The Narragansett Electric Company
d/b/a National Grid

Electric Infrastructure, Safety, and Reliability Plan FY 2021 Proposal

Responses to Division's Data Requests

Book 2 of 2

December 20, 2019

Docket No. 4995

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:
nationalgrid

Division Set 1

nationalgrid

Jennifer Brooks Hutchinson
Acting Assistant General Counsel and Director

November 7, 2019

VIA HAND DELIVERY & ELECTRONIC MAIL

Rhode Island Division of Public Utilities and Carriers
c/o Luly E. Massaro
89 Jefferson Boulevard
Warwick, RI 02888

RE: National Grid's Proposed FY 2021 Electric Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – Set 1

Dear Ms. Massaro:

I have enclosed National Grid's[1] responses to the Division's First Set of Data Requests in the above-referenced matter.

Thank you for your attention to this transmittal. If you have any questions, please contact me at 401-784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosure

cc: Leo Wold, Esq.
John Bell, Division
Greg Booth, Division
Linda Kushner, Division
Al Contente, Division

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1 The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

280 Melrose Street, Providence, RI 02907
T: 401-784-7288 ■ jennifer.hutchinson@nationalgrid.com ■ www.nationalgrid.com

R-I-1

Request:

For each recommendation in the Power Sector Transformation Stakeholder Report, describe how the proposed ISR does or does not advance the recommendation.

Response:

The Company has continued to engage with stakeholders via the PST Advisory Group around the recommendations in the Executive Summary Recommended Actions section of the Power Sector Transformation Phase One Report to Governor Gina M. Raimondo (November 2017) (the Report). This has primarily been around the development of the Company's Grid Modernization Plan and Updated Advanced Metering Functionality Business Case filings.

The FY2021 ISR begins to advance the recommendation relative to synchronizing the ISR and SRP filings as discussed in Section 3.0 of the Report.

SRP is synchronized with distribution system planning and the ISR filing to a certain extent, in that potential NWA opportunities are screened for as a standard part of the distribution system planning process that informs which projects move forward either through the ISR or SRP. The Company recognizes that improved synchronization between SRP and Distribution System Planning, and the ISR filing is necessary. The Company is improving its coordination between the SRP, ISR, and energy efficiency filings through collaboration efforts across the various departments. The Company has also improved stakeholder engagement and participates in enhanced discussions on SRP, NWA, and related policy and programs through the monthly SRP technical working group and quarterly NWA meetings.

Also, please see the Company's response to R-I-3 and R-I-4 for how the proposed ISR begins to advance the recommendations in Section 4.0 of the Report relating to electrification that is beneficial to system efficiency and greenhouse gas emissions.

Prepared by or under the supervision of: Timothy R. Roughan and Kathy Castro

R-I-2

Request:

To what extent is the proposed ISR Plan consistent or inconsistent with the grid modernization proposal from Docket 4780? Does the Company anticipate any alignment or misalignment with the Grid Modernization Plan under development and in discussion with the PST Advisory Group?

Response:

It is the Company's intention to maintain full consistency and alignment between the ISR and the Rhode Island grid modernization proposal that the Company filed as part of the Power Sector Transformation Vision and Implementation Plan in Docket No. 4780 and consolidated with the Company's general rate case in Docket No. 4770. To that end, there are no grid modernization investments that were approved as part of the Amended Settlement Agreement in Docket No. 4770 for recovery in base rates that are included in the FY2021 ISR Plan.

The Company also anticipates alignment between the proposed FY 2021 ISR Plan and the Grid Modernization Plan (GMP) currently under development and in discussion with the PST Advisory Group. To that end, the Company intends to reflect the recovery mechanism (i.e. ISR or base rates) for each investment in the GMP.

Prepared by or under the supervision of: Kathy Castro and Stephen Lasher

R-I-3

Request:

Please identify how the proposed ISR reduces greenhouse gas emissions in Rhode Island, consistent with the targets specified in the Resilient RI Act.

Response:

As part of the FY 2021 ISR Plan, the Company has proposed certain targeted investments to advance distributed energy resources within the state, including on-going 3V0 work, which will help to reduce greenhouse gas emissions and advance state and Company decarbonization goals by promoting additional renewable energy distributed generation projects. In addition, the on-going VVO work proposed in the ISR will reduce customer electricity consumption, which will have a direct impact on reducing greenhouse gas emissions by reducing bulk electricity generation needs.

Prepared by or under the supervision of: Kathy Castro and Timothy R. Roughan

R-I-4

Request:

To what extent is the proposed ISR supporting preparation for electrification of heating and transportation sectors?

Response:

Investments within the ISR typically originate from detailed programmatic initiatives or comprehensive area studies, which are directed by asset management guidelines, distribution area planning criteria, and annual forecasts. The Company's most current annual forecast includes technologies and programs with the most significant impacts on load, which at this time are Energy Efficiency, Demand Response, Distributed Generation and Electric Vehicles. Heat pump penetration was not considered to have a significant impact at this time and was not included in the current annual forecast. There are plans to include the electrification of the heating sector within future forecast cycles. Electrification of heat analysis will be considered in the Company's pending Grid Modernization Plan (GMP).

Load associated with additional electric vehicles and air source heat pumps are considered as part of individual service requests. Customer information regarding the size and characteristics of the load to be served, including electric vehicles and air source heat pumps, is analyzed and considered when developing infrastructure upgrades.

Prepared by or under the supervision of: Kathy Castro and Stephen Lasher

R-I-5

Request:

Regarding electrification of heating and transportation sectors: how does the ISR team interface and coordinate with the relevant internal teams focusing on these sectors?

Response:

The investments in the ISR plan are informed my multiple departments within the Company. For example, the Economics and Load Forecasting group provides the annual forecast which will include electrification of heating and transportation sectors when appropriate. This forecast is an input into Distribution Planning and Asset Managements (DPAM) comprehensive area studies and programmatic initiatives. The same forecast is used by our grid modernization team as a base input to future state scenarios. In addition, DPAM does interact with the teams that are involved in electrification of heat and transportation to understand the potential future direction of programs in those areas.

Prepared by or under the supervision of: Kathy Castro and Stephen Lasher

R-I-6

Request:

Regarding load management categorized as "Customer Requests": how does the ISR team interface with the Energy Efficiency Program team, the System Reliability Procurement team, and the Demand Response program?

Response:

When "Customer Requests" are received through the Customer Order Fulfillment (COF) group the Energy Efficiency Program team is notified so that collaborative efforts with the customer to apply energy efficiency technologies occur. In addition, the COF group informs the Distribution Planning and Asset Management (DPAM) group when preliminary engineering work may be required. The majority of system modifications associated with "Customer Requests" consist of the local extensions required to provide interconnection service to the Customer's site. If additional system upgrades are identified, then a screening is applied to determine whether a Non-Wires Alternative (NWA) would be feasible. Projects associated with Customer services typically fail the NWA screen due to the Customer's schedule needs. If a project would pass the NWA screen, then DPAM would engage the Non-Wires Alternative team to solicit the market for non-wires solutions. The NWA team also engages with the Demand Response team given that demand response is considered part of the NWA technology portfolio.

Interconnection work associated with "Customer Requests" is included in the non-discretionary customer request portion of the ISR plan. If a non-wires alternative is determined to be the best solution, then this will be progressed through the SRP plan.

Prepared by or under the supervision of: Kathy Castro

R-I-7

Request:

Please identify the specific investments proposed for FY 2021 that the Company would classify as improving resilience to climate change (e.g. sea level rise, etc.) and more frequent extreme weather events?

Response:

At the Company, specific areas in which system resiliency/hardening is a focus are:

1. The regular development of the construction and equipment standards applied in execution of projects that result in expansion and/or modification of distribution infrastructure;

2. The Company's vegetation management programs;

3. Asset Management practices and the distribution system planning studies that are executed to identify existing and project future system performance concerns and the infrastructure development required to address the concerns identified;

4. The consideration of both reactive and proactive infrastructure development programs that adopt new, replace, and/or modify existing assets within the Company's infrastructure; and

5. The development, continued refinement, training, and execution of the Company's Emergency Response Plan.

National Grid has developed robust processes in each of these areas which allow the Company the ability to respond both proactively and reactively as the impacts of climate change on distribution system performance are realized. The Company recognizes that, while the threat of climate change is significant, it is not an acute concern that can be resolved through isolated or short-term initiatives. Accordingly, preparing for and responding to climate change is embedded in the way the Company plans, constructs, and operates its system as a normal course of business. As the understanding of the magnitude, scope, and breadth of climate-related challenges matures, the flexibility and robustness of the Company's processes will allow additional measures to be developed and implemented.

R-I-7, page 2

Distribution Construction Standards

In 2014 the Company implemented a Storm Hardening distribution construction standard that is applied to all new or replaced structures. During extreme weather events, most of the damage to the overhead distribution system is caused by falling limbs and trees. The approaches put into practice by the Storm Hardening standard attempt to reduce electrical outages or structural damage caused by trees and limbs. In particular, the standard is aimed at limiting the numbers of customers affected by tree- and limb-related outages and limiting the duration of those outages by allowing partial restoration of feeders and allowing quicker restoration of damaged lines. The standard targets hardening of critical structures, preventing cascading, enhancing structures in coastline areas, and hardening existing lines.

The Company continuously reviews and updates its construction standards to incorporate recent best practices. Additionally, the Company is currently participating in ongoing work at the Electric Power Research Institute (EPRI) on the subject of distribution grid resiliency to inform future standards updates.

All distribution infrastructure investments within the FY 2021 ISR are designed and built to this storm hardening standard. These investments incrementally increase overall distribution system resiliency through the replacement of older equipment with new, hardened structures, even if the specific prompt for the investment is not resiliency-focused. The cost associated with the implementation of the storm hardening standard cannot practically be separated from the overall cost of an effort.

Vegetation Management

Climate change is expected to have a significant impact on the Company's vegetation management program. Rising temperatures mean longer growing seasons which will increase the likelihood of vegetation growing into power lines. The Company's cycle pruning program will be critical in ensuring that necessary clearances are maintained between vegetation and power lines. Currently, four years is still the optimal cycle for the State of Rhode Island. The Company will continue to monitor growth rates throughout the state to determine if any changes to cycle length become necessary.

In addition to longer growing seasons, climate change is expected to result in more frequent and more intense weather events. The Company's EHTM program is constantly evolving to remove trees which could fail during one of these weather events or on blue sky days. Vegetation throughout the region has been exposed to periods of severe drought, invasive species and disease. While these issues may or may not be tied to climate change, they are resulting in large numbers of dead or dying trees throughout Rhode Island which will impact the electric system during weather events.

In addition to these two core programs, the Company has requested an additional $200,000 in fiscal year 2021 to address pockets of poor performance. In these areas, the Company will take a more prescriptive approach to vegetation management to include vegetation which is not normally in our scope of work. In some areas, this will include the removal of vegetation which hangs over the lines, and extensive tree removals.

While the Company is not proposing any significant changes to its vegetation management program for fiscal year 2021 to address climate change, it will be necessary to closely monitor changes to vegetation in Rhode Island to continue providing safe and reliable service to our customers.

Distribution Planning Activities

Long-range distribution system planning studies are holistic reviews of geographic/electric subsets of the Company's service territory and distribution network. System performance assessments executed within these studies include a focus on system voltage, capacity, asset condition, and reliability. The planning process and its performance assessments are fundamental and robust enough to identify trends in system performance degradation that might stem from the environmental impact of climate change, regardless of whether the assessment identifies climate change as the root cause. Through regularly conducting in-depth reviews of distribution system performance in area studies, advancing projects from area studies into the ISR, and applying the storm hardening standard to recommendations stemming from area studies, the Company is ensuring that the incremental impacts of climate change are being identified and addressed as the system becomes hardened to those impacts.

The Company conducts regular analyses of the reliability of the distribution system as part of area studies and in response to acute system concerns. Reliability analyses are conducted on circuits with poor reliability relative to the rest of the distribution system, and on discrete areas when prompted by recent performance concerns. The solutions typically implemented by the Company include leveraging existing programs in the ISR (e.g. recloser replacement or cutout mounted recloser installation), installing new line reclosers, circuit reconfigurations, reconductoring bare wire with tree wire or spacer cable, and targeted vegetation management. Much of this reliability- and resiliency-focused work is low-level spend that is progressed under a blanket (e.g. the Reliability blanket) but could rise to the level of a specific project that would be incorporated into the ISR. These recommendations enhance the ability of the impacted circuits to withstand environmental conditions contributing to their relatively poor reliability and decrease the time it takes for the distribution system to recover from damage.

R-I-7, page 4

Infrastructure Development Programs

Investments which improve resilience to climate change and more frequent extreme weather events appear throughout the FY 2021 ISR plan. Examples of specific capital programs or projects that have resiliency as a main driver or benefit are included in Table R-I-7.

Please see Table R-I-7 on page 5.

R-I-7, page 5

Table R-I-7

Resiliency Focus	Project #	Project Description	FY21 Capital Budget
Reclosers	**C059663**	CUTOUT MNTED RECLOSER PROGRAM_RI	130
	C065830	RECLOSER REPLACEMENT PROGRAM RI	700
	C079331	VIPER RECLOSER REPLACEMENT PGM 1-RI	150
Strategic DER Advancement	**C079195**	Strategic DER Advancement	5000
Underground Asset Replacement	**C047378**	IRURD WILLOWBROOK	360
	C047394	IRURD TANGLEWOOD	40
	C047829	IRURD HIGH HAWK	530
	C049291	IRURD WOOD ESTATES PHASE 2	50
	C049356	IRURD SILVER MAPLE PHASE 2	130
	C050070	IRURD PLACEHOLDER RI	2080
	C055343	RI UG CABLE PLACEHOLDER	65
	C055359	RI UG CABLE REPL PROGRAM - FDR 79F1	340
	C055364	RI UG CABLE REPL PROGRAM - FDR 13F6	255
	C055370	RI UG CABLE REPL PROG FDR 1144/1109	250
	C055371	RI UG CABLE REPL PROG FDR 1142/1105	250
	C055392	RI UG CABLE REPL PROGRAM - SECONDAR	2135
	C056947	IRURD JUNIPER HILLS WWARWICK	300
	C057882	IRURD CHATEAU APTS URD REHAB	140
	C057903	IRURD WESTERN HILLS VILLAGE URD-	20
	C057906	IRURD WOODVALE ESTATES URD-	60
	C069506	IRURD NORTH FARM URD	420
	C070207	IRURD EVERGREEN APTS URD E. PROVID	470
	C074307	RI UG 79F1 DUCT CHARLES & ORMS STS	1020
	C076289	IRURD PEQUAW HONK URD RI-L COMPTON	400
	C078921	RI UG CABLE REPL PROGRAM - FDR 1158	25
	C078926	RI UG CABLE REPL PROGRAM - FDR 1162	230
	C078931	RI UG CABLE REPL PROGRAM - FDR 1166	230
	C081341	CABLE REPLACE WOODLAND MANOR-COVEN	700
EMS	**C074427**	EMS EXPANSION - PHILLIPSDALE 20	150
	C074430	EMS EXPANSION - WOOD RIVER 85	200
	C074431	EMS EXPANSION - BONNET 42	100
	C074433	BRISTOL 51 - EMS EXPANSION	430
	C074438	EMS EXPANSION - MERTON 51	100
Flood Mitigation	**C046697**	HOPE SUBSTATION FLOOD RESTORATION	220
	C059882	FLOOD CONTINGENCY PLAN NECO - D	750

R-I-7, page 6

Reclosers (line reclosers and cutout mounted reclosers) contribute to distribution system resiliency by reducing 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. Programmatic efforts to replace or install reclosers as part of the FY 2021 ISR ensure a population of reclosers installed throughout the distribution system that can operate as intended to support system resiliency. New reclosers installed through the recloser replacement programs are to an upgraded standard that will allow future implementation of advanced automation systems that will further support advancements in system resiliency.

Similarly, strategic DER advancement investments that modernize feeders to promote DER integration also prepare those feeders for automation and future resiliency optimization. The integration of monitoring and control technologies will inform better operational and planning decisions that can improve restoration times and increase overall circuit reliability and resiliency.

Underground distribution systems are largely insulated from storm impacts that affect overhead systems. However, increased temperatures, flooding, more frequent freeze/thaw cycles throughout the winter months, and other climate impacts can exacerbate and accelerate asset condition concerns with underground infrastructure. The Company has robust asset replacement programs within the ISR to proactively identify and mitigate risks associated with this equipment, through its Underground Cable Replacement program and Underground Residential Development program.

Remote status and control of substation locations, implemented through Energy Management System ("EMS") installations, provides improvements in performance and reliability by decreasing incident response and recovery times.

Flood mitigation investments in the FY 2021 ISR include elevating critical substation equipment relative to anticipated flood waters and immediate response actions such as the installation of Floodstop barriers (rapidly deployable earth-filled barriers), and supplemental flood risk reduction elements such as pumps, plugs, and generators to displace water inside substations from general rainfall and potential flood barrier leaks. These measures are intended to reduce the risk of damage during a flood event, enhancing the Company's substations' resiliency to this potential climate change impact.

Prepared by or under the supervision of: Kathy Castro and Ryan Moe

R-I-7, page 7

Emergency Response Plan

While not a component of the ISR, the Company recognizes that regardless of how hardened and/or resilient the distribution systems are, it is inevitable that the Company will experience and must be prepared to respond to extreme weather events that impact its infrastructure in a very significant way. The Company has established its electric Emergency Response Plan ("ERP") for the purpose of managing outages caused by storms and other natural disasters, major equipment failure, or other events. The ERP, and its associated organizations and trainings, allows the Company to respond effectively and efficiently to emergencies in Rhode Island.

R-I-8

Request:

What is the likelihood that forecasted load growth either (i) does not materialize, (ii) materializes for only a short period of time before declining, or (iii) materializes on a slower timeframe than forecasted? Please provide an analytical response with a description of methodology, underlying assumptions, evidence, and summary data.

Response:

The Rhode Island system peak load forecast has generally been flat to declining over the last five planning cycles. A number of factors including, but not limited to economics and distributed energy resources (DER), mainly energy efficiency, solar-PV, electric vehicles, company-sponsored and demand response have influenced the peak demands in the state. Attachment R-I-8 shows the forecasts from the last five planning cycles and compares the weather-adjusted actual peaks over the last five years to those. Weather-adjusted peaks are compared because the forecasts are similarly based on weather-normalized peaks. The last five planning cycles are used because they most closely represent the forecasts which include the multitude of new and existing (but increased) policy based state DER initiatives.

In general, these five forecasts have predicted declining load over time from the year of the forecast to the current year (2019). (The exception is the vintage fall 2015 forecast which predicted a small increase between 2015 and 2019). The weather-adjusted actual values over this period have similarly declined. Table R-1-8.1 in the attachment shows these MW values.

The percentage difference for each forecast for the current year ranges from -3.6% to plus 5.4%. The fact that there are both negative and positive values indicates that the forecast is not generally biased in either direction. Table R-1-8.2 shows these percents.

Statistically, the mean absolute percentage error (MAPE) for year 2019 is 2.9%. Table R-1-8.3 shows this value.

MAPE is a common statistical approach to reviewing differences between forecasts and results. While the ultimate goal of any forecast is naturally to have no error, bandwidths of up to 3% are observed in the electric peak forecasting field.

The analysis summarized above includes a review of forecasts versus results, looking at percentage errors as well as the MAPE statistic. This evidence and summary data is provided in the tables in Attachment R-1-8.

Prepared by or under the supervision of: Joseph F. Gredder

Table R-1-8.1

Forecasts by vintage						
Year	Fall_2014	Fall_2015	Fall_2016	Fall_2017	Fall_2018	w/n Actual
2014						**1,824**
2015	1,802					**1,865**
2016	1,817	1,822				**1,791**
2017	1,818	1,831	1,793			**1,737**
2018	1,816	1,842	1,783	1,706		**1,785**
2019	1,816	1,849	1,780	1,691	1,764	**1,753**

Table R-1-8.2

Weather_Adjusted Actual minus Forecast					
Year	Fall_2014	Fall_2015	Fall_2016	Fall_17	Fall_18
2015	-3.3%				
2016	1.4%	1.7%			
2017	4.7%	5.4%	3.3%		
2018	1.7%	3.2%	-0.1%	-4.4%	
2019	3.6%	5.4%	1.5%	-3.6%	0.6%

Table R-1-8.3

Weather_Adjusted Actual minus Forecast (Absolute Value)								
Year	Fall_2014	Fall_2015	Fall_2016	Fall_17	Fall_18	MAPE (yr 2019)	MAPE (years out)	
2015	3.3%						1	2.7%
2016	1.4%	1.7%					2	2.6%
2017	4.7%	5.4%	3.3%				3	3.1%
2018	1.7%	3.2%	0.1%	4.4%			4	3.6%
2019	3.6%	5.4%	1.5%	3.6%	0.6%	2.9%	5	3.6%

R-I-9

Request:

Provide FY2021-Electric ISR-Att4 (DPUC 9-27-19), also referenced as the "Mega-file" with the accompanying detailed worksheet that includes Project # and Project Description for each ISR Grouping.

Response:

See Excel version of Attachment R-I-9, entitled "*ISR-DIV-1-9 Attachment.xlsx*," which contains two worksheets: The first "Attachment 4 – Mega File" is the as-filed worksheet referenced in the above request. The second "Mega File Detail" contains the same information while including Project # and Project Description detail.

Prepared by or under the supervision of: Patricia C. Easterly

R-I-10

Request:

Provide a copy of the final South County East Area Study.

Response:

See Attachment R-I-10, South County East Area Study. This Attachment contains Critical Energy Infrastructure Information, which is confidential. Accordingly, the Company is providing a redacted version of this Attachment.

Prepared by or under the supervision of: Kathy Castro

REDACTED VERSION

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

REDACTED VERSION

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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

REDACTED VERSION

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.

REDACTED VERSION

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

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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

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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

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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

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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	

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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

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		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

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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

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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

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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

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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.

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9. Appendix

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9.1 Area Maps

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FIGURE 9.1.1 – STUDY AREA

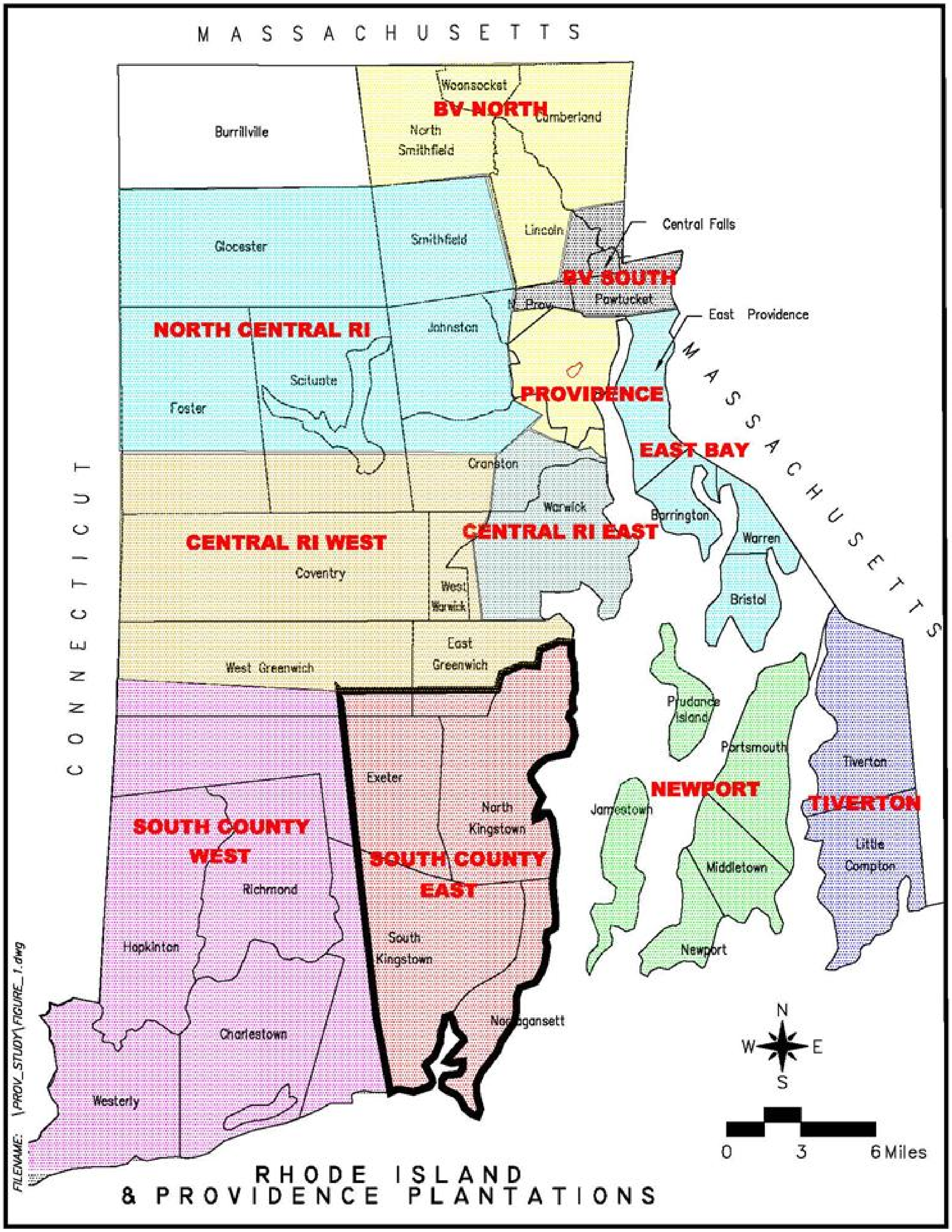

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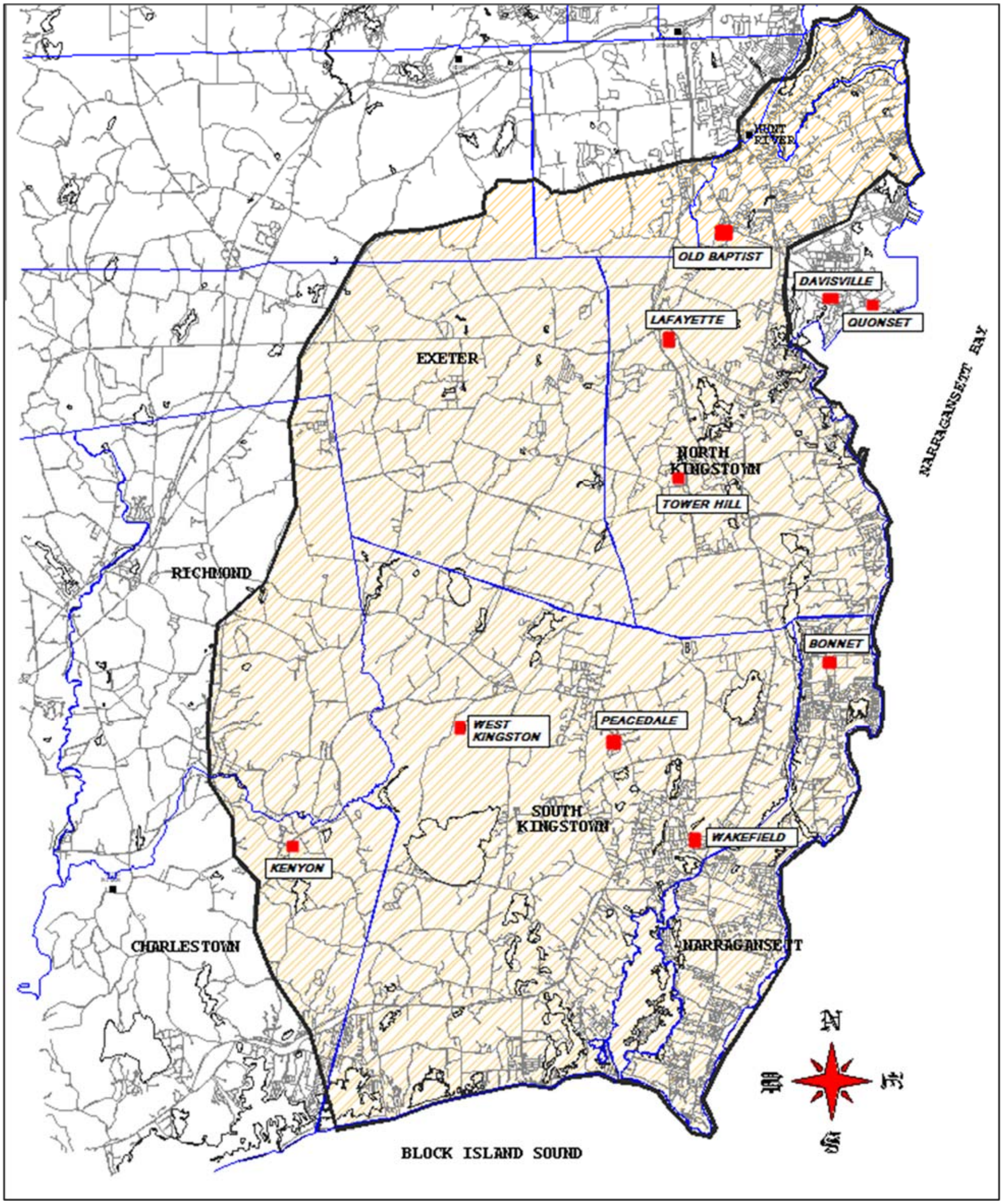
FIGURE 9.1.2 – STUDY AREA SUBSTATIONS



