 3312 Line to roadway	$2.8404	$0.1433	$0.3680	$3.3517
Total Spend	$8.7589	$0.2015	$1.4276	$10.3880

The investments and expenses for Plan 2 are detailed in the table below. These investments refurbish the sub-transmission lines in place and do not relocate them to the roadway. Relocating lines to the roadway as discussed above will increase the cost of Plan 2.

TABLE 9.10.1 - Estimated Investments and Expenses for Plan 2

Component ($M)	Capex	Opex	Removal	Total
Mainsail Substation (T-Line)	$2.030	$0.040	$0.130	$2.200

Mainsail Substation (T-Sub)	$1.950			$1.950
Mainsail Substation (D-Sub)	$10.100			$10.100
Mainsail Substation (D-Line)	$4.410	$0.020	$0.120	$4.550
3312 Line Refurbishment (T-Line)	$7.350	$0.200	$0.550	$8.100
84T3 Line Refurbishment (D-Line)	$9.300		$0.400	$9.700
Plan 2 (T-Spend)	$11.330	$0.240	$0.680	$12.250
Plan 2 (D-Spend)	$23.810	$0.020	$0.520	$24.350
Total PLAN 2 Spend	$35.140	$0.260	$1.200	$36.600

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9.11 Plan Development – Plan 3

This plan recommends expanding the 115/12.47 kV station at Old Baptist by installing a third bay and installing station capacitor banks. The specific scope of work includes installing the 46F5 and 46F6 feeders and installing (2) 7.2 MVAr station capacitor banks each consisting of two 3.6 MVAr stages.

A manhole and ductline system will be built for the feeder getaways. The feeders will general follow existing overhead routes. The existing overhead system will be modified to accommodate the two new feeders. This plan requires approximately ¾-miles of new overhead construction and approximately ¾-miles of underground construction.

This plan maintains an extensive 34.5kV transmission system. Both the 3312 and 84T3 lines will be refurbished to maintain a safe and reliable supply to Lafayette substation. Because of the anticipated wetland challenges along with restrictive backyard construction, it is recommended that the lines be refurbished to include all items needed within the next 20-30 years. Outage restrictions may require line refurbishment outside of peak loading periods.

Opportunities were reviewed and high level estimates developed to relocate portions of the 3312 and 84T3 lines to the roadway where the right-of-way has significant wetland challenges or backyard construction with restricted access. These costs are not included in Plan 3 costs but are documented here as additional costs to relocate sections of these lines to the roadway. If plan 3 was to be selected for implementation, relocation of these lines to the roadway should be further investigated to provide reasonable access to maintain these lines. Because Plan 3 is not recommended, it was not fiscally prudent to further develop the relocation of these lines.

Description	Cap	O&M	Rem	Total
Relocate section of 84T3 line to Lafayette to roadway	$3.9022	$0.0582	$0.8054	$4.7658
Relocate section of 84T3 line section to Anvil to roadway	$2.0162	$0.0000	$0.2542	$2.2704
Relocate 3312 Line to roadway	$2.8404	$0.1433	$0.3680	$3.3517
Total Spend	$8.7589	$0.2015	$1.4276	$10.3880

The investments and expenses for Plan 3 are detailed in Table below. These investments refurbish the sub-transmission lines in place and do not relocate them to the roadway. Relocating lines to the roadway as discussed above will increase the cost of Plan 3.

TABLE 9.11.1 – Estimated Investments and Expenses for Plan 3:

Component ($M)	Capex	Opex	Removal	Total
Old Baptist Substation (D-Sub)	$4.400	$0.000	$0.100	$4.500
Old Baptist Substation (D-Line)	$3.330	$0.030	$0.040	$3.400
3312 Line Refurbishment (T-Line)	$7.350	$0.200	$0.550	$8.100
84T3 Line Refurbishment (D-Line)	$9.300	$0.000	$0.400	$9.700
Plan 3 (T-Spend)	$7.350	$0.200	$0.550	$8.100
Plan 3 (D-Spend)	$17.030	$0.030	$0.540	$17.600
Total PLAN 3 Spend	$24.380	$0.230	$1.090	$25.700

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9.12 Distributed Generation within Study Area

FIGURE 9.12.1 – Existing and Proposed Distributed Generation within Study Area

Circuit	Status	Name Plate (MW)	Type
West Kingston Substation			
3307/3308	Existing	30.000	Inverter Based - Wind
3307/3308	Pending	2.200	Inverter Based - PV
3307/3308	Pending	0.900	Inverter Based - PV
3307/3308	Pending	3.780	Inverter Based - PV
Davisville Substation			
84T3	Pending	3.060	Inverter Based - PV
84T4	Existing	12.500	Cogen-Natural Gas
84T3	Existing	8.000	Cogen-Natural Gas
83F2	Existing	0.495	Inverter Based - PV
115kV Supplied Stations			
46F4	Pending	1.000	Inverter Based - PV
46F4	Existing	2.000	Inverter Based - PV
88F1	Pending	0.878	Inverter Based - PV
88F1	Pending	0.888	Inverter Based - PV
TOTAL		**65.70**	

9.13 Reactive Compensation

ISO-NE conducts an annual survey of actual load power factor operations and compares it against the applicable standards. The latest survey has this overall area compliant at all times. The results of this survey are shown on Table 4.4.6 below:

TABLE 9.12.1: ISO-NE Power Factor Survey Results (Narragansett Electric)

COMPLIANCE REPORT						CURRENT LPF SURVEY SUMMARY					
Spring	Summer		Fall	Winter		Spring	Summer		Fall	Winter	
9,135	22,193	24,409	9,197	18,192	20,556	9,135	22,193	24,409	9,197	18,192	20,556
5/18/14	07/23/2014	07/02/14	10/19/14	12/18/14	1/8/15	5/18/14	07/23/2014	07/02/14	10/19/14	12/18/14	1/8/15
5:00	12:00	15:00	4:00	18:00	18:00	5:00	12:00	15:00	4:00	18:00	18:00
compliant	compliant	compliant	compliant	compliant	compliant	0.971	0.996	0.998	0.974	0.995	0.998

The power factor performance of the study area's feeders is limited to those that have PI data availability. Peak power factor performance for most feeders shows them to be near unity with only a few feeders needing some reactive support. Available data for major 115kV transformer interfaces and the 34.5 kV sub-transmission lines also show power factor near unity.

9.14 Permitting, Licensing, Real Estate, and Environmental Considerations

Recommended Plan (Plan 1)

The recommended plan is to build a new substation at the Lafayette substation site. The new 115kV/12.47kV substation requires plot size 205' x 142' and considers space for future development. The new station will be within National Grid boundary area. No land acquisition is required.

Based upon FEMA Flood Insurance Rate Map 44009C0103H flood zone map the substation is located outside the 100 year flood plan with designated flood zone X as such mitigation is not required. A new 694 feet long perimeter chain link fence with two double swing gates will be required.

An environmental assessment will be required during final design including: Local Soil Erosion and Sediment Control Ordinance triggers (town level) and an SPCC plan since this is a new site; Any additional local zoning by-laws that may have an environmental element; Review of the land by a National Grid cultural/historical consultant; Coordination with Rhode Island Natural Heritage Program (RINHP) for rare, threatened and endangered species.

Alternative Plan (Plan 2)

This alternate plan would build a new substation in Quonset. A suitable substation land parcel must be acquired for this substation. One potential site is owned by the Quonset Development Corporation (QDC). This potential site has reasonable access to the 115kV transmission system, but it still requires a transmission extension of approximately 1,000 feet or more.

The company has approached the QDC about the potential acquisition of this site. The QDC has stated the site in question is under a 25-year lease to Electric Boat (EB). It is unlikely we can reach agreement with QDC and EB to acquire either a portion or the whole site. It is more likely the company will need to find a new site. A new site may add to the challenge in the need to extend the 115kV system to the substation site. Plan 2 has the most risk of the three plans.

Alternative Plan (Plan 3)

This alternative would add a third bay at Old Baptist Road substation with two new 12.47kV distribution feeders and a tie breaker. In addition, it would install (2) two-stage 7.6 MVAr station capacitor banks each with (2) 3.6 MVAr stages.

The existing substation has limited space for expansion and will require extension to existing substation boundary. Existing fence will be extended with new perimeter chain link fence for expansion. The extension work to existing substation will require additional plot area of 60' x 115' and to create level substation pad.

The expansion will be within National Grid's property line and will not require any land acquisition. Review is required if site is located near any wetlands. Based upon FEMA Flood Insurance Rate Map 44009C0101H, the substation is located outside the 100 year flood plan under flood zone X and no mitigation measure is required. 155 feet of new low voltage animal deterrent fence and 250 feet of new 7' high chain link fence will be required.

The following will be performed during final design: Coordination with Rhode Island Natural Heritage Program (RINHP) for rare, threatened and endangered species; Review of Local Soil Erosion and Sediment Control Ordinance triggers (town level); Review of the land by a National Grid cultural/historical consultant; Any additional local zoning by-laws that may have an environmental element; Storm water management plan.

9.15 Narragansett 42F1 NWA RFP Reports

National Grid USA Service Company, Inc.

ISSUED: DECEMBER 13, 2018
SUBMISSION DEADLINE: FEBRUARY 11, 2019

nationalgrid

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1. Introduction

National Grid is a gas and electric investor-owned utility serving nearly 3.3 million electric and 3.5 million gas customers through its subsidiary companies in Massachusetts, New York, and Rhode Island.
National Grid is committed to providing safe, reliable, and affordable energy to all customers throughout our service territory. As a part of providing this service, National Grid is pursuing the potential implementation of Non-Wires Alternative (NWA) solutions in Rhode Island. Such implementation aligns with principles set forth by the RI PUC Title 39 § 39-1-27.7 – System Reliability and Least-Cost Procurement.
National Grid has been pursuing Non-Wires Alternative projects across its service territories for several years.

2. Definition of NWA

Non-Wires Alternative (NWA), sometimes referred to as Non-Wires Solution (NWS), is the inclusive term for any electrical grid investment that is intended to defer or remove the need for traditional equipment upgrades or construction, or "wires investment", to distribution and/or transmission systems.
These NWA investments are required to be cost-effective compared to the traditional wires investment and are required to meet the specified electrical grid need.
An NWA can include any action, strategy, program, or technology that meets this definition and these requirements.
Some technologies and methodologies that can be applicable as an NWA investment include demand response, solar, energy storage, combined heat and power (CHP), microgrid, conservation or energy efficiency measure, and other distributed energy resources (DERs). NWA projects can include these and other investments individually or in combination to meet the specified need in a cost-effective manner.

3. Our Goal

This RFP seeks to identify technologies and/or methodologies that, if implemented, will provide an NWA solution for a geographical area that has an electrical grid need. This area and need are identified in Section 4 – Project Overview.
This RFP is open to all NWA approaches. This RFP is meant to assess the best-fit technology type for this NWA project.
Any proposed NWA solutions will need to defer the traditional distribution asset starting in May 2024 and operating until at least 2030. Any NWA solutions that exceed this timeline will also be considered. Please note that National Grid is seeking solutions that currently exist to solve the stated need.
Proposed technologies and methodologies should have the capability to address the electrical grid need and increase grid reliability while being cost-effective in comparison to the traditional wires investment. Proposed technologies and methodologies should also be available when

needed and respond immediately when called upon for the duration of NWA solution implementation.

To assist qualified bidders this document provides an overview of the project objectives, detailed business requirements and response submission information.

As outlined in the RFP Schedule section of this document, bidders will have the opportunity to submit questions that assist in creating a response for this initiative. Please see the RFP Timeline Schedule for dates associated with RFP milestones below.

4. Project Overview

Potential for Non-Wires Alternative Project in Narragansett, RI

4.1. Background

The Town of Narragansett is mostly supplied by (4) 12.47 kV distribution feeders. Two feeders (42F1 and 17F2) are projected to be loaded above summer normal ratings by 2021 and lack useful feeder ties to reduce loading below their ratings. Either more capacity must be added or load must be reduced in the town. Both a wires and a non-wires option was developed to address these projected overloads.

- **Wires Option:** Upgrade the Wakefield 17F2 feeder and modify the 17F3 feeder. This investment increases capacity and switching flexibility to relieve the heavily loaded facilities and resolves the projected overloads.
- **Non-Wires Option:** See Sections 4.1 and 4.2 below for Non-Wires requirements.

4.2. Technical Requirements

Problem Statement						
Description	The Company is seeking to provide load relief for the Bonnet 42F1 feeder.					
Technical Information	**Substation**	**Feeder**	**Operating Voltage**	**Summer Normal Rating (Amps)**	**Overloaded By**	**Load Reduction Needed (kW)**
	Bonnet	42F1	12.47 kV	525	2024	2070

Solution Requirements	
Technical Requirements	Maintain feeder loading below 90% of summer normal rating over a ten-year period by proposing a NWA solution that reduces loading on the feeder by 2070kW through 2030.
In Service Date	2024

Maximum MWHr need	Based on historic data 23 MWhrs total over the course of a year by 2030.
Lifetime	10 years minimum
Call Response Time	24 hours
Days of the Week needed	Any days that the day-ahead ISO-NE load forecast applied to the Project Feeders indicates that loading will exceed 90% of the Feeder Summer normal rating. This could be both weekdays and weekends.
Time of Day	Any time of day.
Number of Time Called Per Year	A minimum of 5 days based on historic data In order to account for the potential of a heat wave, the project may be called for 5 or more days in a row during peak load times.
Minimum Period between Calls	24 hours


42F1 Feeder Mainline
Bonnet Substation
Narrow River
S Ferry Rd
BONNET SHORES
Middlebridge Rd
Middlebridge Rd
Bonnet Point Rd
Colonel John Gardner Rd
Narragansett
Narragansett Town Beach

Any DER location downstream of the target feeder getaways (where the feeder leaves the station) should solve the loading issue, pending a full interconnection study. See feeder maps above.
NOTE: Subject to changes in forecasted needs, solution pricing, as well as any other applicable costs and benefits, National Grid is targeting to procure demand response and/or generation/storage that could supply the substation(s) load in its entirety or a large portion of it. During normal operation, any excess power could be exported to the National Grid System. Depending on such factors as economics, portfolio fit, etc.

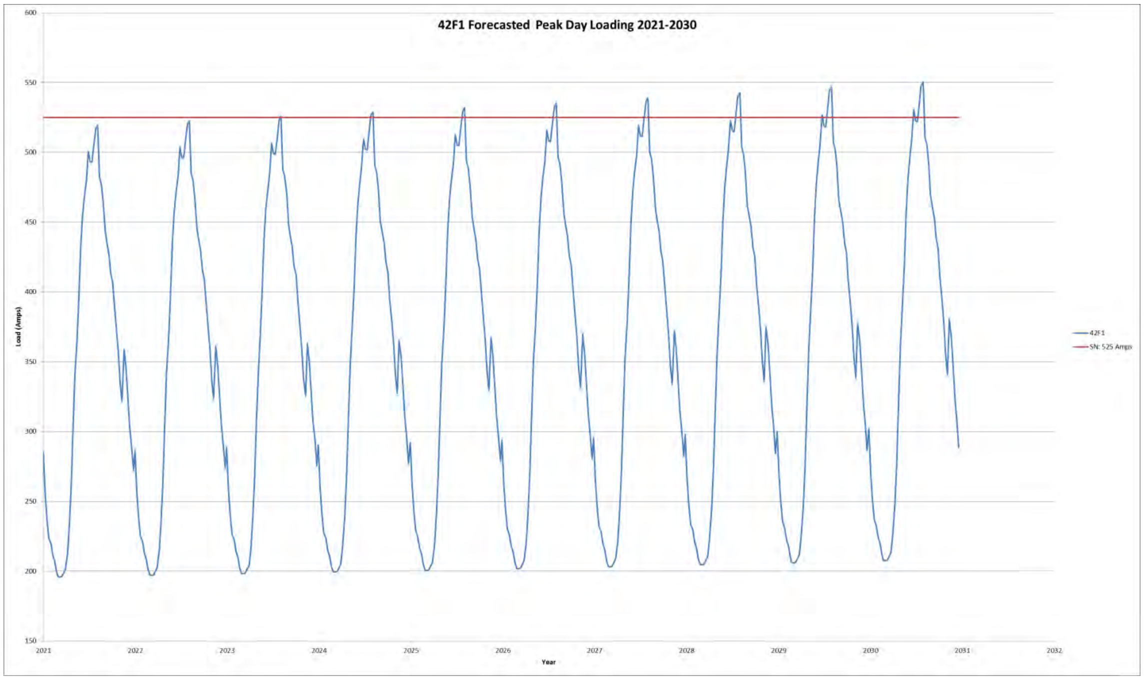
4.3. Technical Details

Substation	Feeder	Operating Voltage	Summer Normal Rating (Amps)	Overloaded By	Load Reduction Needed (kW)
Bonnet	42F1	12.47 kV	525	2024	2070

Substation	Feeder	Commercial Customers	Residential Customers	Total
Bonnet	42F1	184	2714	2898

4.3.1. Feeder Loading

Loading on the 42F1 and 17F2 feeders is predicted to be over 100% of their summer normal ratings and will be overloaded over the next ten years. All other facilities' loadings are within their normal equipment ratings. The rating of feeders is determined by the equipment with the most limiting element (that with the lowest normal summer rating). The load forecast utilizes a technique called weather normalization, a process that assumes future year peaks will occur given high loading condition (e.g., a June peak will occur on hot day, where the temperature in the 95th percentile of hottest years). The charts below show the projected load on the feeders using the peak day at the time of study and the loads are grown according to the forecasted analysis.



4.4. Solution Timeline

National Grid requires that any proposed NWA solutions will need to defer the traditional distribution asset starting in May 2024.
National Grid requires that any proposed NWA solutions will need to defer the traditional distribution asset until at least 2030. Any NWA solutions that exceed this timeline will also be considered.

5. Project Cost

National Grid is seeking solutions that provide value to the customer and are cost-effective.
The NWA solution shall have a total cost not to exceed a Net Present Value (NPV) of $336,800, based on traditional distribution asset deferral until at least 2030.
National Grid is open to considering shared capital costs or owning a non-generation solution or asset.
National Grid encourages vendors to participate in relevant external revenue streams to produce the most cost-effective solution.
Pricing models to be considered shall be as follows:

- Capital Expenditure
- Annual service fee
- Energy Services Agreement for capacity delivered (i.e., dollars per kW)
- Any combination of the above

6. Instructions for Bidders

6.1. Response and Deliverables

This section describes the list of items and deliverables required from the bidder. Please provide detail in your response as to why the technology/solution your firm proposes is the best-fit for this NWA project. All items should be responded to in the context of the project listed in Section 4 – Project Overview.
Please provide a concise written response under 15 pages (excluding appendices) for ease of review. There will be sections to upload additional documents on the Ariba Platform.
Responses that do not provide the requested information below can be disqualified. Bidders must submit their responses in the following format.

- Executive Summary of Proposed Technology/Solution
- Financial Plan
    - Cost of Technology/Solution for the Specified Need
    - Cost comparison to other technologies/solutions
    - Bidder's Suggested Financial Plan
- Implementation of Technology/Solution
    - Technology/Solution Reliability, with Documentation on the Solution's Technical Reliability
    - Examples of Firm's Application of Technology/Solution
- Timeline for Technology/Solution Installation
- Bidder Qualifications (To be included as an Appendix)

Bidders must additionally provide the following as an Appendix/Attachment:

- List of Historical Project Permits
- Historical Safety Record
- List of Current Environmental Certifications
- List of Historical Project Environmental/Eco awards

6.2. Submittal Requirements

Submittal requirements for this NWA RFP are as follows:

- Overall proposal document as detailed in Section 6.1.
- Pricing Model spreadsheet as provided in the Ariba platform.

6.3. Evaluation Criteria

This section describes the evaluation criteria that project bid responses will be screened with.

- Cost
- Scalability
- Load Reduction Capability
- Feasibility of Proposed Technology Type/Solution
- Risk of Proposed Technology Type/Solution Creating Negative System Impacts
- Environmental or "Green" Requirement

6.4. RFP Schedule

- RFP Launch: 12/7/2018
- Bidders Conference Call: 12/17/2018
- Last date to submit questions: 1/18/2019
- Responses Due: 2/11/2019

6.5. Rhode Island System Data Portal

National Grid has developed a new web-based tool called the Rhode Island System Data Portal that houses a collection of maps to help customers, contractors, and developers identify potential project sites and with project bidding and development. Each map provides the location and specific information for selected electric distribution lines and associated substations within the National Grid electric service area in Rhode Island.

The Rhode Island System Data Portal can be found at the following location:

https://www.nationalgridus.com/Business-Partners/RI-System-Portal

9.16 Narragansett 17F2 NWA RFP Reports

National Grid USA Service Company, Inc.

ISSUED: DECEMBER 13, 2018
SUBMISSION DEADLINE: FEBRUARY 11, 2019

nationalgrid

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7. Introduction

National Grid is a gas and electric investor-owned utility serving nearly 3.3 million electric and 3.5 million gas customers through its subsidiary companies in Massachusetts, New York, and Rhode Island.
National Grid is committed to providing safe, reliable, and affordable energy to all customers throughout our service territory. As a part of providing this service, National Grid is pursuing the potential implementation of Non-Wires Alternative (NWA) solutions in Rhode Island. Such implementation aligns with principles set forth by the RI PUC Title 39 § 39-1-27.7 – System Reliability and Least-Cost Procurement.
National Grid has been pursuing Non-Wires Alternative projects across its service territories for several years.

8. Definition of NWA

Non-Wires Alternative (NWA), sometimes referred to as Non-Wires Solution (NWS), is the inclusive term for any electrical grid investment that is intended to defer or remove the need for traditional equipment upgrades or construction, or “wires investment”, to distribution and/or transmission systems.
These NWA investments are required to be cost-effective compared to the traditional wires investment and are required to meet the specified electrical grid need.
An NWA can include any action, strategy, program, or technology that meets this definition and these requirements.
Some technologies and methodologies that can be applicable as an NWA investment include demand response, solar, energy storage, combined heat and power (CHP), microgrid, conservation or energy efficiency measure, and other distributed energy resources (DERs).
NWA projects can include these and other investments individually or in combination to meet the specified need in a cost-effective manner.

9. Our Goal

This RFP seeks to identify technologies and/or methodologies that, if implemented, will provide an NWA solution for a geographical area that has an electrical grid need. This area and need are identified in Section 4 – Project Overview.
This RFP is open to all NWA approaches. This RFP is meant to assess the best-fit technology type for this NWA project.
Any proposed NWA solutions will need to defer the traditional distribution asset starting in May 2021 and operating until at least 2030. Any NWA solutions that exceed this timeline will also be considered. Please note that National Grid is seeking solutions that currently exist to solve the stated need.
Proposed technologies and methodologies should have the capability to address the electrical grid need and increase grid reliability while being cost-effective in comparison to the traditional wires investment. Proposed technologies and methodologies should also be available when

needed and respond immediately when called upon for the duration of NWA solution implementation.
To assist qualified bidders this document provides an overview of the project objectives, detailed business requirements and response submission information.
As outlined in the RFP Schedule section of this document, bidders will have the opportunity to submit questions that assist in creating a response for this initiative. Please see the RFP Timeline Schedule for dates associated with RFP milestones below.

10.Project Overview

Potential for Non-Wires Alternative Project in Narragansett, RI

10.1. Background

The Town of Narragansett is mostly supplied by (4) 12.47 kV distribution feeders. Two feeders (42F1 and 17F2) are projected to be loaded above summer normal ratings by 2021 and lack useful feeder ties to reduce loading below their ratings. Either more capacity must be added or load must be reduced in the town. Both a wires and a non-wires option was developed to address these projected overloads.

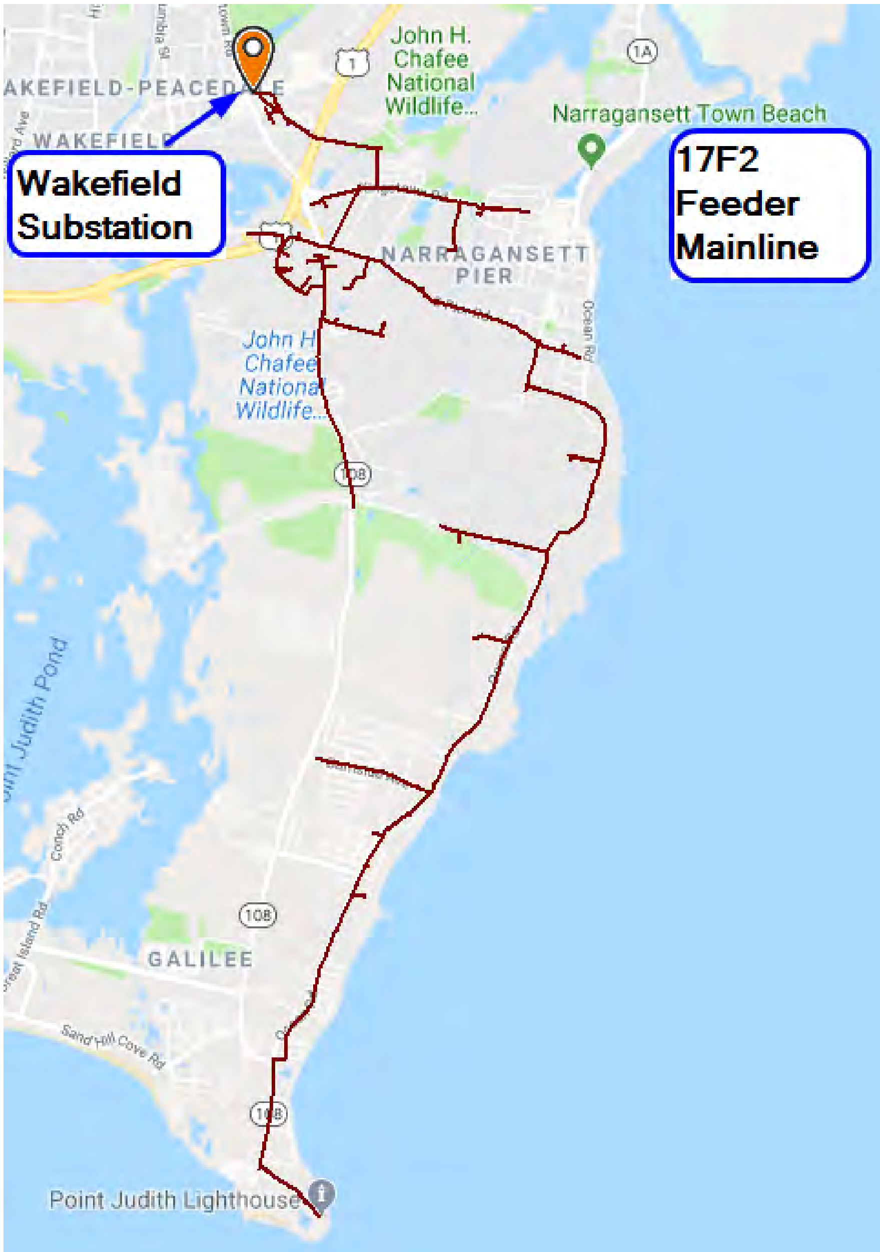
- **Wires Option:** Upgrade the Wakefield 17F2 feeder and modify the 17F3 feeder. This investment increases capacity and switching flexibility to relieve the heavily loaded facilities and resolves the projected overloads.
- **Non-Wires Option:** See Sections 4.1 and 4.2 below for Non-Wires requirements.

10.2. Technical Requirements

Problem Statement							
Description	The Company is seeking to provide load relief for the Wakefield Substation 17F2 feeder.						
Technical Information	**Substation**	**Feeder**	**Operating Voltage**	**Summer Normal Rating (Amps)**	**Overloaded By**	**Load Reduction Needed (kW)**
	Wakefield	17F2	12.47 kV	510	2021	1,794

Solution Requirements	
Technical Requirements	Maintain feeder loading below 90% of summer normal rating over a ten-year period by proposing a NWA solution that reduces loading on the feeder by 1,794kW through 2030.

In Service Date	2021
Maximum MWHr need	Based on historic data 76 MWhrs total over the course of a year by 2030.
Lifetime	10 years minimum
Call Response Time	24 hours
Days of the Week needed	Any days that the day-ahead ISO-NE load forecast applied to the Project Feeders indicates that loading will exceed 90% of the Feeder Summer normal rating. This could be both weekdays and weekends.
Time of Day	Any time of day.
Number of Time Called Per Year	A minimum of 14 days based on historic data In order to account for the potential of a heat wave, the project may be called for 5 or more days in a row during peak load times.
Minimum Period between Calls	24 hours



Any DER location downstream of the target feeder getaways (where the feeder leaves the station) should solve the loading issue, pending a full interconnection study. See feeder maps above.
NOTE: Subject to changes in forecasted needs, solution pricing, as well as any other applicable costs and benefits, National Grid is targeting to procure demand response and/or generation/storage that could supply the substation(s) load in its entirety or a large portion of it. During normal operation, any excess power could be exported to the National Grid System. Depending on such factors as economics, portfolio fit, etc.

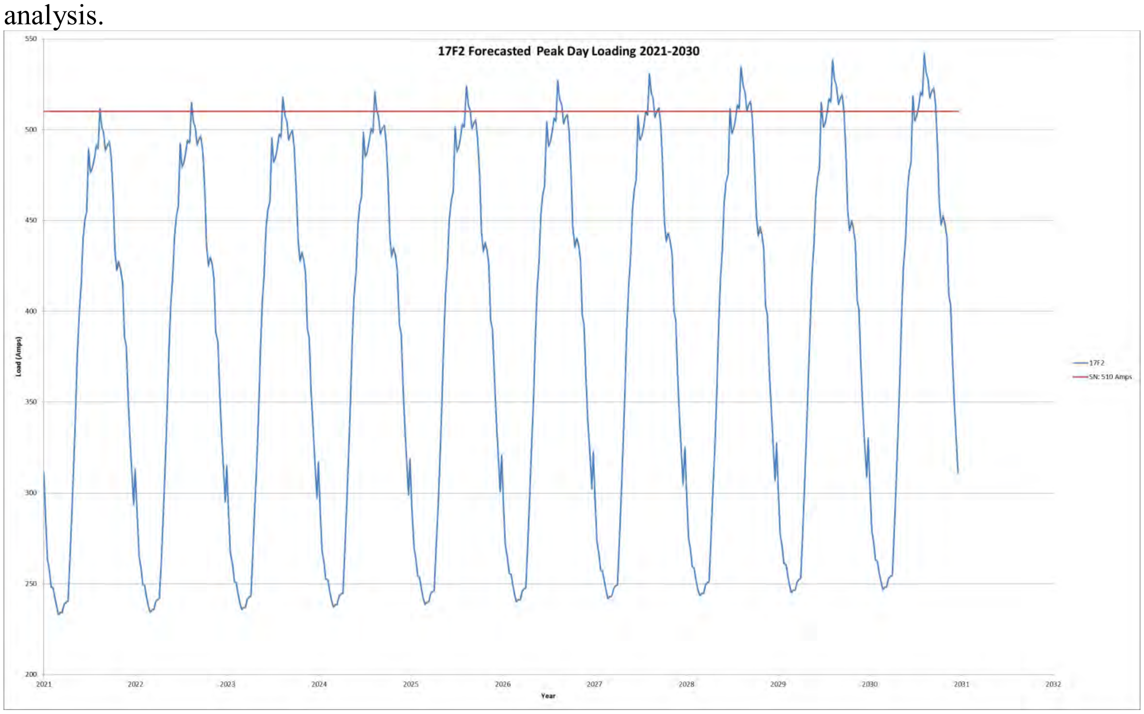
10.3. Technical Details

Substation	Feeder	Operating Voltage	Summer Normal Rating (Amps)	Overloaded By	Load Reduction Needed (kW)
Wakefield	17F2	12.47 kV	510	2021	1,794

Substation	Feeder	Commercial Customers	Residential Customers	Total
Wakefield	17F2	221	2679	2900

10.3.1. Feeder Loading

Loading on the 42F1 and 17F2 feeders is predicted to be over 100% of their summer normal ratings and will be overloaded over the next ten years. All other facilities' loadings are within their normal equipment ratings. The rating of feeders is determined by the equipment with the most limiting element (that with the lowest normal summer rating). The load forecast utilizes a technique called weather normalization, a process that assumes future year peaks will occur given high loading condition (e.g., a June peak will occur on hot day, where the temperature in the 95th percentile of hottest years). The charts below show the projected load on the feeders using the peak day at the time of study and the loads are grown according to the forecasted analysis.



10.4. Solution Timeline

National Grid requires that any proposed NWA solutions will need to defer the traditional distribution asset starting in May 2021.
National Grid requires that any proposed NWA solutions will need to defer the traditional distribution asset until at least 2030. Any NWA solutions that exceed this timeline will also be considered.

11. Project Cost

National Grid is seeking solutions that provide value to the customer and are cost-effective.
The NWA solution shall have a total cost not to exceed a Net Present Value (NPV) of $572,200, based on traditional distribution asset deferral until at least 2030.
National Grid is open to considering shared capital costs or owning a non-generation solution or asset.
National Grid encourages vendors to participate in relevant external revenue streams to produce the most cost-effective solution.
Pricing models to be considered shall be as follows:

- Capital Expenditure
- Annual service fee
- Energy Services Agreement for capacity delivered (i.e., dollars per kW)
- Any combination of the above

12. Instructions for Bidders

12.1. Response and Deliverables

This section describes the list of items and deliverables required from the bidder. Please provide detail in your response as to why the technology/solution your firm proposes is the best-fit for this NWA project. All items should be responded to in the context of the project listed in Section 4 – Project Overview.
Please provide a concise written response under 15 pages (excluding appendices) for ease of review. There will be sections to upload additional documents on the Ariba Platform.
Responses that do not provide the requested information below can be disqualified. Bidders must submit their responses in the following format.

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  - Cost of Technology/Solution for the Specified Need
  - Cost comparison to other technologies/solutions
  - Bidder’s Suggested Financial Plan
- Implementation of Technology/Solution

    - Technology/Solution Reliability, with Documentation on the Solution's Technical Reliability
    - Examples of Firm's Application of Technology/Solution
- Timeline for Technology/Solution Installation
- Bidder Qualifications (To be included as an Appendix)

Bidders must additionally provide the following as an Appendix/Attachment:
- List of Historical Project Permits
- Historical Safety Record
- List of Current Environmental Certifications
- List of Historical Project Environmental/Eco awards

12.2. Submittal Requirements

Submittal requirements for this NWA RFP are as follows:
- Overall proposal document as detailed in Section 6.1.
- Pricing Model spreadsheet as provided in the Ariba platform.

12.3. Evaluation Criteria

This section describes the evaluation criteria that project bid responses will be screened with.
- Cost
- Scalability
- Load Reduction Capability
- Feasibility of Proposed Technology Type/Solution
- Risk of Proposed Technology Type/Solution Creating Negative System Impacts
- Environmental or "Green" Requirement

12.4. RFP Schedule

- RFP Launch: 12/7/2018
- Bidders Conference Call: 12/17/2018
- Last date to submit questions: 1/18/2019
- Responses Due: 2/11/2019

12.5. Rhode Island System Data Portal

National Grid has developed a new web-based tool called the Rhode Island System Data Portal that houses a collection of maps to help customers, contractors, and developers identify potential project sites and with project bidding and development. Each map provides the location and specific information for selected electric distribution lines and associated substations within the National Grid electric service area in Rhode Island.

The Rhode Island System Data Portal can be found at the following location:

https://www.nationalgridus.com/Business-Partners/RI-System-Portal

9.17 South Kingstown NWA RFP Reports

National Grid USA Service Company, Inc.

ISSUED: JANUARY 29, 2019
SUBMISSION DEADLINE: APRIL 23, 2019

nationalgrid

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13. Introduction

National Grid is a gas and electric investor-owned utility serving nearly 3.3 million electric and 3.5 million gas customers through its subsidiary companies in Massachusetts, New York, and Rhode Island.
National Grid is committed to providing safe, reliable, and affordable energy to all customers throughout our service territory. As a part of providing this service, National Grid is pursuing the potential implementation of Non-Wires Alternative (NWA) solutions in Rhode Island. Such implementation aligns with principles set forth by the RI PUC Title 39 § 39-1-27.7 – System Reliability and Least-Cost Procurement.
National Grid has been pursuing Non-Wires Alternative projects across its service territories for several years.

14. Definition of NWA

Non-Wires Alternative (NWA), sometimes referred to as Non-Wires Solution (NWS), is the inclusive term for any electrical grid investment that is intended to defer or remove the need for traditional equipment upgrades or construction, or “wires investment”, to distribution and/or transmission systems.
These NWA investments are required to be cost-effective compared to the traditional wires investment and are required to meet the specified electrical grid need.
An NWA can include any action, strategy, program, or technology that meets this definition and these requirements.
Some technologies and methodologies that can be applicable as an NWA investment include demand response, solar, energy storage, combined heat and power (CHP), microgrid, conservation or energy efficiency measure, and other distributed energy resources (DERs).
NWA projects can include these and other investments individually or in combination to meet the specified need in a cost-effective manner.

15. Our Goal

This RFP seeks to identify technologies and/or methodologies that, if implemented, will provide an NWA solution for a geographical area that has an electrical grid need. This area and need are identified in Section 4 – Project Overview.
This RFP is open to all NWA approaches. This RFP is meant to assess the best-fit technology type for this NWA project.
Any proposed NWA solutions will need to defer the traditional distribution asset starting in May 2022 and operating until at least 2030. Any NWA solutions that exceed this timeline will also be considered. Please note that National Grid is seeking solutions that currently exist to solve the stated need.
Proposed technologies and methodologies should have the capability to address the electrical grid need and increase grid reliability while being cost-effective in comparison to the traditional wires investment. Proposed technologies and methodologies should also be available when

needed and respond immediately when called upon for the duration of NWA solution implementation.
To assist qualified bidders this document provides an overview of the project objectives, detailed business requirements and response submission information.
As outlined in the RFP Schedule section of this document, bidders will have the opportunity to submit questions that assist in creating a response for this initiative. Please see the RFP Timeline Schedule for dates associated with RFP milestones below.

16. Project Overview

Potential for Non-Wires Alternative Project in South Kingstown, RI

16.1. Background

The western section of the Town of South Kingstown is mostly supplied by (3) 12.47 kV distribution feeders. Two feeders (59F3 and 68F2) are projected to be loaded above summer normal ratings and lack useful feeder ties to reduce loading below their ratings. Either new feeder ties must be created or load must be reduced in the western half of the town. Both a wires and a non-wires option was developed to address these projected overloads.

- **Wires Option**: Establish a new feeder tie between the 68F5 feeder and the 59F3 feeder. This new feeder tie provides switching flexibility to relieve both the 59F3 and the 68F2 feeders.