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9.2 One Line Diagrams

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FIGURE 9.2.2 – 34.5kV SUPPLY SYSTEM ONE-LINE DIAGRAM (NORTH)

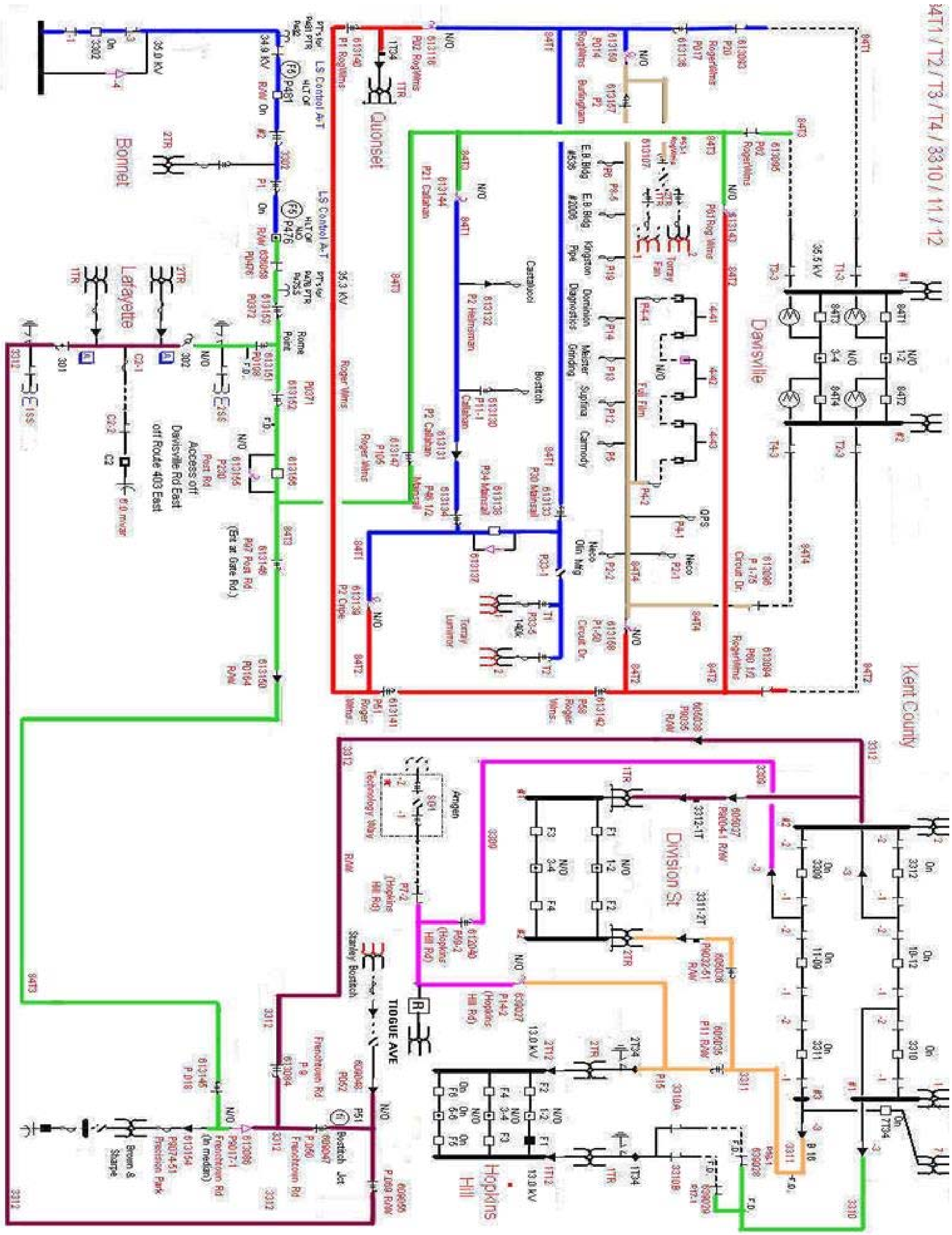

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FIGURE 9.2.3 – 34.5kV SUPPLY SYSTEM ONE-LINE DIAGRAM (SOUTH)

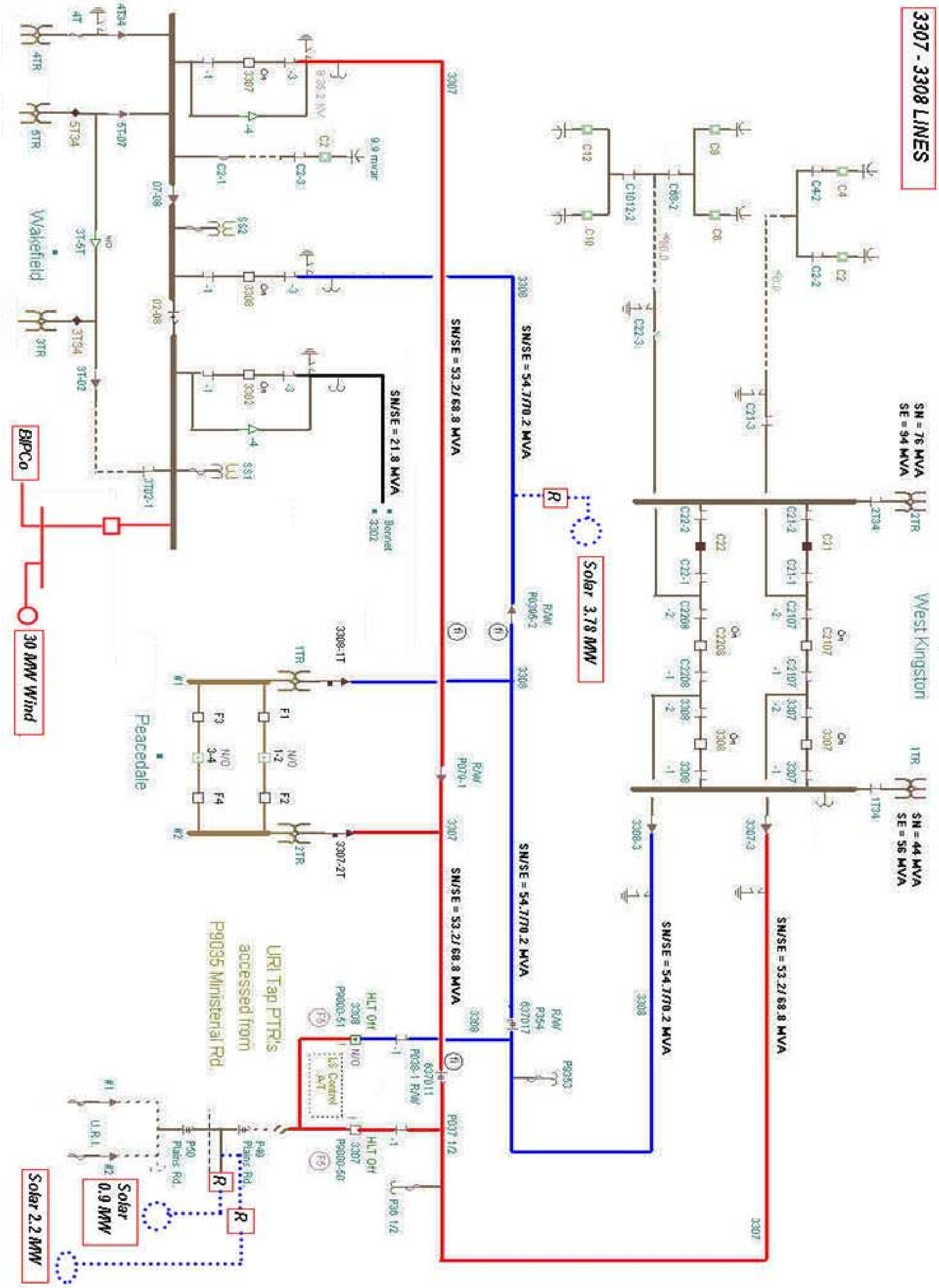

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FIGURE 9.2.4 – BONNET SUBSTATION ONE-LINE DIAGRAM

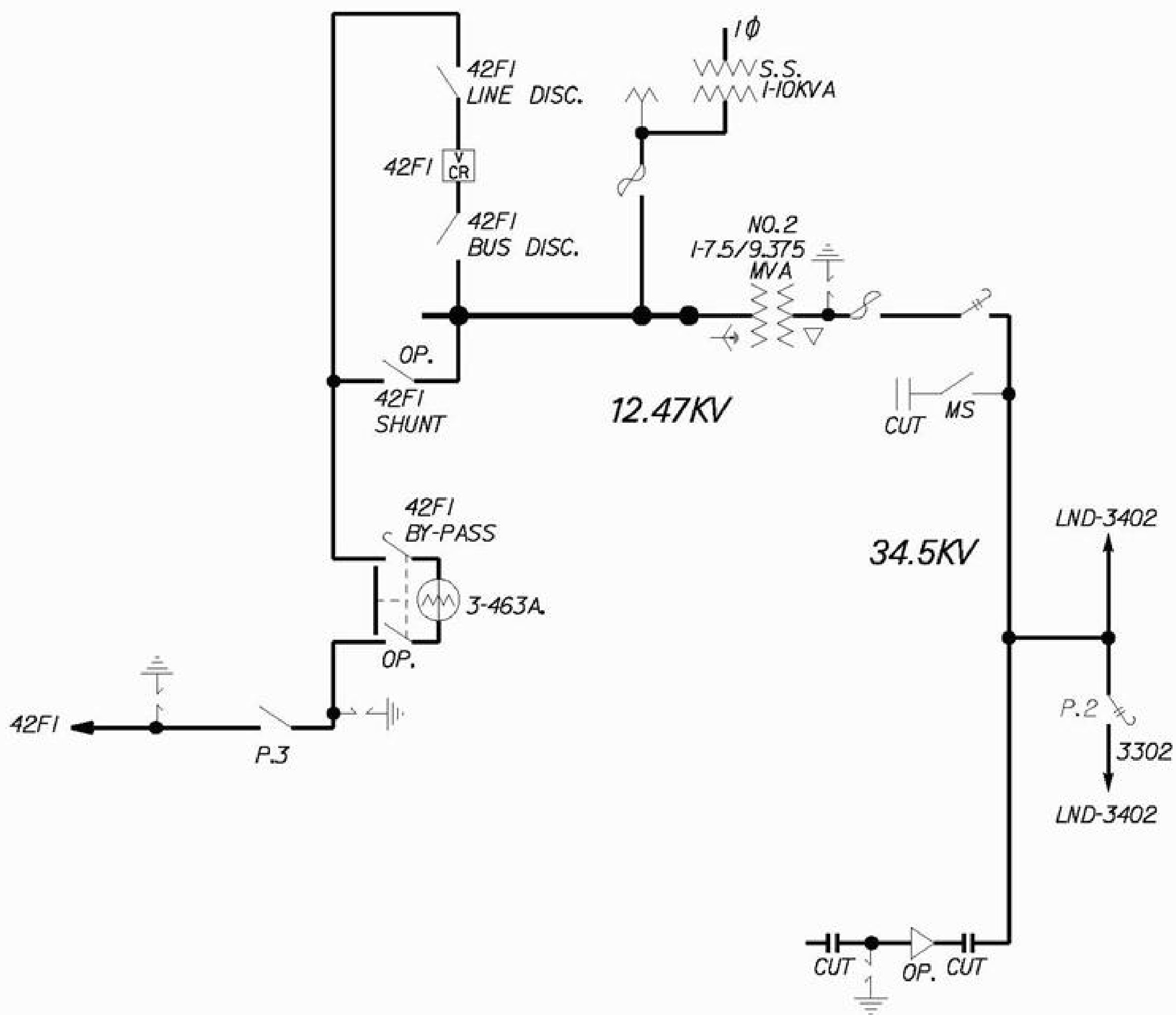

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FIGURE 9.2.6 – LAFAYETTE SUBSTATION ONE-LINE DIAGRAM

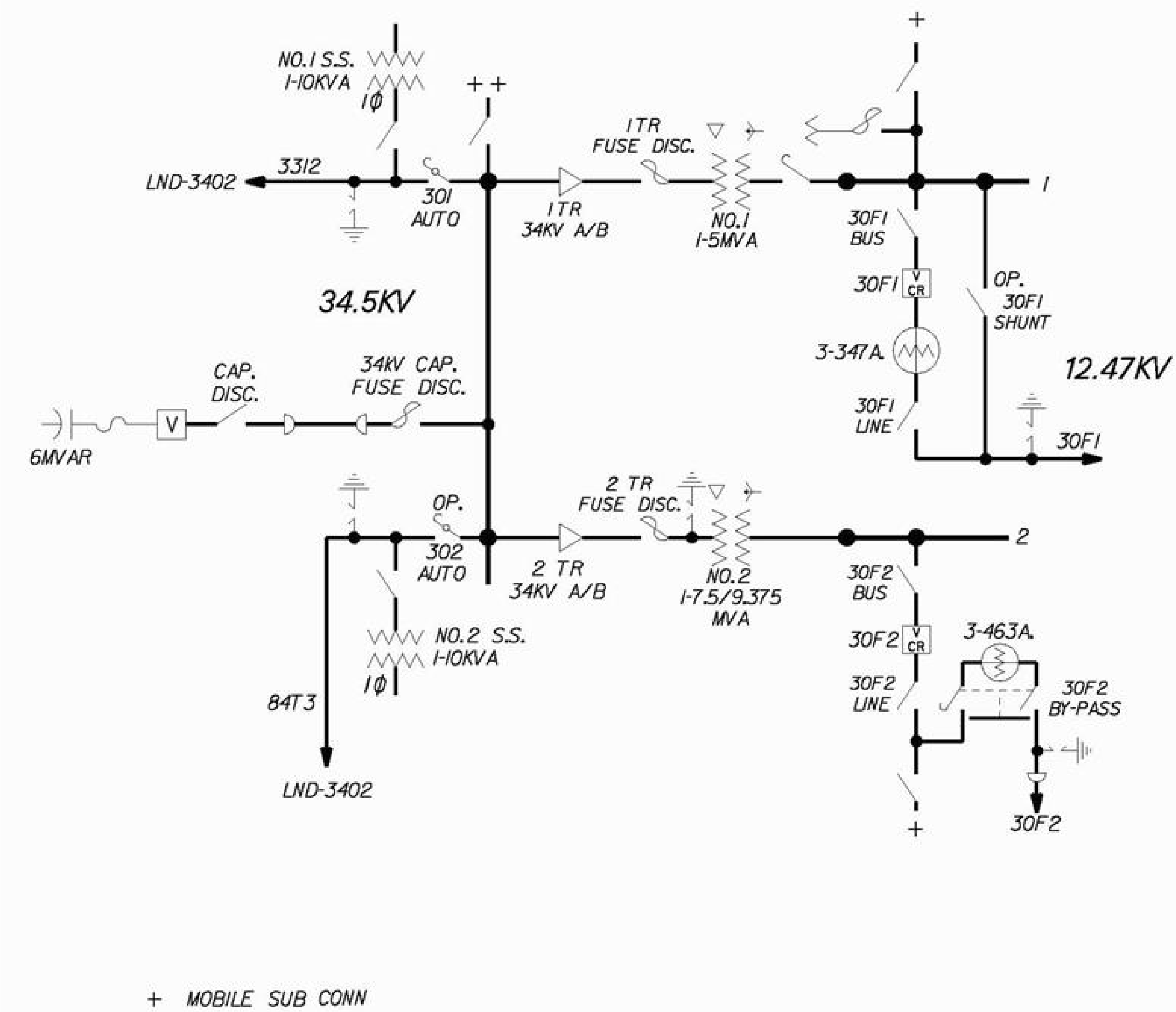

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FIGURE 9.2.8 – PEACEDALE SUBSTATION ONE-LINE DIAGRAM

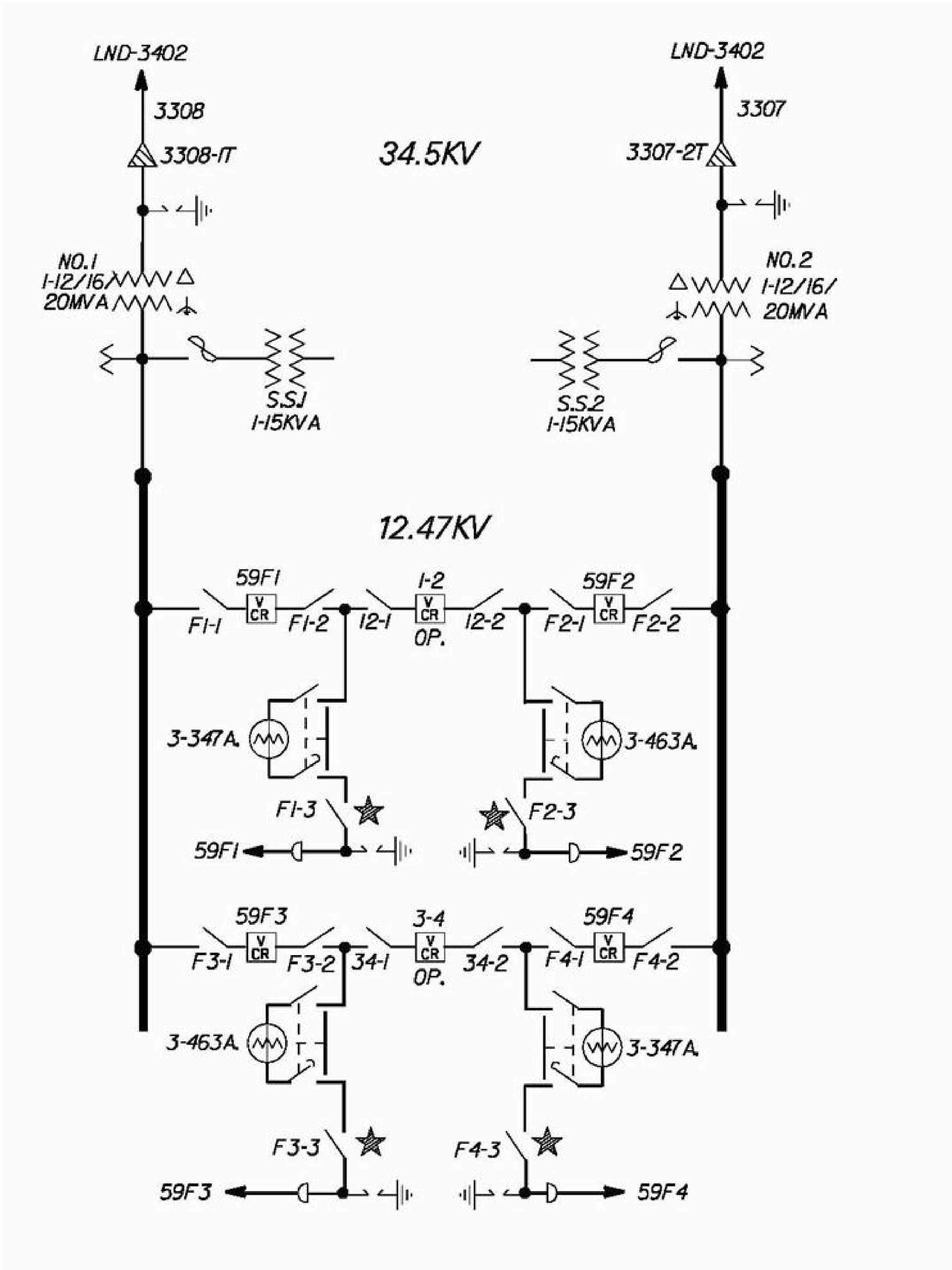

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FIGURE 9.2.9 – QUONSET SUBSTATION ONE-LINE DIAGRAM

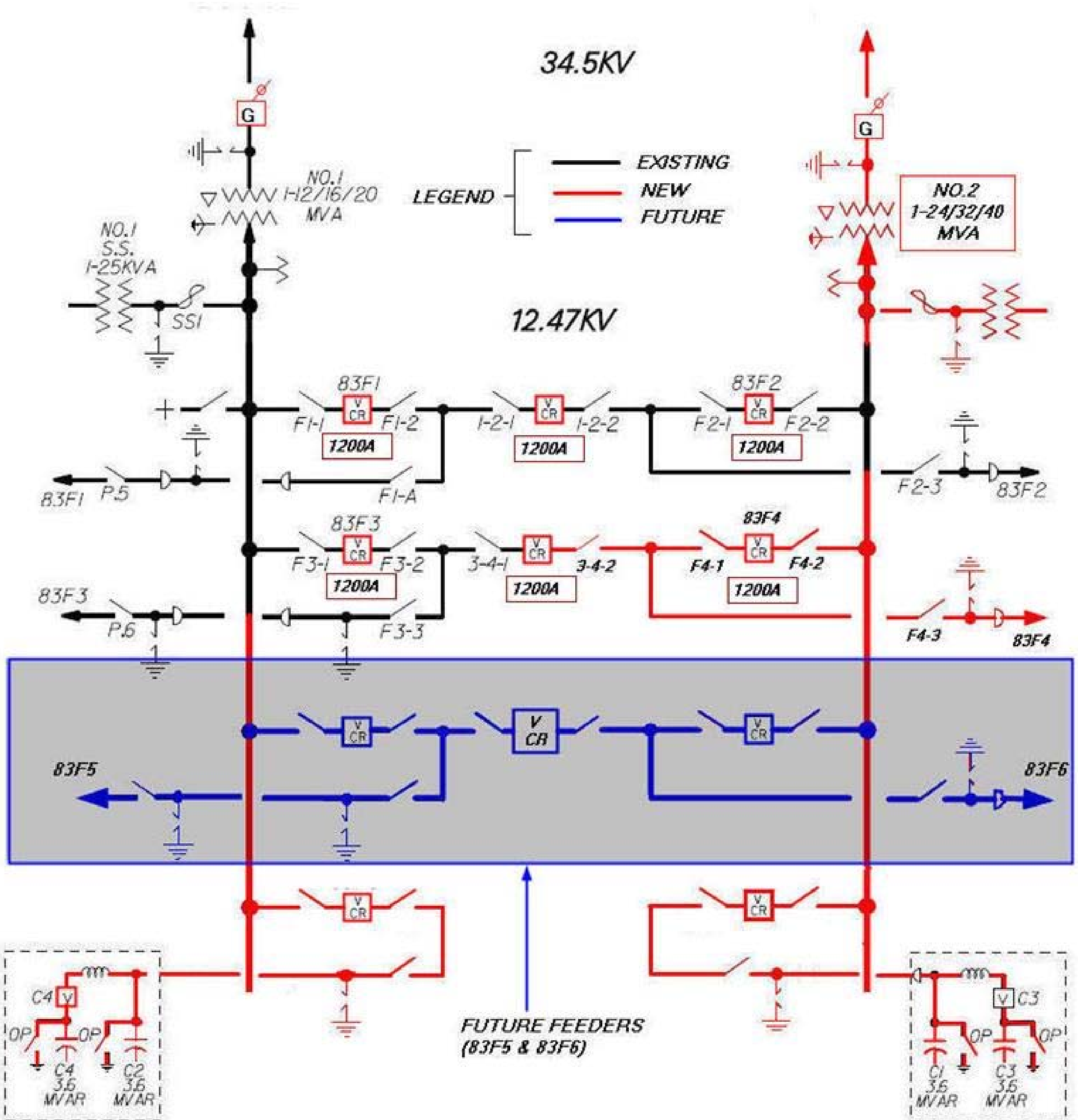

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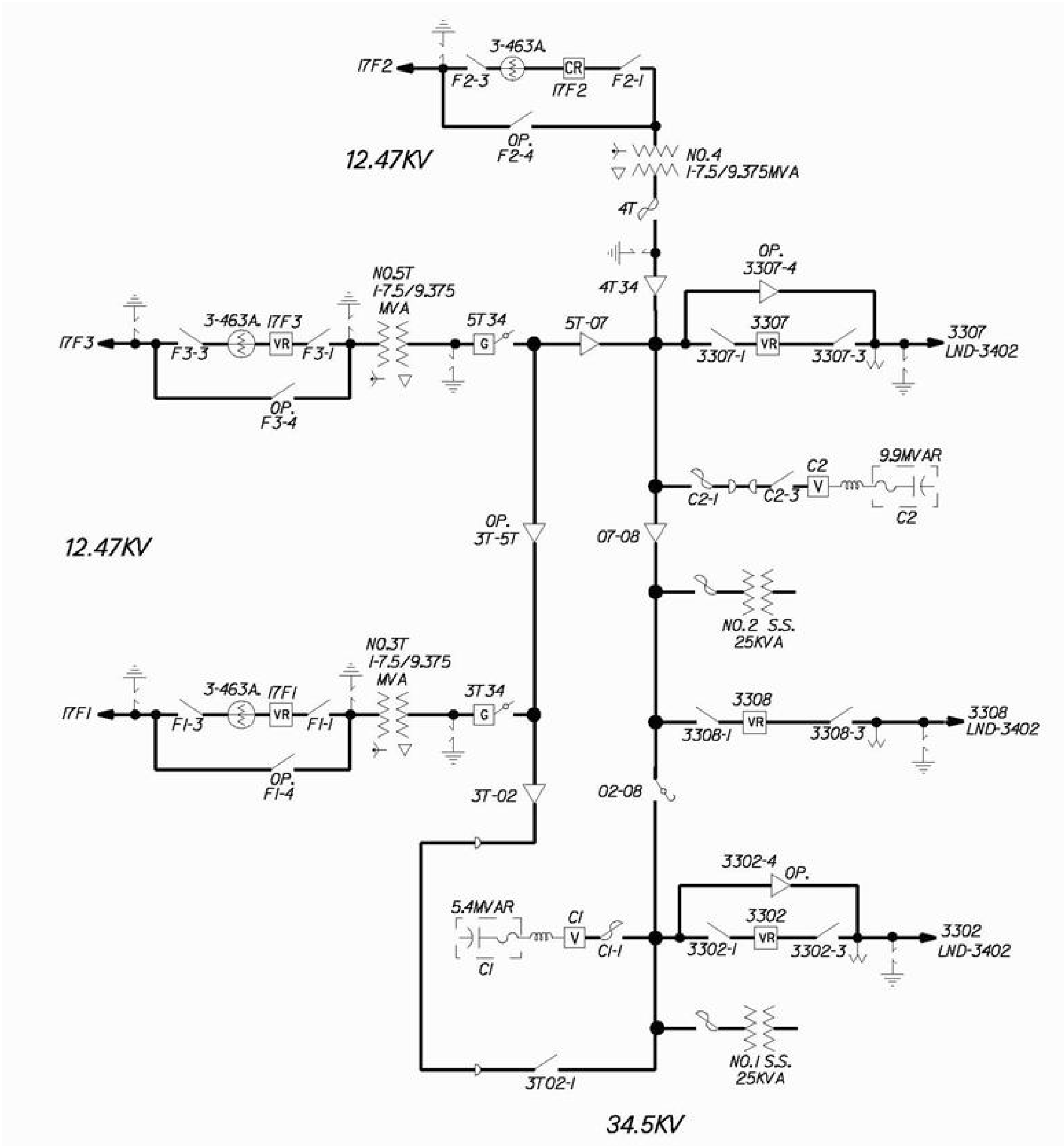
FIGURE 9.2.11 - WAKEFIELD SUBSTATION ONE-LINE DIAGRAM



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9.3 Loading Tables

TABLE 9.3.1 – Feeder Loading Before Improvements

Substation	Feeder	SN Rating (Amps)	Projected Load							
			2018		2022		2026		2030	
			Amps	%SN	Amps	%SN	Amps	%SN	Amps	%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%

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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

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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%

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TABLE 9.3.5 – Feeder Loading After Improvements

Substation	Feeder	SN Rating (Amps)	Projected Load						
			2025		2026		2030		
			Amps	%SN	Amps	%SN	Amps	%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

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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