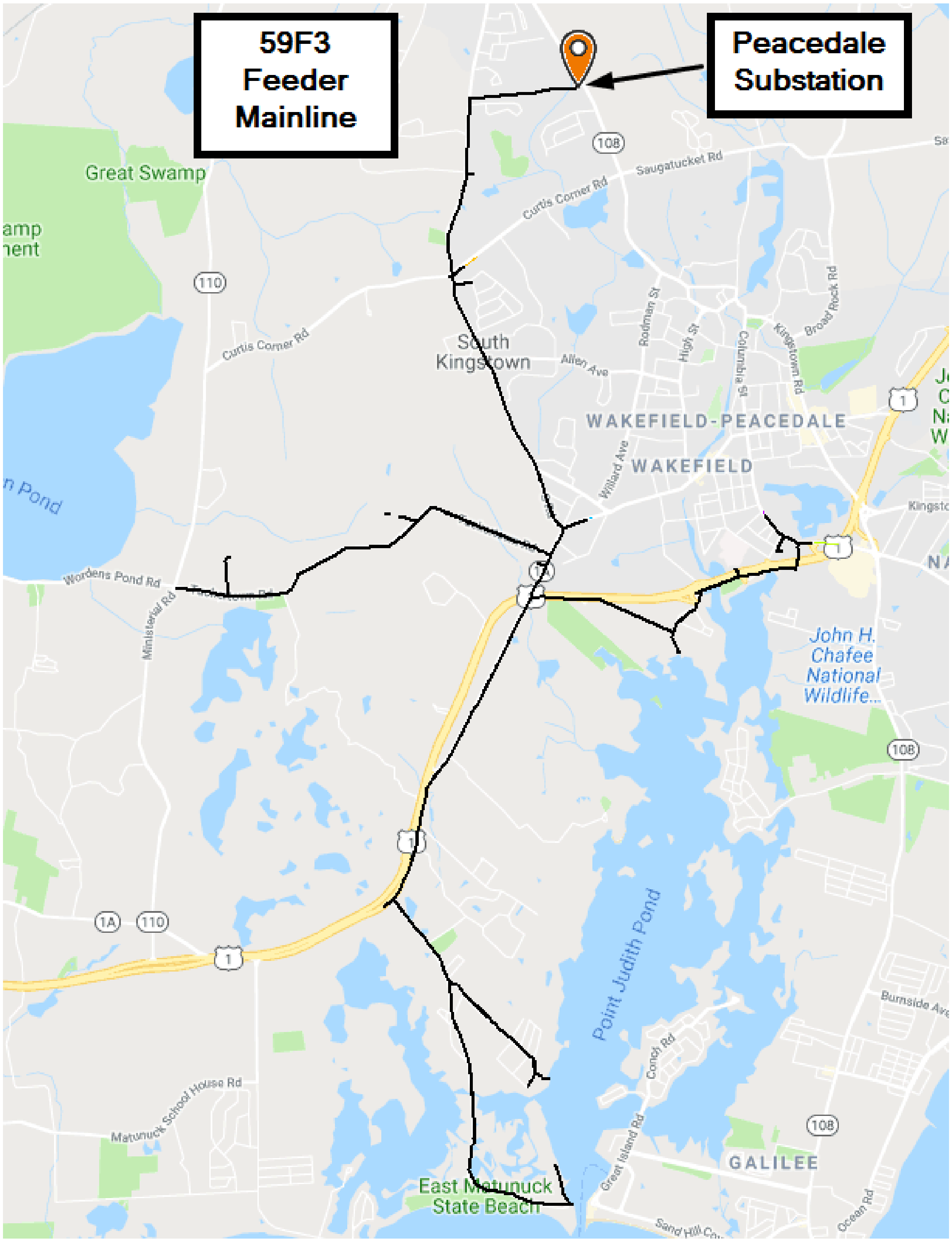
- **Non-Wires Option**: See Sections 4.1 and 4.2 below for Non-Wires requirements.

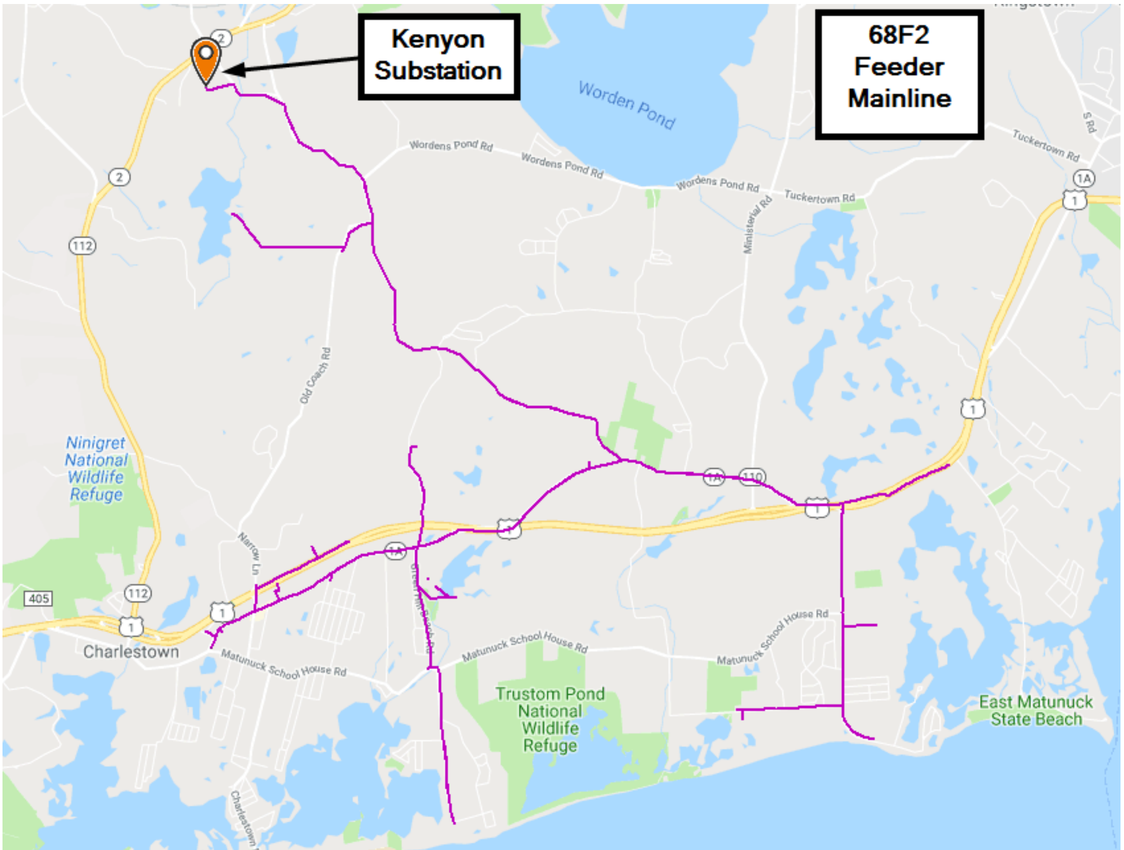
16.2. Technical Requirements

Problem Statement						
Description	The Company is seeking to provide load relief for the Peacedale 59F3 and the Kenyon 68F2 feeders.					
Technical Information	**Substation**	**Feeder**	**Operating Voltage**	**Summer Normal Rating (Amps)**	**Overloaded By**	**Load Reduction Needed (kW)**
	Peacedale	59F3	12.47 kV	492	2024	1448
	Kenyon	68F2	12.47 kV	511	2022	1646
					Total (kW)	3094

Solution Requirements

Technical Requirements	Maintain feeder loading below 90% of summer normal rating over a ten-year period by proposing a NWA solution that reduces loading on the feeder as outlined in the Problem Statement through 2030.
In Service Date	59F3: 2024 68F2: 2022
Maximum MWHr need	Based on historic data 59F3: 13.7 MWhrs total over the course of a year by 2030. 68F2: 18.0 MWhrs total over the course of a year by 2030.
Lifetime	10 years minimum
Call Response Time	24 hours
Days of the Week needed	Any days that the day-ahead ISO-NE load forecast applied to the Project Feeders indicates that loading will exceed 90% of the Feeder Summer normal rating. This could be both weekdays and weekends.
Time of Day	Any time of day.
Number of Time Called Per Year	59F3: A minimum of 6 days based on historic data 68F2: A minimum of 5 days based on historic data In order to account for the potential of a heat wave, the project may be called for 5 or more days in a row during peak load times.
Minimum Period between Calls	24 hours


59F3 Feeder Mainline
Peacedale Substation
Great Swamp
Saugatucket Rd
Curtis Corner Rd
South Kingstown
WAKEFIELD-PEACEDALE
WAKEFIELD
Wordens Pond Rd
John H. Chafee National Wildlife...
Point Judith Pond
East Matunuck State Beach
GALILEE
Matunuck School House Rd



Any DER location downstream of the target feeder getaways (where the feeder leaves the station) should solve the loading issue, pending a full interconnection study. See feeder maps above.

NOTE: Subject to changes in forecasted needs, solution pricing, as well as any other applicable costs and benefits, National Grid is targeting to procure NWA solutions that can supply the substation(s) load in its entirety or a large portion of it. During normal operation, for NWA technologies such as generation or storage solutions, any excess energy could be exported to the National Grid System depending on such factors as economics, portfolio fit, or others.

16.3. Technical Details

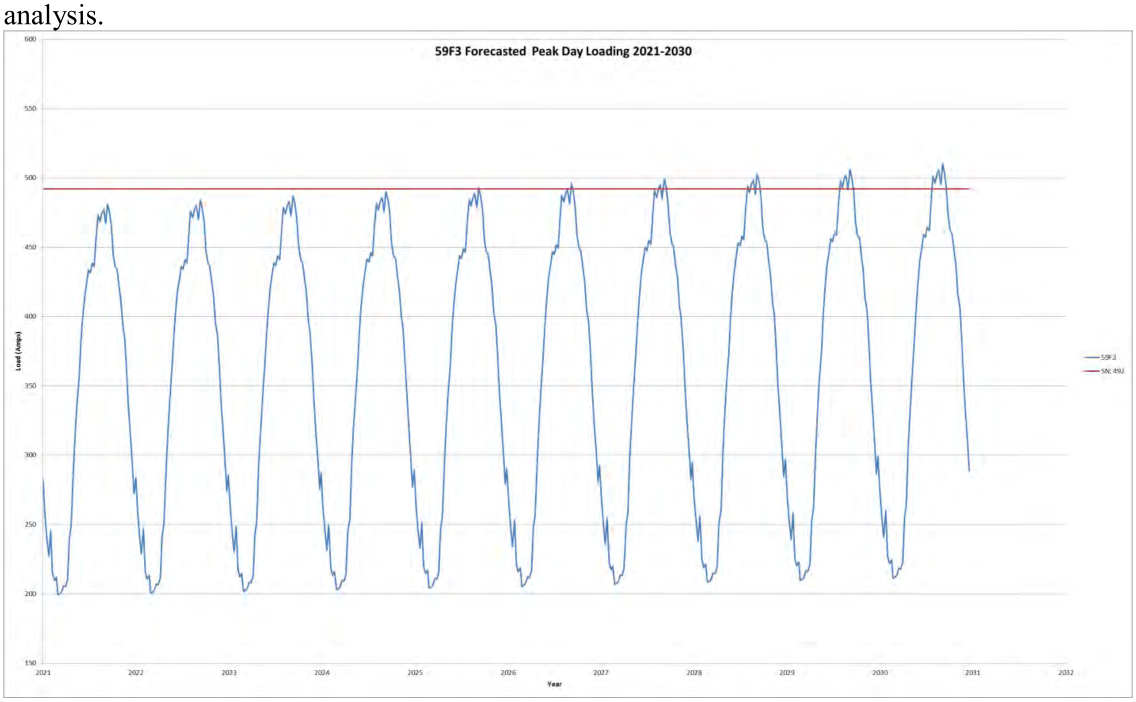
Substation	Feeder	Operating Voltage	Summer Normal Rating (Amps)	Overloaded By	Load Reduction Needed (kW)
Peacedale	59F3	12.47 kV	492	2024	1448
Kenyon	68F2	12.47 kV	511	2022	1646
				Total (kW)	3094

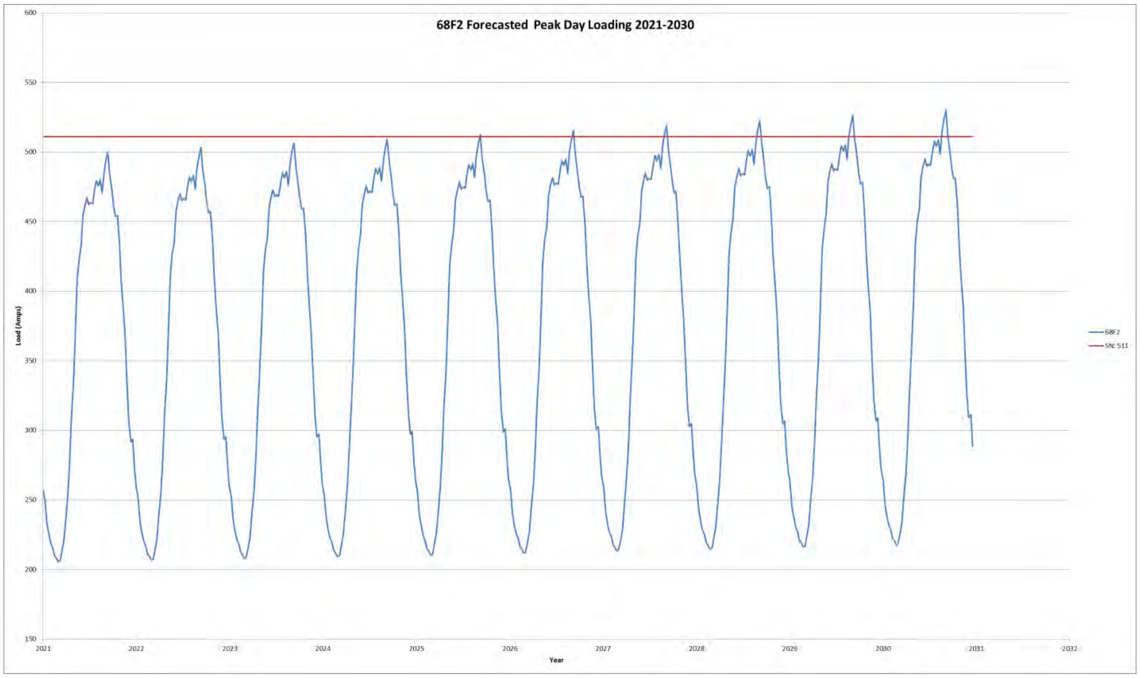
Substation	Feeder	Commercial Customers	Residential Customers	Total

Peacedale	59F3	73	2671	2744
Kenyon	68F2	16	4113	4129
Grand Total		89	6784	**6873**

16.3.1. Feeder Loading

Loading on the 59F3 and 68F2 feeders is predicted to be over 100% of their summer normal ratings and will be overloaded over the next ten years. All other facilities' loadings are within their normal equipment ratings. The rating of feeders is determined by the equipment with the most limiting element (that with the lowest normal summer rating). The load forecast utilizes a technique called weather normalization, a process that assumes future year peaks will occur given high loading condition (e.g., a June peak will occur on hot day, where the temperature in the 95th percentile of hottest years). The charts below show the projected load on the feeders using the peak day at the time of study and the loads are grown according to the forecasted analysis.





16.4. Solution Timeline

National Grid requires that any proposed NWA solutions will need to defer the traditional distribution asset starting in May 2022.
National Grid requires that any proposed NWA solutions will need to defer the traditional distribution asset until at least 2030. Any NWA solutions that exceed this timeline will also be considered.

17.<u>Project Economics</u>

National Grid is seeking solutions that provide value to the customer and are cost-effective.
The NWA solution shall have a total cost not to exceed a Net Present Value (NPV) of $965,400, based on traditional distribution asset deferral until at least 2030. This NPV includes all project work, capital expenditure, annual service feeds, energy service agreement payments, and the Rhode Island locational incentive value. The total NPV is to be viewed as the maximum limit of project spend and will be competitively evaluated.
National Grid is open to considering shared capital costs or owning a non-generation solution or asset.
National Grid encourages vendors to pursue additional relevant revenue streams to produce the most cost-effective solution.
Pricing models to be considered shall be as follows:

- Capital Expenditure
- Annual service fee

- Energy Services Agreement for capacity delivered (i.e., dollars per kW)
- Any combination of the above

18. Instructions for Bidders

18.1. Response and Deliverables

This section describes the list of items and deliverables required from the bidder. Please provide detail in your response as to why the technology/solution your firm proposes is the best-fit for this NWA project. All items should be responded to in the context of the project listed in Section 4 – Project Overview.
Please provide a concise written response under 15 pages (excluding appendices) for ease of review. There will be sections to upload additional documents on the Ariba Platform. Responses that do not provide the requested information below can be disqualified. Bidders must submit their responses in the following format.

- Executive Summary of Proposed Technology/Solution
- Financial Plan
  - Cost of Technology/Solution for the Specified Need
  - Cost comparison to other technologies/solutions
  - Bidder's Suggested Financial Plan
- Implementation of Technology/Solution
  - Technology/Solution Reliability, with Documentation on the Solution's Technical Reliability
  - Examples of Firm's Application of Technology/Solution
- Timeline for Technology/Solution Installation
- Bidder Qualifications (To be included as an Appendix)

Bidders must additionally provide the following as an Appendix/Attachment:

- List of Historical Project Permits
- Historical Safety Record
- List of Current Environmental Certifications
- List of Historical Project Environmental/Eco awards

18.2. Evaluation Criteria

This section describes the evaluation criteria that project bid responses will be screened with.

- Cost
- Scalability
- Load Reduction Capability

- Feasibility of Proposed Technology Type/Solution
- Risk of Proposed Technology Type/Solution Creating Negative System Impacts
- Environmental or "Green" Requirement

18.3. RFP Schedule

- RFP Launch: 1/29/2019
- Bidders Conference Call: 2/13/2019
- Last date to submit questions: 3/25/2019
- Responses Due: 4/23/2019

18.4. Rhode Island System Data Portal

National Grid has developed a new web-based tool called the Rhode Island System Data Portal that houses a collection of maps to help customers, contractors, and developers identify potential project sites and with project bidding and development. Each map provides the location and specific information for selected electric distribution lines and associated substations within the National Grid electric service area in Rhode Island.
The Rhode Island System Data Portal can be found at the following location:
https://www.nationalgridus.com/Business-Partners/RI-System-Portal

RI Gas Main Inventory by Decade

Material	Decade of Installation										
	Pre 1940	1940s	1950s	1960s	1970s	1980s	1990s	2000s	2010s	Unknown	Total
Bare Steel	34.5	16.9	51.7	45.0	1.0	0.0	0.0	0.0	0.0	42.5	191.7
Cast Iron	399.8	41.8	38.1	4.9	0.0	0.0	0.0	0.0	0.0	203.8	688.4
Ductile Iron	0.1	0.0	0.2	5.5	2.3	0.0	0.0	0.0	0.0	5.4	13.5
Plastic	0.0	0.0	0.0	0.0	45.5	293.4	333.9	275.5	567.9	55.9	1572.3
Protected Coated Steel	0.3	0.2	38.9	232.6	147.7	69.4	38.8	12.6	3.7	26.1	570.4
Unknown	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unprotected Coated Steel	0.0	0.0	16.3	119.0	15.2	0.0	0.0	0.0	0.0	6.5	157.2
Wrought Iron	0.5	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.9	1.4
Grand Total	**435.2**	**59.0**	**145.2**	**407.0**	**211.8**	**362.9**	**372.7**	**288.1**	**571.7**	**341.1**	**3194.9**

RI Main Replacement Program

				History CY9-19									
Region	Program	CY8	CY9	CY10	CY11	CY12	CY13	CY14	CY15	CY16	CY17	CY18	CY19	Total through CY 19
RI	All Programs	-	32.1	27.2	46.3	54.3	44.0	28.8	56.0	60.3	53.6	67.8	60.0	530.4
	Proactive	-	-	-	-	50.0	39.9	23.0	50.3	46.2	48.3	51.2	50.0	358.9

				Projected CY 20 -CY 34												
Region	Program	CY20	CY21	CY22	CY23	CY24	CY25	CY26	CY27	CY28	CY29	CY30	CY31	CY32	CY33	CY34	Totals
RI	All Programs	56	70	70	75	80	85	88	88	85	80	75	70	65	60	55	1,102
	Proactive	48	49	49	57	62	72	74	74	73	70	65	63	60	59	54	929

All Programs	Includes all gas main replacement including PW, Proactive and Reacitve replacements
Proactive	Includes Proactive Main replacement mileage of LPP (BS,CI &Aldyl- A Plastic)

MATERIAL SPECIFICATION

New or Revised Gas Material Acceptance

Effective Date: 8/15/2013

TABLE OF CONTENTS

1 GENERAL

1.1 **Responsibilities**

The Lead Organization for this Material Specification is Gas Materials Standards.

1.2 **Purpose**

This specification describes the policy to evaluate new or changed materials intended for use in the natural gas systems at National Grid.

1.3 **Application**: National Grid US, Inventory Gas Materials

2 PROCEDURE

2.1 Prerequisites for material test and evaluation:

a. User need, gas materials standardization or competitive pricing / elimination of sole sourcing.

b. Economic advantage – use of new product results in lower life cycle costs, inclusive of initial installation and maintenance costs.

c. Technological improvement.

d. Mandated by Federal, State or Local code.

2.2 Evaluation Criteria

The following minimum criteria should be researched by the area submitting a material for acceptance testing.

a. Economic analysis.

b. Manufacturer's engineering specifications including quality manuals, product proof test data and MSDS if applicable.

c. Contemplated use and associated operating system.

d. Governing jurisdictional code requirements of the territory in question.

2.3 Administration

a. Gas Materials Standards shall be responsible for administrative requirements related to this procedure and will have responsibility for final product acceptance. The material will follow the process shown in Attachment 1 – "Approved Product Flowchart" in order to establish it in inventory or to approve as a non-inventory item for a special gas engineering project.

b. Area requesting new materials shall assist in providing field trials, feedback, and anticipated usage requirements.

c. Gas Materials Standards shall determine the operating regions affected and be responsible for changes made to standard drawings.

d. Gas Materials Standards shall recommend disposal/salvage requirements of existing product that is replaced or made obsolete and implementation plan of new / revised material.

e. Gas Materials Standards shall obtain a new inventory stock code and establish the new item into corporate inventory or modify existing codes as required. The request must be accompanied by the appropriate documentation including the source warehouse, material description and vendor's part number. Inventory documentation requests by other areas will not be honored by Inventory Management in order to maintain control on inventory additions.

f. Gas Materials Standards will coordinate with Gas Work Methods to revise operating procedures as required.

2.4 Records

a. Test records for approved products/materials shall be maintained for the life of the approved product/material.

b. Test records for unapproved products shall likewise be maintained in the event that future enhancements are made to products such that they might be resubmitted for re-evaluation. This may prevent repetitive testing and allow comparative evaluation of enhancements.

2.5 Training

a. Initial requirements relative to installation methods and qualifications shall be given by Learning and Development (L&D) as required. Gas Materials Standards will notify L&D in advance of such requirements. As deemed necessary, Gas Materials Standards and L&D will coordinate vendor performed training to L&D staff and the operating area as required.

b. Initial installer certifications shall be the responsibility of L&D.

c. Maintenance of installer qualifications and periodic re-training shall be determined by operating area (and /or applicable code) and shall be administered as part of annual re-qualifications.

2.6 Tooling

a. Gas Materials Standards will be responsible for initial review and evaluation of tooling required with input from Field Operations for the installation of new materials.

b. Except for inventory tooling, Auxiliary Operations will be responsible for procurement and distribution of tooling required.

3 MARKINGS

3.1 Markings as required including material print lines, casting print, and bar codes will be specified to the vendor by Gas Materials Standards to ensure product traceability.

4 TESTING & INSPECTION

4.1 Gas Materials Standards will perform testing in accordance with industry standards and methods consistent to represent actual daily field conditions. Vendor shall supply test samples in quantities as requested by Gas Materials Standards. Samples shall be of latest production lots and/or include latest changes agreed to between Gas Materials Standards and vendor.

5 QUALITY CONTROL AND RECEIPT INSPECTION

5.1 Gas Materials Standards shall perform periodic testing as required to ensure material meets agreed upon specifications. Testing may be random in nature for spot inspections or due to nonconformance reported from end users. All costs associated with problematic materials and time spent to rectify shall be billed back to the vendor for full reimbursement.

6 CARE & HANDLING BY VENDOR

6.1 Material shall be furnished in accordance with the National Grid Specifications and procurement area terms and conditions.

7 PURCHASE ORDER REQUIREMENTS

7.1 Purchase orders for accepted material will include the material description and vendor's part number identifying the as tested finished product as agreed to between National Grid and the vendor.