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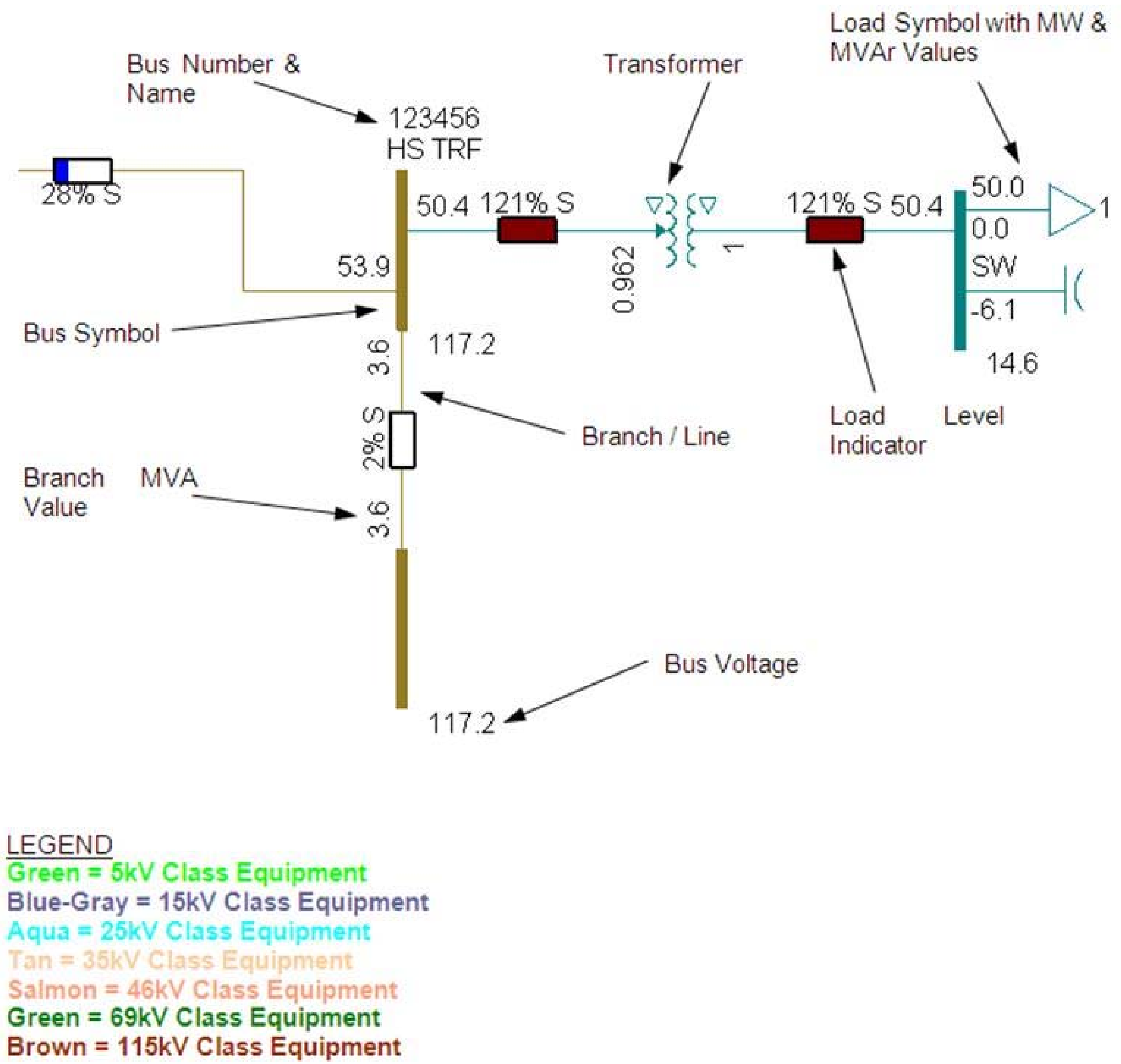
9.4 Loadflow Diagrams

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



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9.5 CYME Radial Distribution Analysis Diagrams

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Figure 9.5.1 – CYME Existing Configuration – Circuit Arrangement

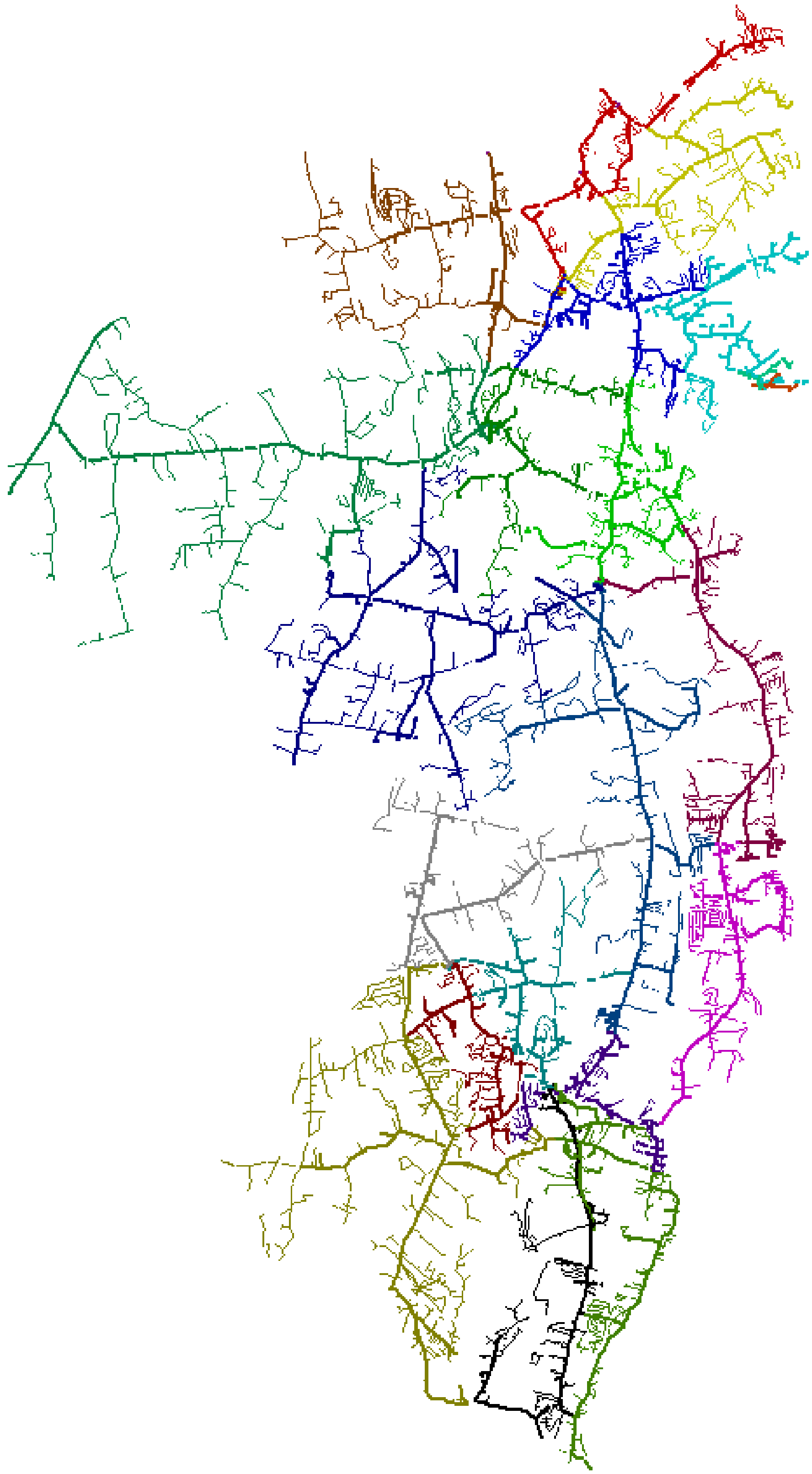

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Figure 9.5.2 – CYME Existing Configuration – Loading Analysis

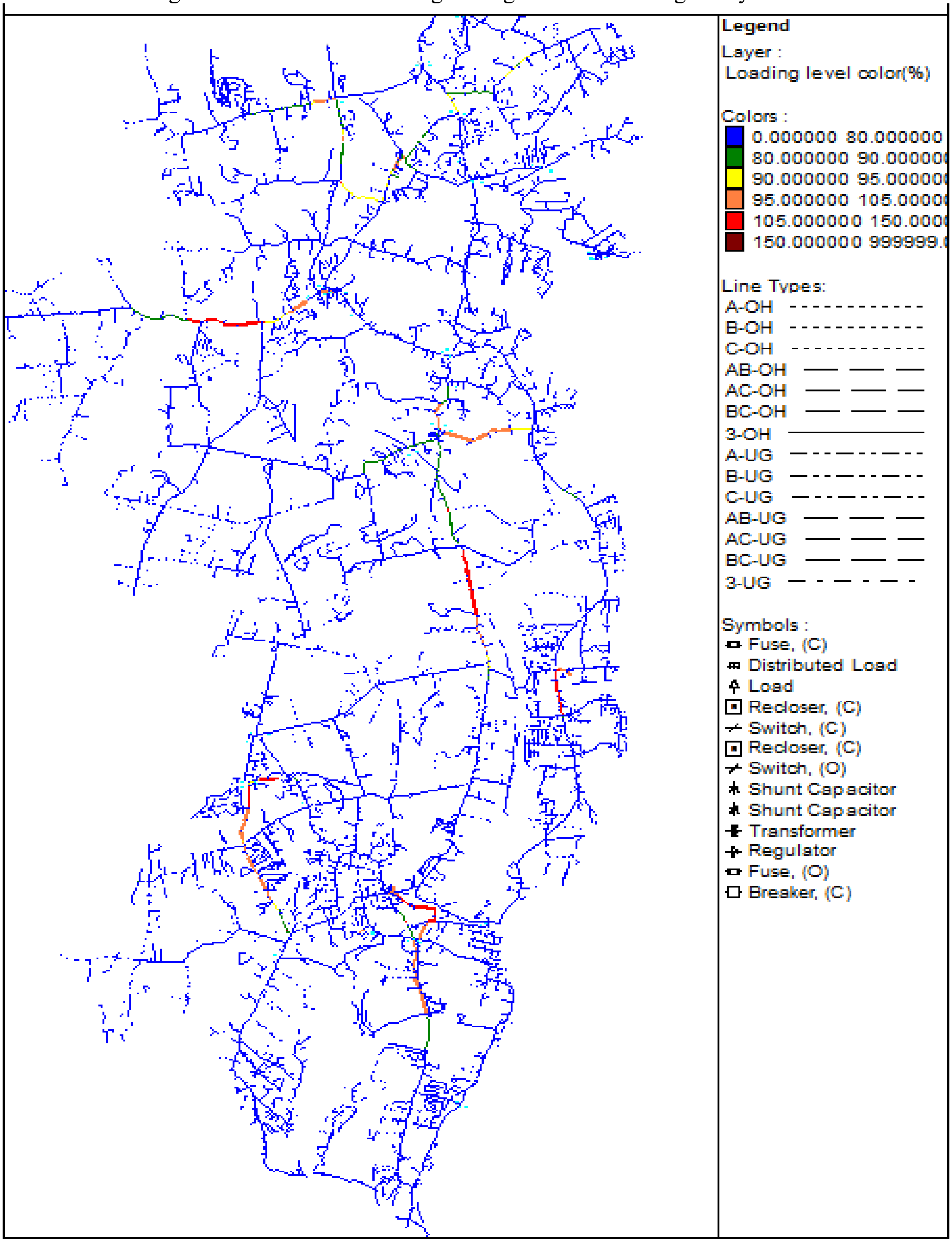

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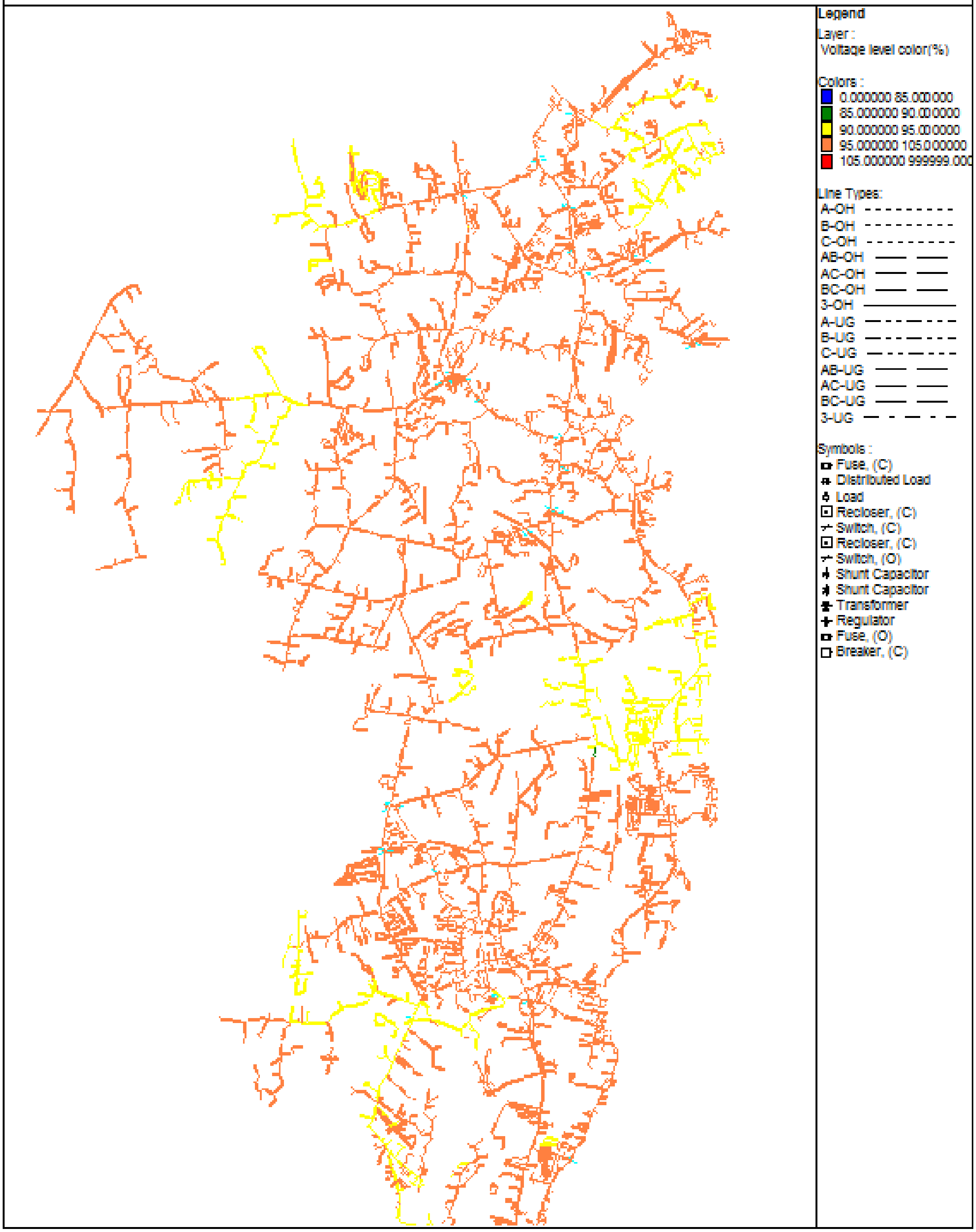
Figure 9.5.3 – CYME Existing Configuration – Voltage Analysis



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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

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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

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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

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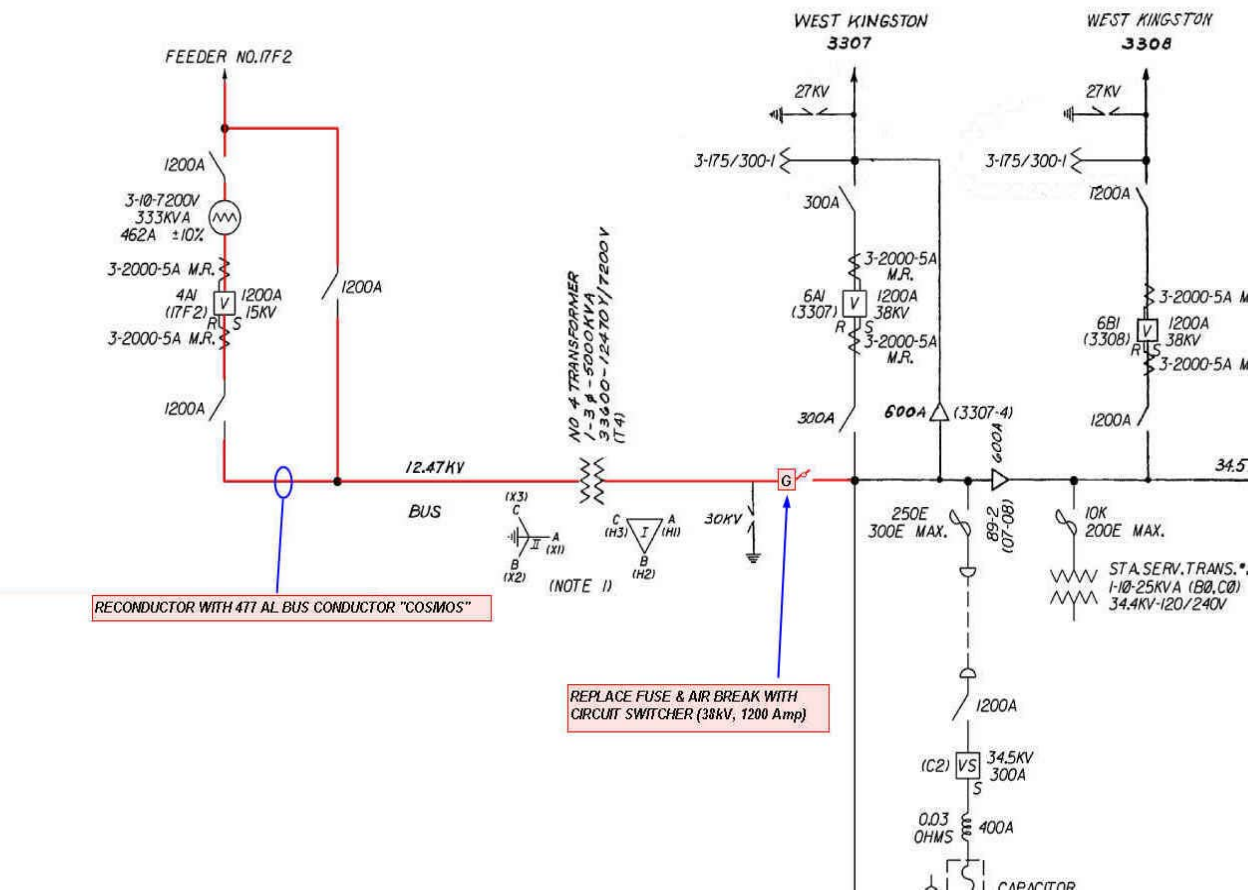
9.8 Plan Development – Common Items

FIGURE 9.8.1 – WAKEFIELD SUBSTATION ONE-LINE DIAGRAM (COMMON ITEM)



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9.9 Plan Development – Plan 1

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FIGURE 9.9.3 – PROPOSED 34.5 kV SUPPLY SYSTEM (PLAN 1)

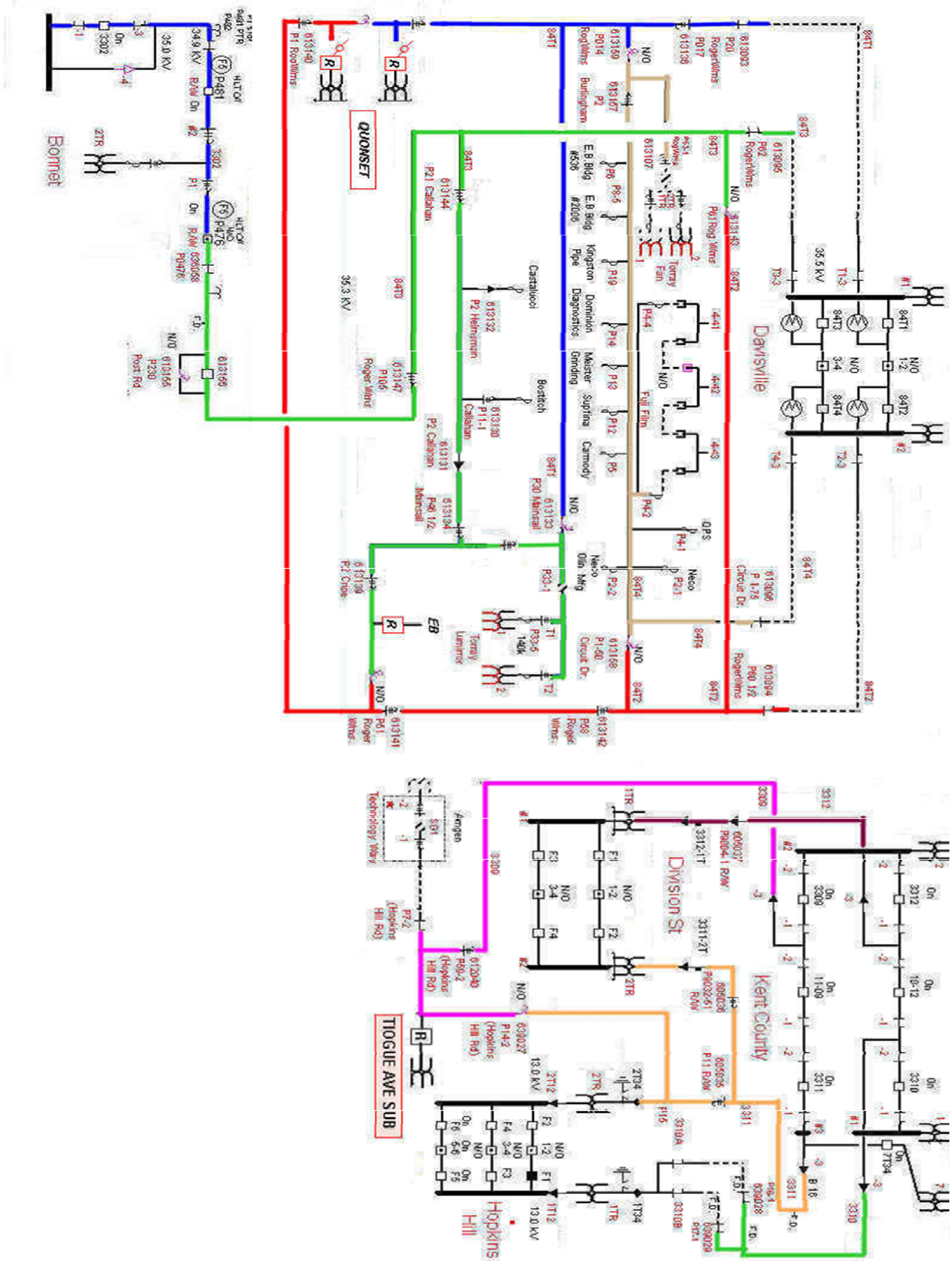

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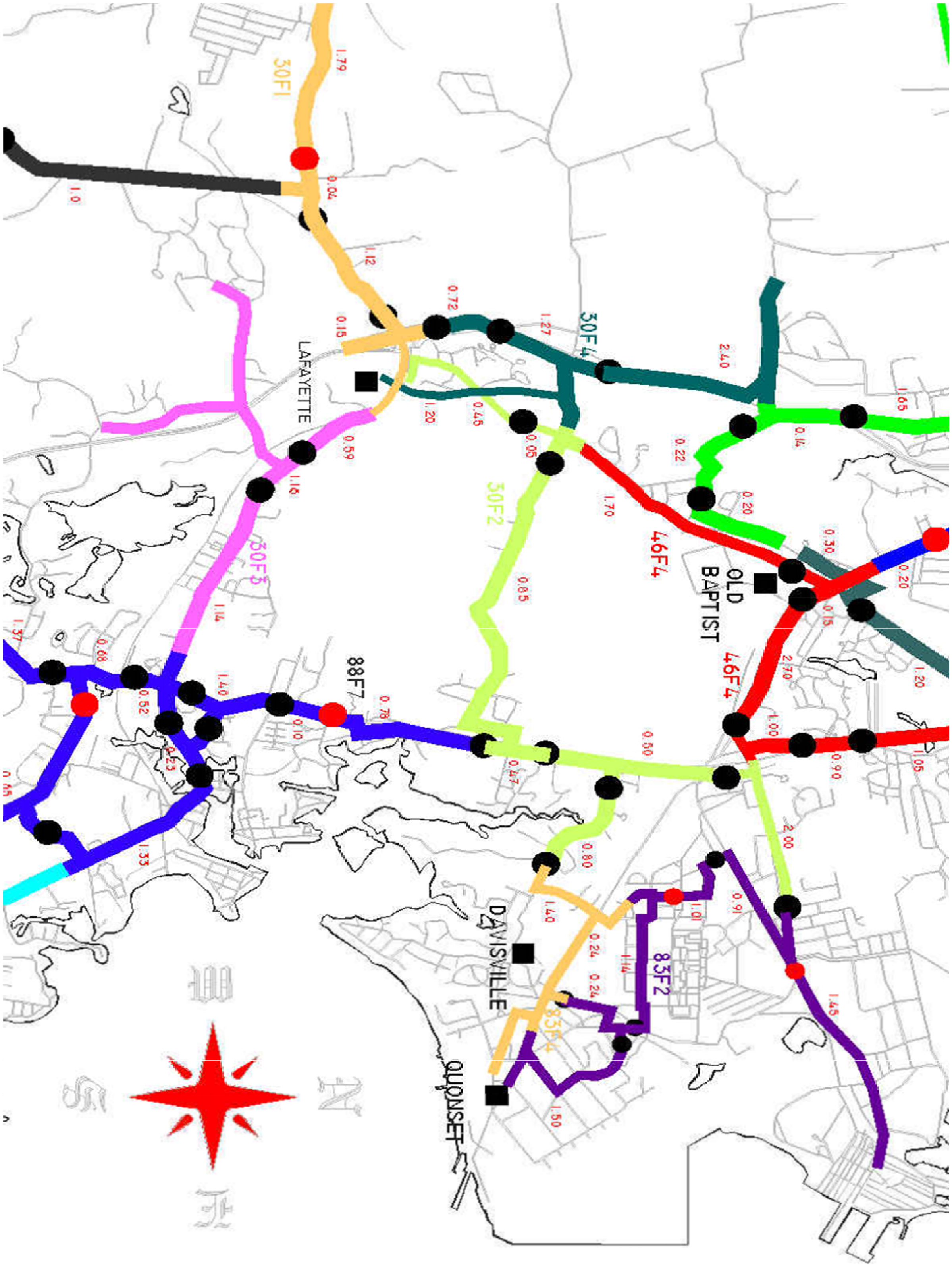
FIGURE 9.9.4 – PROPOSED MAINLINE DISTRIBUTION (PLAN 1)



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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

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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.

REDACTED VERSION

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**	

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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.

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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.

REDACTED VERSION

9.15 Narragansett 42F1 NWA RFP Reports

National Grid USA Service Company, Inc.

ISSUED: DECEMBER 13, 2018
SUBMISSION DEADLINE: FEBRUARY 11, 2019

nationalgrid

REDACTED VERSION

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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

REDACTED VERSION

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

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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

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/ /

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.

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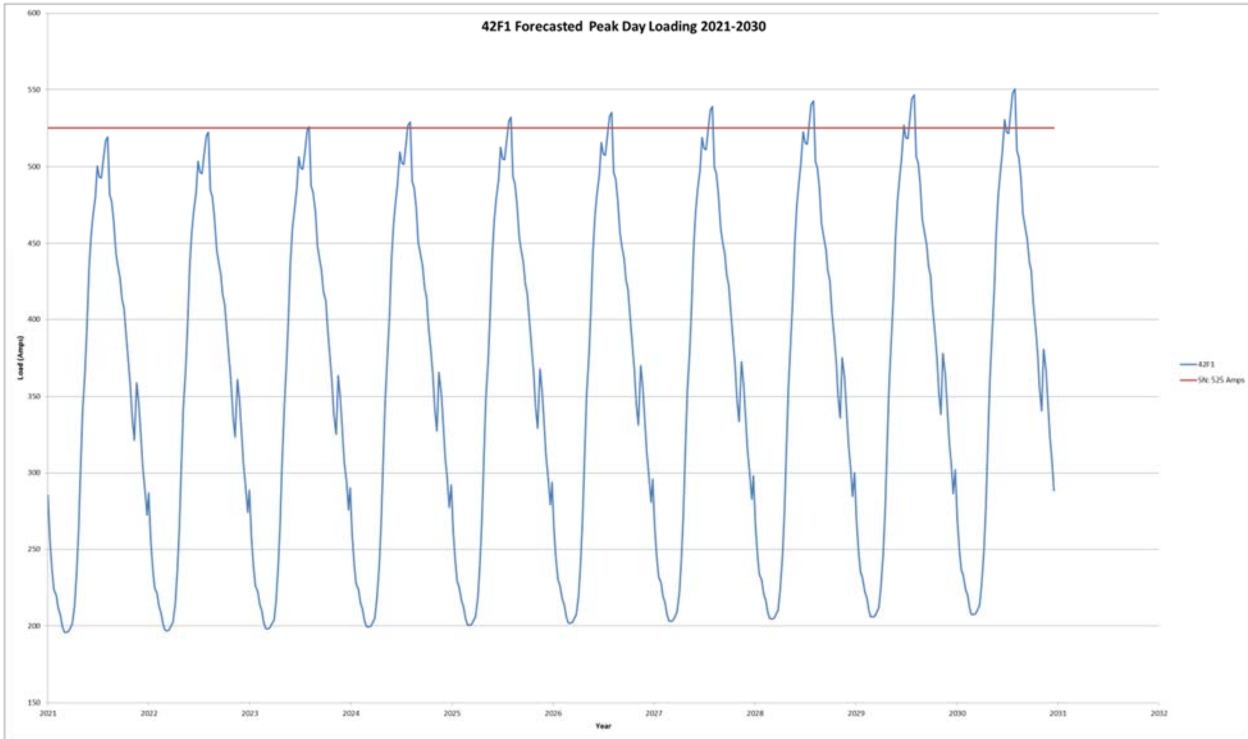

4.4. Solution Timeline

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

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9.16 Narragansett 17F2 NWA RFP Reports

National Grid USA Service Company, Inc.

ISSUED: DECEMBER 13, 2018
SUBMISSION DEADLINE: FEBRUARY 11, 2019

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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.

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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

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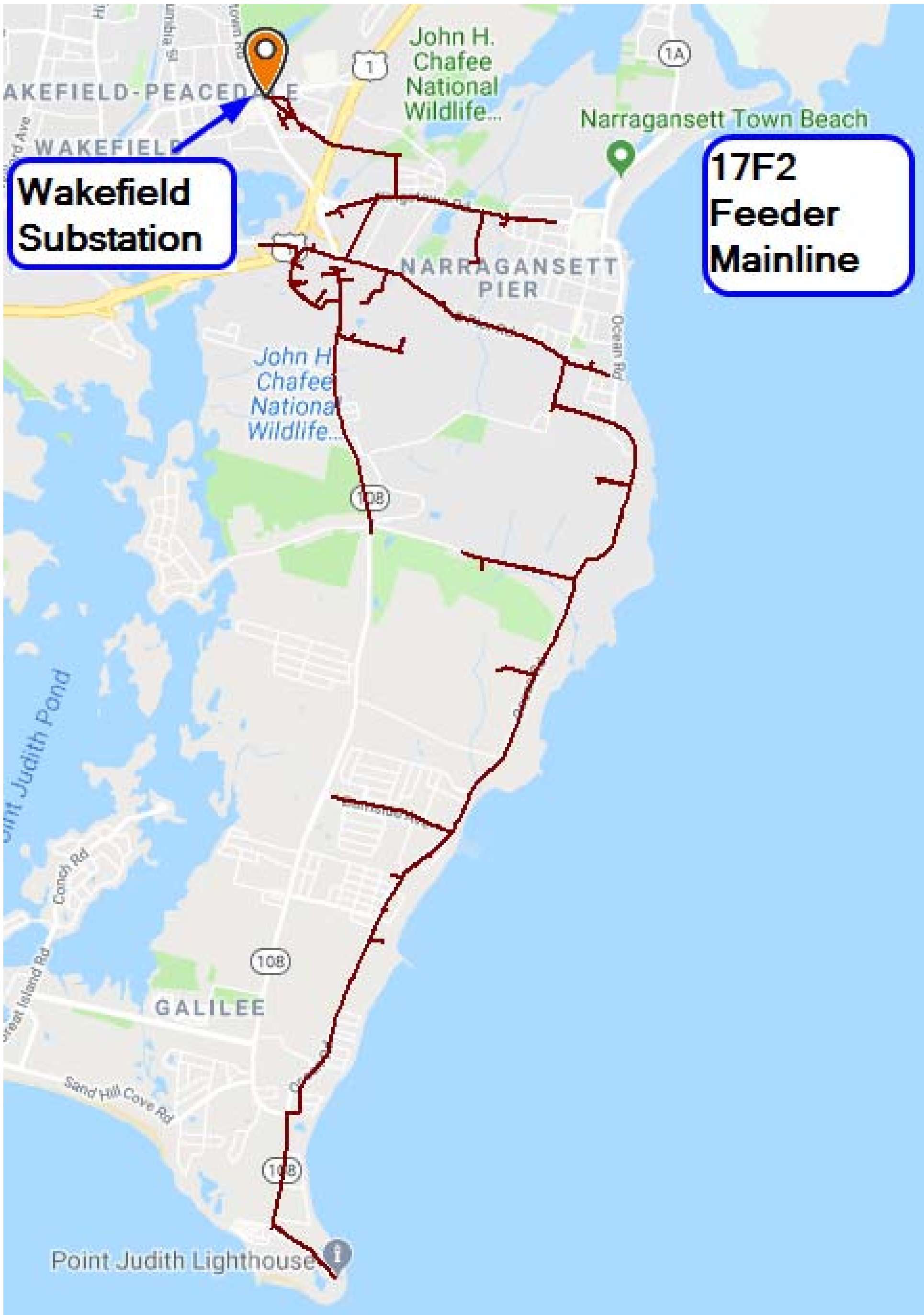


Any DER location downstream of the target feeder getaways (where the feeder leaves the station) should solve the loading issue, pending a full interconnection study. See feeder maps above.

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.

REDACTED VERSION

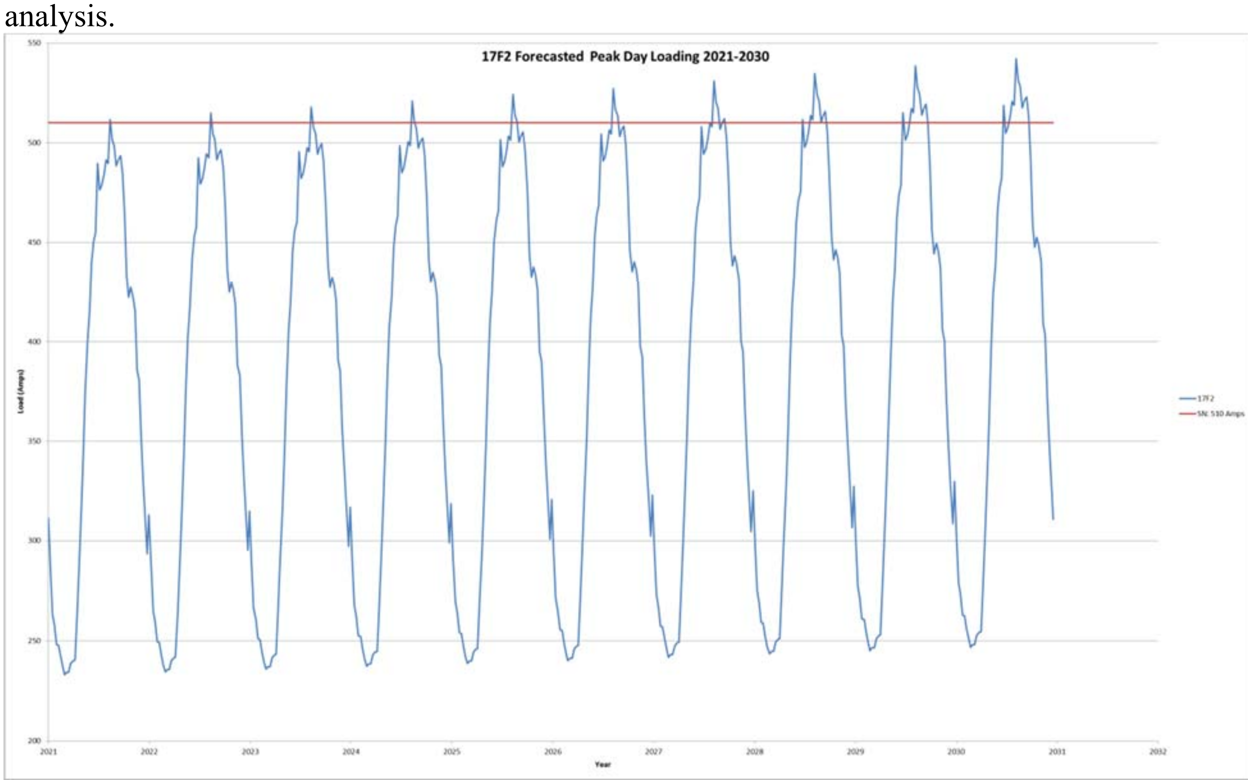
10.3. Technical Details

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.
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- Executive Summary of Proposed Technology/Solution
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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

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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

REDACTED VERSION

9.17 South Kingstown NWA RFP Reports

National Grid USA Service Company, Inc.

ISSUED: JANUARY 29, 2019
SUBMISSION DEADLINE: APRIL 23, 2019

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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

REDACTED VERSION

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

REDACTED VERSION

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

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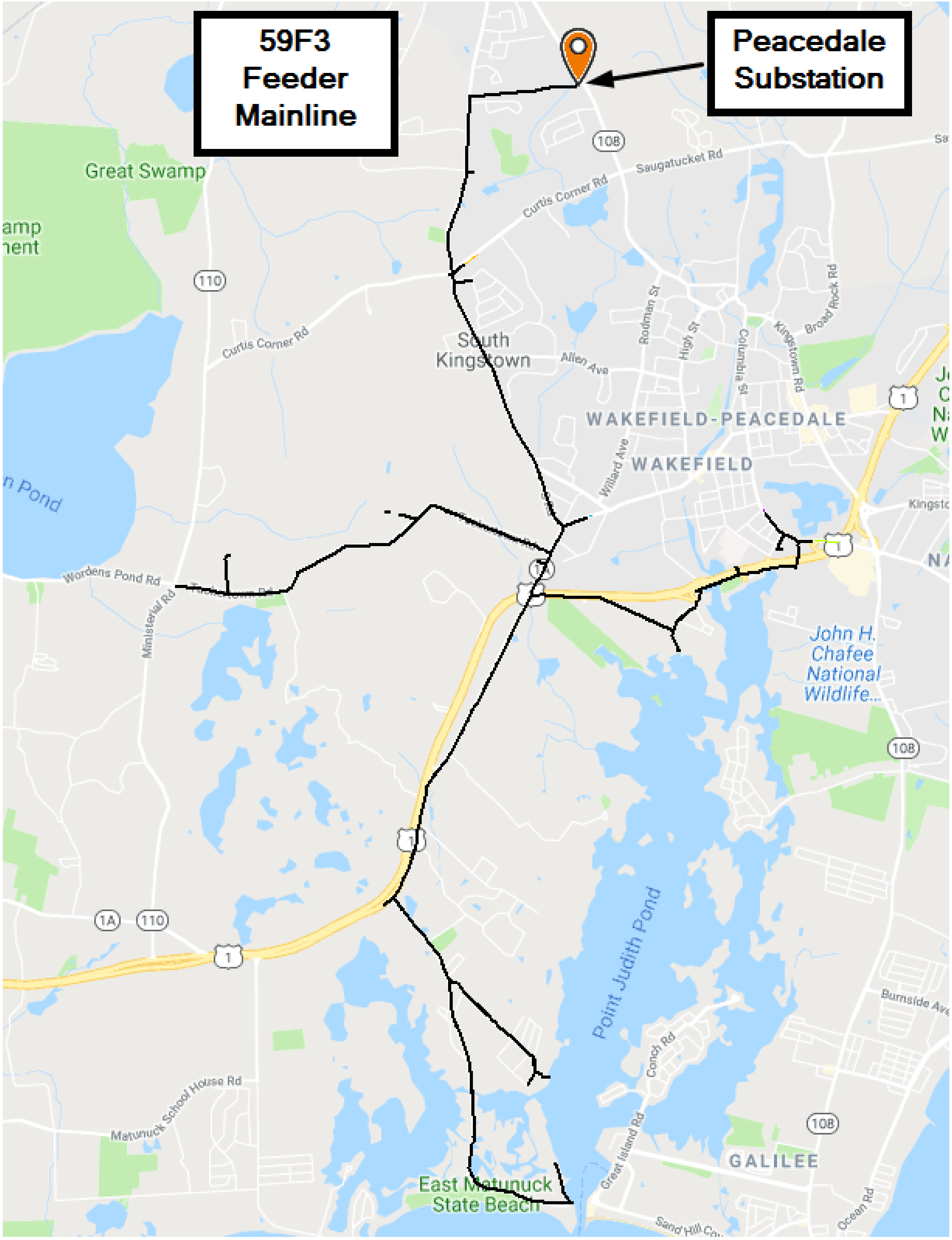

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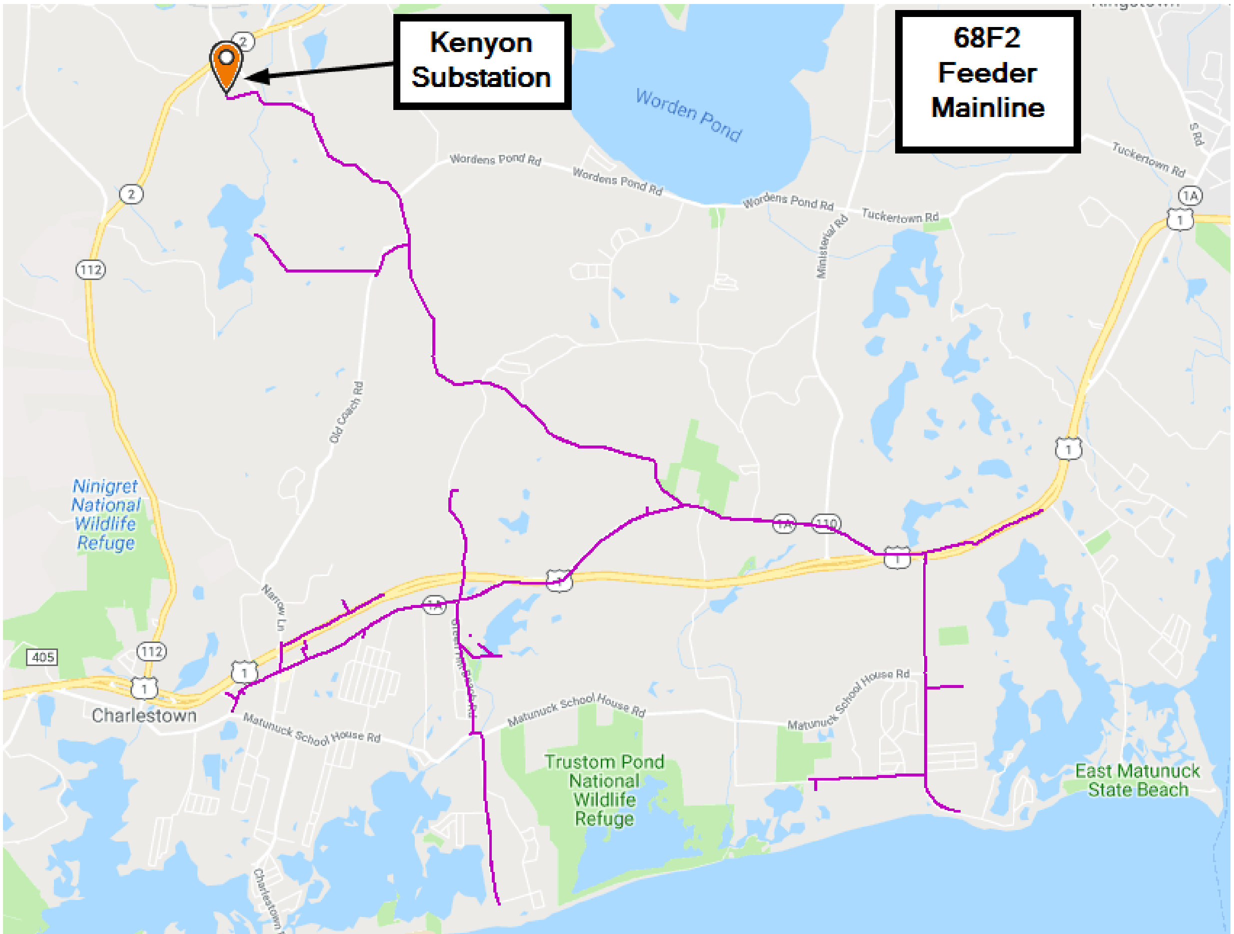


Any DER location downstream of the target feeder getaways (where the feeder leaves the station) should solve the loading issue, pending a full interconnection study. See feeder maps above.

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

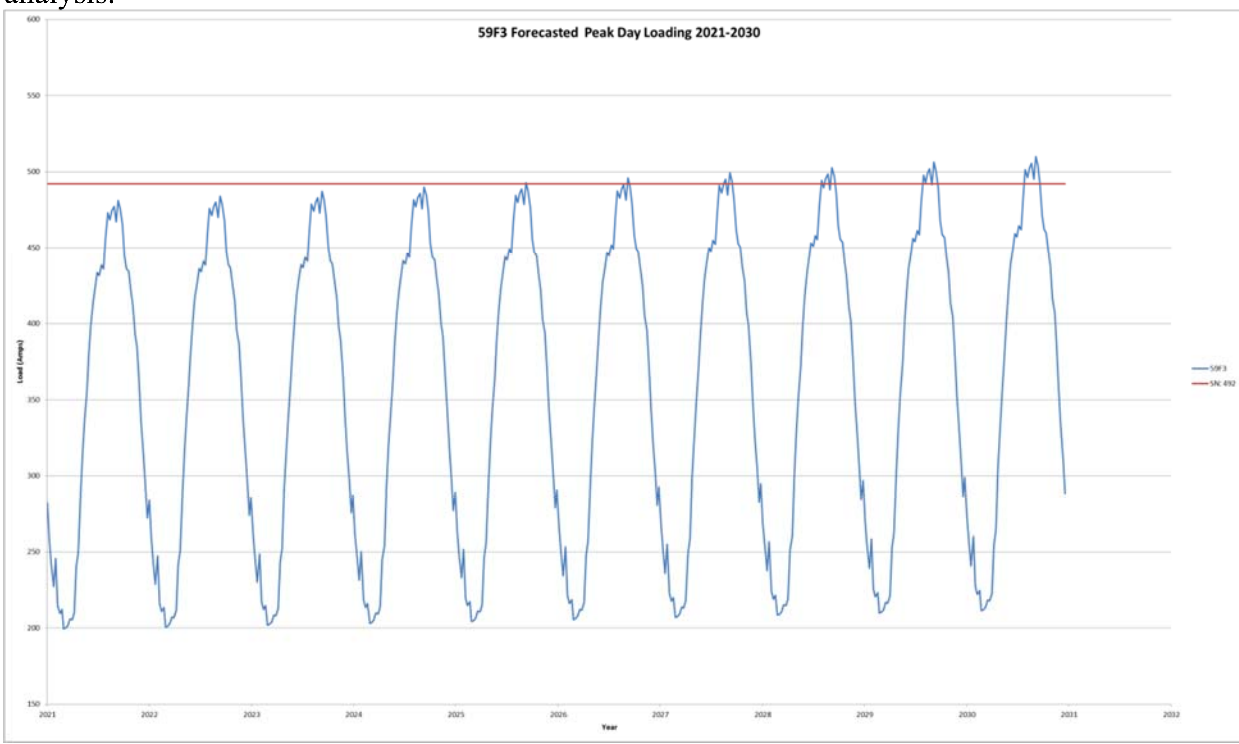
Substation	Feeder	Commercial Customers	Residential Customers	Total

REDACTED VERSION

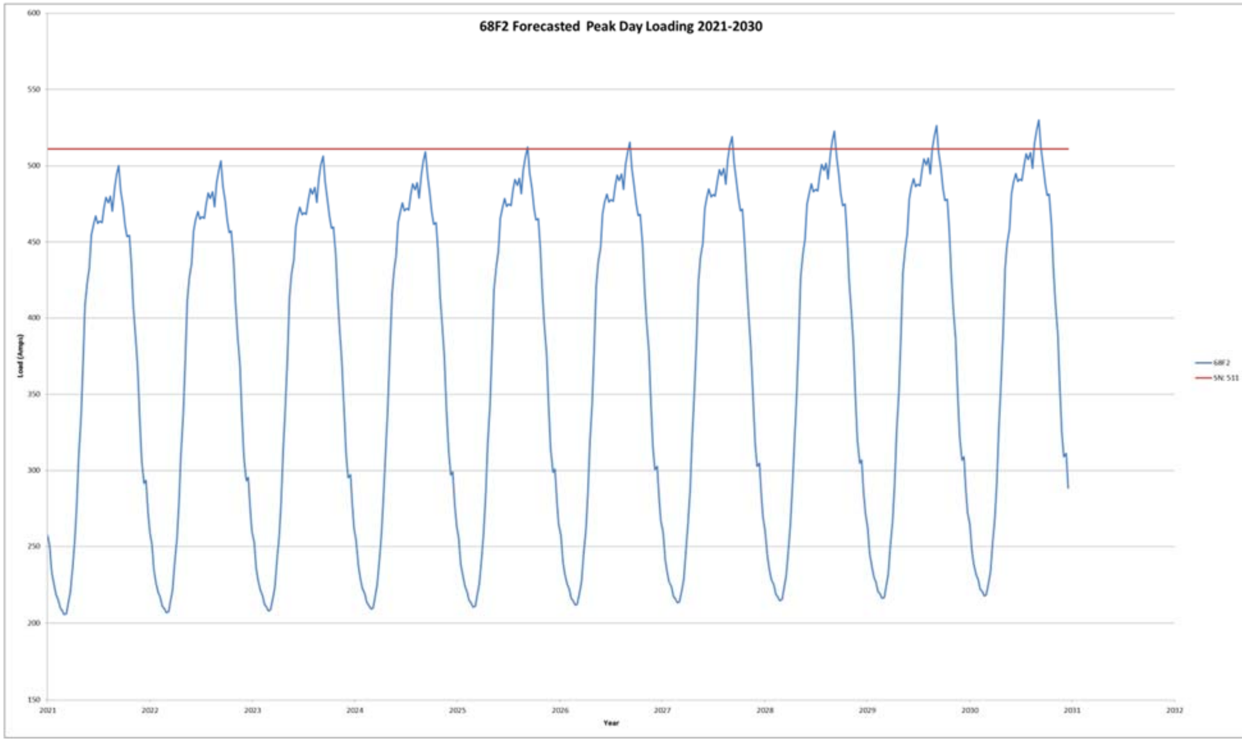
Peacedale	59F3	73	2671	2744
Kenyon	68F2	16	4113	4129
Grand Total		89	6784	**6873**

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.



REDACTED VERSION



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

R-I-11

Request:

Referencing Section 2, pages 7 and 8; provide Charts 5a and 5b: RI Interruptions by Cause, in executable format.

Response:

Please see Attachment R-I-11 for Charts 5a and 5b, RI Interruptions by Cause, in Excel format.

Prepared by or under the supervision of: Daniel Marceau

Attachment R-I-11

Please see Excel version of Attachment R-I-11

Prepared by or under the supervision of: Daniel Marceau

R-I-12

Request:

Regarding the increase in outages due to trees from 83,471 to 139,454 between FY18 and FY19, provide additional information on the drivers for the increase. Were specific species of trees susceptible to pest infestation, causing increased outages? Does the Company have an explanation for the increase given its aggressive vegetation management and EHTM programs?

Response:

There are several factors which may have contributed to the increase in tree-related outages in FY19. With climate change, we are beginning to see higher temperatures, more frequent and more severe weather, and widespread infestation of invasive species. Higher temperatures result in longer growing seasons and faster tree growth. This could result in more branches growing into power lines and longer, less stable limbs hanging over the wires. Climate change is also affecting weather patterns. We have seen periods of drought, followed by extended periods of rain and wind. This can have a dramatic impact on the health of vegetation throughout the state. Lastly, we are seeing the impacts of Gypsy Moth infestation throughout Rhode Island. While we have removed thousands of dead oak trees, many could still be impacting our system.

The Company has not historically performed detailed field reviews of tree-related outages, and, therefore, does not have any additional data, such as species or pest infestation, related to tree outages in FY18 and FY19. We will begin doing field reviews of tree-related outages in November 2019 to collect more detailed data about these events. The Company expects that these investigations will provide information which we can use to reduce the number and severity of tree-related interruptions throughout the state.

The Company's cycle pruning and EHTM programs, while they have proven to be effective at improving reliability, cannot fully protect our system from every storm. As long as vegetation grows within striking distance of power lines, there will be tree-related outages. To help address these issues, the Company has requested additional funds this year to deal with pockets of poor performance. This program is discussed in more detail in the Company's FY2021 Proposed ISR Plan and in the response to R-I-23.

Prepared by or under the supervision of: Ryan Moe

R-I-13

Request:

Regarding "Intentional" outages, provide the criteria that defines an outage in this category. Provide a list of intentional outages for FY17, FY18 and FY19 including the outage date and time, a description of the outage, total outage time, number of customers affected, and whether impacted lines were underground or overhead. Also, provide an explanation of why intentional outages could not be handled through work on energized lines.

Response:

"Intentional" outages mean any outage as a result of planned maintenance, 911 response, emergency repair work, and load shedding.

The safety of Company's employees and the public is of paramount importance. The Company recognizes that any outages can be an inconvenience for customers, and, therefore, endeavors to do work on energized lines where possible. Work is done during an intentional outage if it is determined that workers cannot perform the work safely while the equipment is energized.

Please see Attachment R-I-13 for the list of intentional outages for fiscal year (FY) 2017, FY 2018 and FY 2019.

Attachment R-I-13

Please see Excel version of Attachment R-I-13

Prepared by or under the supervision of: Daniel Marceau

R-I-14

Request:

Regarding "Human Element/Other" related outages, provide the criteria that defines an outage in this category. Provide a list of Human Element/Other outages for FY17, FY18 and FY19 including the outage date and time, a description of the outage, total outage time, and number of customers affected.

Response:

The criteria that define an outage in the Human Element/Other category include the following:

- Human Contact – Interruption caused by contact with energized lines/equipment by a human being who is not an employee or company contractor.
- Non-Company Activities – Interruption due to inadvertent contact during the construction or reconstruction of distribution facilities by non-utility personnel. Interruption caused by contact with energized lines and/or equipment by a crane, derrick, bucket truck or similar equipment operated by non-utility personnel. Interruption caused by contact with energized lines/equipment by trees or limbs cut by customer or customer contractor.
- Vandalism – Interruption caused by vandalism includes operation of switches by unauthorized persons, damage by gunfire, objects thrown onto lines and equipment, etc.
- Vehicle – Interruption caused by a collision of a motor vehicle with distribution equipment.

Please see Attachment R-I-14 for this list of Human Element/Other outages for fiscal year (FY) 2017, FY 2018 and FY 2019.