8 ATTACHMENTS

8.1 Attachment 1 – New Product Approval Process Steps

8.2 Attachment 2 – Approval Process Flowchart

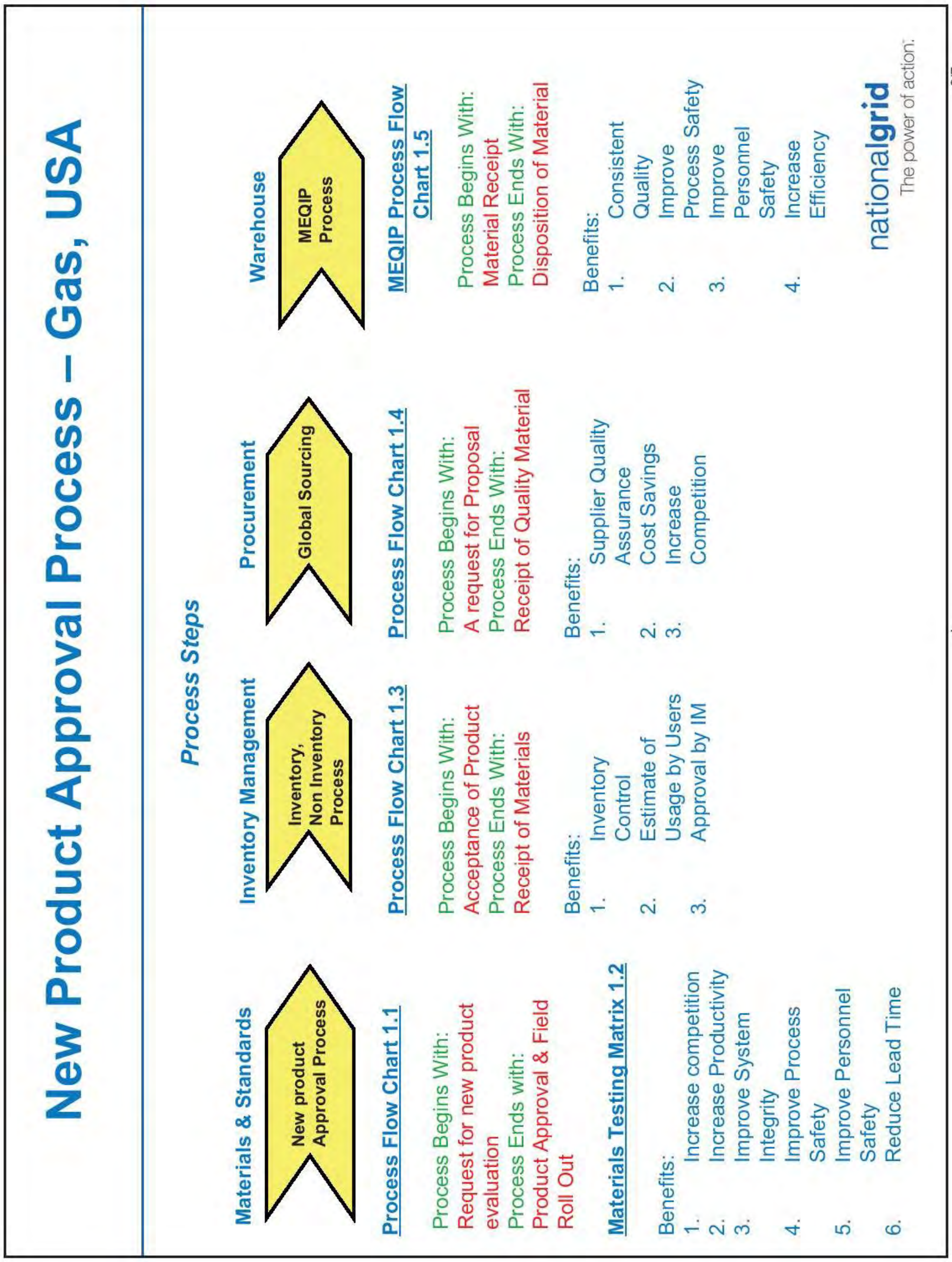
8.3 Attachment 3 – Testing Matrix

8.4 Attachment 4 – Inventory Management

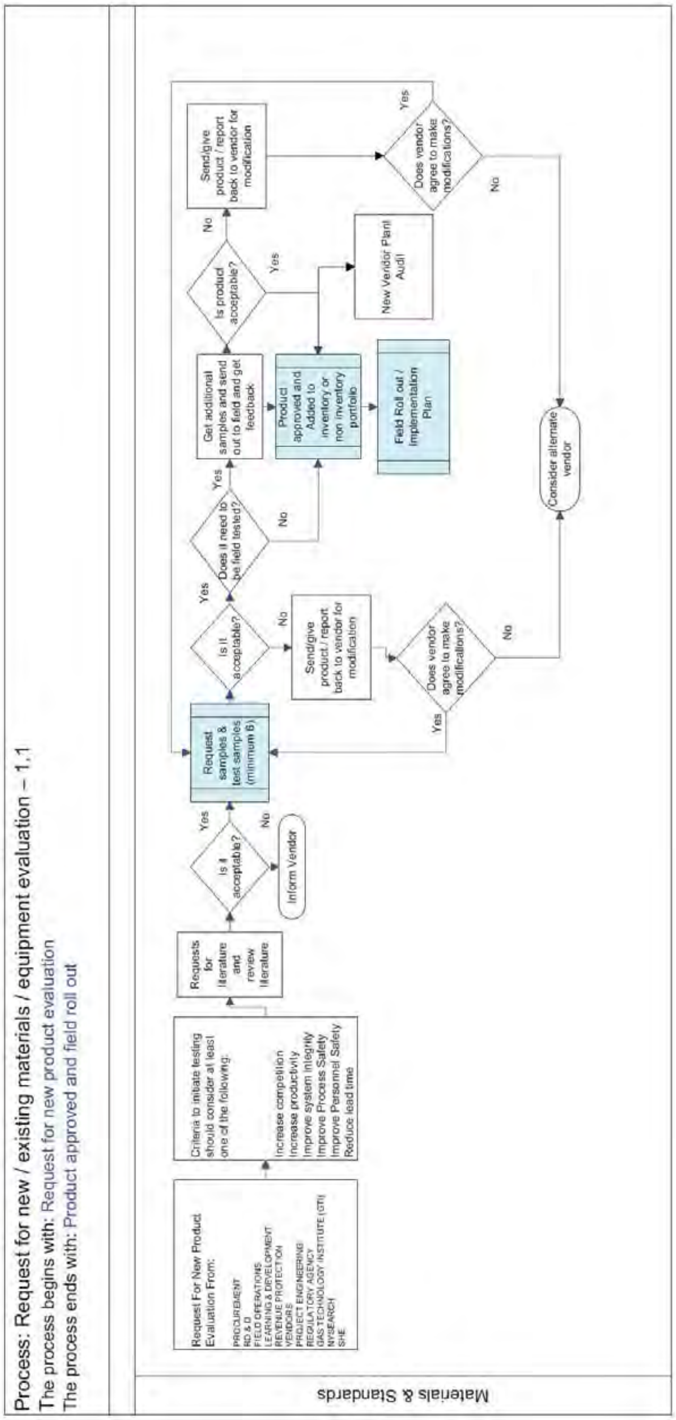
8.5 Attachment 5 – Procurement

8.6 Attachment 6 – MEQIP

Attachment 1 - New Product Approval Process Steps



Attachment 2 – Approval Process Flowchart



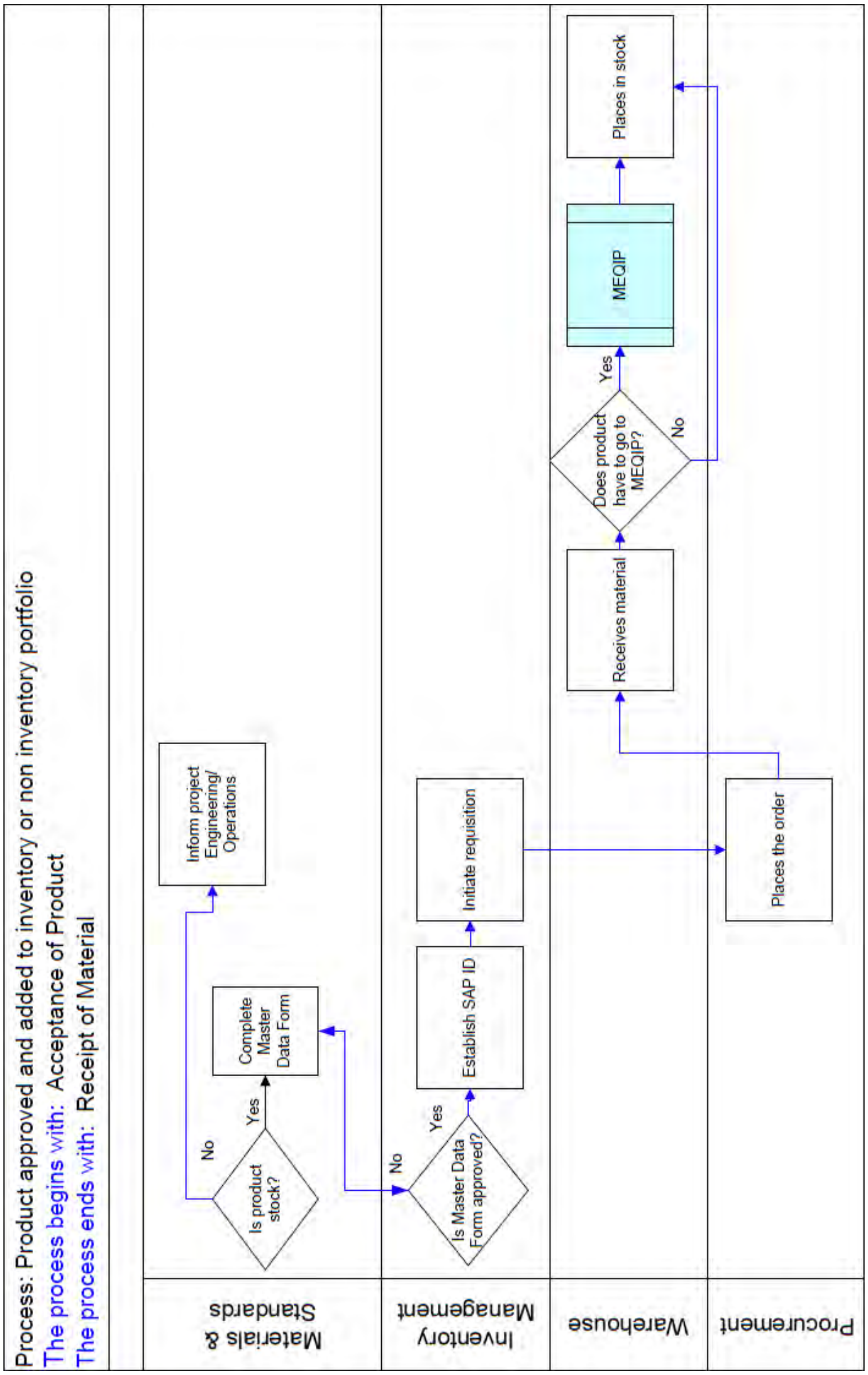
Attachment 3 – Testing Matrix

Material Testing Matrix - 1.2

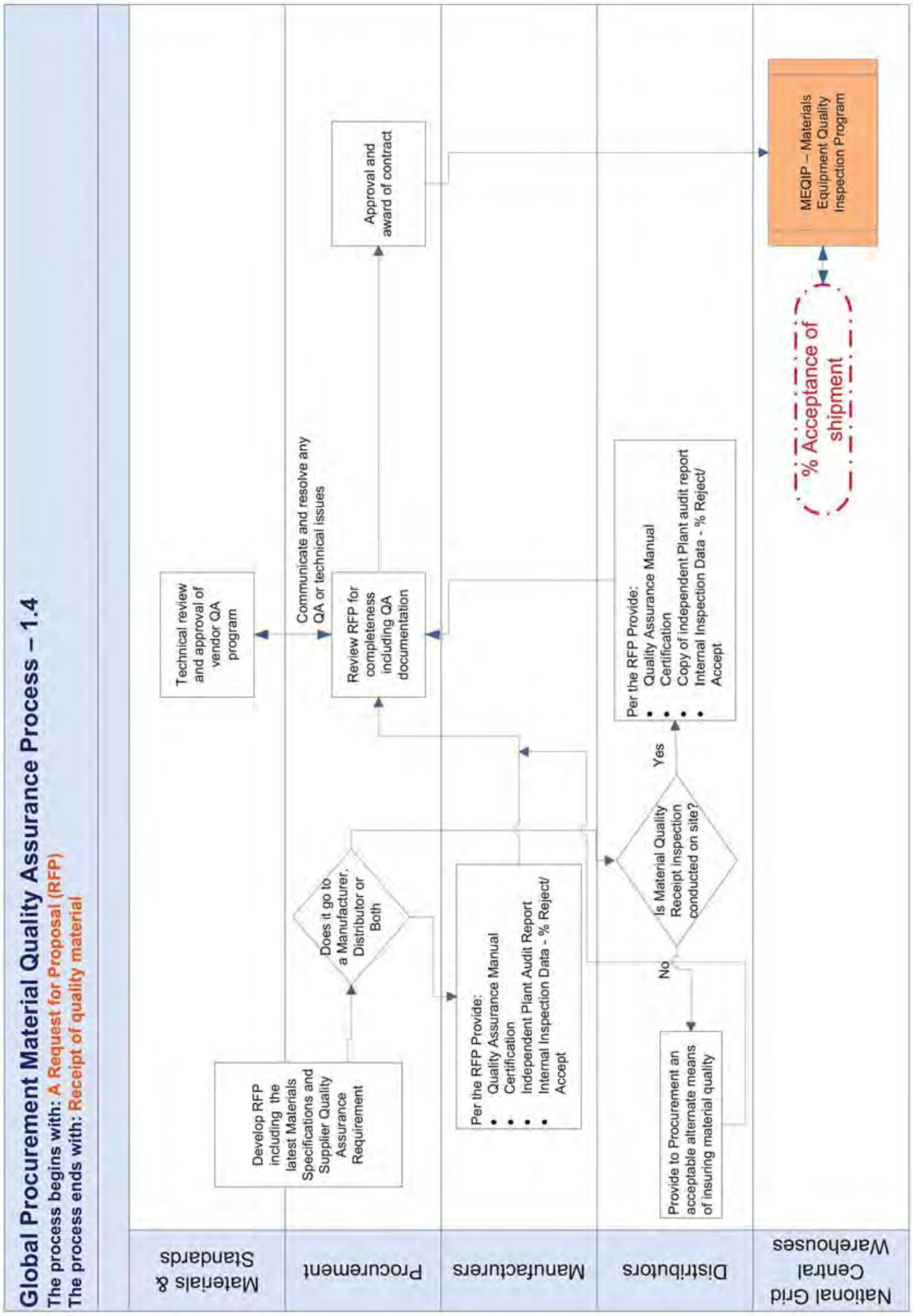
	Plastic							Steel						Misc.												
	Pipe	Fittings	Valves	Couplings	Valve Tees	Serv. Saddle Tees		Pipe	Fittings	Valves	Couplings	Valve Tees		Flow Limiters	Saddles	Repair Sleeves	Joint Seals	Coatings	Leak Detection Fluid	Tran. Fittings	Serv. Head Adapters	Pipe Dopes	Pipe Protection	Regulators	Service Risers	Anode
Visual	x	x	x	x	x	x		x	x	x	x	x		x	x	x	x	x	x	x	x	x	x	x	x	x
Dimensional	x	x	x	x	x	x		x	x	x	x	x		x	x	x	x			x	x		x	x	x	x
Assembly	x	x	x	x	x	x			x	x	x	x			x	x	x	x		x	x			x	x	
Operational			x		x					x		x												x		
Pressure Test 70ºF and -20ºF	x	x	x	x	x	x		x	x	x	x	x		x	x	x	x			x	x			x	x	
Hot & Cold Cycle 176ºF & -20ºF		x	x	x	x	x			x	x	x	x		x	x	x	x	x		x	x	x			x	
Deflection	x	x	x	x	x	x			x	x	x	x		x	x	x	x	x		x	x				x	
Tensile	x	x	x	x	x	x					x						x	x		x	x				x	
Impact 70ºF & -20ºF	x	x	x	x	x	x				x	x	x		x	x	x	x	x		x	x		x	x		
Compression				x		x					x									x	x	x				
Melt Index(Manufacturer)	x	x	x	x	x															x						
MUD Test			x		x					x		x														
Continuity - Resistance - Potential - Current											x				x	x		x		x			x			x
Holiday Detection																		x								
Salt Crock																	x	x								
Adhesion																	x	x								
Quick Burst	x	x	x	x	x	x														x	x				x	
Accelerated Sustained	x	x	x	x	x	x														x	x				x	
Aging																						x				
Pressure Drop			x		x	x				x		x		x							x			x		
Bleed By					x	x								x										x		
Application																x	x	x								
Lubrication																			x							
Bubbling Qualities																			x							
Chemical Compatibility																		x	x							
Turning Torque			x		x	x				x		x														
U.V.	x	x	x	x	x	x												x		x						
Weathering																		x								
X Ray								x	x	x	x	x			x	x										
Full Flow Capacity			x			x				x				x							x			x		
Toxicity																	x	x	x			x				
Twist	x	x	x	x	x	x														x	x					
Fusion Compatibility	x	x	x	x	x	x														x						
Dissection	x	x	x	x	x	x			x	x	x	x		x			x			x	x				x	
Bendback	x	x	x	x	x	x																				
Squeeze-off	x																									
Vibration					x	x						x					x							x		
Humidity - 100%																		x								
Chemical Analysis																										x
Fluorescent Die			x	x																						
Peel Test				x																						
Crush Test				x						3													2/7			

02/04/2011 Rev.3

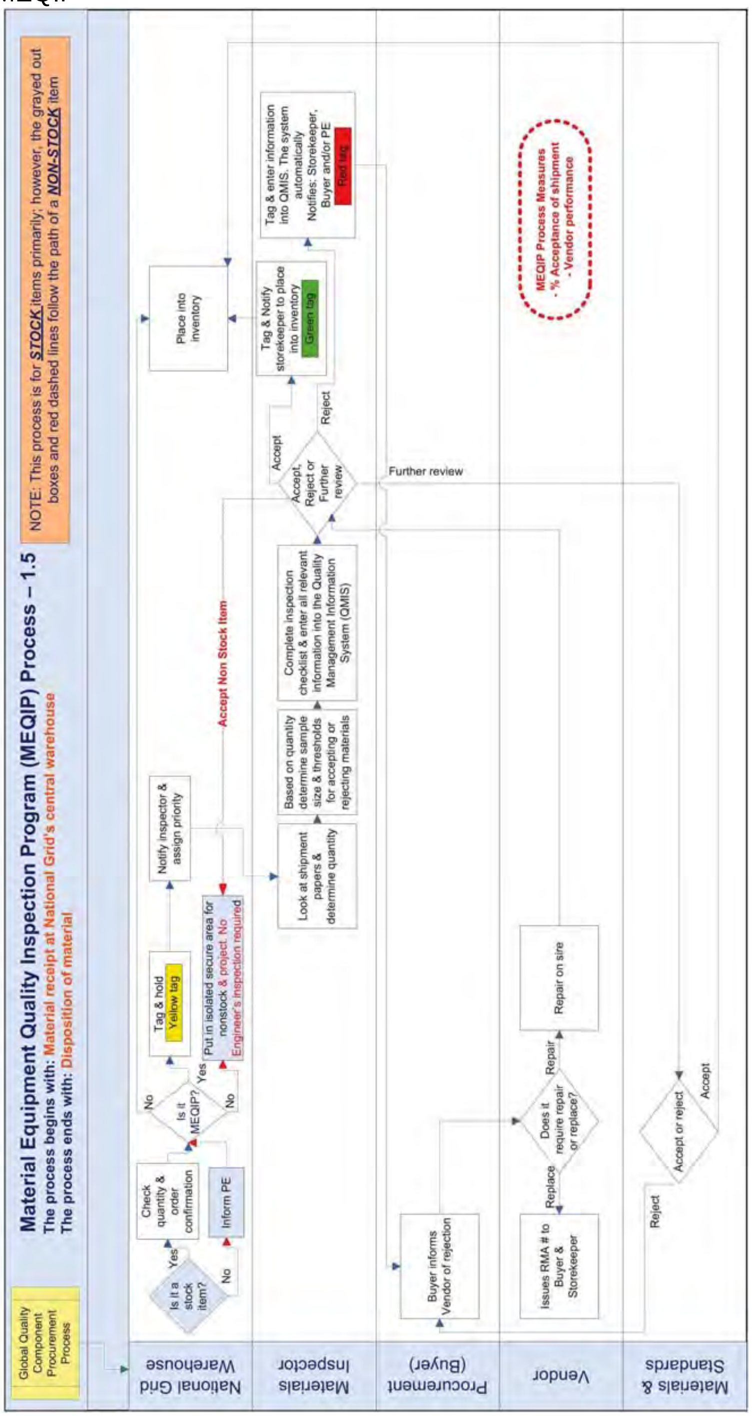
Attachment 4 – Inventory Management



Attachment 5 – Procurement



Attachment 6 – MEQIP



Q351. Follow up to Q 85000044. Appears there is no Rover Only - Energy Insurance Mutual Pipeline Questionnaire. So please provide details for Rover that is substantially equivalent to the information in this Questionnaire. Specifically address the following topics:

1. **Provide a breakout of capital expenditures with respect to pipeline maintenance for the past three years.**

   See Q85000351 Att. 1 shows gas operations and maintenance expense for calendar years ending December 31, 2020 and 2019.

2. **Has/is Rover involved in the specifications and design of the pipeline?**

   Rover utilizes both internal engineering department as well as outside resources for the design of pipeline projects. Typically, the spread within engineering versus outsourcing is approximately 70% and 30%, respectively.

3. **Provide details how material suppliers and contractors that work on the pipeline are controlled and qualified.**

   Contractors:
   Contractor Vetting Prior to Construction:

   - Construction Contractors are vetted through Procurement process, prior to being allowed on the bid list for complex gas projects. Vetting process includes:
     - Training and Operator Qualification (OQ) Program Review
     - Relevant Experience with Type of Work to be performed
     - Site Visits by Construction & Procurement personnel while they are working for other clients
   - Once the construction contractor is approved to be included on complex gas project bid list:
     - RFP Launched for New Complex Gas Project
     - Contractor bids are reviewed with clarification meetings held
     - Contractor bids are scored based on contractor means and methods, resource availability, experience with similar work (which includes safety performance review and ISNetworld grade) and pricing
   - Highest scoring contractor is awarded the project
   - Prior to Notice to Proceed (NTP), Contractors submit Health & Safety Plan (HASP) and list of workers for qualification/certification/license review. Contractors are contractually obligated to provide a trained, qualified and experienced workforce to perform all work in accordance with applicable procedures.

   Material Suppliers: See Q85000351 Att. 2.

4. **What methods are used for pipeline inspections?**

- In Line Inspection (ILI)
- External Corrosion Direct Assessment (ECDA)
- Cathodic Protection Inspection

5. **Are company employees present at 3rd party excavations?**

Company employees are present at excavations near to transmission pipelines and some critical distribution mains.

6. **Provide the following details: o Total miles of Pipeline o Miles of Pipeline capable of In-Line Inspections o How much of the pipeline has been inspected with in-line tool? o Miles of pipe in HCAs o Miles of pipe in HCAs assessed to date o 2020 total miles of ILI tools run o 2021 total miles of ILI tools planned to be run.**

Total Miles of Pipeline, distribution mains	3,203 (approx.)
Miles of pipeline capable of in-line inspections	1.45
Miles of pipeline inspected with in-line tool	1.45
Miles of pipe in HCAs	0
Miles of pipe in HCAs assessed to date	0
2020 total miles of ILI tools run	0
2021 total miles of ILI tools planned to run	0

Electric Transmission and Distribution Asset Management

Areas of transmission system investment are; system capacity, asset condition, reliability, and state requirements.

Investments in capacity are in accordance with North American Electric Reliability Corporation ("NERC") and Northeast Power Coordinating Council ("NPCC") planning standards. National Grid's transmission planning guidelines specify compliance with NERC reliability standards, NPCC, and ISO reliability rules, requiring the transmission system to meet voltage, thermal, and stability criteria.

National Grid's Transmission Inspection and Maintenance (I&M) Program evaluates asset health on a five-year cycle. This program is aligned with National Electrical Safety Code (NESC) Section 214, which outlines equipment inspection guidelines. The I&M program informs replacement of deteriorated, damaged or failed transmission components. Asset replacement prior to failure reduces risk, improves safety, mitigates outages, and minimizes potential environmental impacts related to some assets. Additionally, the I&M program enhances asset strategy by providing data trends on fail rates of inspected assets. National Grid's I&M programs address both regulated maintenance programs such as Equipment Elevated Voltage Testing and Ground Level Visual Inspection, and self-directed programs including yearly aerial visual and infrared patrol, 10-year wood pole inspection and treatment, 20-year steel tower footer inspection and repair, and 20-year steel tower painting.

Damage failure programs associated with severe weather and non-storm events have been implemented for the replacement or repair of known damaged or failed station and line equipment required to restore the electric system to its original configuration and capability. This program allows the Company to quickly return failed assets to service and minimize customer interruption durations.

Each of the states that National Grid operates in has mandates that require utilities to account for distributed energy resources and clean energy initiatives within its investment plans. States review these plans and investments to ensure that they satisfy their goals. The state mandates are continuously evolving, and National Grid's participation in these state proceedings influence many of requirements.

National Grid annually reviews the capacity and performance of its electric distribution system. Historic asset utilization data is applied to a weather-adjusted econometric forecast of future peak demand growth. Forecasted peak loads are compared to equipment ratings, and the system is analyzed for operational flexibility to respond to various contingency scenarios. This review informs infrastructure development investments to ensure that the distribution system has adequate capacity to operate reliably for the analyzed scenarios.

Reliability performance is continuously monitored and addressed through ad hoc reviews of discrete performance concerns or cyclical evaluations of distribution circuits with poor reliability. Distribution asset condition is monitored through I&M inspections, equipment test reports, assessment of known issues, safety and environmental reviews, and review of operational and maintenance history. Identified issues with individual assets or asset classes are addressed through proactive asset replacements.

Regular system performance reviews are supplemented by holistic reviews of geographic or electric subsets of the distribution system. Assessments executed within these long-range distribution system planning studies include a focus on system voltage, capacity, asset condition, and reliability. National Grid regularly reviews its distribution system planning guidelines to integrate emerging best practices, new technology, and regulatory considerations in its distribution asset management activities.

National Grid's vegetation management program is responsible for developing a long-term strategy and delivering an annual work plan that mitigates the impacts of vegetation to distribution assets and ensures safe and reliable service. National Grid continues to adapt its vegetation management program to address the latest research, meet regulatory and financial targets, and achieve high levels of customer reliability so that the program reflects best practices as an industry best in class program.

This document has been redacted for Critical Energy/Electric Infrastructure Information

i. LNG Plants / Permanent

Location	Company	Address	Year Built	Condition	No. of LNG Tanks	Capacity of Tanks (MMBTU)	Vaporization Capability (MMBTU/day)	Liquefaction (MMBTU/day)	Inspection Schedule	[redacted]
Exeter LNG	Rhode Island	53 South County Trail, Exeter	1972	The Exeter LNG plant is in satisfactory operating condition overall and is compliant with applicable regulatory requirements mandated by 49CFR193 and NFPA 59A, 2001. All preventive maintenance is scheduled, performed, and documented per mandated code requirements. Capital improvement program is in place to continuously improve, upgrade, and prolong useful life of plant assets, and ensure safe, reliable, and efficient operations.	1	202,000 MMBTU	24,000 MMBTU/Day	0	1. Daily a. Visual check for cold spots 2. Weekly a.Clean the spill trenches and pump out area 3. Monthly a.Replace burnt out light bulbs (Procedure 17.EX-M4) b.Inspect LNG tank founda. on (Procedure 1.EX-M1) c.Inspect dike area (Procedure 1.EX-M1) d.Inspect tank relief valves (Procedure 1.EX-M1) e.Test ring wall for presence of gas (Procedure 1.EX-M1) f.Check operation of tank vent valve (RSV-106) (Procedure 1.EX-M1) 4. Annual Inspections a. Elevation survey (Procedure 17.EX-M2) b. Atmospheric Corrosion Inspection (Procedure 17.EX-M3)	[redacted]

ii. Temporary/Portable LNG

Location	Company	Address	Year Built	Condition	No. of LNG Tanks	Capacity of Tanks (MMBTU)	Vaporization Capability (MMBTU/day)	Liquefaction (MMBTU/day)	Inspection Schedule	[redacted]
Old Mill Ln	Rhode Island	135 Old Mill Ln, Portsmouth R	2018	The site is a mobile and temporaty LNG facility. National grid owns the site but a third party owns, manages and operate the quipment. They address the maintenance required for the facility while National Grid provides oversight.	5 temporary portable tanks (trailer storage)	6,200 MMBTU (all 5 tanks)	19,000 MMBTU/Day	0	N/A	
Cumberland LNG	Rhode Island	1595 Mendon Road, Cumberla	1972	Since the **decommissioning and demolition of the Cumberland LNG tank**, the Cumberland LNG plant has been operating in a hybrid configuration using temporary LNG storage/pumpout, which feed into existing plant vaporization equipment. The remaining balance of plant equipment is in satisfactory operating condition overall and is compliant with applicable regulatory requirements mandated by 49CFR193 and NFPA 59A, 2001. All applicable preventive maintenance is scheduled, performed, and documented per mandated code requirements. Capital improvement program is in place to continuously improve, upgrade, and prolong useful life of plant assets, and ensure safe, reliable, and efficient operations.	4 temporary portable tanks (trailer storage)	4,000 MMBTU (all 4 tanks)	19,000 MMBTU/Day	0	N/A	[redacted]

[redacted]

This document has been redacted for Critical Energy/Electric Infrastructure Information (CEII)

[redacted]

CHI ENGINEERING
the experience to innovate

FOR:
NATIONAL GRID
CUMBERLAND LNG FACILITY
CUMBERLAND, R.I.

PROJ NO : NGCU
BY : AAF
CHKD : CTA
DATE : 4/16/2020
CHRIS ALBERS
ENGINEERING SUPERVISOR

TITLE:
ANNUAL LNG TANK
AND FOUNDATION SURVEY

DWG NO : CUMBERLAND-LNG-SURVEY
REV. C
SCALE : AS NOTED
SHT : 1 OF 2

17.CU-M3 – Rev.5

LNG PIPE SUPPORT INSPECTION and CORROSION REPORT

Inspection Date (MM/YY): 05/20

PSB CONDITION:
Good (needs no work)
Fair (need to be reviewed by Supervisor and dated set for repair)
Poor (needs attention as soon as possible)

PSB	Condition as Found	Repair Required	Date Repaired	Inspection / Repaired By	
1	GOOD	No		MP BL	
2A	Fair Scrape clean Paint	Yes			
2B					
3A					
3B					
4A					
4B					
5A					
5B					
6A					
6B					
7A					
7B					
8A					
8B					
9A					
9B					
10A					
10B					

17.CU-M3 – Rev.5

PSB	Condition as Found	Repair Required	Date Repaired	Inspection / Repaired By
11A	Fair Scrape Clean Paint	Yes		MPBL
11B				
12A				
12B				
13A				
13B				
14A				
14B				
15A				
15B				
16A				
16B				
17A				
17B				
18A				
18B				
19A				
19B				
20A				
20B				
21A				
21B				

17.CU-M3 – Rev.5

PSB	Condition as Found	Repair Required	Date Repaired	Inspection / Repaired By
22A	Fair Scrape clean Paint	yes		MP BL
22B				
23A				
24A				
24B				
25A				
25B				
26A				
26B				
27A				
27B				
28A				
28B				
34	Good	No		
35	Good	No		
36	Good	No		
37	Good	No		
38	Good	No		
39	Good	No		
40	Good	No		
41	Fair renumber	yes		
42	Fair renumber	yes		
43	Fair renumber	yes		

17.CU-M3 – Rev.5

PSB	Condition as Found	Repair Required	Date Repaired	Inspection / Repaired By
44A	Good	No		MP BL
44B	Good	No		MP BL

OPSB	Condition as Found	Repair Required	Date Repaired	Inspection / Repaired By
1A	Fair Scrape clean paint crossbars	Yes		MP BL
1B				
2A				
2B				
3A				
3B				
4A				
4B				
5A				
5B				
6A	renumber			
6B	renumber			
7	renumber			

17.CU-M3 – Rev.5

Foundations etc.	Condition as Found	Repair Required	Date Repaired	Inspection / Repaired By	
HEX 101 Support Columns X 4	Good	No		MP BL	
HEX 102 Support Columns X 4	Good	No		MP BL	
HEX Spill Containment	Good	No		MP BL	
HEX Spill Through	Good	No		MP BL	
HEX Spill Pit	Good	No		MP BL	

17.CU-M3 – Rev.5

LNG ATMOSPHERIC CORROSION REPORT

Inspection Date (MM/YY): 05/20

PSB CONDITION:
Good (needs no work)
Fair (need to be reviewed by Supervisor and dated set for repair)
Poor (needs attention as soon as possible)

Plant Location / Comments	Condition	Remedial Action	Date Repaired	Inspection / Repaired By	
HEATERS/GLYCOL CIRCULATING SYSTEM	Good			MP BL	
INSTRUMENT AIR SYSTEM Some outside couplings on piping to vaporizers from heater bldg. surface rust	Fair			MP BL	
LNG PIPING mesh + clamps required at flanges.	Fair			MP BL	
VAPORIZERS/NATURAL GAS PIPING outside piping needs painting	Fair			MP BL	

17.CU-M3 – Rev.5

Plant Location / Comments	Condition	Remedial Action	Date Repaired	Inspection / Repaired By	
ELECTRICAL CONDUITS existing conduits ok some rust on couplings. Some abandoned conduit needs to be removed	Fair			MP/BL	
EMERGENCY GENERATOR	Good			MP/BL	
RTU #3 PROTECTIVE SHED	Good			MP/BL	

REVIEWED OK . WILL REMEDIATE OVER SUMMER .