FY2017

Date Time	Total Duration (min)	Customer Affected	Event Description
5/17/2016 11:00:00 AM	71.00	10	Blown 100k line fuse (1 of 3) at P9140 Randall St, Cranston - Cause was non company activities (tree crew).
6/13/2016 01:05:34 PM	39.43	138	Blown 65k branch fuse - P24 Wilbur Ave - Caused by tree limb dropped by non-NGRID tree crew on Locust Glen.
6/17/2016 10:59:20 AM	106.67	10	Transformer fuse found open at P3 Heritage, not blown, fell open when verizon worker was working on telephone lines
7/10/2016 02:28:29 PM	84.52	12	Blown 40k line fuse at Pole 31 Ferry Ln. Cause was due to customer dropping branch on primary.
8/31/2016 11:05:00 AM	55.00	16	Blown riser fuse pole 40 Oliphant Lane. Non company dig-in to primary between Pad 5 Coggeshell Cir and Pole 40.
9/14/2016 08:29:32 AM	65.47	37	Blown 25k line fuse @ pole 195 Hartford Ave - cause was private tree crew knocked limb onto line.
12/2/2016 02:59:54 PM	65.10	15	Customer's tree crew hit phase at pole 1 Holly Hill Ln. Blown 40k line fuse at pole 72 Scituate Ave.
4/1/2016 02:40:00 PM	244.00	2	MVA/Broken pole, service down to house 310 Victory Hwy. Vz set.
4/3/2016 08:17:07 AM	132.17	38	108W60 Circuit Breaker (CB) at Riverside Sub locked out. Cause: Plow hit P10 Wood St, which slapped phases together. This IDS is for Capital - Rhode Island customers. Most customers on this feeder are in Southeast - Massachusetts in Bellingham - see other IDS event. Manually closed 108W60 CB, via SCADA, to pick up customers.
4/4/2016 10:08:43 AM	103.28	31	Pole 46 Harkney Hill Rd blown line fuse due to MVA at Pole 18 Fish Hill Rd. No damage to pole, but it knocked phase off insulator pin Pole 17.
4/4/2016 01:48:59 PM	24.43	79	Pole top recloser lockout at pole 16 Harris Ave. Cause MVA at pole 38 Cobble Hill Rd brought phases off insulators.
4/4/2016 01:48:59 PM	51.08	629	Pole top recloser lockout at pole 16 Harris Ave. Cause MVA at pole 38 Cobble Hill Rd brought phases off insulators.
4/5/2016 11:13:10 PM	136.45	489	127W40 feeder trip and reclose at Nasonville Sub. MVA/broken pole took down A phase pole 185-186 Douglas Pike. Opened disconnects pole 199 Douglas Pike to de-energize to make repairs.
4/5/2016 11:13:10 PM	183.50	125	127W40 feeder trip and reclose at Nasonville Sub. MVA/broken pole took down A phase pole 185-186 Douglas Pike. Opened disconnects pole 199 Douglas Pike to de-energize to make repairs.
4/16/2016 01:36:56 PM	59.07	115	Blown line fuse at Pole 15 Log Rd, Burrillville - Motor Vehicle Accident with broken pole at Pole 55 Log Rd -
4/21/2016 11:32:00 AM	47.00	8	Manually opened transformer cutout pole 7 South Shore Rd to make repairs to secondary damaged by backhoe pole 6-7 South Shore Rd.
5/11/2016 06:32:52 AM	241.00	35	Manually opened line fuses at pole 423 Plainfield Pike to replace pole and failed transformer at pole 11 Green Hill Road after MVA.
5/11/2016 06:32:52 AM	328.13	3	Manually opened line fuses at pole 423 Plainfield Pike to replace pole and failed transformer at pole 11 Green Hill Road after MVA.
5/15/2016 04:38:37 PM	303.00	100	Blown line fuse (1 of 3) at pole 26 Old Forge Rd - Phase down and pole 18 Old Forge Rd broken due to motor vehicle accident. Opened other 2 fuses to make repairs/set pole.
5/15/2016 04:38:37 PM	474.38	53	Blown line fuse (1 of 3) at pole 26 Old Forge Rd - Phase down and pole 18 Old Forge Rd broken due to motor vehicle accident. Opened other 2 fuses to make repairs/set pole.
5/19/2016 10:51:00 AM	39.00	7	Blown 25k line fuse pole 18 Fruit Hill Ave caused by a truck backing into phone wires and shaking pole.
5/25/2016 11:00:56 AM	104.07	3	Blown 15K line fuse at P3 Ives Rd - cause backhoe hit guy wire Pole 4-50.
5/25/2016 03:59:32 PM	141.47	4	Blown transformer fuse P311 Douglas Pike - Cause vehicle - a service was ripped down.
5/28/2016 01:14:41 AM	87.62	716	Pole top recloser lockout @ P396 Putnam Pike - MVA @ P83 Reynolds Rd - telco set.
5/28/2016 01:14:41 AM	439.32	38	Pole top recloser lockout @ P396 Putnam Pike - MVA @ P83 Reynolds Rd - telco set.
5/29/2016 10:46:00 AM	174.00	16	Blown line fuse P3 Indian Run Trl - Cause was MVA - Verizon to replace pole.
6/9/2016 08:53:54 AM	38.08	680	Pole top recloser trip and reclose at 8:53 at P301 Diamond Hill Rd - Cause MVA/broken pole/wires down at P370 Diamond Hill Rd - opened PTR to make temporary repairs.
6/9/2016 08:53:54 AM	61.98	185	Pole top recloser trip and reclose at 8:53 at P301 Diamond Hill Rd - Cause MVA/broken pole/wires down at P370 Diamond Hill Rd - opened PTR to make temporary repairs.
6/16/2016 10:02:49 AM	6.50	242	107W84 feeder trip and reclose at Pawtucket #1 Sub. Manually opened 107W84 breaker via SCADA - Cause was MVA / wires down P14 Sharon St Pawtucket - 107W84 was feeding Hyde Sub (28J1) at the time of the event.
6/16/2016 10:02:49 AM	39.20	2058	107W84 feeder trip and reclose at Pawtucket #1 Sub. Manually opened 107W84 breaker via SCADA - Cause was MVA / wires down P14 Sharon St Pawtucket - 107W84 was feeding Hyde Sub (28J1) at the time of the event.
6/16/2016 10:02:49 AM	85.18	82	107W84 feeder trip and reclose at Pawtucket #1 Sub. Manually opened 107W84 breaker via SCADA - Cause was MVA / wires down P14 Sharon St Pawtucket - 107W84 was feeding Hyde Sub (28J1) at the time of the event.
6/16/2016 07:14:00 PM	34.52	661	Blown transformer fuse pole 32 Hope St. Broken pole / MVA. Manually opened load break at P25 Hope St to make temporary repairs
6/16/2016 07:14:00 PM	502.00	9	Blown transformer fuse pole 32 Hope St. Broken pole / MVA. Manually opened load break at P25 Hope St to make temporary repairs
6/17/2016 09:24:00 PM	27.00	26	Blown transformer fuse @ P5 Crossman - Broken stub pole @ P4-2 - Vehicle
6/19/2016 04:04:58 PM	121.03	98	Blown line fuse (1 of 3) at P130 Cucumber Hill Rd - Blown riser fuse P10-50 Cucumber Hill Rd - Cause MVA/broken pole at P10-50 Cucumber Hill Rd - Vz set.
6/24/2016 05:30:59 PM	41.98	2476	38F5 circuit breaker locked out at Putnam Pike Sub. Cause: MVA/broken pole at P355 Greenville Ave.

FY2018

Date Time	Total Duration (min)	Customer Affected	Event Description
3/20/2018 11:21:07 AM	374.50	4	Blown riser fuse at P71 Rumstick Rd. Cause was a dig in near Pad 71-2 Rumstick Rd.
3/30/2018 01:40:49 PM	424.55	27	Blown line fuse at P73 Shun Pike. Cause was a tree down due to a non-company tree crew at P72-50 Shun Pike which resulted in a downed primary line. Had to call in crew to repair.
1/3/2018 11:32:19 AM	78.22	23	Blown line fuse P52 Hazard Rd - truck pulled telco line into primary P6 Hazard Rd.
1/9/2018 02:38:55 PM	112.22	21	Blown line fuses P9168 Jefferson Blvd. Cause was a failed guy wire P34 & 35 due to vehicle contact.
1/14/2018 12:04:53 AM	42.20	9	Blown transformer fuse P23 Central St. Cause - MVA pole hit P23 Central St.
1/15/2018 06:04:57 PM	203.58	229	2 of 2 blown line fuses at P11 Reservoir Ave - Broken pole at P3 Shore - MVA -
1/25/2018 09:36:05 AM	217.90	2	Blown transformer fuse at P14-7 East Frontage Rd. Cause was a MVA at P14-11 Smithfield Ave which resulted in a failed cutout at P14-7 East Frontage Rd.
1/29/2018 08:06:46 PM	379.12	49	Manually opened line fuses (3 of 3) at Pole 181 New River Road, Manville. Reason: Motor vehicle accident caused broken pole and primaries down at Pole 181-30.
1/30/2018 08:31:33 AM	197.98	3	Failed transformer on P111 Matunuck School House Rd. Cause: MVA at P111 Matunuck School House Rd.
1/30/2018 08:44:38 AM	76.37	19	Line fuse on P81 Division St knocked open (fuse did not blow) by plow hitting P81 Division St.
1/30/2018 11:28:25 AM	31.58	10	Blown line fuse at P25 North St. Cause: snow plow hit P25 North Rd.
2/1/2018 03:37:00 PM	476.00	5	Blown transformer fuse - truck hit wires and took down pole 5 Chestnut Ave.
2/2/2018 04:40:05 AM	109.63	309	Pole top recloser trip and reclose at pole 3 Shermantown Rd at 4:40. Found phase down, phases off insulators at P56 Shermantown Rd due to MVA. Opened PTR at pole 3 Shermantown Rd to make repairs.
2/2/2018 04:40:05 AM	213.15	101	Pole top recloser trip and reclose at pole 3 Shermantown Rd at 4:40. Found phase down, phases off insulators at P56 Shermantown Rd due to MVA. Opened PTR at pole 3 Shermantown Rd to make repairs.
2/4/2018 02:26:47 PM	26.80	940	Car hit and broke pole at P85 Old Baptist Rd, phase down. Via SCADA, opened 30F1 breaker at Lafayette Sub. Isolated between pole 96 and pole 69 Old Baptist Rd, closed 30F1 breaker and picked up end of feeder on 30F2.
2/4/2018 02:26:47 PM	41.82	175	Car hit and broke pole at P85 Old Baptist Rd, phase down. Via SCADA, opened 30F1 breaker at Lafayette Sub. Isolated between pole 96 and pole 69 Old Baptist Rd, closed 30F1 breaker and picked up end of feeder on 30F2.
2/4/2018 02:26:47 PM	53.82	67	Car hit and broke pole at P85 Old Baptist Rd, phase down. Via SCADA, opened 30F1 breaker at Lafayette Sub. Isolated between pole 96 and pole 69 Old Baptist Rd, closed 30F1 breaker and picked up end of feeder on 30F2.
2/4/2018 02:26:47 PM	222.82	167	Car hit and broke pole at P85 Old Baptist Rd, phase down. Via SCADA, opened 30F1 breaker at Lafayette Sub. Isolated between pole 96 and pole 69 Old Baptist Rd, closed 30F1 breaker and picked up end of feeder on 30F2.
2/6/2018 12:32:39 AM	181.13	416	Pole top recloser at P170 Hartford Ave locked out. Cause--MVA broke P207 and P207-50 Hartford Ave. Attempted to close PTR and locked out again. Found additional issue of broken insulator on P207 Hartford Ave.
2/6/2018 04:12:40 AM	312.63	3	Failed tap and failed pole at P207-54 Hartford Ave. Cause--MVA broke P207-54 Hartford Ave and broke tap wire.
2/16/2018 03:53:32 PM	116.47	9	Blown 40k line fuse pole 60 Bald Hill Rd. Fuse was put back in and then blew again. Further investigation revealed slack in lines from MVA, causing phase to hit tree. Cause: MVA pole 59 Bald Hill Rd.
2/25/2018 05:57:23 PM	40.43	139	26W5 circuit breaker at Woonsocket Substation locked out. Cause--MVA broke P466 and P467 Great Rd in North Smithfield. Isolated and picked up most customers. Made airgaps at P464 and P468 - only 1 transformer was out of service while poles were replaced.

FY2018

Date Time	Total Duration (min)	Customer Affected	Event Description
2/25/2018 05:57:23 PM	52.12	986	26W5 circuit breaker at Woonsocket Substation locked out. Cause--MVA broke P466 and P467 Great Rd in North Smithfield. Isolated and picked up most customers. Made airgaps at P464 and P468 - only 1 transformer was out of service while poles were replaced.
2/25/2018 05:57:23 PM	98.37	162	26W5 circuit breaker at Woonsocket Substation locked out. Cause--MVA broke P466 and P467 Great Rd in North Smithfield. Isolated and picked up most customers. Made airgaps at P464 and P468 - only 1 transformer was out of service while poles were replaced.
2/25/2018 05:57:23 PM	98.98	1177	26W5 circuit breaker at Woonsocket Substation locked out. Cause--MVA broke P466 and P467 Great Rd in North Smithfield. Isolated and picked up most customers. Made airgaps at P464 and P468 - only 1 transformer was out of service while poles were replaced.
2/25/2018 05:57:23 PM	210.75	355	26W5 circuit breaker at Woonsocket Substation locked out. Cause--MVA broke P466 and P467 Great Rd in North Smithfield. Isolated and picked up most customers. Made airgaps at P464 and P468 - only 1 transformer was out of service while poles were replaced.
2/25/2018 05:57:23 PM	554.82	8	26W5 circuit breaker at Woonsocket Substation locked out. Cause--MVA broke P466 and P467 Great Rd in North Smithfield. Isolated and picked up most customers. Made airgaps at P464 and P468 - only 1 transformer was out of service while poles were replaced.
2/26/2018 04:13:07 PM	30.27	25	Manually opened transformer fuse at P2 Croade St for repairs. Truck pulled down triplex 55 Railroad Ave.
2/27/2018 12:26:54 PM	93.10	112	Blown 2 of 3 line fuses at P90 Post Rd. Cause--moving truck pulled wires down at P90-6 Post Rd.
3/14/2018 07:42:36 AM	112.22	167	6J3 and 6J6 circuit breakers at Olneyville Substation locked out. Cause--MVA broke P18 Manton Ave and phases on this double-circuited pole wrapped together. On 6J6 feeder isolated damage by opening disconnects at P19 Delaine St and closing in circuit breaker. On 6J3 feeder, opened loadbreak at P 4 Aleppo St and closed tie disconnects at P3 Hartford Ave and backfed from 6J6 once 6J6 circuit breaker was closed. Winter storm Skylar.
3/14/2018 07:42:36 AM	576.88	67	6J3 and 6J6 circuit breakers at Olneyville Substation locked out. Cause--MVA broke P18 Manton Ave and phases on this double-circuited pole wrapped together. On 6J6 feeder isolated damage by opening disconnects at P19 Delaine St and closing in circuit breaker. On 6J3 feeder, opened loadbreak at P 4 Aleppo St and closed tie disconnects at P3 Hartford Ave and backfed from 6J6 once 6J6 circuit breaker was closed. Winter storm Skylar.
5/23/2017 08:19:00 AM	101.00	3	Blown 25k line fuse P245 Snake Hill Rd. Cause - Customer tree crew dropped tree on primary P245-3 Snake Hill Rd.
5/23/2017 11:26:02 AM	111.97	81	Blown 25k line fuse P58 K G Ranch Rd. Cause- Non Company contractor dropped tree on primary at P4 Cul de Sac Dr.
6/2/2017 11:25:29 AM	154.52	9	Blown line fuse P8-50 Maple Root Rd. Cause - Non Company Tree crew caused tree to land on primary wire at P1 Steere Ln.
7/28/2017 10:34:00 AM	163.00	3	Blown transformer fuse P73 Fish Rd. Cause - Work by non company contractor at P70-1.
8/6/2017 07:50:30 PM	51.68	492	Blown 2 of 3 100k line fuses at P5 Main St. Cause--phases pulled together by fishing line at P61 Hill St.
8/22/2017 07:20:51 PM	34.15	36	Blown line fuse at P25 Academy Ave. Cause was a ladder made contact with lines at P1 Hendrick St.
9/17/2017 05:09:00 PM	121.00	2	Blown 10K transformer fuse at P11 White Pine Dr. Cause--house fire at house 55 White Pine Dr. Pulled meter and cut taps for safety. Customer needs electrician and inspection before can reconnect.
9/28/2017 07:31:53 AM	54.12	65	Blown 65K line fuse at P33 Wilbur Ave. Cause--private tree crew dropped limb at P10 Hines Farm Rd.
10/7/2017 11:09:48 AM	115.20	18	Blown line fuse at P11 Chickory Ln. Cause--customer cut down tree in right of way at P11-9 Jacqueline Ct. Created airgap at P11-7 to isolate and restore customers.

FY2018

Date Time	Total Duration (min)	Customer Affected	Event Description
10/7/2017 11:09:48 AM	574.20	2	Blown line fuse at P11 Chickory Ln. Cause--customer cut down tree in right of way at P11-9 Jacqueline Ct. Created airgap at P11-7 to isolate and restore customers.
11/24/2017 10:15:29 AM	62.45	12	Blown 25k line fuse pole 1044 Juniper Rd. Cause was fallen tree limb from private tree company.

FY2019

Date Time	Total Duration (min)	Customer Affected	Event Description
5/19/2018 02:03:55 AM	16.62	2445	107W43 feeder trip and reclose at Pawtucket #1 Sub at 2:03. Found guy wire at pole 41 Barton St broken and flipped onto primary. Manually opened 107W43 breaker at sub, removed guy wire, and closed breaker. However, still getting no power calls on two phases. Patrolling back to sub, found C phase tap burnt off at pole 12 Conant/Weeden St and B phase tap at pole 49-1 Pine St. Opened disconnect at pole 49 then pole 12, repaired taps and closed disconnects. Note: Manually opening 107W43 also caused short interruption to 106J1, 106J3, and 106J7 feeders from Centre St Sub. Cause: MVA at P41 Barton St.
5/19/2018 02:03:55 AM	217.88	706	107W43 feeder trip and reclose at Pawtucket #1 Sub at 2:03. Found guy wire at pole 41 Barton St broken and flipped onto primary. Manually opened 107W43 breaker at sub, removed guy wire, and closed breaker. However, still getting no power calls on two phases. Patrolling back to sub, found C phase tap burnt off at pole 12 Conant/Weeden St and B phase tap at pole 49-1 Pine St. Opened disconnect at pole 49 then pole 12, repaired taps and closed disconnects. Note: Manually opening 107W43 also caused short interruption to 106J1, 106J3, and 106J7 feeders from Centre St Sub. Cause: MVA at P41 Barton St.
5/19/2018 02:03:55 AM	307.47	474	107W43 feeder trip and reclose at Pawtucket #1 Sub at 2:03. Found guy wire at pole 41 Barton St broken and flipped onto primary. Manually opened 107W43 breaker at sub, removed guy wire, and closed breaker. However, still getting no power calls on two phases. Patrolling back to sub, found C phase tap burnt off at pole 12 Conant/Weeden St and B phase tap at pole 49-1 Pine St. Opened disconnect at pole 49 then pole 12, repaired taps and closed disconnects. Note: Manually opening 107W43 also caused short interruption to 106J1, 106J3, and 106J7 feeders from Centre St Sub. Cause: MVA at P41 Barton St.
11/7/2018 09:41:13 AM	40.87	1881	45F2 feeder lockout at West Greenville Sub. Cause - Broken guy wire from vehicle hit wrapped around phase P25 Hartford Pike. Pole top recloser at pole 58 did not clear the fault.
9/5/2018 08:25:45 AM	188.07	2	Vehicle took down service line to 2 family house at 71 Hill Farm Rd. Ran new service.
1/9/2019 07:30:38 PM	71.73	2	Tree company cut service when trimming tree from P13 Merino St to house 90 Merino St.
3/21/2019 03:33:08 PM	16.85	339	108W62 feeder lockout at Riverside Sub. Caused was private tree company dropping tree onto primary and phase down P4 River St. Isolated for repair, and picked up most customers on a feeder tie. Had to open the feeder breaker again at 16:34 to close the disconnects at pole 1 Bernon St dead for final restoration.
3/21/2019 03:33:08 PM	37.40	339	108W62 feeder lockout at Riverside Sub. Caused was private tree company dropping tree onto primary and phase down P4 River St. Isolated for repair, and picked up most customers on a feeder tie. Had to open the feeder breaker again at 16:34 to close the disconnects at pole 1 Bernon St dead for final restoration.
3/21/2019 03:33:08 PM	48.25	1123	108W62 feeder lockout at Riverside Sub. Caused was private tree company dropping tree onto primary and phase down P4 River St. Isolated for repair, and picked up most customers on a feeder tie. Had to open the feeder breaker again at 16:34 to close the disconnects at pole 1 Bernon St dead for final restoration.
3/21/2019 03:33:08 PM	77.80	45	108W62 feeder lockout at Riverside Sub. Caused was private tree company dropping tree onto primary and phase down P4 River St. Isolated for repair, and picked up most customers on a feeder tie. Had to open the feeder breaker again at 16:34 to close the disconnects at pole 1 Bernon St dead for final restoration.
2/11/2019 08:54:08 AM	144.63	14	Single customer outage. Service ripped off house 29 Wainwright. Cause - construction activity at neighbors.

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Date Time	Total Duration (min)	Customer Affected	Event Description
6/15/2018 01:56:06 AM	342.98	34	Blown line fuse at P336 Boston Neck Rd. Cause - MVA at P336 Boston Neck Rd. Broken cross arm.
6/15/2018 01:56:06 AM	348.93	3	Blown line fuse at P336 Boston Neck Rd. Cause - MVA at P336 Boston Neck Rd. Broken cross arm.
6/15/2018 01:56:06 AM	349.03	18	Blown line fuse at P336 Boston Neck Rd. Cause - MVA at P336 Boston Neck Rd. Broken cross arm.
6/15/2018 01:56:06 AM	380.83	7	Blown line fuse at P336 Boston Neck Rd. Cause - MVA at P336 Boston Neck Rd. Broken cross arm.
7/8/2018 07:20:16 PM	38.18	1263	18F7 circuit breaker at Johnston Sub locked out. Cause was a MVA at P109 Dyer Ave which resulted in a broken crossarm and a phase down.
7/8/2018 07:20:16 PM	50.25	1138	18F7 circuit breaker at Johnston Sub locked out. Cause was a MVA at P109 Dyer Ave which resulted in a broken crossarm and a phase down.
7/8/2018 07:20:16 PM	212.15	613	18F7 circuit breaker at Johnston Sub locked out. Cause was a MVA at P109 Dyer Ave which resulted in a broken crossarm and a phase down.
7/23/2018 12:16:06 PM	79.65	102	Blown line fuses at P90 Post Rd due to failed cross arm P90-22 Post Rd due to truck pulling down wires. Lifted taps at pole 90-2 to make a partial restoration.
7/23/2018 12:16:06 PM	243.90	66	Blown line fuses at P90 Post Rd due to failed cross arm P90-22 Post Rd due to truck pulling down wires. Lifted taps at pole 90-2 to make a partial restoration.
5/11/2018 11:48:47 PM	540.22	65	Blown 65K (2 of 3) line fuse at P124 Pound Hill Rd. Cause was MVA. Failed cutouts.
5/5/2018 03:33:59 AM	5.00	2135	Failed disconnect on 1 of 3 phases pole 49-1 Pine St due to motor vehicle accident. Transferred Centre St Sub to 107W51, then manually opened 107W43 breaker at Pawtucket #1 Sub to deenergize work zone and jump out disconnect.
5/5/2018 03:33:59 AM	135.02	148	Failed disconnect on 1 of 3 phases pole 49-1 Pine St due to motor vehicle accident. Transferred Centre St Sub to 107W51, then manually opened 107W43 breaker at Pawtucket #1 Sub to deenergize work zone and jump out disconnect.
7/13/2018 02:23:23 PM	166.55	107	Blown 40k line fuse P19 Lydia Ave. Cause - tree company cut down tree and broke P15 Lydia Ave.
10/31/2018 01:35:17 PM	94.77	332	Blown 2 of 3 line fuses at P160 Post Rd, broken pole at P6 West Beach Rd, caused by non-company tree removal.
4/4/2018 02:47:00 PM	199.40	33	Blown line fuse at P154 Kingstown Rd. Cause was a MVA / broken pole at P154-2 Kingstown Rd.
4/6/2018 01:05:20 AM	13.20	1034	107W81 circuit breaker locked out at Pawtucket #1 Sub. Cause was a MVA at P49 Division St which resulted in a broken pole. Double circuit pole - had to de-energize 148J7 feeder as well from Pawtucket #2 Sub.
4/6/2018 01:05:20 AM	81.25	146	107W81 circuit breaker locked out at Pawtucket #1 Sub. Cause was a MVA at P49 Division St which resulted in a broken pole. Double circuit pole - had to de-energize 148J7 feeder as well from Pawtucket #2 Sub.
4/6/2018 01:05:20 AM	93.37	1963	107W81 circuit breaker locked out at Pawtucket #1 Sub. Cause was a MVA at P49 Division St which resulted in a broken pole. Double circuit pole - had to de-energize 148J7 feeder as well from Pawtucket #2 Sub.
4/6/2018 01:05:20 AM	406.77	147	107W81 circuit breaker locked out at Pawtucket #1 Sub. Cause was a MVA at P49 Division St which resulted in a broken pole. Double circuit pole - had to de-energize 148J7 feeder as well from Pawtucket #2 Sub.
4/6/2018 01:05:20 AM	476.57	81	107W81 circuit breaker locked out at Pawtucket #1 Sub. Cause was a MVA at P49 Division St which resulted in a broken pole. Double circuit pole - had to de-energize 148J7 feeder as well from Pawtucket #2 Sub.
4/25/2018 08:41:45 AM	254.00	22	Blown 1 of 3 B-phase line fuse P15 Webster at Pocassett Ave due to broken P12 Pocassett Ave. Crew manually opened transformer P11 Pocasset to repair services.

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Date Time	Total Duration (min)	Customer Affected	Event Description
4/25/2018 08:41:45 AM	158.25	25	Blown 1 of 3 B-phase line fuse P15 Webster at Pocassett Ave due to broken P12 Pocassett Ave. Crew manually opened transformer P11 Pocasset to repair services.
4/28/2018 05:36:14 PM	479.18	3	Blown transformer fuse at P214 Warwick Ave. Caused by motor vehicle accident which broke pole at P214 Warwick Ave.
5/1/2018 03:36:11 AM	17.62	423	Pole top recloser trip and reclose at 00:33. Manually open PTR at P1-1 Parker St for broken P43 Cobble Hill - cause was MVA.
5/5/2018 06:50:56 AM	275.50	15	Failed service and broken pole at 52 Narragansett Ave. Manually opened transformer at P8 Narragansett Ave to make repairs to poles. Caused by motor vehicle accident.
5/25/2018 03:40:15 PM	96.75	22	Blown line fuse at P1 Trafford Park Dr. Cause was MVA at P18 Tiffany Rd, broken pole P18 Tiffany Rd.
6/12/2018 11:24:15 AM	59.40	1003	14F3 and 14F4 feeders locked out at Drumrock Sub. Car hit and broke pole 103 Providence St on 14F3. Phase came down at P26 Centerville Rd on 14F4. Caused by failed sleeve at P26 Centerville Rd.
6/12/2018 11:24:15 AM	75.03	529	14F3 and 14F4 feeders locked out at Drumrock Sub. Car hit and broke pole 103 Providence St on 14F3. Phase came down at P26 Centerville Rd on 14F4. Caused by failed sleeve at P26 Centerville Rd.
6/12/2018 11:24:15 AM	88.55	615	14F3 and 14F4 feeders locked out at Drumrock Sub. Car hit and broke pole 103 Providence St on 14F3. Phase came down at P26 Centerville Rd on 14F4. Caused by failed sleeve at P26 Centerville Rd.
6/12/2018 11:24:15 AM	117.90	255	14F3 and 14F4 feeders locked out at Drumrock Sub. Car hit and broke pole 103 Providence St on 14F3. Phase came down at P26 Centerville Rd on 14F4. Caused by failed sleeve at P26 Centerville Rd.
6/12/2018 11:24:15 AM	435.75	20	14F3 and 14F4 feeders locked out at Drumrock Sub. Car hit and broke pole 103 Providence St on 14F3. Phase came down at P26 Centerville Rd on 14F4. Caused by failed sleeve at P26 Centerville Rd.
6/15/2018 10:11:02 PM	38.45	2083	27F5 feeder lockout at Pontiac Sub. Cause was MVA / broken pole at P23 Mayfield Rd. Isolated and picked up most customers on feeder tie.
6/15/2018 10:11:02 PM	47.62	299	27F5 feeder lockout at Pontiac Sub. Cause was MVA / broken pole at P23 Mayfield Rd. Isolated and picked up most customers on feeder tie.
6/15/2018 10:11:02 PM	69.63	99	27F5 feeder lockout at Pontiac Sub. Cause was MVA / broken pole at P23 Mayfield Rd. Isolated and picked up most customers on feeder tie.
6/15/2018 10:11:02 PM	428.17	446	27F5 feeder lockout at Pontiac Sub. Cause was MVA / broken pole at P23 Mayfield Rd. Isolated and picked up most customers on feeder tie.
7/3/2018 02:20:49 PM	52.32	607	Pole top recloser at P1 North Rd locked out. Cause was a MVA at P216-3 Kingstown Rd which resulted in a broken pole. Switching completed to restore customers.
7/3/2018 02:20:49 PM	355.17	4	Pole top recloser at P1 North Rd locked out. Cause was a MVA at P216-3 Kingstown Rd which resulted in a broken pole. Switching completed to restore customers.
7/9/2018 01:28:47 PM	27.05	56	5F1 feeder lockout at Warren Sub. MVA / broken pole at pole 1 Sowams Rd. Backfed most customers on feeder ties.
7/9/2018 01:28:47 PM	42.12	448	5F1 feeder lockout at Warren Sub. MVA / broken pole at pole 1 Sowams Rd. Backfed most customers on feeder ties.
7/9/2018 01:28:47 PM	62.18	407	5F1 feeder lockout at Warren Sub. MVA / broken pole at pole 1 Sowams Rd. Backfed most customers on feeder ties.

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Date Time	Total Duration (min)	Customer Affected	Event Description
7/9/2018 01:28:47 PM	64.35	1105	5F1 feeder lockout at Warren Sub. MVA / broken pole at pole 1 Sowams Rd. Backfed most customers on feeder ties.
7/14/2018 08:35:38 PM	185.70	226	Blown 1 of 3 shunt fuses P57 Old County Rd. Cause - MVA P22 Old County Rd. Crew manually opened other 2 of 3 shunt fuses to clear vehicle and set pole.
7/14/2018 08:35:38 PM	217.57	44	Blown 1 of 3 shunt fuses P57 Old County Rd. Cause - MVA P22 Old County Rd. Crew manually opened other 2 of 3 shunt fuses to clear vehicle and set pole.
7/23/2018 12:53:54 PM	21.05	1771	37W42 feeder lockout at Jepson Sub. MVA / broken pole at pole 298 West Main Rd. Double circuit with 37K33 - see other IDS - 37K33 had no damage - phases slapped together.
7/23/2018 12:53:54 PM	34.78	1003	37W42 feeder lockout at Jepson Sub. MVA / broken pole at pole 298 West Main Rd. Double circuit with 37K33 - see other IDS - 37K33 had no damage - phases slapped together.
7/24/2018 03:25:00 PM	374.77	9	Blown line fuse at P8 High Service Ave. Cause--MVA broke P2 Worcester Ave.
8/3/2018 11:54:59 AM	111.33	3	Blown 25k line fuse - P71 Mapleville Rd - Caused by MVA / broken pole.
8/27/2018 08:30:09 AM	47.58	485	85T1 feeder locked out at Wood River Sub. Cause was MVA / broken pole at P96 Switch Rd. Isolated for repairs and restored most customers.
8/27/2018 08:30:09 AM	273.37	321	85T1 feeder locked out at Wood River Sub. Cause was MVA / broken pole at P96 Switch Rd. Isolated for repairs and restored most customers.
8/31/2018 09:51:00 PM	479.45	5	Found 65k Trip Savers open (2 of 3) at P56 West Ironstone Rd caused by MVA broken pole at P38 West Ironstone Rd. Manually opened remaining Trip Saver to make repairs.
8/31/2018 09:51:00 PM	598.45	44	Found 65k Trip Savers open (2 of 3) at P56 West Ironstone Rd caused by MVA broken pole at P38 West Ironstone Rd. Manually opened remaining Trip Saver to make repairs.
9/3/2018 11:48:47 PM	238.38	264	Pole top recloser lockout at P136 Nooseneck Hill Rd. Cause: MVA and broken pole at P112 Nooseneck Hill Rd.
9/30/2018 07:16:27 AM	54.35	21	Blown 40K line fuse at P23 Mayfield Ave. Cause--MVA broke P23 Mayfield Ave.
10/4/2018 07:20:52 AM	56.30	63	Blown transformer fuse P104 Little Pond County Rd. Cause: MVA/broken pole at P55 Little Pond County Rd.
10/4/2018 07:20:52 AM	219.32	2	Blown transformer fuse P104 Little Pond County Rd. Cause: MVA/broken pole at P55 Little Pond County Rd.
10/14/2018 03:21:50 AM	22.58	371	107W85 feeder lockout at Pawtucket #1 Sub, 148J3 feeder trip and reclose at Pawtucket #2 Sub. Found MVA / broken pole at pole 2 Mineral Spring Ave. Via SCADA, opened 148J3 breaker to de-energize. Isolated 107W85 with disconnects pole 26 Pine St and closed breaker. 107W85 tripped open. Isolated 148J3 and picked up customers on tie. Had to make airgap at pole 20 Church St to restore additional customers. Patrol of 107W85 found phases wrapped up at pole 38 Pleasant St (probably from fault current). Unwrapped phases and closed 107W85 breaker. When repairs were complete, had to de-energize a portion of 148J3 to put the taps back on.
10/14/2018 03:21:50 AM	67.67	826	107W85 feeder lockout at Pawtucket #1 Sub, 148J3 feeder trip and reclose at Pawtucket #2 Sub. Found MVA / broken pole at pole 2 Mineral Spring Ave. Via SCADA, opened 148J3 breaker to de-energize. Isolated 107W85 with disconnects pole 26 Pine St and closed breaker. 107W85 tripped open. Isolated 148J3 and picked up customers on tie. Had to make airgap at pole 20 Church St to restore additional customers. Patrol of 107W85 found phases wrapped up at pole 38 Pleasant St (probably from fault current). Unwrapped phases and closed 107W85 breaker. When repairs were complete, had to de-energize a portion of 148J3 to put the taps back on.

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Date Time	Total Duration (min)	Customer Affected	Event Description
10/14/2018 03:21:50 AM	142.02	371	107W85 feeder lockout at Pawtucket #1 Sub, 148J3 feeder trip and reclose at Pawtucket #2 Sub. Found MVA / broken pole at pole 2 Mineral Spring Ave. Via SCADA, opened 148J3 breaker to de-energize. Isolated 107W85 with disconnects pole 26 Pine St and closed breaker. 107W85 tripped open. Isolated 148J3 and picked up customers on tie. Had to make airgap at pole 20 Church St to restore additional customers. Patrol of 107W85 found phases wrapped up at pole 38 Pleasant St (probably from fault current). Unwrapped phases and closed 107W85 breaker. When repairs were complete, had to de-energize a portion of 148J3 to put the taps back on.
10/14/2018 03:21:50 AM	198.98	401	107W85 feeder lockout at Pawtucket #1 Sub, 148J3 feeder trip and reclose at Pawtucket #2 Sub. Found MVA / broken pole at pole 2 Mineral Spring Ave. Via SCADA, opened 148J3 breaker to de-energize. Isolated 107W85 with disconnects pole 26 Pine St and closed breaker. 107W85 tripped open. Isolated 148J3 and picked up customers on tie. Had to make airgap at pole 20 Church St to restore additional customers. Patrol of 107W85 found phases wrapped up at pole 38 Pleasant St (probably from fault current). Unwrapped phases and closed 107W85 breaker. When repairs were complete, had to de-energize a portion of 148J3 to put the taps back on.
10/14/2018 03:21:50 AM	300.37	232	107W85 feeder lockout at Pawtucket #1 Sub, 148J3 feeder trip and reclose at Pawtucket #2 Sub. Found MVA / broken pole at pole 2 Mineral Spring Ave. Via SCADA, opened 148J3 breaker to de-energize. Isolated 107W85 with disconnects pole 26 Pine St and closed breaker. 107W85 tripped open. Isolated 148J3 and picked up customers on tie. Had to make airgap at pole 20 Church St to restore additional customers. Patrol of 107W85 found phases wrapped up at pole 38 Pleasant St (probably from fault current). Unwrapped phases and closed 107W85 breaker. When repairs were complete, had to de-energize a portion of 148J3 to put the taps back on.
10/14/2018 03:21:50 AM	325.80	90	107W85 feeder lockout at Pawtucket #1 Sub, 148J3 feeder trip and reclose at Pawtucket #2 Sub. Found MVA / broken pole at pole 2 Mineral Spring Ave. Via SCADA, opened 148J3 breaker to de-energize. Isolated 107W85 with disconnects pole 26 Pine St and closed breaker. 107W85 tripped open. Isolated 148J3 and picked up customers on tie. Had to make airgap at pole 20 Church St to restore additional customers. Patrol of 107W85 found phases wrapped up at pole 38 Pleasant St (probably from fault current). Unwrapped phases and closed 107W85 breaker. When repairs were complete, had to de-energize a portion of 148J3 to put the taps back on.
10/15/2018 10:40:43 AM	64.10	100	Blown 40k line fuse at P44 Fairview Ave - caused by MVA / broken pole at P3 Fairview Ave -
10/15/2018 10:40:43 AM	169.33	7	Blown 40k line fuse at P44 Fairview Ave - caused by MVA / broken pole at P3 Fairview Ave -
10/24/2018 01:58:24 PM	127.28	30	Blown 65k line fuse at pole 165 Greenville Ave. Cause: MVA / broken pole at pole 21 Farnum Ave....lifted tap to restore some customers while repairs were made.
10/24/2018 01:58:24 PM	343.05	37	Blown 65k line fuse at pole 165 Greenville Ave. Cause: MVA / broken pole at pole 21 Farnum Ave....lifted tap to restore some customers while repairs were made.
10/28/2018 12:01:00 AM	218.00	82	Blown 1 of 3 line fuses at pole 1 Lighthouse Rd (aka Ocean Rd). MVA / broken pole at pole 12 Ocean Rd.
11/2/2018 11:51:43 PM	50.20	192	Pole top recloser at P99 South County Trl locked out due to an MVA / broken pole at P32 South County Trl.
11/2/2018 11:51:43 PM	152.88	303	Pole top recloser at P99 South County Trl locked out due to an MVA / broken pole at P32 South County Trl.
11/10/2018 08:21:03 PM	111.48	82	Blown line fuse at P23 Maple Valley Rd. Cause--MVA broke P51 Town Farm Rd.

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Date Time	Total Duration (min)	Customer Affected	Event Description
11/13/2018 09:34:11 PM	51.82	466	6J2 feeder lockout at Olneyville Sub. Cause was an MVA / broken pole at P9 Troy St which resulted in broken poles at P9 Troy St, P12 and P12-50 Pilsudski St. Isolated for repair between substation and airgap created at pole 17 Magnolia St.
11/13/2018 09:34:11 PM	75.82	506	6J2 feeder lockout at Olneyville Sub. Cause was an MVA / broken pole at P9 Troy St which resulted in broken poles at P9 Troy St, P12 and P12-50 Pilsudski St. Isolated for repair between substation and airgap created at pole 17 Magnolia St.
11/13/2018 09:34:11 PM	461.82	8	6J2 feeder lockout at Olneyville Sub. Cause was an MVA / broken pole at P9 Troy St which resulted in broken poles at P9 Troy St, P12 and P12-50 Pilsudski St. Isolated for repair between substation and airgap created at pole 17 Magnolia St.
11/29/2018 07:24:18 AM	53.98	575	Pole top recloser at P454 Plainfield Pike locked out. Cause was a MVA / broken pole at P435-5.
12/4/2018 08:31:52 PM	87.53	54	Blown line fuse at pole 2 Ridge St, caused by an MVA and broken pole at pole 85 Pleasant St.
12/11/2018 10:30:33 AM	107.62	28	Blown line fuses pole 4 Dunnell Lane due to motor vehicle accident at pole 4 Dunnell Lane (different P4 from fuses). Lifted taps towards pole 5 feeding down Dunnel Lane East to pick up some customers during repair -
12/11/2018 10:30:33 AM	304.28	14	Blown line fuses pole 4 Dunnell Lane due to motor vehicle accident at pole 4 Dunnell Lane (different P4 from fuses). Lifted taps towards pole 5 feeding down Dunnel Lane East to pick up some customers during repair -
12/11/2018 08:37:12 PM	194.52	44	Blown transformer fuse at P111 Matunuck School House Rd. Manually opened line fuse at P29 Matunuck Beach Rd to make repairs. Cause was a MVA at P111 Matunuck School House Rd which resulted in a broken pole.
12/11/2018 08:37:12 PM	367.37	3	Blown transformer fuse at P111 Matunuck School House Rd. Manually opened line fuse at P29 Matunuck Beach Rd to make repairs. Cause was a MVA at P111 Matunuck School House Rd which resulted in a broken pole.
12/13/2018 02:18:01 PM	451.40	109	3 blown 100K line fuses at pole 104 Tiogue Ave - MVA / broken pole at pole 2-50 Jefferson Dr.
12/15/2018 11:30:42 PM	55.43	2078	107W63 feeder locked out at Pawtucket 1 Sub, caused by an MVA and broken pole at pole 3 Lonsdale Ave.
12/15/2018 11:30:42 PM	72.32	666	107W63 feeder locked out at Pawtucket 1 Sub, caused by an MVA and broken pole at pole 3 Lonsdale Ave.
12/15/2018 11:30:42 PM	111.10	361	107W63 feeder locked out at Pawtucket 1 Sub, caused by an MVA and broken pole at pole 3 Lonsdale Ave.
12/18/2018 11:17:37 AM	18.37	968	107W81 feeder lockout at Pawtucket #1 Sub. Cause was broken pole and cross arm P21 School St due to MVA.
12/18/2018 11:17:37 AM	41.73	131	107W81 feeder lockout at Pawtucket #1 Sub. Cause was broken pole and cross arm P21 School St due to MVA.
12/18/2018 11:17:37 AM	43.30	563	107W81 feeder lockout at Pawtucket #1 Sub. Cause was broken pole and cross arm P21 School St due to MVA.
12/18/2018 11:17:37 AM	106.83	13	107W81 feeder lockout at Pawtucket #1 Sub. Cause was broken pole and cross arm P21 School St due to MVA.
12/21/2018 02:25:59 PM	46.83	764	150F2 feeder lockout at New London Ave Sub. Cause was MVA / broken pole at P117 Providence St West Warwick. This is a new feeder, not in GIS or OMS yet. 150F2 took load from 14F3 past pole 96 Tollgate Rd. Windy.

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Date Time	Total Duration (min)	Customer Affected	Event Description
12/21/2018 02:25:59 PM	81.03	551	150F2 feeder lockout at New London Ave Sub. Cause was MVA / broken pole at P117 Providence St West Warwick. This is a new feeder, not in GIS or OMS yet. 150F2 took load from 14F3 past pole 96 Tollgate Rd. Windy.
12/28/2018 06:40:54 AM	45.15	90	Blown 1 of 3 line fuses at pole 337 Putnam Pike. MVA at pole 3 Chesnut Hill Rd - manually opened 2nd line fuse at pole 337 Putnum Pike in Glocester to replace pole 3.
12/28/2018 06:40:54 AM	109.25	18	Blown 1 of 3 line fuses at pole 337 Putnam Pike. MVA at pole 3 Chesnut Hill Rd - manually opened 2nd line fuse at pole 337 Putnum Pike in Glocester to replace pole 3.
1/4/2019 11:12:52 AM	59.58	155	Blown line fuse P151 Douglas Pike due to a motor vehicle accident - broken pole at P142 Douglas Pike.
1/4/2019 11:12:52 AM	226.35	3	Blown line fuse P151 Douglas Pike due to a motor vehicle accident - broken pole at P142 Douglas Pike.
1/4/2019 11:12:52 AM	226.67	4	Blown line fuse P151 Douglas Pike due to a motor vehicle accident - broken pole at P142 Douglas Pike.
1/14/2019 08:09:00 AM	40.92	1208	18F11 feeder lockout at Johnston Sub. Motor vehicle accident / broken pole at P356 Plainfield Pike. Pole top recloser did not operate at pole 2 Simmonsville Rd due to a faulty control cable.
1/14/2019 08:09:00 AM	64.78	12	18F11 feeder lockout at Johnston Sub. Motor vehicle accident / broken pole at P356 Plainfield Pike. Pole top recloser did not operate at pole 2 Simmonsville Rd due to a faulty control cable.
1/14/2019 08:09:00 AM	341.00	6	18F11 feeder lockout at Johnston Sub. Motor vehicle accident / broken pole at P356 Plainfield Pike. Pole top recloser did not operate at pole 2 Simmonsville Rd due to a faulty control cable.
1/27/2019 08:16:31 PM	224.43	9	Pole 320 Flat River Rd blown transformer fuse due to MVA / broken pole.
1/28/2019 01:26:44 AM	66.97	1241	Pole top recloser lockout at pole 149 Ten Rod Rd. MVA / broken pole at pole 11 Ten Rod Rd in Exeter, guy wire snapped and landed on conductor. Cleared guy wire and closed PTR.
2/5/2019 04:01:44 PM	8.90	417	Blown line fuse at P32 West Allenton Rd caused by car hit and broke P32 West Allenton Rd. Backfed most customers on a feeder tie, then manually opened loadbreak at P24 West Allenton Rd for repair to spacer cable wrapped onto itself.
2/5/2019 04:01:44 PM	678.48	21	Blown line fuse at P32 West Allenton Rd caused by car hit and broke P32 West Allenton Rd. Backfed most customers on a feeder tie, then manually opened loadbreak at P24 West Allenton Rd for repair to spacer cable wrapped onto itself.
2/17/2019 06:39:39 PM	186.85	64	Blown line fuse P66 Hillsdale Rd. Cause: MVA at P35 Hillsdale Rd.
2/26/2019 10:41:04 AM	54.13	1331	107W53 feeder lockout at Pawtucket #1 Sub. Trash truck hit and broke pole 48-1 School St. Isolated at pole 58 School St and backfed most customers on a feeder tie.
2/26/2019 10:41:04 AM	250.95	51	107W53 feeder lockout at Pawtucket #1 Sub. Trash truck hit and broke pole 48-1 School St. Isolated at pole 58 School St and backfed most customers on a feeder tie.
3/4/2019 03:11:46 AM	338.42	65	Blown line fuse at pole 33 Wilbur Ave. Plow hit pole 8 Hines Farm Rd. Replaced pole and refused.
3/10/2019 09:03:18 AM	55.85	17	Blown line fuse at P71 Switch Rd - broken pole at P68 Pine Hill due to MVA -
3/23/2019 11:51:23 PM	43.23	4	Blown transformer fuse P29 Arcadia Rd. Cause - MVA pole hit and broken.
3/29/2019 07:29:51 AM	29.05	1315	155F8 feeder trip and reclose at Chase Hill Sub. MVA broke riser pole 34 Ashaway Rd near the substation and damaged one of the riser disconnects, B phase dead. Manually opened the 155F8 breaker to de-energize. Picked up whole feeder on tie to 155F4.
3/29/2019 07:29:51 AM	48.22	786	155F8 feeder trip and reclose at Chase Hill Sub. MVA broke riser pole 34 Ashaway Rd near the substation and damaged one of the riser disconnects, B phase dead. Manually opened the 155F8 breaker to de-energize. Picked up whole feeder on tie to 155F4.
11/6/2018 01:44:00 PM	199.72	52	Blown line fuse at P32 Burchard Ave. Cause--MVA at P6 Sakonnet Trl resulted in phase off pin.

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Date Time	Total Duration (min)	Customer Affected	Event Description
12/1/2018 08:47:43 AM	34.02	66	Blown line fuse at pole 15 Elder Ballou Rd, blown line fuse at pole 27 Elder Ballou Rd (not shown in OMS), caused by an MVA and dislodged primary conductor at pole 36 Elder Ballou Rd.
12/1/2018 08:47:43 AM	65.30	9	Blown line fuse at pole 15 Elder Ballou Rd, blown line fuse at pole 27 Elder Ballou Rd (not shown in OMS), caused by an MVA and dislodged primary conductor at pole 36 Elder Ballou Rd.
4/5/2018 01:47:54 PM	135.80	147	Blown line fuses at P4 Boston Neck Rd. Cause was a tree branch down due to an outside tree company at P7 Indian Trail.
4/9/2018 02:48:17 PM	136.78	58	Blown line fuse pole 55 West Shore Rd - garbage truck hit low wire on Bluff Ave.
4/23/2018 02:05:58 PM	74.03	23	Blown 25k line fuse at P11 New Road. Cause: Verizon truck shook pole.
5/22/2018 12:09:17 PM	69.58	31	Blown 25k line fuse at pole 1 Central Pike. Cause - Customer hired tree crew cut down tree and it hit primary.
6/23/2018 12:24:48 PM	77.10	63	Blown line fuse at P7 Forbes St - Cause: Tree crew dropped limb on primary at P5 Leroy Dr.
6/27/2018 03:20:42 PM	79.57	2	Blown transformer fuse at P9 Laurel Lane - Cause: Non-company tree trimming.
7/24/2018 04:15:29 PM	49.52	43	Blown line fuse at P49 Tollgate Rd. Cause--tree service dropped limb at P1 Becker St.
8/3/2018 04:00:00 PM	114.00	5	Blown 1 of 3 line fuses at pole 150-10 off Nooseneck Hill Rd - backhoe got into primaries. Initially part power to 1 customer. Opened all 3 fuses at 16:00 to make repairs.
8/24/2018 11:47:53 AM	50.32	55	Blown line fuse Pole 18 Fourth St. Cause was fallen branch due to tree trimming by non-company tree service corner of Bayard & Fourth.
10/29/2018 03:44:21 PM	61.15	13	Blown 25k line fuse pole 75 Washington St. Cause was private tree crew cutting down tree at pole 2 Echo Rd.
11/21/2018 11:13:20 AM	62.73	80	Blown 1 of 3 40K line fuses at P27 Hawkins Ave. Cause--ladder fell into primary at P2 Monticello St.
12/18/2018 01:12:15 PM	66.47	473	150F4 feeder lockout at New London Ave Sub. Construction company digging damaged guy and anchor. Guy swung over A and B phase at P128 Main St. Isolated at P132 and P126 Main St for repair, picked up most customers on a feeder tie. Note: 150F4 is a new feeder and is not in GIS/OMS. Customer counts are correct, showing sections of former feeders that were affected. Note: Feeder crosses the capital/coastal boundary, so there is a second IDS event to cover the capital feeders.
12/18/2018 01:12:15 PM	66.63	68	150F4 feeder lockout at New London Ave Sub. Construction company digging damaged guy and anchor. Guy swung over A and B phase at P128 Main St. Isolated at P132 and P126 Main St for repair, picked up most customers on a feeder tie. Note: 150F4 is a new feeder and is not in GIS/OMS. Customer counts are correct, showing sections of former feeders that were affected. Note: Feeder crosses the capital/coastal boundary, so there is a second IDS event to cover the capital feeders.
12/18/2018 01:12:15 PM	95.53	1122	150F4 feeder lockout at New London Ave Sub. Construction company digging damaged guy and anchor. Guy swung over A and B phase at P128 Main St. Isolated at P132 and P126 Main St for repair, picked up most customers on a feeder tie. Note: 150F4 is a new feeder and is not in GIS/OMS. Customer counts are correct, showing sections of former feeders that were affected. Note: Feeder crosses the capital/coastal boundary, so there is a second IDS event to cover the coastal feeders.

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Date Time	Total Duration (min)	Customer Affected	Event Description
12/18/2018 01:12:15 PM	229.63	27	150F4 feeder lockout at New London Ave Sub. Construction company digging damaged guy and anchor. Guy swung over A and B phase at P128 Main St. Isolated at P132 and P126 Main St for repair, picked up most customers on a feeder tie. Note: 150F4 is a new feeder and is not in GIS/OMS. Customer counts are correct, showing sections of former feeders that were affected. Note: Feeder crosses the capital/coastal boundary, so there is a second IDS event to cover the capital feeders.
4/3/2018 08:49:37 AM	124.12	72	Blown line fuse at P14 Old Boston Neck Rd. Cause was a MVA at P1 President Dr.
4/28/2018 05:45:37 PM	110.95	6	Blown 15k transformer fuse at P108 River Rd. Caused by MVA.
5/19/2018 07:42:44 AM	89.70	22	Blown transformer fuse P30 Bayview Ave. Cause was MVA.
6/11/2018 12:30:00 AM	35.00	33	Blown line fuses (2 of 3) at P9220 West Shore Rd - Cause: MVA in vicinity of 17 Haswill St.
6/13/2018 09:54:54 AM	66.20	117	Blown line fuses (1 of 3) at P1 Old Pocasset Ln. - Cause: Garbage truck hit pole on Industrial Ln, causing phases to slap together.
6/21/2018 02:59:54 PM	214.50	16	Blown line fuse at P140 Snake Hill Rd - Cause: MVA at this location.
6/23/2018 01:10:01 AM	54.53	5	Blown transformer fuse at P43 Central St - Cause: MVA at this location.
7/1/2018 06:00:06 PM	315.18	9	Blown line fuse Pole 3 North Switch Rd at Nichols Rd due to motor vehicle accident at Pole 766 North Switch Rd.
7/27/2018 08:25:28 AM	33.87	6	Blown riser fuse at P143 West Main Rd. Cause--MVA struck P143 West Main Rd.
8/1/2018 11:00:17 AM	102.48	2	Blown line fuse at pole 392 Ten Rod Rd due to MVA at pole 1 Frosty Hollow. Garbage truck into wires.
8/7/2018 04:31:48 AM	79.38	632	Blown 140k line fuses (2 of 3) at Pole 118 Nate Whipple Hwy. Cause - Phases slapped together due to MVA at Pole 138 Nate Whipple at Quaker.
8/14/2018 12:38:17 PM	85.65	44	Blown line fuse at P123 Spring St caused by MVA at P180 Spring St.
8/26/2018 07:45:35 PM	74.77	74	Blown line fuse pole 3 Shumankanuc Hill Rd (at stepdown). Cause was MVA.
9/13/2018 10:26:14 PM	239.23	10	Blown 25K line fuse P50 Shippee School House Rd - caused was vehicle contact at P38 Shippee School House Rd.
9/19/2018 03:14:23 PM	46.18	12	Transformer cutout door fell open at P433 Cranston St. Cause--impact of MVA bumped door open. Closed in cutout.
9/28/2018 10:30:26 AM	89.98	34	Blown 1 of 3 line fuses at P418 Sakonnet Point Rd. Cause--vehicle hit line at P440 Sakonnet Point Rd.
10/5/2018 01:00:40 AM	49.43	186	Blown 65k line fuses (2 of 3) P1 Bear Hill Rd. Cause - MVA P108-84 Abbot Run Valley Rd.
12/11/2018 10:47:00 AM	74.38	147	Blown line fuse (2 of 3) at pole 12 Martin St due to motor vehicle accident at pole 16 Vincent -
12/13/2018 04:02:41 PM	198.03	2	2 of 3 blown transformer fuses at pole 3 Wentworth St - mva - no damage to pole.
12/24/2018 08:39:25 AM	57.87	11	Blown 25K line fuse at P25 Buttonwoods Ave. Caused by vehicle contact at P25-84 Buttonwoods Ave.
12/26/2018 12:25:39 PM	69.35	6	Blown 15K line fuse at P186 Taunton Ave. Cause was truck hitting cable wire and flipping it up over our triplex.
1/17/2019 01:03:53 PM	202.92	5	Blown pad transformer fuse at Pad 46 High Hawk Rd. At 985 High Hawk Rd, electrician pulled meter and socket flashed. Non-company activities.
2/2/2019 09:21:17 AM	39.42	83	Blown line fuse at P1 Benedict Rd due to a tree branch dropped by a tree crew at P17 Benedict Rd.
2/12/2019 02:32:13 PM	83.35	49	Blown line fuse at P5 Phillips St. Cause: possible private tree crew dropped branch.
1/4/2019 05:57:53 AM	62.17	3	Blown transformer fuse at P26 Hartford Pike due to a motor vehicle accident at P26 Hartford Pike.
1/15/2019 02:38:40 PM	122.20	3	2 of 3 blown line fuses at P9 Dexter Rd caused by vehicle hitting P9-1 causing conductors to slap together.

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Date Time	Total Duration (min)	Customer Affected	Event Description
1/23/2019 08:53:42 PM	19.25	238	14F3 feeder lockout at Drumrock Sub. 14F4 feeder trip and reclose. Cause was RI State crews boom truck equipment made contact P33 Centerville Rd (at I-95). Note: customer count reduced because most of this feeder was moved to new feeder 150F2 and GIS is not up to date yet.
2/26/2019 04:10:42 PM	70.98	52	6J3 feeder lockout at Olneyville Sub. Cause was hit and run MVA at P7 R/W, truck bumped pole and slapped phases together.
3/3/2019 07:27:55 PM	98.22	18	Car knocked meter off house. Tman able to repair old meter an make work for tonight. Will need electrician to check out.
5/9/2018 01:35:56 PM	219.15	9	Failed transformer P127 Great Rd caused by vehicle ripping service from 1072 Great Rd.
6/6/2018 04:04:08 PM	256.30	49	Blown transformer fuse at P10 Wisdom Ave - Cause: Failed transformer due to MVA at this location.
9/13/2018 02:34:41 PM	227.07	2	Manually opened riser fuse at P2 Douglas Hook Rd to replace pad mount transformer. Caused by vehicle damage. Customer still has no power - waiting for electrician to pull wire.
4/3/2018 04:06:02 PM	209.73	32	Blown transformer fuse at Pad 1164 Governor St. Cause was a dig in on secondary cable by a non-company contractor near Pad 1164 Governor St.
4/11/2018 08:33:57 AM	181.08	16	Blown riser fuse at pole 47 South Rd due to outside company dig in between pads 97 Dewberry and pad 3 Gentian.
10/30/2018 12:40:39 PM	649.65	2	Loss of service to 1 & 21 Regal Way. Caused by dig in at HH #3 from transformer pad 4 on Regal Way.
11/8/2018 11:10:00 AM	181.00	17	Blown riser fuse at pole 12 Harris Rd - dig in to URD cable between pole 12 and pad 1.