BLR 09 JUNE 2020

17.CU.M4 – Rev. 11

LNG Operations Department

Cumberland LNG Plant

Monthly Plant Lighting Systems Inspection

Inspect and ensure that all plant lighting is operational. Turn on lights using switches, manually activated timers, or shorting/covering photo cells as required.

A check mark "√" in the INSPECTED box indicates that the light worked properly. An **"X"** in the box indicates that something malfunctioned. A description of the malfunction shall be listed in the comments section and the resolution to that malfunction shall also be shown when completed.

PLANT LOCATIONS	INSPECTED	COMMENTS
Control Building		
A. Control Room	√	
B. Break Room	√	
C. Utility Room	√	
D. Locker Room	√	
E. Bathrooms	√	
Mechanical Building		
A. MCC/Workshop	√	
B. Guard Room	√	
C. Meter Room	√	
D. Exterior doors (3)	√	
Heater Building		
A. Inside	√	
B. Outside (photo cell)	√	
Unloading Building		
A. Inside (switch in building)	√	
Exterior Plant Lighting		
A. Poles (#5, 6, 7) along road (photo cell)	√	
B. Pole outside Heater Building (Pole #1 photo cell)	√	
C. Pole at top of hill (Pole #2 photo cell)	√	
D. Pole at center of hill (Pole #8 photo cell)	√	
E. Vaporizers (wall switch in Heater Building with photo cell outside)	√	
F. Pole North of Vaporizers (switch on Pole #3)	√	
G. Pole outside Control Building (Pole #4 photo cell)	√	
H. Control Building & Unloading Area – North Side (photo cell)	√	

Completed By: B. LeBlanc S. DESMOND MM/YY: 12/20

REVIEWED OK - [signature]
14 JANUARY 2021

17.CU.M4 – Rev. 11

LNG Operations Department

Cumberland LNG Plant

Monthly Plant Lighting Systems Inspection

Inspect and ensure that all plant lighting is operational. Turn on lights using switches, manually activated timers, or shorting/covering photo cells as required.

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Control Building		
A. Control Room	✓	
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C. Utility Room	✓	
D. Locker Room	✓	
E. Bathrooms	✓	
Mechanical Building		
A. MCC/Workshop	✓	
B. Guard Room	✓	
C. Meter Room	✓	
D. Exterior doors (3)	✓	
Heater Building		
A. Inside	✓	
B. Outside (photo cell)	✓	
Unloading Building		
A. Inside (switch in building)	✓	
Exterior Plant Lighting		
A. Poles (#5, 6, 7) along road (photo cell)	✓	
B. Pole outside Heater Building (Pole #1 photo cell)	✓	
C. Pole at top of hill (Pole #2 photo cell)	✓	
D. Pole at center of hill (Pole #8 photo cell)	✓	
E. Vaporizers (wall switch in Heater Building with photo cell outside)	✓	
F. Pole North of Vaporizers (switch on Pole #3)	✓	
G. Pole outside Control Building (Pole #4 photo cell)	✓	
H. Control Building & Unloading Area – North Side (photo cell)	✓	

Completed By: Peliot Leblanc   MM/YY: 11/20

REVIEWED OK - EKK
10 DECEMBER 2020

17.CU.M4 – Rev. 11

LNG Operations Department

Cumberland LNG Plant

Monthly Plant Lighting Systems Inspection

Inspect and ensure that all plant lighting is operational. Turn on lights using switches, manually activated timers, or shorting/covering photo cells as required.

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Control Building		
A. Control Room	✓	
B. Break Room	✓	
C. Utility Room	✓	
D. Locker Room	✓	
E. Bathrooms	✓	
Mechanical Building		
A. MCC/Workshop	✓	
B. Guard Room	✓	
C. Meter Room	✓	
D. Exterior doors (3)	✓	
Heater Building		
A. Inside	✓	
B. Outside (photo cell)	✓	
Unloading Building		
A. Inside (switch in building)	✓	
Exterior Plant Lighting		
A. Poles (#5, 6, 7) along road (photo cell)	✓	
B. Pole outside Heater Building (Pole #1 photo cell)	✓	
C. Pole at top of hill (Pole #2 photo cell)	✓	
D. Pole at center of hill (Pole #8 photo cell)	✓	
E. Vaporizers (wall switch in Heater Building with photo cell outside)	✓	
F. Pole North of Vaporizers (switch on Pole #3)	✓	
G. Pole outside Control Building (Pole #4 photo cell)	✓	
H. Control Building & Unloading Area – North Side (photo cell)	✓	

Completed By: B. LeBlanc MM/YY: 10/20

Reviewed ... - [illegible]

04 November 2020

17.CU.M4 – Rev. 11

LNG Operations Department

Cumberland LNG Plant

Monthly Plant Lighting Systems Inspection

Inspect and ensure that all plant lighting is operational. Turn on lights using switches, manually activated timers, or shorting/covering photo cells as required.

A check mark "√" in the INSPECTED box indicates that the light worked properly. An **"X"** in the box indicates that something malfunctioned. A description of the malfunction shall be listed in the comments section and the resolution to that malfunction shall also be shown when completed.

PLANT LOCATIONS	INSPECTED	COMMENTS
Control Building		
A. Control Room	✓	
B. Break Room	✓	
C. Utility Room	✓	
D. Locker Room	✓	
E. Bathrooms	✓	
Mechanical Building		
A. MCC/Workshop	✓	
B. Guard Room	✓	
C. Meter Room	✓	
D. Exterior doors (3)	✓	
Heater Building		
A. Inside	✓	
B. Outside (photo cell)	✓	
Unloading Building		
A. Inside (switch in building)	✓	
Exterior Plant Lighting		
A. Poles (#5, 6, 7) along road (photo cell)	✓	
B. Pole outside Heater Building (Pole #1 photo cell)	✓	
C. Pole at top of hill (Pole #2 photo cell)	✓	
D. Pole at center of hill (Pole #8 photo cell)	✓	
E. Vaporizers (wall switch in Heater Building with photo cell outside)	✓	
F. Pole North of Vaporizers (switch on Pole #3)	✓	
G. Pole outside Control Building (Pole #4 photo cell)	✓	
H. Control Building & Unloading Area – North Side (photo cell)	✓	

Completed By: Poliot Leblanc MM/YY: 09/20

Reviewed ok.

04 November 2020

17.CU.M4 – Rev. 11

LNG Operations Department

Cumberland LNG Plant

Monthly Plant Lighting Systems Inspection

Inspect and ensure that all plant lighting is operational. Turn on lights using switches, manually activated timers, or shorting/covering photo cells as required.

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PLANT LOCATIONS	INSPECTED	COMMENTS
Control Building		
A. Control Room	✓	
B. Break Room	✓	
C. Utility Room	✓	
D. Locker Room	✓	
E. Bathrooms	✓	
Mechanical Building		
A. MCC/Workshop	✓	
B. Guard Room	✓	
C. Meter Room	✓	
D. Exterior doors (3)	✓	
Heater Building		
A. Inside	✓	
B. Outside (photo cell)	✓	
Unloading Building		
A. Inside (switch in building)	✓	
Exterior Plant Lighting		
A. Poles (#5, 6, 7) along road (photo cell)	✓	
B. Pole outside Heater Building (Pole #1 photo cell)	✓	
C. Pole at top of hill (Pole #2 photo cell)	✓	
D. Pole at center of hill (Pole #8 photo cell)	✓	
E. Vaporizers (wall switch in Heater Building with photo cell outside)	✓	
F. Pole North of Vaporizers (switch on Pole #3)	✓	
G. Pole outside Control Building (Pole #4 photo cell)	✓	
H. Control Building & Unloading Area – North Side (photo cell)	✓	

Completed By: Pouliot Leblanc MM/YY: 08/20

REVIEWED OK. [signature]

02 SEPTEMBER 2020

17.CU.M4 – Rev. 10

LNG Operations Department

Cumberland LNG Plant

Monthly Plant Lighting Systems Inspection

Inspect and ensure that all plant lighting is operational. Turn on lights using switches, manually activated timers, or shorting/covering photo cells as required.

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Control Building		
A. Control Room	✓	
B. Break Room	✓	
C. Utility Room	✓	
D. Locker Room	✓	
E. Bathrooms	✓	
Mechanical Building		
A. MCC/Workshop	✓	
B. Guard Room	✓	
C. Meter Room	✓	
D. Exterior doors (3)	X ✓	replace bulb outside meter room + guard Room
Heater Building		
A. Inside	✓	
B. Outside (photo cell)	✓	
Unloading Shed		
A. Inside (timer on second floor)	✓	
Exterior Plant Lighting		
A. Unloading Building (switch in building)	✓	
B. Poles (#5, 6, 7) along road (photo cell)	✓	
C. Pole outside Heater Building (Pole #1 photo cell)	✓	
D. Pole at top of hill (Pole #2 photo cell)	✓	
E. Pole at center of hill (Pole #8 photo cell)	✓	
F. Vaporizers (wall switch in Heater Building with photo cell outside)	✓	
G. Pole North of Vaporizers (switch on Pole #3)	✓	
H. Pole outside Control Building (Pole #4 photo cell)	✓	
I. Control Building & Unloading Area – North Side (photo cell)	✓	

OK [illegible]

Completed By: Pouliot MM/YY: 07/20

REVIEWED OK · [illegible]
10 AUGUST 2020

17.CU.M4 – Rev. 9

LNG Operations Department

Cumberland LNG Plant

Monthly Plant Lighting Systems Inspection

Inspect and ensure that all plant lighting is operational. Turn on lights using switches, manually activated timers, or shorting/covering photo cells as required.

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Control Building		
A. Control Room	✓	
B. Break Room	✓	
C. Utility Room	✓	
D. Locker Room	✓	
E. Bathrooms	✓	
Mechanical Building		
A. MCC/Workshop	✓	
B. Guard Room	✓	
C. Meter Room	✓	
D. Exterior doors (3)	✓	
Heater Building		
A. Inside	✓	
B. Outside (photo cell)	✓	
Unloading Shed		
A. Inside (timer on second floor)	✓	
Exterior Plant Lighting		
A. Unloading Area (timer on 2nd Floor)	✓	
B. Poles (#5, 6, 7) along road (photo cell)	✓	
C. Pole outside Heater Building (Pole #1 photo cell)	✓	
D. Pole at top of hill (Pole #2 photo cell)	✓	
E. Pole at center of hill (Pole #8 photo cell)	✓	
F. Vaporizers (wall switch in Heater Building with photo cell outside)	✓	
G. Pole North of Vaporizers (switch on Pole #3)	✓	
H. Pole outside Control Building (Pole #4 photo cell)	✓	
I. Control Building – North Side (photo cell)	✓	

Completed By: M. Pouliot, B. LeBlanc MM/YY: 06/20

Reviewed OK · [signature]
30 June 2020

17.CU.M4 – Rev. 9

LNG Operations Department

Cumberland LNG Plant

Monthly Plant Lighting Systems Inspection

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Control Building		
A. Control Room	√	
B. Break Room	√	
C. Utility Room	√	
D. Locker Room	√	
E. Bathrooms	√	
Mechanical Building		
A. MCC/Workshop	√	
B. Guard Room	√	
C. Meter Room	√	
D. Exterior doors (3)	√	
Heater Building		
A. Inside	√	
B. Outside (photo cell)	√	
Unloading Shed		
A. Inside (timer on second floor)	√	
Exterior Plant Lighting		
A. Unloading Area (timer on 2nd Floor)	√	
B. Poles (#5, 6, 7) along road (photo cell)	√	
C. Pole outside Heater Building (Pole #1 photo cell)	√	
D. Pole at top of hill (Pole #2 photo cell)	√	
E. Pole at center of hill (Pole #8 photo cell)	√	
F. Vaporizers (wall switch in Heater Building with photo cell outside)	√	
G. Pole North of Vaporizers (switch on Pole #3)	√	
H. Pole outside Control Building (Pole #4 photo cell)	√	
I. Control Building – North Side (photo cell)	√	

Completed By: M. Pouliot, B. LeBlanc MM/YY: 05/20

Reviewed OK · BK
09 June 2020

17.CU.M4 – Rev. 9

LNG Operations Department

Cumberland LNG Plant

Monthly Plant Lighting Systems Inspection

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Control Building		
A. Control Room	√	
B. Break Room	√	
C. Utility Room	√	
D. Locker Room	√	
E. Bathrooms	√	
Mechanical Building		
A. MCC/Workshop	√	CHANGED BURNT BULB
B. Guard Room	√	
C. Meter Room	√	
D. Exterior doors (3)	√	
Heater Building		
A. Inside	√	
B. Outside (photo cell)	√	
Unloading Shed		
A. Inside (timer on second floor)	√	
Exterior Plant Lighting		
A. Unloading Area (timer on 2^{nd} Floor)	√	
B. Poles (#5, 6, 7) along road (photo cell)	√	
C. Pole outside Heater Building (Pole #1 photo cell)	√	
D. Pole at top of hill (Pole #2 photo cell)	√	
E. Pole at center of hill (Pole #8 photo cell)	√	
F. Vaporizers (wall switch in Heater Building with photo cell outside)	√	
G. Pole North of Vaporizers (switch on Pole #3)	√	
H. Pole outside Control Building (Pole #4 photo cell)	√	
I. Control Building – North Side (photo cell)	√	

Completed By: B. LeBlanc, M. Pouliot MM/YY: 04/20

REVIEWED OK BKC

10 MAY 2020

17.CU.M4 – Rev. 9

LNG Operations Department

Cumberland LNG Plant

Monthly Plant Lighting Systems Inspection

Inspect and ensure that all plant lighting is operational. Turn on lights using switches, manually activated timers, or shorting/covering photo cells as required.

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Control Building		
A. Control Room	✓	
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C. Utility Room	✓	
D. Locker Room	✓	
E. Bathrooms	✓	
Mechanical Building		
A. MCC/Workshop	✓	
B. Guard Room	✓	
C. Meter Room	✓	
D. Exterior doors (3)	✓	
Heater Building		
A. Inside	✓	
B. Outside (photo cell)	✓	
Unloading Shed		
A. Inside (timer on second floor)	✓	
Exterior Plant Lighting		
A. Unloading Area (timer on 2nd Floor)	✓	
B. Poles (#5, 6, 7) along road (photo cell)	✓	
C. Pole outside Heater Building (Pole #1 photo cell)	✓	
D. Pole at top of hill (Pole #2 photo cell)	✓	
E. Pole at center of hill (Pole #8 photo cell)	✓	
F. Vaporizers (wall switch in Heater Building with photo cell outside)	✓	
G. Pole North of Vaporizers (switch on Pole #3)		
H. Pole outside Control Building (Pole #4 photo cell)	✓	
I. Control Building – North Side (photo cell)	✓	

Completed By: Paulut & Freene MM/YY: 03/2020

REVIEWED OK 03 APRIL 2020

17.CU.M4 – Rev. 8

LNG Operations Department

Cumberland LNG Plant

Monthly Plant Lighting Systems Inspection

Inspect and ensure that all plant lighting is operational. Turn on lights using switches, manually activated timers, or shorting/covering photo cells as required.

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PLANT LOCATIONS	INSPECTED	COMMENTS
Control Building		
A. Control Room	✓	
B. Break Room	✓	
C. Utility Room	✓	
D. Locker Room	✓	
E. Bathrooms	✓	
Mechanical Building		
A. MCC/Workshop	X ✓	replace bulb 2/20/20
B. Guard Room	✓	
C. Meter Room	✓	
D. Exterior doors (3)	X ✓	replace bulb 2/20/20
Heater Building		
A. Inside	X ✓	replace bulb 2/20/20
B. Outside (photo cell)	✓	
Unloading Shed		
A. Inside (timer on second floor)	✓	
Exterior Plant Lighting		
A. Unloading Area (timer on 2nd Floor)	✓	
B. Poles (#5, 6, 7) along road (photo cell)	✓	
C. Pole outside Heater Building (Pole #1 photo cell)	✓	ONE LIGHT INTERMITTENT *
D. Pole at top of hill (Pole #2 photo cell)	✓	
E. Pole at center of hill (Pole #8 photo cell)	✓	
F. Vaporizers (wall switch in Heater Building with photo cell outside)	X ✓	replace bulb 2/20/20
G. Pole North of Vaporizers (switch on Pole #3)	✓	SOME LED'S BURNED OUT *

Completed By: T. WAHL
M. POULIOT

MM/YY: 02/20

* REPLACED WITH LED LIGHT IN MARCH 2020. BKK

REVIEWED OK. BH
20 MARCH 2020

17.CU.M4 – Rev. 8

LNG Operations Department

Cumberland LNG Plant

Monthly Plant Lighting Systems Inspection

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Control Building		
A. Control Room	✓	
B. Break Room	✓	
C. Utility Room	✓	
D. Locker Room	✓	
E. Bathrooms	✓	
Mechanical Building		
A. MCC/Workshop	✓	
B. Guard Room	✓	
C. Meter Room	✓	
D. Exterior doors (3)	✓	
Heater Building		
A. Inside	✓	
B. Outside (photo cell)	✓	
Unloading Shed		
A. Inside (timer on second floor)	✓	
Exterior Plant Lighting		
A. Unloading Area (timer on 2nd Floor)	✓	
B. Poles (#5, 6, 7) along road (photo cell)	✓	
C. Pole outside Heater Building (Pole #1 photo cell) *	X	ONE LIGHT GOES ON+OFF
D. Pole at top of hill (Pole #2 photo cell)	✓	
E. Pole at center of hill (Pole #8 photo cell)	✓	
F. Vaporizers (wall switch in Heater Building with photo cell outside)	✓	
G. Pole North of Vaporizers (switch on Pole #3) *	✓	SOME LED'S BURNED OUT

Completed By: T. WAHL / M. POULIOT

MM/YY: 01/20

* REPLACING WITH NEW LED FIXTURES. OK @ THIS TIME.

REVIEWED OK - [signature]
04 FEBRUARY 2020.

5/20

17.EX-M3 Rev. 2

LNG Operations Department

Exeter LNG Plant

Atmospheric Corrosion Inspection Procedure

This procedure shall be used to perform an inspection for potential atmospheric corrosion problems in the various plant systems and equipment. Use an attached sheet for any additional inspection information that doesn't fit on this cover sheet. This is required by code 193.2635 (d) at intervals not exceeding three years. Also refer to General Procedure 99.EX-G12.

1. Personnel who perform this inspection shall have successfully completed the Atmospheric Corrosion Training Module. Then follow the items covered in the training to perform the inspection.
2. Inspect steel components for evidence of corrosion damage (surface rust, pitting, and discoloration).
3. If evidence of corrosion damage exists give location with reference point for future reference.
4. Mark the corrosion damaged area in an appropriate manner.
5. If appropriate take photographs of the damaged area.
6. If a component is insulated, inspect the insulation for signs of damage.
7. If any insulation damage is observed the area may be photographed if it deemed useful.
8. If evidence of insulation damage exists, record the location in the comment box for future reference.
9. The LNG Operations Department recommends that the atmospheric corrosion inspections should be performed and documented annually

Turn in this completed document to the plant supervisor. This document shall be kept in the plant maintenance records (5 years) for future reference and inspection purposes.