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Date Time	Total Duration (min)	Customer Affected	Event Description
6/24/2016 05:30:59 PM	449.02	8	38F5 circuit breaker locked out at Putnam Pike Sub. Cause: MVA/broken pole at P355 Greenville Ave.
7/7/2016 07:08:46 PM	158.23	104	Blown 2 of 2 line fuses at P337 Putnam Pike. Cause - MVA at P15 Chestnut Hill.
7/8/2016 02:45:46 PM	359.23	42	Blown 40k line fuse P445 Post Road. Cause: MVA broken pole 445 Post Road.
7/11/2016 08:29:39 AM	92.35	15	Blown line fuse at P91 Sharpe St at Weaver Hill Rd - due to town brush trimming - hit P91 with bucket.
7/13/2016 10:52:01 AM	68.98	13	Blown transformer fuse at P1 Dinsdale Ct due to vehicle hitting P1 Disnsdale Ct.
7/14/2016 08:27:31 AM	41.85	206	Pole top recloser lockout at pole 183 Putnam Pike, Smithfield. Cause: MVA with broken pole @ pole 24 Putnam Pike, Gloucester. Isolated between pole 2 and pole 36 Putnam Pike and restored most customers on 45F2.
7/14/2016 08:27:31 AM	49.23	1147	Pole top recloser lockout at pole 183 Putnam Pike, Smithfield. Cause: MVA with broken pole @ pole 24 Putnam Pike, Gloucester. Isolated between pole 2 and pole 36 Putnam Pike and restored most customers on 45F2.
7/14/2016 08:27:31 AM	77.77	313	Pole top recloser lockout at pole 183 Putnam Pike, Smithfield. Cause: MVA with broken pole @ pole 24 Putnam Pike, Gloucester. Isolated between pole 2 and pole 36 Putnam Pike and restored most customers on 45F2.
7/20/2016 01:31:51 AM	38.73	1591	Blown line fuse pole 511 East Main Rd. Car on fire at P511 East Main Rd due to MVA with broken pole. Manually opened 36W41 circuit breaker at Dexter Sub via SCADA to make safe, backfed from other feeders.
7/20/2016 01:31:51 AM	57.78	260	Blown line fuse pole 511 East Main Rd. Car on fire at P511 East Main Rd due to MVA with broken pole. Manually opened 36W41 circuit breaker at Dexter Sub via SCADA to make safe, backfed from other feeders.
7/20/2016 01:31:51 AM	99.92	122	Blown line fuse pole 511 East Main Rd. Car on fire at P511 East Main Rd due to MVA with broken pole. Manually opened 36W41 circuit breaker at Dexter Sub via SCADA to make safe, backfed from other feeders.
7/20/2016 01:31:51 AM	227.62	90	Blown line fuse pole 511 East Main Rd. Car on fire at P511 East Main Rd due to MVA with broken pole. Manually opened 36W41 circuit breaker at Dexter Sub via SCADA to make safe, backfed from other feeders.
8/5/2016 08:27:31 AM	127.48	13	Blown 10k transformer fuse at P12 Parker St. Cause was an MVA that also took off arm on pole.
8/9/2016 11:26:42 AM	48.30	1007	Background info: 3309 line locked out at Kent County Sub causing loss of supply to 100F1 at Tiogue Ave Sub. Remotely switched 100F1 to alternate feeder supply by opening feeder breaker and closing tie PTR at pole 106 Nooseneck Rd. This event: Pole top recloser @ P7 Hopkins Hill Rd locked out on 63F4 feeder. Cause: fire truck struck guy wire at Intersection of Tiogue Ave and Hopkins Hill Rd sending it up and wrapping around the 34kv (3309 Kent County Sub) and 12kv (63F4 from Hopkins Hill Sub). See other IDS event for 100F1 customers affected.
8/9/2016 11:26:42 AM	77.58	240	Background info: 3309 line locked out at Kent County Sub causing loss of supply to 100F1 at Tiogue Ave Sub. Remotely switched 100F1 to alternate feeder supply by opening feeder breaker and closing tie PTR at pole 106 Nooseneck Rd. This event: Pole top recloser @ P7 Hopkins Hill Rd locked out on 63F4 feeder. Cause: fire truck struck guy wire at Intersection of Tiogue Ave and Hopkins Hill Rd sending it up and wrapping around the 34kv (3309 Kent County Sub) and 12kv (63F4 from Hopkins Hill Sub). See other IDS event for 100F1 customers affected.
8/14/2016 08:42:42 PM	81.98	791	Pole top recloser at P204 Danielson Pike locked out due to an MVA/broken pole at P64 Danielson Pike. Lifted taps at pole 65 Danieldson Pike while pole was replaced.
8/14/2016 08:42:42 PM	229.57	84	Pole top recloser at P204 Danielson Pike locked out due to an MVA/broken pole at P64 Danielson Pike. Lifted taps at pole 65 Danieldson Pike while pole was replaced.
8/14/2016 08:42:42 PM	471.30	7	Pole top recloser at P204 Danielson Pike locked out due to an MVA/broken pole at P64 Danielson Pike. Lifted taps at pole 65 Danieldson Pike while pole was replaced.
8/25/2016 06:59:23 PM	85.62	158	Blown 40k line fuse at pole 294 Main St due to MVA at pole 7 Perkins St.
8/28/2016 12:42:15 PM	96.75	11	Line fuse door knocked open at P63 Fairview Ave due to MVA.
8/29/2016 12:56:15 PM	40.75	33	Blown tranformer fuse P4 Schiller St due to motor vehicle accident.
9/1/2016 06:25:51 PM	25.77	1896	112W41 feeder lockout at Staples Sub. Broken pole @ P15 Manville Hill Rd - MVA
9/2/2016 01:00:44 AM	374.27	7	Blown transformer fuse at P20 Commonwealth Ave due to an MVA with broken pole at P20 Commonwealth Ave.
9/2/2016 06:27:08 AM	87.87	186	Blown 65k line fuse P275 East Rd. Cause was a motor vehicle accident P223 East Rd.
9/2/2016 03:15:43 PM	21.28	35	Pole top recloser at pole 2 Eagleville Rd locked out due to MVA at pole 12 Eagleville Rd. Picked up most customers on tie to 33F4, made airgap at pole 28 for additional restoration. Had to de-energize a section again later to put the taps back on.
9/2/2016 03:15:43 PM	62.98	1335	Pole top recloser at pole 2 Eagleville Rd locked out due to MVA at pole 12 Eagleville Rd. Picked up most customers on tie to 33F4, made airgap at pole 28 for additional restoration. Had to de-energize a section again later to put the taps back on.
9/2/2016 03:15:43 PM	127.28	35	Pole top recloser at pole 2 Eagleville Rd locked out due to MVA at pole 12 Eagleville Rd. Picked up most customers on tie to 33F4, made airgap at pole 28 for additional restoration. Had to de-energize a section again later to put the taps back on.
9/2/2016 03:15:43 PM	365.57	8	Pole top recloser at pole 2 Eagleville Rd locked out due to MVA at pole 12 Eagleville Rd. Picked up most customers on tie to 33F4, made airgap at pole 28 for additional restoration. Had to de-energize a section again later to put the taps back on.

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Date Time	Total Duration (min)	Customer Affected	Event Description
9/2/2016 11:45:01 PM	32.68	2380	26W5 feeder lockout at Woonsocket Sub and pole top recloser lockout at pole 3-1 St Paul St. MVA caused broken pole at pole 6 St Paul St.
9/2/2016 11:45:01 PM	297.15	368	26W5 feeder lockout at Woonsocket Sub and pole top recloser lockout at pole 3-1 St Paul St. MVA caused broken pole at pole 6 St Paul St.
9/11/2016 11:25:11 PM	60.82	2	2 of 3 blown line fuses pole 9014 Phenix Ave due to MVA.
9/12/2016 07:53:00 AM	45.00	177	Blown 1 of 3 line fuses 100K at pole 1 Franklin St due to an MVA at pole 23 Chapel st - phase off insulator.
9/13/2016 12:01:45 PM	57.25	16	Blown 25k line fuse P9 Church St. Cause MVA P3 Tilton St. Crew replaced transformer at P3 Tilton St.
9/13/2016 12:01:45 PM	377.25	4	Blown 25k line fuse P9 Church St. Cause MVA P3 Tilton St. Crew replaced transformer at P3 Tilton St.
9/21/2016 10:10:18 PM	114.70	11	Blonw line fuse - failed cutout at P114 Cottage St due to motor vehicle accident.
10/2/2016 03:18:00 PM	208.00	3	Failed service connectors 893 Hartford Pike due to motor vehicle accident.
10/2/2016 04:40:17 PM	68.72	32	Blown line fuse P28 Narragansett Bay Ave due to motor vehicle contact.
10/4/2016 08:29:00 AM	58.00	73	Blown 1 of 3 line fuses at P6 Babcock St due to a truck taking down wires and breaking pole at P2 Verndale Ave.
10/4/2016 08:29:00 AM	78.00	22	Blown 1 of 3 line fuses at P6 Babcock St due to a truck taking down wires and breaking pole at P2 Verndale Ave.
10/5/2016 12:36:00 AM	456.00	13	Blown transformer fuse at P88 River Ave due to an MVA/broken pole and damaged transformer at P88 River Ave.
10/29/2016 10:36:55 PM	193.08	131	Blown 65K line fuse @ P434 Stafford Rd - MVA with broken pole @ P4 Hancock -
10/31/2016 08:56:16 AM	1128.73	51	Blown line (riser) fuses P3 Village Rd due to failed padmount transformer 3-31 Village Rd via motor vehicle accident.
11/1/2016 01:32:09 PM	47.85	16	Blown line fuse P28 Daggett Ave. Cause: truck took down primary.
11/3/2016 10:58:16 AM	40.73	4	2222 and 2224 lines locked out at Drumrock Sub, 87F5 feeder tripped at reclosed at Kilvert St Sub. Cause was MVA with broken pole at pole 9320 Main Ave. Warwick Sub transferred OK - did switching to restore 23kV customers. Before repairs could be initiated, 87F5 locked out - see other IDS event.
11/3/2016 10:58:16 AM	61.77	2	2222 and 2224 lines locked out at Drumrock Sub, 87F5 feeder tripped at reclosed at Kilvert St Sub. Cause was MVA with broken pole at pole 9320 Main Ave. Warwick Sub transferred OK - did switching to restore 23kV customers. Before repairs could be initiated, 87F5 locked out - see other IDS event.
11/3/2016 11:09:05 AM	32.68	234	87F5 feeder lockout at Kilvert St Sub. MVA/broken pole at pole 9320 Main Ave in Warwick. Isolated at pole 29 Chapman Ave and closed breaker. Note: 87F5 is not in GIS yet. 87F5 comprises parts of 14F2 and 87F3 feeder. Note: 2224 and 2222 lines had locked out earlier - see other IDS event.
11/3/2016 11:09:05 AM	43.82	622	87F5 feeder lockout at Kilvert St Sub. MVA/broken pole at pole 9320 Main Ave in Warwick. Isolated at pole 29 Chapman Ave and closed breaker. Note: 87F5 is not in GIS yet. 87F5 comprises parts of 14F2 and 87F3 feeder. Note: 2224 and 2222 lines had locked out earlier - see other IDS event.
11/3/2016 11:09:05 AM	75.10	544	87F5 feeder lockout at Kilvert St Sub. MVA/broken pole at pole 9320 Main Ave in Warwick. Isolated at pole 29 Chapman Ave and closed breaker. Note: 87F5 is not in GIS yet. 87F5 comprises parts of 14F2 and 87F3 feeder. Note: 2224 and 2222 lines had locked out earlier - see other IDS event.
11/10/2016 12:28:54 AM	82.30	90	Blown 2 of 3 65k line fuses at P556 Putnam Pike caused by a MVA/broken pole at P570 Putnam Pike.
11/10/2016 10:00:39 AM	110.35	22	Blown line fuse at P27 Cowesett Ave due to a tractor getting caught in phone lines and shaking the pole at P1 High View Dr.
11/19/2016 01:26:09 AM	121.85	3	Blown line fuse - MVA @ P67 Perry Hill Rd - Pole is OK.
11/29/2016 10:02:30 PM	162.50	2	Blown line fuse at Pole 20 Ten Rod Rd, Exeter - MVA/broken pole at pole 20 Ten Rod Rd -
12/11/2016 10:10:16 PM	26.47	664	87F5 feeder trip and reclose at Kilvert St Sub. Blown line fuse at pole 9307 Main Ave due to MVA and broken pole. Had to de-energize portion of 87F5 from pole 9312 to pole 9293 Main Ave to make temporary repairs. Also double circuit with 2224 line; 23kV customers switched out to tie with no interruption. Note: 87F5 doesn't exist yet in GIS, customers show on 87F3 feeder.
12/11/2016 10:10:16 PM	228.73	42	87F5 feeder trip and reclose at Kilvert St Sub. Blown line fuse at pole 9307 Main Ave due to MVA and broken pole. Had to de-energize portion of 87F5 from pole 9312 to pole 9293 Main Ave to make temporary repairs. Also double circuit with 2224 line; 23kV customers switched out to tie with no interruption. Note: 87F5 doesn't exist yet in GIS, customers show on 87F3 feeder.

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Date Time	Total Duration (min)	Customer Affected	Event Description
12/30/2016 03:55:28 PM	33.83	391	107W43 feeder lockout at Pawtucket #1 Sub, also loss of supply to Centre St Sub. Report of MVA at pole 47 Pine St, 2 broken insulators, phases on crossarm. Isolated with pole top recloser at pole 8 Barton St and disconnects at pole 49-1 Pine St. Picked up tail end of 107W43 feeder on 102W52. Closed 107W43 breaker at Sub, restoring Centre St Sub. Began repairs. At 17:15, 107W43 feeder locked out at Pawtucket #1 Sub, and 106J1 feeder locked out at Centre St Sub. Investigating flash, found wires down at pole 5 Conant St, double circuit with 107W43/106J1. Isolated 107W43 with disconnects at pole 6 Conant St, picked up most of 107W43 and 2 feeders at Centre St Sub on tie to 107W51. When repairs complete, closed 107W43. 106J1 breaker would not close, picked up customers on tie to 106J7. Mutliple meters replaced in vicinity of Conant St fault, likely due to transient overvoltage condition. **106J1 would not close - found control circuit fuse blown and fixed. **Post event analysis indicates part power and no power calls from Centre St and on 107W43 continued after 107W43 breaker was closed the first time, indicating a phase was down on Conant St, possibly due to fault current from the initial MVA.
12/30/2016 03:55:28 PM	34.45	1788	107W43 feeder lockout at Pawtucket #1 Sub, also loss of supply to Centre St Sub. Report of MVA at pole 47 Pine St, 2 broken insulators, phases on crossarm. Isolated with pole top recloser at pole 8 Barton St and disconnects at pole 49-1 Pine St. Picked up tail end of 107W43 feeder on 102W52. Closed 107W43 breaker at Sub, restoring Centre St Sub. Began repairs. At 17:15, 107W43 feeder locked out at Pawtucket #1 Sub, and 106J1 feeder locked out at Centre St Sub. Investigating flash, found wires down at pole 5 Conant St, double circuit with 107W43/106J1. Isolated 107W43 with disconnects at pole 6 Conant St, picked up most of 107W43 and 2 feeders at Centre St Sub on tie to 107W51. When repairs complete, closed 107W43. 106J1 breaker would not close, picked up customers on tie to 106J7. Mutliple meters replaced in vicinity of Conant St fault, likely due to transient overvoltage condition. **106J1 would not close - found control circuit fuse blown and fixed. **Post event analysis indicates part power and no power calls from Centre St and on 107W43 continued after 107W43 breaker was closed the first time, indicating a phase was down on Conant St, possibly due to fault current from the initial MVA.
12/30/2016 03:55:28 PM	52.20	2305	107W43 feeder lockout at Pawtucket #1 Sub, also loss of supply to Centre St Sub. Report of MVA at pole 47 Pine St, 2 broken insulators, phases on crossarm. Isolated with pole top recloser at pole 8 Barton St and disconnects at pole 49-1 Pine St. Picked up tail end of 107W43 feeder on 102W52. Closed 107W43 breaker at Sub, restoring Centre St Sub. Began repairs. At 17:15, 107W43 feeder locked out at Pawtucket #1 Sub, and 106J1 feeder locked out at Centre St Sub. Investigating flash, found wires down at pole 5 Conant St, double circuit with 107W43/106J1. Isolated 107W43 with disconnects at pole 6 Conant St, picked up most of 107W43 and 2 feeders at Centre St Sub on tie to 107W51. When repairs complete, closed 107W43. 106J1 breaker would not close, picked up customers on tie to 106J7. Mutliple meters replaced in vicinity of Conant St fault, likely due to transient overvoltage condition. **106J1 would not close - found control circuit fuse blown and fixed. **Post event analysis indicates part power and no power calls from Centre St and on 107W43 continued after 107W43 breaker was closed the first time, indicating a phase was down on Conant St, possibly due to fault current from the initial MVA.
12/30/2016 03:55:28 PM	58.67	79	107W43 feeder lockout at Pawtucket #1 Sub, also loss of supply to Centre St Sub. Report of MVA at pole 47 Pine St, 2 broken insulators, phases on crossarm. Isolated with pole top recloser at pole 8 Barton St and disconnects at pole 49-1 Pine St. Picked up tail end of 107W43 feeder on 102W52. Closed 107W43 breaker at Sub, restoring Centre St Sub. Began repairs. At 17:15, 107W43 feeder locked out at Pawtucket #1 Sub, and 106J1 feeder locked out at Centre St Sub. Investigating flash, found wires down at pole 5 Conant St, double circuit with 107W43/106J1. Isolated 107W43 with disconnects at pole 6 Conant St, picked up most of 107W43 and 2 feeders at Centre St Sub on tie to 107W51. When repairs complete, closed 107W43. 106J1 breaker would not close, picked up customers on tie to 106J7. Mutliple meters replaced in vicinity of Conant St fault, likely due to transient overvoltage condition. **106J1 would not close - found control circuit fuse blown and fixed. **Post event analysis indicates part power and no power calls from Centre St and on 107W43 continued after 107W43 breaker was closed the first time, indicating a phase was down on Conant St, possibly due to fault current from the initial MVA.
12/30/2016 03:55:28 PM	69.42	132	107W43 feeder lockout at Pawtucket #1 Sub, also loss of supply to Centre St Sub. Report of MVA at pole 47 Pine St, 2 broken insulators, phases on crossarm. Isolated with pole top recloser at pole 8 Barton St and disconnects at pole 49-1 Pine St. Picked up tail end of 107W43 feeder on 102W52. Closed 107W43 breaker at Sub, restoring Centre St Sub. Began repairs. At 17:15, 107W43 feeder locked out at Pawtucket #1 Sub, and 106J1 feeder locked out at Centre St Sub. Investigating flash, found wires down at pole 5 Conant St, double circuit with 107W43/106J1. Isolated 107W43 with disconnects at pole 6 Conant St, picked up most of 107W43 and 2 feeders at Centre St Sub on tie to 107W51. When repairs complete, closed 107W43. 106J1 breaker would not close, picked up customers on tie to 106J7. Mutliple meters replaced in vicinity of Conant St fault, likely due to transient overvoltage condition. **106J1 would not close - found control circuit fuse blown and fixed. **Post event analysis indicates part power and no power calls from Centre St and on 107W43 continued after 107W43 breaker was closed the first time, indicating a phase was down on Conant St, possibly due to fault current from the initial MVA.

FY2017

Date Time	Total Duration (min)	Customer Affected	Event Description
12/30/2016 03:55:28 PM	82.32	570	107W43 feeder lockout at Pawtucket #1 Sub, also loss of supply to Centre St Sub. Report of MVA at pole 47 Pine St, 2 broken insulators, phases on crossarm. Isolated with pole top recloser at pole 8 Barton St and disconnects at pole 49-1 Pine St. Picked up tail end of 107W43 feeder on 102W52. Closed 107W43 breaker at Sub, restoring Centre St Sub. Began repairs. At 17:15, 107W43 feeder locked out at Pawtucket #1 Sub, and 106J1 feeder locked out at Centre St Sub. Investigating flash, found wires down at pole 5 Conant St, double circuit with 107W43/106J1. Isolated 107W43 with disconnects at pole 6 Conant St, picked up most of 107W43 and 2 feeders at Centre St Sub on tie to 107W51. When repairs complete, closed 107W43. 106J1 breaker would not close, picked up customers on tie to 106J7. Mutliple meters replaced in vicinity of Conant St fault, likely due to transient overvoltage condition. **106J1 would not close - found control circuit fuse blown and fixed. **Post event analysis indicates part power and no power calls from Centre St and on 107W43 continued after 107W43 breaker was closed the first time, indicating a phase was down on Conant St, possibly due to fault current from the initial MVA.
12/30/2016 03:55:28 PM	114.58	585	107W43 feeder lockout at Pawtucket #1 Sub, also loss of supply to Centre St Sub. Report of MVA at pole 47 Pine St, 2 broken insulators, phases on crossarm. Isolated with pole top recloser at pole 8 Barton St and disconnects at pole 49-1 Pine St. Picked up tail end of 107W43 feeder on 102W52. Closed 107W43 breaker at Sub, restoring Centre St Sub. Began repairs. At 17:15, 107W43 feeder locked out at Pawtucket #1 Sub, and 106J1 feeder locked out at Centre St Sub. Investigating flash, found wires down at pole 5 Conant St, double circuit with 107W43/106J1. Isolated 107W43 with disconnects at pole 6 Conant St, picked up most of 107W43 and 2 feeders at Centre St Sub on tie to 107W51. When repairs complete, closed 107W43. 106J1 breaker would not close, picked up customers on tie to 106J7. Mutliple meters replaced in vicinity of Conant St fault, likely due to transient overvoltage condition. **106J1 would not close - found control circuit fuse blown and fixed. **Post event analysis indicates part power and no power calls from Centre St and on 107W43 continued after 107W43 breaker was closed the first time, indicating a phase was down on Conant St, possibly due to fault current from the initial MVA.
12/30/2016 03:55:28 PM	162.45	206	107W43 feeder lockout at Pawtucket #1 Sub, also loss of supply to Centre St Sub. Report of MVA at pole 47 Pine St, 2 broken insulators, phases on crossarm. Isolated with pole top recloser at pole 8 Barton St and disconnects at pole 49-1 Pine St. Picked up tail end of 107W43 feeder on 102W52. Closed 107W43 breaker at Sub, restoring Centre St Sub. Began repairs. At 17:15, 107W43 feeder locked out at Pawtucket #1 Sub, and 106J1 feeder locked out at Centre St Sub. Investigating flash, found wires down at pole 5 Conant St, double circuit with 107W43/106J1. Isolated 107W43 with disconnects at pole 6 Conant St, picked up most of 107W43 and 2 feeders at Centre St Sub on tie to 107W51. When repairs complete, closed 107W43. 106J1 breaker would not close, picked up customers on tie to 106J7. Mutliple meters replaced in vicinity of Conant St fault, likely due to transient overvoltage condition. **106J1 would not close - found control circuit fuse blown and fixed. **Post event analysis indicates part power and no power calls from Centre St and on 107W43 continued after 107W43 breaker was closed the first time, indicating a phase was down on Conant St, possibly due to fault current from the initial MVA.
12/30/2016 03:55:28 PM	245.53	43	107W43 feeder lockout at Pawtucket #1 Sub, also loss of supply to Centre St Sub. Report of MVA at pole 47 Pine St, 2 broken insulators, phases on crossarm. Isolated with pole top recloser at pole 8 Barton St and disconnects at pole 49-1 Pine St. Picked up tail end of 107W43 feeder on 102W52. Closed 107W43 breaker at Sub, restoring Centre St Sub. Began repairs. At 17:15, 107W43 feeder locked out at Pawtucket #1 Sub, and 106J1 feeder locked out at Centre St Sub. Investigating flash, found wires down at pole 5 Conant St, double circuit with 107W43/106J1. Isolated 107W43 with disconnects at pole 6 Conant St, picked up most of 107W43 and 2 feeders at Centre St Sub on tie to 107W51. When repairs complete, closed 107W43. 106J1 breaker would not close, picked up customers on tie to 106J7. Mutliple meters replaced in vicinity of Conant St fault, likely due to transient overvoltage condition. **106J1 would not close - found control circuit fuse blown and fixed. **Post event analysis indicates part power and no power calls from Centre St and on 107W43 continued after 107W43 breaker was closed the first time, indicating a phase was down on Conant St, possibly due to fault current from the initial MVA.
4/3/2016 03:19:00 AM	114.00	3	3 smashed meters from vandalism, address 105 State St.
2/16/2017 04:25:00 PM	87.00	2	19 Water St, electrician damaged meters at this location, tman had to replace meters.
1/3/2017 09:32:09 AM	199.00	6	2 blown line fuses P469 Mendon Rd. Manually opened 3rd line fuse at 1015. All 3 Phase Customers. Transformer at P471 out for duration of outage. Cause - MVA with broken pole at P471.
1/3/2017 09:32:09 AM	241.85	12	2 blown line fuses P469 Mendon Rd. Manually opened 3rd line fuse at 1015. All 3 Phase Customers. Transformer at P471 out for duration of outage. Cause - MVA with broken pole at P471.
1/14/2017 10:21:31 PM	231.48	7	Blown line fuse at P219 Tower Hill Rd caused by MVA at P219Tower Hill Rd. Pole was replaced.
1/18/2017 10:59:00 AM	57.00	202	Blown 1 of 3 line fuses (B phase) at P18-2 Tower Hill Rd. Manually opened 2 of 3 line fuses (AC phases) at P18-2 Tower Hill Rd at 12:10. Cause was MVA at P13 Bridgetown Rd.

FY2017

Date Time	Total Duration (min)	Customer Affected	Event Description
1/18/2017 10:59:00 AM	128.00	167	Blown 1 of 3 line fuses (B phase) at P18-2 Tower Hill Rd. Manually opened 2 of 3 line fuses (AC phases) at P18-2 Tower Hill Rd at 12:10. Cause was MVA at P13 Bridgetown Rd.
1/29/2017 01:38:36 AM	48.00	122	Blown 1 of 3 stepdown fuses (B phase) at P49 York Ave. Manually opened other 2 line fuses at P49 York Ave at 2:12. Blown 3 of 3 transformer fuses at P1 State St. Cause was a MVA at P1 State St. Pole and transformer were down.
1/29/2017 01:38:36 AM	81.40	98	Blown 1 of 3 stepdown fuses (B phase) at P49 York Ave. Manually opened other 2 line fuses at P49 York Ave at 2:12. Blown 3 of 3 transformer fuses at P1 State St. Cause was a MVA at P1 State St. Pole and transformer were down.
1/31/2017 09:42:18 AM	117.70	3	Broken meters and sockets at 49 Marietta St apartments 1FR, 2FR and 3FR. Cause was a truck backed into meters at 49 Marietta St. Customer will need electrician as well.
2/2/2017 11:53:14 PM	86.77	41	1 of 3 (B phase) blown line fuses at P154 Ocean Rd. Cause - MVA at P1 Angell Rd.
2/4/2017 07:57:00 AM	103.00	6	Blown transformer fuse pole 272-2 West Shore Rd - 25k - car hit guy wire.
2/10/2017 10:30:00 AM	306.00	2	Blown transformer fuse P37 Prosser Trl - caused by MVA/broken pole.
2/11/2017 01:12:26 AM	159.57	57	Blown line fuse at P12 John St--cause was MVA at P4 Angelico St.
2/11/2017 01:18:48 AM	286.20	14	Blown 1 of 3 15K line fuses at P15-1 Ralco Way--cause was MVA at P4 Carpenter St, broken pole.
2/12/2017 10:28:52 PM	92.00	81	Blown line fuse at P25 Smithfield Rd due to an MVA. Also opened transformer fuse briefly at P28 Smithfield Rd. Cause--replaced broken P25 Smithfield Rd.
2/12/2017 10:28:52 PM	495.13	24	Blown line fuse at P25 Smithfield Rd due to an MVA. Also opened transformer fuse briefly at P28 Smithfield Rd. Cause--replaced broken P25 Smithfield Rd.
3/1/2017 10:55:34 AM	30.43	50	6J3 feeder lockout at Olneyville Sub. Cause: MVA P8 Hartford Ave, phases made contact with each other, pole OK.
3/5/2017 07:45:15 AM	17.18	2596	126W41 feeder locked out at Washington Sub. MVA at P382 Mendon Rd in Cumberland caused phases to slap together. Checked safe and closed breaker via SCADA.
3/5/2017 09:37:00 AM	178.00	14	Blown 25K line fuse at P41 Whipple Rd. Cause--MVA hit and broke P55 Whipple Rd.
3/7/2017 04:52:15 PM	60.30	599	Airbreak at P37 Rose Hill Rd knocked open as a result of a MVA striking and breaking this pole. Isolated and backfed customers from 59F2 and 88F3 feeders.
3/7/2017 04:52:15 PM	83.85	263	Airbreak at P37 Rose Hill Rd knocked open as a result of a MVA striking and breaking this pole. Isolated and backfed customers from 59F2 and 88F3 feeders.
3/7/2017 04:52:15 PM	123.43	149	Airbreak at P37 Rose Hill Rd knocked open as a result of a MVA striking and breaking this pole. Isolated and backfed customers from 59F2 and 88F3 feeders.
3/8/2017 08:38:00 PM	540.00	74	Blown line fuse P49 Park Ave. Cause--MVA hit and broke P48 Park Ave. Replaced junction pole.
3/11/2017 10:49:51 AM	96.15	5	Blown 6K transformer fuse at P3 Bay Rd. Cause--vehicle hit service line to house 8 Bay Rd.
3/12/2017 03:09:00 AM	152.00	4	Blown transformer fuse at P114 Woodville Alton Rd. Cause--MVA.
3/14/2017 11:20:37 AM	90.08	234	Pole top recloser locked out at pole 159 Waterman Ave. 1 operation, did not reclose. PTR would not close - closed shunt loadbreak to restore customers. Plow possible hit pole. Nor'easter.
3/25/2017 01:17:00 AM	103.00	33	Broken line cutout at P18 Matunuck School House Rd. Cause--MVA at P18 Matunuck School House Rd.
3/29/2017 02:37:03 PM	76.95	13	Blown transformer fuse P1-50 David St, cause MVA - truck backed into guy wire and cutout dropped open.
3/31/2017 10:56:38 PM	55.38	740	34F3 feeder lockout at Chopmist Sub - Broken pole @ P220 Hartford Pk - MVA. Fuses at pole 191 Hartford Turnpike did not blow. Opened 3-100K fuses, closed breaker to restore service to most customers.
3/31/2017 10:56:38 PM	107.80	59	34F3 feeder lockout at Chopmist Sub - Broken pole @ P220 Hartford Pk - MVA. Fuses at pole 191 Hartford Turnpike did not blow. Opened 3-100K fuses, closed breaker to restore service to most customers.
3/31/2017 10:56:38 PM	579.37	31	34F3 feeder lockout at Chopmist Sub - Broken pole @ P220 Hartford Pk - MVA. Fuses at pole 191 Hartford Turnpike did not blow. Opened 3-100K fuses, closed breaker to restore service to most customers.

R-I-15

Request:

Referencing Section 2, page 17; The Company states that projects over $1.0 million require a Project Sanctioning Paper (PSP). Further, the Project Development group writes the PSP for complex projects that have a complexity score of 19 or greater, while the project sponsor writes the PSP for non-complex projects, or those with a complexity score of 18 or lower:

a. Provide additional information on how the Company derives a complexity score, including the risk factors evaluated.
b. Describe the differences in the PSP required for complex vs. non-complex projects.
c. Describe how the PSP process differs from that described in previous ISR filings.
d. Describe the anticipated impacts to ISR budget estimates due to any changes.