Plant Areas:

- **LNG Tank/LNG Pumps**
- **Boiloff System**
- **HEX Vaporizers**
- **Emergency Generator**
- **Heaters/Glycol Circulator System**
- **Instrument Air System**
- **Truck Station**

17.EX-M3 Rev. 2

Plant: **Exeter LNG Plant** Plant Area: **LNG Tank/LNG Pumps**

Inspected By: Nelson Month/Year: MAY/2020

Comments:
RUST ON I/A HANDLE AV53
RUST ON PIPE HANGER NEAR CVD-4B
RUST - CHIPPED PAINT ON HANDLE (WHEEL) GAV101
INSULATION NEEDS REPAIR NEAR RSV101 + BFV109
RUSTY HANDLES ON GLOBE VALVES ABOVE BARTON GAUGE

Plant: **Exeter LNG Plant** Plant Area: **Boiloff System**

Inspected By: Nelson Month/Year: MAY/2020

Comments:
SLIGHT RUST ON CV200 NEAR AFTERCOOLER FAN
HV 200C VALVE NEEDS PAINT (TOP OF GLYCOL FAN)
CHIPPING PAINT ON BACK OF PIPE STAND PS48B
RUSTY PIPE STAND NEAR KNOCK OUT POT
RUST ON 2" BOIL OFF LINE TO KNOCK OUT POT
TEMP T'COUPLE HOUSINGS FOR TC1, T/C2 BOC INLET - RUSTY
(ON TOP OF 4" STAINLESS PIPE)

Plant: **Exeter LNG Plant** Plant Area: **HEX Vaporizers**

Inspected By: Nelson Month/Year: MAY/2020

Comments:
BOLTS ON GLYCOL VALVES V264, V266 NEED REPAINT
HEX 201 GLYCOL INSULATION NEEDS REPAIR
SEND OUT LINES FROM BOTH HEXES HAVE SOME
RUST - NEED REPAINTING
RUSTY SEAL POT AT HEX 201 METER NEEDS PAINTING

17.EX-M3 Rev. 2

Plant: **Exeter LNG Plant** Plant Area: **Emergency Generator**

Inspected By: Nelson Month/Year: May/2020

Comments:
NO RUST OR CORROSSION
GOOD CONDITION

Plant: **Exeter LNG Plant** Plant Area: **Heaters/Glycol Circulator System**

Inspected By: Nelson Month/Year: May/2020

Comments:
H-401 - slight rust on drain valve V405 piping
slight rust on piping at LSLL401 and PI401
H-402 - slight rust on fittings - drain valve V454

Plant: **Exeter LNG Plant** Plant Area: **Instrument Air System**

Inspected By: Nelson Month/Year: May/2020

Comments:
NO RUST OR CORROSION
GOOD CONDITION

17.EX-M3 Rev. 2

Plant: **Exeter LNG Plant** Plant Area: **Truck Station**

Inspected By: Nelson Month/Year: May / 2020

Comments:
very little surface rust
Yellow racks + poles have flaking paint
Pipe stands PS-1B; PS-1A need repaint

Comments:
slight rust - base of light pole next to truck shack
slight rust - base of light pole - bridgeway

3/4" coupling on 3" make up gas line
above meter ~~[illegible]~~ corroded

17.EX-M2 Rev. 1

LNG Operations Department

Exeter LNG Plant

Annual Elevation Survey of Plant Components

This procedure describes the annual civil survey of the LNG Tank and other plant equipment foundations. This procedure covers code compliance 193.2623, inspecting LNG tanks.

Plant management is responsible for scheduling a licensed surveyor to perform an annual civil survey of designated plant components or after a major meteorological or geophysical disturbance as described in the plant's Emergency Plan in the "Natural Phenomena" and "Hurricane" procedures.

The Survey Contractor is responsible for performing this work based on professional experience and industry standards.

Plant personnel shall provide a work permit and job brief to all personnel involved before any work is started.

The Survey Contractor shall use the appropriate survey drawing that provides all the designated survey points in the plant. This drawing shall be updated as items are added or subtracted by plant management. The drawing can provide a yearly view or historical view of what was found at each point.

The completed survey drawing shall be stamped by the surveyor every time they perform a complete survey. This is done to assure plant management that the professional survey contractor has reviewed the work and attested to it accuracy.

Plant management shall keep the civil survey drawing in the plant's maintenance records for future reference and inspection purposes.

SEE: CIVIL SURVEY BINDER

4/5/20

This document has been redacted for Critical Energy/Electric Infrastructure Information (CEII)

CHI ENGINEERING
An NV5 Company

OCTOBER 29, 2020

Mr. Brian Kirkwood
Senior Supervisor, LNG Operations

National Grid
1595 Mendon Road
Cumberland, RI 02864
617-455-5521 (cell)

RE: Annual Foundation Survey for Exeter RI LNG Tank (2020)

Mr. Kirkwood,

CHI Engineering Services, Inc. performed an elevation survey of the LNG tank foundation at National Grid's Exeter LNG Storage Facility on Friday, October 16, 2020. This survey is intended to satisfy the Code of Federal Regulation, 49 CFR 193.2623(a), Liquefied Natural Gas Facilities: Federal Safety Standards, which requires periodic evaluation of foundations within LNG storage facilities.

The typical annual survey conducted at this site includes various pipe and equipment supports, as well as the vaporizer and boil-off compressor foundations. Drawing EXETER-LNG-SURV has been enclosed with this letter. The elevation data for current and historical surveys are also illustrated in a table on this drawing.

There were no notable differences in the majority of the surveyed elevations as compared to previous years' data; Slight discrepancies in previously recorded elevations of some points can be observed in the survey data but these differences, generally less than ¼ of an inch, are within the accuracy of the equipment and the methods used and are considered acceptable.

Please let me know if you have any questions or concerns.

Sincerely,

Chris Albers Digitally signed by Chris Albers
DN: C=US,
E=chris.albers@nv5.com,
OU=NV5, CN=Chris Albers
Date: 2020.11.05 09:12:37-05'00'

Chris Albers,

Sr. Project Civil Engineer

This document has been redacted for Critical Energy/Electric Infrastructure Information (CEII)

[redacted]

CHI ENGINEERING
the experience to innovate

FOR:
NATIONAL GRID
LNG FACILITY
EXETER, RHODE ISLAND

PROJ NO : NGEX
BY : CTA
CHKD : JDL
DATE : 10/30/2017
JOHN LAMB
ENGINEERING SUPERVISOR

TITLE:
ANNUAL LNG TANK
AND FOUNDATION SURVEY

DWG NO :	EXETER-LNG-SURVEY		REV.
SCALE :	NONE	SHT : 1 OF 2	2

			PK NAIL				TOP FLANGE																						
DATE	BM1	BM2	1	2	3	4	A	B	C	J	K	L	M-25	M-26	M-27	XM-28	M-29	M-30	M-31	M-32	N	O	P	Q	W	X	Y	Z	PS-22
05/07/87			186.14	186.12	186.12	186.14	187.70	187.66	187.57																				
07/15/88			186.14	186.12	186.13	186.11	187.71	187.67	187.57																				
11/30/89			186.14	186.12	186.12	186.12	187.71	187.67	187.57																				
07/23/90			186.16	186.11	186.15	186.14	187.72	187.68	187.58																				
09/10/91			186.16	186.13	186.14	186.14	187.73	187.68	187.58																				
09/11/92			186.15	186.12	186.13	186.12	187.72	187.67	187.56																				
10/14/94			186.15	186.16	186.15	186.14	187.72	187.68	187.59																193.83	193.84	193.83	193.81	
12/03/97	193.00	192.10	186.16	186.13	186.15	186.16	187.73	187.70	187.60																193.85	193.85	193.84	193.82	
09/22/98	193.00	192.10	186.14	186.11	186.11	186.11	187.71	187.65	187.52																193.83	193.84	193.83	193.82	
09/30/99	192.98	192.06	186.13	186.10	186.11	186.12	187.71	187.65	187.56																193.79	193.80	193.78	193.77	
08/17/00	192.97	192.06	186.14	186.11	186.14	186.14	187.71	187.67	187.52																193.81	193.81	193.81	193.79	
03/13/01	192.98	192.08	186.16	186.14	186.17	186.16	187.74	187.71	187.58																193.83	193.83	193.82	193.82	
09/24/02	192.98	192.06	186.15	186.13	186.14	186.12	187.73	187.66	187.56																193.77	193.78	193.79	193.76	
09/10/03	192.99	192.08	186.16	186.13	186.15	186.14	187.73	187.68	187.58																193.82	193.82	193.86	193.80	
10/13/04	192.98	192.07	186.14	186.11	186.13	186.13	187.71	187.66	187.56																193.81	193.82	193.82	193.80	
10/13/05	192.98	192.07	186.14	186.12	186.14	186.13	187.72	187.67	187.58																193.83	193.83	193.82	193.81	
08/30/06	192.98	192.10	186.14	186.12	186.14	186.13	187.71	187.64	187.56																193.80	193.80	193.80	193.81	
08/22/07	192.98	192.08	186.14	186.12	186.15	186.14	187.71	187.67	187.58																193.83	193.83	193.81	193.81	
09/29/08	192.98	192.09	186.14	186.10	186.11	186.11	187.70	187.65	187.53																193.85	193.84	193.82	193.81	
09/30/09	192.98	192.07	186.15	186.12	186.14	186.13	187.72	187.67	187.57																193.83	193.83	193.83	193.78	
09/13/10	192.98	192.08	186.19	186.14	186.16	186.16	187.71	187.67	187.57																193.81	193.80	193.81	193.81	
09/20/11	192.98		186.20	186.17	186.18	186.17	187.72	187.68	187.59	192.93	192.66	192.66			191.76						192.37				193.84	193.85	193.81	193.80	
08/21/12	192.98		186.17	186.15	186.16	186.14	187.69	187.66	187.56	192.92	192.15	192.16			191.71						192.36				193.79	193.78	193.79	193.76	
08/28/13	192.98		186.19	186.16	186.15	186.14	187.70	187.67	187.57	192.95	192.66	192.65			191.73						192.36				193.82	193.81	193.81	193.78	
09/23/14	192.98		186.20	186.18	186.16	186.14	187.72	187.68	187.58	192.94	192.66	192.65			191.72						192.37				193.81	193.80	193.81	193.78	
08/13/15	192.98		186.18	186.15	186.16	186.12	187.68	187.67	187.55	192.94	192.66	192.66			191.72						192.37				193.78	193.81	193.78	193.79	
09/28/16	192.98		186.19	186.16	186.18	186.12	187.71	187.68	187.59	192.95	192.66	192.65	191.70	191.73	191.71	191.70	191.69	191.71	191.70	191.69	192.37	185.28	194.34	194.33	193.81	193.82	193.81	193.79	185.76
10/16/17	192.98		186.19	186.15	186.16	186.15	187.73	187.69	187.59	192.95	192.67	192.66	191.71	191.75	191.73	191.72	191.71	191.73	191.73	191.71	192.37	185.30	194.34	194.34	193.83	193.83	193.83	193.80	185.77
9/24/18	192.98		186.19	186.15	186.17	186.14	187.73	187.68	187.58	192.97	192.68	192.66	191.72	191.74	191.72	191.72	191.72	191.72	191.73	191.70	192.38	185.30	194.34	194.33	193.82	193.83	193.83	193.80	185.76
9/20/19	192.98		186.20	186.13	186.13	186.11	187.71	187.66	187.58	192.96	192.66	192.67	191.70	191.72	191.72	191.71	191.70	191.72	191.72	191.70	192.37	185.28	194.33	194.34	193.81	193.81	193.81	193.78	185.75
4 10/16/2020	192.98		186.20	186.14	186.14	186.13	187.73	187.68	187.59	192.95	192.67	192.66	191.71	191.74	191.72	191.72	191.71	191.72	191.72	191.70	192.37	185.29	194.34	194.34	193.81	193.81	193.81	193.79	185.76

NOTES:
1. 09/13/01 – TANK FOUNDATION GROUTED. SET PK NAILS AT POINTS 1, 2, 3, 4 & BM1
2. 09/13/10 – TANK FOUNDATION GROUTED. SET PK NAILS AT POINTS 1, 2, 3, & 4
3. 09/20/11 – EXPANDED SCOPE OF SURVEY WITH POINTS "J", "K", "L", "M", & "N". BM2 COVERED WITH BUILDING CONSTRUCTION.
4. 03/28/16 – EXPANDED SCOPE OF SURVEY WITH POINTS "O", "P", "Q", "PS-22", AND CONVERTED POINT "M" TO "M-25 THROUGH "M-32"
5. SUMMER 2017 – PK'S 2,3, & 4 WERE SEALED OVER W/ A WATERPROOF MEMBRANE. NEW ELEVATIONS FROM TOP OF COATING @ RED PAINTED NUMBERS.

FINAL

REVISIONS	DESCRIPTION	DESIGN APPROVAL	REVISIONS	DESCRIPTION	DESIGN APPROVAL
4	ANNUAL SURVEY 2020	CTA	2	ANNUAL SURVEY 2018	CTA
3	ANNUAL SURVEY 2019	CTA	1	ANNUAL SURVEY 2017	CTA

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FOR: NATIONAL GRID
LNG FACILITY
EXETER, RHODE ISLAND

BY: CTA
CHKD: JCL
DATE: 11/18/2019
JOHN LAMB
ENGINEERING SUPERVISOR

TITLE: ANNUAL LNG TANK AND FOUNDATION SURVEY
DWG NO: EXETER-LNG-SURV
SCALE: NONE
SHT: 2 OF 2
REV. 4

17.EX-M4 Rev. 7

LNG Operations Department 12/20

Exeter LNG Plant

Monthly Lighting Checklist

Monthly check of emergency lighting, and record (ON) on form if tested good. If it did not test good record (OFF) and note in comments section what was done to correct problem.

Plant Locations	ON/OFF	COMMENTS
1. Office Building	on	
A. Utility Room	on	
B. Locker Room	on	
D. Control Room	on	
F. Restroom	on	
2. Office Building Doorways (3)	on	
3. Compressor Rooms (Old and New)	on	
4. Garage	on	
5. Truck Station Area	on	
6. LNG Tank Area	on	
7. Vaporizers	on	
8. Stairway into dike area	on	
9. Boiler room	on	
10.Boiler room Exterior	on	
Emergency Lighting	**Lighting test**	**Comments**
New addition S. Entrance door	on	
Outside bathroom in Hallway	on	
Control Room	on	
Utility Room	on	
Utility Room Box for Boil-off Compressor Room	on	
Locker Room # 1	on	
Locker Room # 2	on	
Heater Bldg West Entrance Door	on	
Heater Bldg North West Door	on	
Heater Bldg North East Door	on	
New Compressor Room	on	

Comments

Inspected By: K. Sanborn Month/Year: Dec - 2020

Reviewed OK 12/30/20

17.EX-M4 Rev. 7

11/20

LNG Operations Department

Exeter LNG Plant

Monthly Lighting Checklist

Monthly check of emergency lighting, and record (ON) on form if tested good. If it did not test good record (OFF) and note in comments section what was done to correct problem.

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9. Boiler room	on	
10.Boiler room Exterior	on	
Emergency Lighting	**Lighting test**	**Comments**
New addition S. Entrance door	on	
Outside bathroom in Hallway	on	
Control Room	on	
Utility Room	on	
Utility Room Box for Boil-off Compressor Room	on	
Locker Room # 1	on	
Locker Room # 2	on	
Heater Bldg West Entrance Door	on	
Heater Bldg North West Door	on	
Heater Bldg North East Door	on	
New Compressor Room	on	

Comments

Inspected By: K. Sanborn R. Botelho Month/Year: November - 2020

REVIEWED OK 12/10/20

10/2020

17.EX-M4 Rev. 7

LNG Operations Department

Exeter LNG Plant

Monthly Lighting Checklist

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Emergency Lighting	**Lighting test**	**Comments**
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Control Room	on	
Utility Room	on	
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Locker Room # 1	on	
Locker Room # 2	on	
Heater Bldg West Entrance Door	on	
Heater Bldg North West Door	on	
Heater Bldg North East Door	on	
New Compressor Room	on	

Comments Reviewed OK 11/2/20

Inspected By: K. Sanborn Month/Year: October 2020

9/2020

17.EX-M4 Rev. 7

LNG Operations Department

Exeter LNG Plant

Monthly Lighting Checklist

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6. LNG Tank Area	On	
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9. Boiler room	On	
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Emergency Lighting	**Lighting test**	**Comments**
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Control Room	On	
Utility Room	On	
Utility Room Box for Boil-off Compressor Room	On	
Locker Room # 1	On	
Locker Room # 2	On	
Heater Bldg West Entrance Door	On	
Heater Bldg North West Door	On	
Heater Bldg North East Door	On	
New Compressor Room	On	

Comments

Inspected By: K. Sanborn

Month/Year: Sept 2020

Reviewed OK ~~[illegible]~~
16 October 2020

8/2020

17.EX-M4 Rev. 7

LNG Operations Department

Exeter LNG Plant

Monthly Lighting Checklist

Monthly check of emergency lighting, and record (ON) on form if tested good. If it did not test good record (OFF) and note in comments section what was done to correct problem.

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Utility Room	on	
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Locker Room # 1	on	
Locker Room # 2	on	
Heater Bldg West Entrance Door	on	
Heater Bldg North West Door	on	
Heater Bldg North East Door	on	
New Compressor Room	on	

Comments

Inspected By: K. Sanborn Month/Year: August 2020

REVIEWED OK. [signature]
16 OCTOBER 2020

July 23

17.EX-M4 Rev. 7

LNG Operations Department

Exeter LNG Plant

Monthly Lighting Checklist

Monthly check of emergency lighting, and record (ON) on form if tested good. If it did not test good record (OFF) and note in comments section what was done to correct problem.

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Utility Room	ON	
Utility Room Box for Boil-off Compressor Room	ON	
Locker Room # 1	ON	
Locker Room # 2	ON	
Heater Bldg West Entrance Door	ON	
Heater Bldg North West Door	ON	
Heater Bldg North East Door	ON	
New Compressor Room	ON	

Comments

Inspected By: M Pierson Month/Year: JULY 2020

REVIEWED OK - [signature]
21 AUGUST 2020

June 2020 **17.EX-M4 Rev. 7**

LNG Operations Department

Exeter LNG Plant

Monthly Lighting Checklist

Monthly check of emergency lighting, and record (ON) on form if tested good. If it did not test good record (OFF) and note in comments section what was done to correct problem.

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Utility Room	on	
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Locker Room # 1	on	
Locker Room # 2	on	
Heater Bldg West Entrance Door	on	
Heater Bldg North West Door	on	
Heater Bldg North East Door	on	
New Compressor Room	on	

Comments

Inspected By: K. Sanborn, E. Wojcik Month/Year: June 2020

Reviewed by . [signature]
09 July 2020

17.EX-M4 Rev. 7

5/20

LNG Operations Department

Exeter LNG Plant

Monthly Lighting Checklist

Monthly check of emergency lighting, and record (ON) on form if tested good. If it did not test good record (OFF) and note in comments section what was done to correct problem.

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Locker Room # 1	on	
Locker Room # 2	on	
Heater Bldg West Entrance Door	on	
Heater Bldg North West Door	on	
Heater Bldg North East Door	on	
New Compressor Room	on	

Comments

Inspected By: K. Sanborn, E. Wojcik Month/Year: May 2020

4/20

17.EX-M4 Rev. 7

LNG Operations Department

Exeter LNG Plant

Monthly Lighting Checklist

Monthly check of emergency lighting, and record (ON) on form if tested good. If it did not test good record (OFF) and note in comments section what was done to correct problem.

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Utility Room	on	
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Locker Room # 1	on	
Locker Room # 2	on	
Heater Bldg West Entrance Door	on	
Heater Bldg North West Door	on	
Heater Bldg North East Door	on	
New Compressor Room	on	

Comments

Inspected By: K. Sanborn O. Kelleher Month/Year: April 2020

3/20

17.EX-M4 Rev. 7

LNG Operations Department

Exeter LNG Plant

Monthly Lighting Checklist

Monthly check of emergency lighting, and record (ON) on form if tested good. If it did not test good record (OFF) and note in comments section what was done to correct problem.

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Locker Room # 1	on	
Locker Room # 2	on	
Heater Bldg West Entrance Door	on	
Heater Bldg North West Door	on	
Heater Bldg North East Door	on	
New Compressor Room	on	

Comments

Inspected By: K. Sanborn E. Wojcik Month/Year: March 2020

2/20

17.EX-M4 Rev. 7

LNG Operations Department

Exeter LNG Plant

Monthly Lighting Checklist

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Locker Room # 2	ON	
Heater Bldg West Entrance Door	ON	
Heater Bldg North West Door	ON	
Heater Bldg North East Door	ON	
New Compressor Room	ON	

Comments

Inspected By: K. Sanborn

Month/Year: Feb - 2020

1/20

17.EX-M4 Rev. 7

LNG Operations Department

Exeter LNG Plant

Monthly Lighting Checklist

Monthly check of emergency lighting, and record (ON) on form if tested good. If it did not test good record (OFF) and note in comments section what was done to correct problem.

Plant Locations	ON/OFF	COMMENTS
1. Office Building	on	
A. Utility Room	on	
B. Locker Room	on	
D. Control Room	on	
F. Restroom	on	
2. Office Building Doorways (3)	on	
3. Compressor Rooms (Old and New)	on	
4. Garage	on	
5. Truck Station Area	on	
6. LNG Tank Area	on	
7. Vaporizers	on	
8. Stairway into dike area	on	
9. Boiler room	on	
10.Boiler room Exterior	on	
Emergency Lighting	**Lighting test**	**Comments**
New addition S. Entrance door	on	
Outside bathroom in Hallway	on	
Control Room	on	
Utility Room	on	
Utility Room Box for Boil-off Compressor Room	on	
Locker Room # 1	on	
Locker Room # 2	on	
Heater Bldg West Entrance Door	on	
Heater Bldg North West Door	on	
Heater Bldg North East Door	on	
New Compressor Room	on	

Comments

Inspected By: K. Sanborn

Month/Year: Jan - 2020

EXETER LNG FACILITY

Month	Equipment Description	Work Description	Related Procedure	CHI Task ID from Database
SEP	Exeter Emissions	Monthly Meter Reads		
SEP	LNG Storage Syst	Annual Instrument Testing	99.EX-G30	Standard
SEP	LNG Storage Syst	Annual Testing of Relief Valves	1.EX-M2	27
SEP	LNG Storage Tan	Annual Civil Survey of Foundation	17.EX-M2	82
SEP	LNG Storage Tan	Monthly Tank Inspection	01 LNG M1	Standard
SEP	LNG Pumping Sy	Annual Instrument Testing	3.EX-O2	Standard
SEP	LNG Pumping Sy	Annual Testing of Relief Valves	2.EX-M1	27
SEP	Vaporization Syst	Annual Testing of Plant Relief Valves	3.EX-M1 &	27
SEP	Vaporization Syst	Annual Instrument Testing	99.EX-G30	Standard
SEP	Heater-402	Boiler Inspection (Due 2022)	None	
SEP	House Heat Boile	Boiler Inspection (Due 2019)	None	
SEP	Heater-401	Boiler Inspection (Due 2019)	None	103

Month	Equipment Description	Work Description	Related Procedure	CHI Task ID from Database
SEP	Boiloff System	Annual Instrument Testing	99.EX-G30	Standard
SEP	BO Compressor-	Run Compressor		97
SEP	Boil Off Compres	Check Perma Grease cartridge on C101A		
SEP	BO Compressor-	Run Compressor		97
SEP	LNG Truck Trans	Annual Instrument Testing	99.EX-G30	Standard
SEP	Fire & Emergenc	Monthly Inspection	7.EX-M1	29
SEP	Portable CGI Uni	Perform Monthly Test	7.EX-M4	Standard
SEP	Emergency Gener	Monthly Operational Test	15.EX-O1	35
SEP	Plant Structures	Monthly Inspection	17.EX-M1	
SEP	Plant Structures	Annual Civil Survey of Foundation	17.EX-M2	82
SEP	Plant Lighting	Monthly Inspection	17.EX-M4	Standard
SEP	Plant Security Sys	Monthly Inspection	18.EX-M1	

Month	Equipment Description	Work Description	Related Procedure	CHI Task ID from Database
SEP	Safety Locker	Monthly Inspection	7.EX-M3	

June 2020

1.EX-M1 Rev. 3

LNG Operations Department

Exeter LNG Plant

Monthly Inspection of LNG Storage Tank

Purpose

This maintenance procedure was developed to meet the following code requirements;

- 193.2623 Each LNG tank must be inspected or tested to verify that each of the following conditions does not impair the structural integrity or safety of the tank:
  (a) Foundation and tank movement during normal operation and after a major meteorological or geophysical disturbance.
  (b) Inner tank leakage.
  (c) Effectiveness of insulation
  (d) Frost heave

The purpose of this procedure is to provide performance instructions to LNG plant personnel who conduct or arrange the inspections and how to document completion of the inspections for auditing purposes.

Scope

LNG Operations performs the following functions to meet the above listed code requirements:

(a) Perform and document Civil Surveys of the LNG storage tank foundation. This is done annually or after a major meteorological or geophysical disturbance. All civil survey readings shall be shown on one drawing covered under the code. This work is provided by an SME.
(b) Plants take liquid level readings daily and check for any abnormal shifts in level that can't be accounted for by normal plant operations.
(c) Visual inspection documented by this maintenance procedure.
(d) Visual inspection documented by this maintenance procedure. Performance of a civil survey as needed.

LNG plant personnel who conduct these inspections are trained to perform visual observations on a scheduled timeframe. They are looking for detrimental changes that occur over time and could impair plant systems. These inspections will be documented using the procedure checklists and then submitting them to plant management. Then plant management has the responsibility to review the submitted report and file it in the plant maintenance records. If the report findings indicate issues then plant management shall investigate the issue and develop, implement and document a remediation plan.

The training and experience of personnel working in the plant give them a knowledge base of what to look for when performing this function. After these baseline inspections, plant management will determine if any noted conditions require further evaluation by an SME.

A work permit is not required to perform this maintenance procedure.

Related Policies and Standards

- Natural Phenomena Plan located in the plant's Emergency Plan
- G1 Cryogenic Piping and Equipment Cool Down
- RCS 8 Inspection & Maintenance

Training and Performance Instructions

The following outlines what to look for when performing this procedure. It also provides "How To" and "General" information. Training will be provided by performing this procedure with plant personnel or departmental personnel who are experienced in this function. If you have any questions contact plant management.

Cold and frost spots – The tank side wall should be dry. However, dependent upon the time of day and weather conditions the dew point will cause sweating. So perform this check when weather conditions are dry and sunny. Look for sweat spots or frost spots which could be an indication of tank annular space insulation issues.

Concrete ring wall – Check for flaking or spalling of concrete support systems. Check for major cracks that could affect the function of the foundation. Check that water is not collecting on the ring wall and that water runoff is sloped away from the tank.

Coating system (paint) – Check that tank coating system is in good condition and protecting the carbon steel plates. Check for any corrosion (rust) spots at the support straps (if so equipped), anchor bolts and nuts (if so equipped) and algae build up. Mild corrosion or normal wear tear need not be reported as a deficiency. If unsure, inform the plant supervisor so that they can make a determination of the corrosion level.

Foundation heating system – All electrical box covers should be in place and properly secured. Conduit should not be damaged or broken. There should be no exposed wiring.

Excessive icing - Under normal operating conditions, frost or an icing condition will occur on the outer portion of the bellows or thermal distance piece. This icing could be up to several inches thick, but should not build up to the point where it contacts the exterior wall of the tank. If unsure, inform the plant supervisor so that they can make a determination of the icing condition.

For LNG product pumps located at the base of the tank look for excessive ice build-up on piping systems. This is a sign that the insulation is breaking down and losing its insulation quality. The potential exists for the ice to limit the thermal contraction of the piping. Look at any non-insulated piping or valves used for LNG service. Ice that may develop on these items could create unwanted movement or restriction of piping, structures, valves and etc.

Documentation

Checklists are to be completed in ink. Turn in the completed checklist to the plant supervisor. Note: only the checklist and deficiency form (if used) are required to be saved as proof of performance. Information from theses inspections can be used by the plant to develop repair / replacement list. The checklist shall be kept in the plant maintenance records (5 years) for future reference and inspection purposes. Storage of these documents should be hard copy in the binders and electronically via the Rack2Filer system.

Performance Checklist

This checklist form is used to document the inspection findings. A checkmark √ indicates no findings (everything passed inspection). An X indicates a deficiency which means the Deficiency Findings Form shall be completed and submitted.

1. √ LNG Tank Frost Spots. Walk around the entire tank looking for any ice or excessive condensation spots. Cold spots on the tank could be an indication of a break down in the annular space insulation. If not addressed it could expose the carbon steel outer tank to temperatures that the steel is not designed for.
2. √ LNG Tank Foundation, walk around entire tank. Visually inspect seal of tank bottom to concrete foundation. Visually inspect foundation of tank for any degradation such as cracking, spalling or any other symptoms of distress.
3. √ Dike, inspect for soil erosion, frost heave or symptoms of distress. Check dike pump area(s) for vandalism or tampering. Check dike pump(s) operation.
4. √ Inner Tank Relief Valve (north/south). Check for frost or leakage.
5. √ Insulation Space (Typically done with First of Month Readings). Test insulation space for the presence of natural gas.
6. √ LNG Tank Discretionary Vent Valve. Check operation of RSV- 106 the 3" air-operated tank vent valve.
7. √ Pipe Supports, Pipe Hanger Suspension and footings. Inspect all pipe-related structures. Verify free operation of pump area pipe suspension.

Date: 12-16-20   Completed By: K. Sanborn, E. Nelson

REVIEWED OK
[signature] 12/30/20

11/20

1.EX-M1 Rev. 3

Documentation

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Date: 11-9-20 Completed By: K. Seaborn R. Botelho

1.EX-M1 Rev. 3

Deficiency Findings Form for Monthly Inspection of Piping, Insulation and Foundation Systems

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Step Number being Referenced	Deficiency Description and Remediation Description
	N/A

Date Submitted: ________________ Submitted By: ________________________________

Date Deficiency Remediated: __________ Plant Management: ________________________

REVIEWED OK
12/10/20

Documentation

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7. ✓ Pipe Supports, Pipe Hanger Suspension and footings. Inspect all pipe-related structures. Verify free operation of pump area pipe suspension.

Date: 11-8-2020 Completed By: R. Stamp
11/9/20 N. Dube

* Procedure was done in response to earthquick
Civil Survey was performed on 11/14/20 by CHI

1.EX-M1 Rev. 3

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	NA

Date Submitted: ________________ Submitted By: ________________________________

Date Deficiency Remediated: __________ Plant Management: ________________________

REVIEWED JR
12/10/20

Documentation

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Date: 10-26-20 Completed By: K. Sanborn, E. Nelson

REVIEWED OK
11/2/20

1.EX-M1 Rev. 3

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	N/A

Date Submitted: ________________ Submitted By: ______________________________

Date Deficiency Remediated: __________ Plant Management: ______________________

9|20
1.EX-M1 Rev. 3

Documentation

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Date: 9-29-20 Completed By: K. Sanborn

1.EX-M1 Rev. 3

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	N/A

Date Submitted: ________________ Submitted By: ________________________________

Date Deficiency Remediated: __________ Plant Management: ________________________

Reviewed on [signature]

16 October 2020

AUG 2020
1.EX-M1 Rev. 3

Documentation

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Date: 8-24-20 Completed By: K. Sanborn E. Nelson

1.EX-M1 Rev. 3

Deficiency Findings Form for Monthly Inspection of Piping, Insulation and Foundation Systems

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Step Number being Referenced	Deficiency Description and Remediation Description
	N/A
	N/A

Date Submitted: ________________ Submitted By: ________________________________

Date Deficiency Remediated: __________ Plant Management: ________________________

Reviewed OK ~~ESK~~
16 October 2020

JULY 2020
1.EX-M1 Rev. 3

Documentation

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Date: 7-24-20 Completed By: K. Sanborn, E. Nelson E. Wojcik

REVIEWED OK. [signature]
21 AUGUST 2020

1.EX-M1 Rev. 3

Deficiency Findings Form for Monthly Inspection of Piping, Insulation and Foundation Systems

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Step Number being Referenced	Deficiency Description and Remediation Description
	N/A

Date Submitted: ________________ Submitted By: ______________________________

Date Deficiency Remediated: __________ Plant Management: ______________________

JUNE 2020
1.EX-M1 Rev. 3

Documentation

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7. √ Pipe Supports, Pipe Hanger Suspension and footings. Inspect all pipe-related structures. Verify free operation of pump area pipe suspension.

Date: 6-23-20 Completed By: Nelson, Wojcik, Pierson

Reviewed OK · [illegible]
09 July 2020

1.EX-M1 Rev. 3

Deficiency Findings Form for Monthly Inspection of Piping, Insulation and Foundation Systems

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Step Number being Referenced	Deficiency Description and Remediation Description
	N/A

Date Submitted: __________________ Submitted By: ______________________________________

Date Deficiency Remediated: ___________ Plant Management: __________________________

Documentation

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Date: 5-27-20 Completed By: K. Sanborn E. Wojcik

REVIEWED OK
11/30/20

Deficiency Findings Form for Monthly Inspection of Piping, Insulation and Foundation Systems

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Step Number being Referenced	Deficiency Description and Remediation Description
	N/A
	NA

Date Submitted: ________________ Submitted By: ______________________________

Date Deficiency Remediated: __________ Plant Management: ________________________

4/20

Documentation

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Date: 4-20-20 Completed By: Nelson, Botelho

REVIEWED OK
11/30/20

Deficiency Findings Form for Monthly Inspection of Piping, Insulation and Foundation Systems

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Step Number being Referenced	Deficiency Description and Remediation Description
	N/A

Date Submitted: ________________ Submitted By: ______________________________

Date Deficiency Remediated: __________ Plant Management: ______________________

Documentation

Checklists are to be completed in ink. Turn in the completed checklist to the plant supervisor. Note: only the checklist and deficiency form (if used) are required to be saved as proof of performance. Information from theses inspections can be used by the plant to develop repair / replacement list. The checklist shall be kept in the plant maintenance records (5 years) for future reference and inspection purposes. Storage of these documents should be hard copy in the binders and electronically via the Rack2Filer system.

Performance Checklist

This checklist form is used to document the inspection findings. A checkmark √ indicates no findings (everything passed inspection). An X indicates a deficiency which means the Deficiency Findings Form shall be completed and submitted.

1. √ LNG Tank Frost Spots. Walk around the entire tank looking for any ice or excessive condensation spots. Cold spots on the tank could be an indication of a break down in the annular space insulation. If not addressed it could expose the carbon steel outer tank to temperatures that the steel is not designed for.
2. √ LNG Tank Foundation, walk around entire tank. Visually inspect seal of tank bottom to concrete foundation. Visually inspect foundation of tank for any degradation such as cracking, spalling or any other symptoms of distress.
3. √ Dike, inspect for soil erosion, frost heave or symptoms of distress. Check dike pump area(s) for vandalism or tampering. Check dike pump(s) operation.
4. √ Inner Tank Relief Valve (north/south). Check for frost or leakage.
5. √ Insulation Space (Typically done with First of Month Readings). Test insulation space for the presence of natural gas.
6. √ LNG Tank Discretionary Vent Valve. Check operation of RSV- 106 the 3" air-operated tank vent valve.
7. √ Pipe Supports, Pipe Hanger Suspension and footings. Inspect all pipe-related structures. Verify free operation of pump area pipe suspension.

Date: 3-23-20 Completed By: K. Sanborn E. Wojcik E. Nelso

REVIEWED OK
11/30/20

1.EX-M1 Rev. 3

Deficiency Findings Form for Monthly Inspection of Piping, Insulation and Foundation Systems

This form shall be submitted to plant management for remediation of the listed deficiencies. Use additional sheets as needed to describe the deficiency and remediation. If used this sheet shall be attached to the inspection checklist for documentation purposes.

Step Number being Referenced	Deficiency Description and Remediation Description
	NA

Date Submitted: __________________ Submitted By: ______________________________________

Date Deficiency Remediated: ___________ Plant Management: __________________________

2/20

1.EX-M1 Rev. 3

Documentation

Checklists are to be completed in ink. Turn in the completed checklist to the plant supervisor. Note: only the checklist and deficiency form (if used) are required to be saved as proof of performance. Information from theses inspections can be used by the plant to develop repair / replacement list. The checklist shall be kept in the plant maintenance records (5 years) for future reference and inspection purposes. Storage of these documents should be hard copy in the binders and electronically via the Rack2Filer system.

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7. √ Pipe Supports, Pipe Hanger Suspension and footings. Inspect all pipe-related structures. Verify free operation of pump area pipe suspension.

Date: 2-25-20 Completed By: K. Sanborn, E. Nelson

REVIEWED OK 11/30/20

Deficiency Findings Form for Monthly Inspection of Piping, Insulation and Foundation Systems

This form shall be submitted to plant management for remediation of the listed deficiencies. Use additional sheets as needed to describe the deficiency and remediation. If used this sheet shall be attached to the inspection checklist for documentation purposes.

Step Number being Referenced	Deficiency Description and Remediation Description
	N/A

Date Submitted: ____________ Submitted By: ____________

Date Deficiency Remediated: ____________ Plant Management: ____________

1|20

1.EX-M1 Rev. 3

Documentation

Checklists are to be completed in ink. Turn in the completed checklist to the plant supervisor. Note: only the checklist and deficiency form (if used) are required to be saved as proof of performance. Information from theses inspections can be used by the plant to develop repair / replacement list. The checklist shall be kept in the plant maintenance records (5 years) for future reference and inspection purposes. Storage of these documents should be hard copy in the binders and electronically via the Rack2Filer system.

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5. √ Insulation Space (Typically done with First of Month Readings). Test insulation space for the presence of natural gas.
6. √ LNG Tank Discretionary Vent Valve. Check operation of RSV- 106 the 3" air-operated tank vent valve.
7. √ Pipe Supports, Pipe Hanger Suspension and footings. Inspect all pipe-related structures. Verify free operation of pump area pipe suspension.

Date: 1-30-20 Completed By: K. Sanborn, M. Pierson

REVIEWED OK
11/30/20

1.EX-M1 Rev. 3

Deficiency Findings Form for Monthly Inspection of Piping, Insulation and Foundation Systems

This form shall be submitted to plant management for remediation of the listed deficiencies. Use additional sheets as needed to describe the deficiency and remediation. If used this sheet shall be attached to the inspection checklist for documentation purposes.

Step Number being Referenced	Deficiency Description and Remediation Description
	N/A
	N/A

Date Submitted: ____________ Submitted By: ____________

Date Deficiency Remediated: ____________ Plant Management: ____________