Response:

a. The Company scores each project based on nine separate factors detailed below. Each factor is given a 1, 2 or 3 [lower complexity to higher] and added up to determine overall complexity:
   - Cost – Projects are scored on a scale based on three thresholds >$8M, <$8M/>$1M and <$1M. Projects with greater costs are scored higher. It is understood that lower costs does not always equal lower complexity, which is why there are more factors considered as detailed below.
   - Project Components – If the project has multiple components to be installed, then the project receives a higher complexity score.
   - Outage Requirements – Assets requiring significant outage coordination are scored higher. A scoring matrix was developed to capture and rank issues such as a mobile substation requirement, if customer outages needed, if circuit cut overs are required, and if critical service lines are affected.
   - Duration – The duration component is scored differently depending upon if the project is on a company standard driven timeline or customer (internal or external) driven timeline.

     - Standard company timeline driven projects are scored higher if there is an overall longer duration of the project timeline which would include large projects with significant spend over multiple years.
     - Customer Drive Projects are scored higher if there is a timeline compression needed to meet an internal or external deliverable requiring exceptions and waivers to the standard company processes and procedures.

R-I-15, page 2

- Stakeholder Management – Projects that require significant involvement managing customers, area residents, local / federal governments and communities with significant vocal interest are scored higher.
- Asset Complexity – A matrix was developed to determine the overall complexity of the project based on assets being replaced or added. For example, a project which requires the replacement of one asset with the exact same type (i.e. one-to-one replacement) is scored lower than the expansion of a substation with new equipment.
- Land Rights – Projects requiring land rights that involve the Company’s Real Estate Department are scored higher than projects that do not have land rights issues.
- Permits – Permitting is scored on three levels. The lowest is a project that either requires existing permits to be utilized or requires no permits. The next level is projects that require permitting, which is done on a regular basis by the Company. The highest score is given to projects requiring significant permitting and legal representation.
- Procurement – Material /Labor Procurement is scored on three levels. The lowest is a project that only requires Stock material, which can be obtained from the Company’s local stores, and labor being performed by local resources or existing contractor agreements. The next level is projects requiring non-stock material, which have short duration timelines to obtain. The highest score is given to projects requiring unique material bids and labor contracts of significant value.

b. The project sanction paper process does not change dependent upon complex vs. non-complex. The process only changes dependent on overall costs, as detailed below.
    - <$1M – Electronic DOA [no sanction paper]
    - <$8M->$1M – Short form sanction process
    - <$25M-$>8M – Long form sanction, full United States Sanction Committee (USSC) Process
    - >$25M – Long form sanction, USSC Approval and Senior Executive Sanction Committee (SESC) approval

It is more likely that a complex project would require moving through the higher costs sanctioning process, but it is not a rule. There could be a high cost non-complex project depending upon overall score.

R-I-15, page 3

c. The project sanction process differs from the previous ISR filings based on the timing of the Project Sanction. The new Complex Capital Delivery process requires Project Sanction after preliminary engineering has been completed. The old process required Project Sanction after final design was completed and final contractor bids were received. In addition, the new Complex Capital Delivery process aims to reduce or eliminate partial sanctions.

d. There are no major anticipated impacts as to how the ISR budget estimates are set due to the timing of the Project Sanction Paper. The new Complex Capital Delivery process will improve the visibility and reasons for changes in projects cost.

R-I-16

Request:

Referencing Section 2, page 21:

a. Explain the Company's refined definitions for Damage/Failure and Asset Replacement work, and how the refined definitions resulted in a $1 million reduction in the Damage/Failure blanket work.

b. Does the Company anticipate that the $1 million reduction in the Damage/Failure blanket budget represents work that will not be completed, will be deferred, or will be completed under another ISR category? Please explain.

Response:

a. The previous definition of Damage/Failure work was as follows:

Damage/Failure category projects are those capital expenditures required to replace failed or damaged equipment and to restore the electric system to its original configuration and capability following equipment damage or failure. Damage may be caused by storms, vehicle accidents, vandalism or unplanned/other deterioration, among other causes. The Company views the Damage/Failure category as a mandatory category of work that is non-discretionary in terms of scope and timing.

As part of undertaking the review of Damage/Failure work processes, an internal working team was created with representatives from Field Operations, Engineering Design, Distribution Planning & Asset Management, Resource Planning, Resource Coordination, Inspection & Maintenance, Work Support, and Electric Process and Planning. That working group agreed on definitions for Damage/Failure and Asset Replacement as follows:

Damage/Failure: Work performed when equipment fails and has created an outage, contingency condition and/or jeopardizes safety, reliability or environment. This work restores the electric system to its original configuration and capability following the equipment damage or failure. The definition is supported by the following subcategories of non-discretionary work to help drive decision making:

- Customer Outage
- Safety Hazard
- Risk of Imminent Failure or Outage
- Environmental Hazard
- Feeder Lockout/Contingency Condition
- Street Lights

Prepared by or under the supervision of: Patricia C. Easterly and Kathy Castro

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Asset Replacement: Planned replacement of equipment to reduce the risk and consequences of failures and to maintain the overall reliability of the system. This work replaces equipment that has reached the end of its useful life due to age or present condition. This equipment may be operating correctly; however, replacement or upgrade is necessary to ensure that an in-service failure does not occur.

The updated definitions are meant to create more clarity around how to charge work in the field for damaged assets. In addition, as part of the review of the Damage/Failure processes, the working group reviewed the charges in the Damage/Failure category for six months of FY 2019. That review indicated that there were approximately $230,000 of charges that would have met the old definition but not the updated definition of Damage/Failure. By extrapolating that amount for a full year and rounding up to an even $1 million the Company adjusted the Damage/Failure budget down accordingly.

b. The Company is proposing to use the decrease of $1 million in the Damage/Failure category to perform increased targeted asset replacement work as part of its Inspection and Maintenance program.

Prepared by or under the supervision of: Patricia C. Easterly and Kathy Castro

R-I-17

Request:

Provide details on the Sockanosett transformer failure including, but not limited to:

a. Nameplate for the failed transformer.
b. Past five years of dissolved gas analysis for the failed transformer.
c. Nameplate data for the replacement transformer.
d. Detailed cost estimate for the replacement work by labor and materials.

Response:

a. General Electric
115\66.4 kV GRDY - 23000Y/13280 180º lag
24/32/40 MVA
Serial #: G-860121B
Reference #: 023633
Mfr. Date: 1972

b.

Report #	212216	Sample # 5	National Grid USA Service Co. Inc.	Received	01/29/2019
Serial Number:	G860121B	Equipment Number:	023633	Container Id:	BP 385
Substation Name:	Sockanosset 24	Preservation System:	Gas Blanketed	Miscellaneous Id:	WR: 27768653
Design Type:		Transformer Name:	1 3PH TRF	Second Name:	WO: 2019-3002143786
Manufacturer:	GE	Transformer Type:	Transformer	Sample Point:	Main Tank Bottom
MFR. Year:	1972	Maximum kV:	115	Sequence #:	
Cooling System:	OA/FA/FOA	Maximum MVA:	40	Sample Date/By:	1/23/2019 CG
Fluid Type:	Mineral	XFMR Oil Capacity:	3795 Gallons	Appr Type:	TRF
LTC MFR./Model:		LTC Type:		LTC Tank Type :	LTC Capacity:

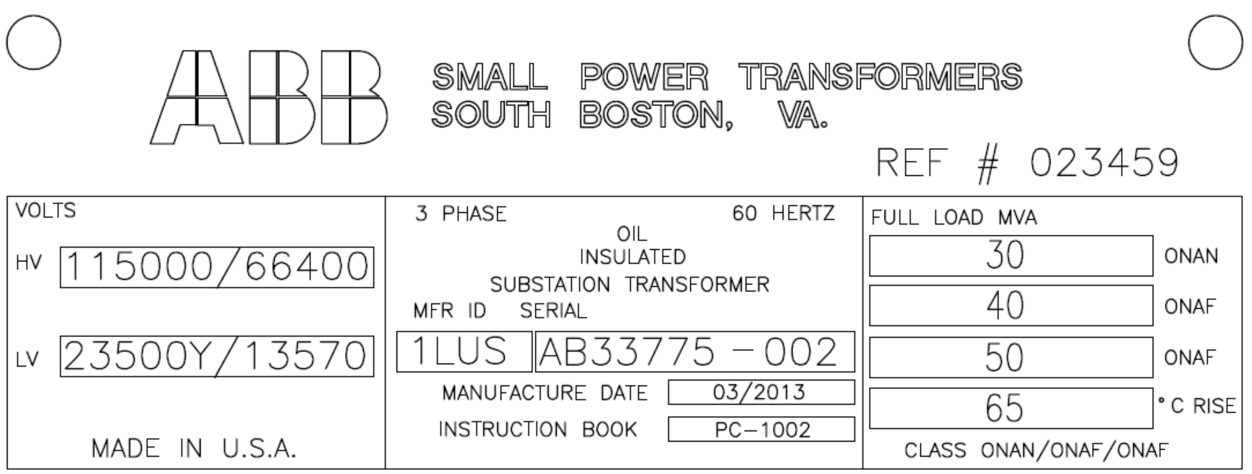
Dissolved Gas Analysis The dissolved gas analysis is run in accordance with ASTM D 3612 and IEC 60567. Values are reported in ppm vol/vol at STP and calil
Values before August 15, 2002 are reported at NTP and calibrated with gas standards.

Report #	Sample Date	Top Oil Temp °C	Hydrogen (H2)	Oxygen (O2)	Nitrogen (N2)	Methane (CH4)	Carbon Monox. (CO)	Ethane (C2H6)	Carbon Dioxide (CO2)	Ethylene (C2H4)	Acetylene (C2H2)	Total Gas	COMB GAS
212216	**01/23/2019**	**35**	**4850**	**1810**	**53500**	**27600**	**641**	**10300**	**3180**	**41700**	**841**	**144422**	**85932**
197100	01/19/2018	20	38	528	80300	175	96	58	2620	321	0	84136	688
179364	01/17/2017	40	35	124	76800	161	95	56	2580	308	0	80159	655
159998	12/10/2015	35	34	492	78700	154	99	53	2570	268	0	82370	608
147079	12/08/2014	22	43	368	68800	156	98	51	2540	296	0	72352	644
140579	05/22/2014	40	40	1610	71200	165	96	52	2890	311	0	76364	664

R-I-17, page 2

c. Mobile Substation No. 7661 was installed in the station and placed in service on February 20, 2019. A project is underway to move and install a system spare transformer permanently. A new system spare transformer is being procured with expected delivery to the National Grid Storage facility in March 2021.

Nameplate Data for the system spare currently being installed is as follows:
ABB
115\66.4 kV GRDY - 23500Y/13570 180º lag
30/40/50 MVA
Serial #: 1LUSAB33775-002
Reference #: 023459
Mfr. Date: 3/2013



d. Below is the detailed cost estimate for the replacement work.

	Material	Cost
FY20 & FY21	Purchase of replacement for spare transformer used (30%-FY20, 70%-FY21)	$750,000
FY20	Upgraded oil containment system	$24,000
FY20	Miscellaneous (primary, secondary, conduits)	$7,000
	Estimated Subtotal	**$781,000**

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	Labor	**Cost**
FY20	Installation of mobile & removal of failed transformer	$65,000
FY20	Civil work replacement of pad & containment system in station	$200,000
FY20	Spare transformer disassembly, move, install on site	$200,000
FY20	Removal of mobile from site	$25,000
FY21	Inspections spare transformer drawings, build, site assembly	$10,000
	Estimated Total	**$1,281,000**

R-I-18

Request:

Provide the most recent sanctioning papers for the Southeast and Dyer Street projects.

Response:

Please see Attachment R-1-18-1 and Attachment R-1-18-2.

This document has been reviewed for Critical Energy/Electric Infrastructure Information (CEII). 08/09/19

nationalgrid

Long: US Sanction Paper

Title:	New Southeast Substation	Sanction Paper #:	USSC-15-109v2
Project #:	C053657, C053658, C055683, C055563, C056343, C055583 and C061766	Sanction Type:	Sanction
Operating Company:	The Narragansett Electric and Gas Co.	Date of Request:	7/22/2019
Author:	Maximovich, George	Sponsor(s):	Sedewitz, Carol A. VP Electric Asset Mgmt & Planning Gemmell, Brian VP Trnsmsn Asset Mgmt Plan & Del
Utility Service:	Electricity T&D	Project Manager:	Maximovich, George

Executive Summary

This paper requests Sanction of C053657, C053658, C055683, C055563, C056343, C055583 and C061766 in the amount of $38.182M with a tolerance of +/-10% for the purposes of full implementation.

This sanction amount is $38.182M broken down into:
- $33.642M Capex
- $0.781M Opex
- $3.759M Removal

With a CIAC/Reimbursement of $0.000M
With a Salvage Value of $0.000M

This project is in final design and/or has secured the necessary agency approvals to proceed and is ready to be released for construction. At this stage, re-evaluation of the project design would likely result in significant delays to the project schedule and an increase in cost. This project will be evaluated for any procurement or construction efficiency opportunities upon its release for construction.

Project Summary

This project addresses safety, asset condition, and reliability concerns associated with the Pawtucket No 1 indoor station on the four story brick building located on Tidewater Street on the west bank of the Seekonk River in the City of Pawtucket. Pawtucket No 1 supplies approximately 36,000 customers with a peak electrical demand of 109 MW. The project includes the installation of a new eight feeder 115/13.8 kV metal clad substation with two transformers and breaker and a half design on a site adjacent to the transmission right of way on York Avenue in the City of Pawtucket; the supply to the proposed station from the existing 115 kV lines crossing the site, X-3 and T-7; the rearrangement of the 13.8kV distribution system in the City of Pawtucket to transfer approximately 55 MVA of load from Pawtucket No 1 to the new substation; the construction of a new control house at the Pawtucket No 1 substation site to house the control equipment for the 115 kV station presently located in the indoor station building; the upgrade of 115 kV line protection for P-11 at Valley station; and the decommission and removal of the indoor station and the demolition of the four story brick building at Pawtucket No 1 substation.

Background

Pawtucket No. 1 station is located on Tidewater Street on the west bank of the Seekonk River in the City of Pawtucket. It consists of a four story brick building constructed in 1907 and an outdoor switchyard. It has nineteen 13.8 kV distribution circuits that supply approximately 36,000 customers with a peak electrical demand of 109 MW. Three feeders supply a network in downtown Pawtucket with approximately 3 MW of load.

The brick building was part of a former power plant that was decommissioned in 1975 and is less than 25% utilized. This building houses indoor distribution switchgear and other electrical equipment. The electrical equipment still in service within the building is associated with both the indoor switchgear and the outdoor yard. Some electrical equipment associated with the former power plant has been abandoned in place.

The indoor substation was designed based on the standards at the time it was built. Operating and working in this station now requires special procedures and added safeguards to be followed. Additionally, it is challenging to find replacement parts for the equipment in the station since parts have to be custom made or salvaged from facilities that have been removed from service. The building layout is such that it precludes the implementation of modern installation standards in order to replace original equipment.

The breakers in the indoor substation consist of General Electric "H"-type circuit breakers ranging in age from 40 to 94 years old. The 1920 breakers are live-tank, oil-filled circuit breakers which are obsolete due to a lack of spare parts, slow operation, and the potential for failure. The 1970 breakers have a history of poor reliability especially during switching operations with three documented failures of the breaker motor and two documented failures of the trip/close coils.

A contingency at Pawtucket No.1 involving loss of a transformer or main bus would require significant load to be transferred to adjacent stations utilizing feeder ties. Pawtucket No. 1 only has weak ties to Valley St. station, therefore a significant amount of Pawtucket No. 1 load cannot be picked up during these contingencies. The projected bus loading and projected un-served load at Pawtucket No 1 for each bus section is shown in the table below:

Substation	Tranf. ID.	Rating (MVA)		2019 Peak Load		2019 Projected Un-Served Load Under Contingency	
		SN	SE	MW	% SN	MW	MWh Exposure
Pawtucket No.1	T71	47.8	47.8	43.9	92%	17.3	445
Pawtucket No.1	T73	47.8	47.8	35.0	73%	4.3	200
Pawtucket No.1	T74	47.8	47.8	29.8	62%	23.7	576

National Grid's Distribution Planning Criteria recommends mitigating any un-served load exposure in excess of 10 MW or 240 MWh. The loss of the T71 transformer, the T74 transformer, or a bus section at Pawtucket No. 1 would result in outage exposures in excess of those recommended by distribution planning criteria.

Project Descriptions

Construct a new 115/13.8 kV metal clad substation, breaker and a half design, adjacent to the transmission right of way on York Avenue. The new station designated as Dunnell Park will have an ultimate layout for eight distribution circuits with two 115/13.8 kV 33/44/55 MVA LTC transformers and two station capacitor banks. The station will be supplied from two 115 kV transmission lines on the right of way, X-3 and T-7.

Rearrange the 13.8kV distribution system in the City of Pawtucket to transfer approximately 55 MVA of load from Pawtucket No 1 to Dunnell Park substation. The remaining Pawtucket No. 1 load will be rearranged and supplied from switchgear sections 73 and 74. The new station will supply the bulk of the load east of the Seekonk River while Pawtucket No. 1 will supply most of the load west of the Seekonk River.

Install a new control house at Pawtucket No. 1 to house the control equipment for the 115 kV station that is presently housed in the indoor substation building. EMS functionality will be expanded to provide remote status, control and monitoring of all switching devices, transformers, voltage regulation and battery systems. Alarming will include transformer low oil; transformer, circuit breaker, relay and battery system trouble. Monitoring will include voltage and current for all three phases and neutral, MW, MVAR, and MVA. Control will include trip and close on all switching devices; reclose on/off on circuit breakers; ground relay control on feeders for switching, and control of voltage regulation.

Upgrade the 115 kV line protection for P-11 at Valley substation.

Remove the indoor station and all electrical equipment from the four story brick building, demolish the building and provide final grading and arrangement on this area at Pawtucket No. 1.

Summary of Benefits

This project addresses safety, asset condition, and reliability concerns associated with the Pawtucket No 1 indoor station. This work benefits all the customers in the City of Pawtucket and the surrounding areas.

Business and Customer Issues

There are no significant business or customer issues beyond what has been described elsewhere in this paper.

Alternatives

Number	*Title*
1	Install a new Metal Clad 115/13.8 kV Station at the Pawtucket No 1 This alternative proposes development of a new 115/13.8 kV metal clad substation, breaker and a half design, in the Pawtucket No. 1 yard. The station would be constructed with two 115/13.8 kV 33/44/55 MVA LTC transformers, eight distribution circuits and two station capacitor banks. After installation of the new switchgear, load at Pawtucket No 1 will be rearranged to allow for the elimination of the 71 bus. There are presently eight circuits on section 71, including three network feeders. The three network circuits are currently dedicated feeders with approximately 3.0 MVA of peak load. It is proposed to supply these network circuits from section 73. The remaining circuits will be resupplied from the new station. Three circuits in section 73 will be resupplied from the new station to free up feeders for the three network circuits. This work will reduce loading on section 73 below the rating of the 2,000 Amp bus. The distribution infrastructure from Pawtucket No 1 is all underground. Therefore, new manhole and ductline systems will be built from the new station out to city streets and intercept the existing underground system when practical. New underground feeder getaways will be installed from the new station and will intercept the existing cables or be routed directly to the riser poles. The existing manhole and ductline infrastructure predominantly consists of 3-inch conduits installed on city streets. Although the age of this infrastructure is unknown, based on the age of the indoor substation it would be reasonable to assume that the majority of this infrastructure dates back to the early 1900's. The 3-inch duct diameter is not suitable for routing of the proposed solid dielectric cables required for the new feeders. New 5 inch diameter duct is required for the new cable. This plan would install a new manhole and duct system necessary to bypass the limiting 3-inch infrastructure. The conceptual grade estimate for this plan was $30.600M of which $26.100M was capital, $0.400M was O&M and $4.100M was removal and the conceptual grade estimate for the recommended plan was $23.000M of which $18.100M was capital, $0.300M was O&M and $4.600M was removal. This alternative was estimated to be 33.0% more expensive than the recommended plan.

2 Non-Wires Alternative
The primary driver for this project is to address the asset condition, including the safety and reliability concerns with the Pawtucket No 1 indoor substation. Non Wires Alternatives are not applicable for this project. New supply and distribution infrastructure is the only reasonable alternative to address the asset conditions.

Related Projects, Scoring and Budget

Summary of Projects

Project Number	*Project Type* (Elec only)	*Project Title*	*Estimate Amount($M)*
C053657	D-Sub	Southeast Sub (D -Sub)	10.766
C053658	D-Line	Southeast Sub (D-Line)	10.618
C055683	D-Sub	Pawtucket No 1 (D-Sub)	4.056
		Total:	25.440

Project Number	*Project Type* (Elec only)	*Project Title*	*Estimate Amount($M)*
C055563	T-Line	Southeast Sub (T-Line)	1.305
C056343	T-Sub	Southeast Sub (T -Sub)	3.094
C055583	T-Sub	Pawtucket No 1 (T-Sub)	7.370
C061766	T-Sub	Valley Sub P11 Upgrades	0.973
		Total:	12.742

Associated Projects

Project Number	*Project Title*	*Estimate Amount ($M)*
C053249	Robinson Ave Control House Upgrades	9.087
		9.087

Prior Sanctioning History

Date	*Governance Body*	*Sanctioned Amount*	*Potential Project Investment*	*Sanction Type*	*Sanction Paper*	*Potential Investment Tolerance*
5/13/2015	USSC	5.600	23.000	Partial Sanction	USSC-15-109	-25%/+50%

The variance between the initial potential project investment and this sanction was caused by:
1. Addition of new 115kV equipment on Pawtucket No. 1 and on the new Dunnell Park substation as result of the review of protection requirements for the project. The updated scope includes the installation of 115kV CCVT's, Line Traps, Line Tuners and related relaying and civil & structural work on X-3 and T-7 transmission line terminals on both substations ($4.485M).
2. Additional civil and environmental scope of work on Pawtucket No. 1 based on the final location of the new control house inside the 100 year floodplain and the alignment with Tidewater Environmental Project requirements ($4.865M).
3. Underestimation on the scope and level of effort on the distribution line work for the new feeders and distribution circuits rearrangement on the City of Pawtucket ($4.517M).
4. Increase on equipment market value and other miscellaneous additional costs ($1.315M).

Key Milestones

Milestone	Date (Month / Year)
Partial Sanction	May, 2015
Project Sanction	July, 2019
Engineering Design Complete - EDC	August, 2019
Gate C1 - Approval to Progress to Field Execution	September, 2019
Construction Start	October, 2019
Ready for Load / Use	May, 2021
Construction Complete - CC	October, 2021
Gate D - Approval to Progress to Closeout	December, 2021
Gate E - Approval to Close Project	September, 2022
Project Closure Sanction	October, 2022

Next Planned Sanction

Date (Month/Year)	Purpose of Sanction Review
October, 2022	Closure

Category

Category	Reference to Mandate, Policy, NPV, or Other
○ Mandatory ◉ Policy-Driven ○ Justified NPV ○ Other	The investment is policy driven. The Asset Management & Engineering Business Management Standard (BMS 04) sets performance requirements for the "maintenance, repair, replacement, operations and retirement of assets".

Asset Management Risk Score: 44

PRIMARY RISK SCORE DRIVER

◉ Reliability ○ Environment ○ Health & Safety ○ Not Policy Driven

Complexity Level: 25

◉ High Complexity ○ Medium Complexity ○ Low Complexity ○ N/A

Process Hazard Assessment

A Process Hazard Assessment (PHA) is required for this project: ◉ Yes ○ No

Current Planning Horizon

Distribution

$M	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
		Current Planning Horizon						
CapEx	2.560	6.315	10.083	2.089	0.006	0.000	0.000	21.053
OpEx	0.006	0.111	0.449	0.108	0.000	0.000	0.000	0.674
Removal	0.065	0.153	1.542	1.953	0.000	0.000	0.000	3.713
Total	2.631	6.579	12.074	4.150	0.006	0.000	0.000	25.440

Transmission

$M	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
		Current Planning Horizon						
CapEx	1.185	2.455	8.610	0.335	0.004	0.000	0.000	12.589
OpEx	0.003	0.012	0.088	0.004	0.000	0.000	0.000	0.107
Removal	0.000	0.006	0.032	0.008	0.000	0.000	0.000	0.046
Total	1.188	2.473	8.730	0.347	0.004	0.000	0.000	12.742

Capex	3.745	8.770	18.693	2.424	0.010	0.000	0.000	33.642
Opex	0.009	0.123	0.537	0.112	0.000	0.000	0.000	0.781
Removal	0.065	0.159	1.574	1.961	0.000	0.000	0.000	3.759
Total	3.819	9.052	20.804	4.497	0.010	0.000	0.000	38.182

Resources, Operations, & Procurement

RESOURCE SOURCING			
Engineering & design Resources to be provided	☑ Internal		☑ Contractor
Construction/Implementation Resources to be provided	☑ Internal		☑ Contractor
RESOURCE DELIVERY			
Availability of internal resources to delivery project:	○ Red	○ Amber	◉ Green
Availability of external resources to delivery project:	○ Red	○ Amber	◉ Green
OPERATIONAL IMPACT			
Outage impact on network system	○ Red	○ Amber	◉ Green
PROCUREMENT IMPACT			
Procurement impact on network system:	○ Red	○ Amber	◉ Green

Key Issues

1 Permitting is required for the proposed new Dunnell Park substation.

2	Environmental, engineering design, permitting and construction coordination is required with Tidewater Environmental Project at Pawtucket No 1 substation.
3	Outages required on X-3, T-7 and P-11 transmission lines during construction activities on the new Dunnell Park substation and on Pawtucket No 1 and Valley substations will be coordinated with other projects in the same area.

Climate Change

Contribution to National Grid's 2050 80% emissions reduction target:	◉ Neutral	○ Positive	○ Negative
Impact on adaptability of network for future climate change:	○ Neutral	◉ Positive	○ Negative

List References

1	E18-0203, E18-0057, E18-0056, E18-0055, E18-0054, E18-0053, E-18-0052 4.4 Estimates, dated April 2019
2	Distribution Annual Plan 2019 - 2024
3	Pawtucket Area Study - December 2014
4	Conceptual Engineering Report and Estimates - May 2014

Safety, Environmental and Project Planning Issues

Safety	A health and safety plan will be developed for all project areas and all National Grid safety and environmental rules will be followed. During the development of the Transmission and Distribution Line works the Process Hazard Analysis (PHA) will be considered.
Environmental	Environmental, engineering design, permitting and construction activities will continue in coordination with Tidewater Environmental Project at Pawtucket No 1 substation.
Project Planning	The Permitting & Licensing and Outreach team will continue working with Project Management to address any permitting, environmental or community issues.

Permitting

Permit Name	*Probability Required*	*Duration to Acquire Permit*	*Status*	*Estimated Completion Date*
EFSB Notice of Intent	Certain	3 months	In Progress	September, 2019
Historic Commission Review	Certain	2 months	Complete	January, 2019

Rhode Island Coastal Resources Management Council (CRMC) Maintenance Assent Permit	Certain	3 months	In Progress	September, 2019
Local Soil Erosion and Sediment Control (SESC) Permit	Certain	3 months	In Progress	September, 2019
Rhode Island Department of Environmental Management (RIDEM) Oil and Hazardous	Certain	1 month	In Progress	August, 2019
Pawtucket Riverfront Commission – Development Plan Review	Certain	2 months	In Progress	September, 2019
Pawtucket Zoning Board of Appeals – Special use permit	Certain	3 months	In Progress	September, 2019
Pawtucket Planning Board Staff – Development Plan Review	Certain	1 month	In Progress	August, 2019
Pawtucket Street Opening Permit	Certain	3 months	In Progress	September, 2019
Building Permit	Certain	1 month	In Progress	October, 2019

Investment Recovery and Customer Impact

Investment Recovery

The transmission project split is 65.5% PTF and 34.5% Non-PTF. The PTF-related plant will be recovered through New England Power's Regional Network Service ("RNS") rates, whereas the Non-PTF plant will be recovered through the Local Network Service ("LNS") rates.

Customer Impact

This project results in an indicative first full year revenue requirement when the asset is placed in service equal to approximately $6.220M.

Execution Risk Appraisal

Risk Breakdown Structure Category	Qualitative Assessment / Risk Response Strategy					Risk Score
	Risk ID + Title	IF Statement	THEN Statement	Risk Response Strategy		
10. Line Outages	R1 - Outage Planning	If an outage is not approved	Then there will be schedule delay and extra expenses incurred	Accept	Reschedule the outage based on availability	4
10. Line Outages	R2 - Missed Outage	If an outage is cancelled or missed during construction	Then there will be schedule delay and construction cost impact due to mob/demobs, stanby condition, equipment rental	Accept	Reschedule the outage based on availability	9
5. Environmental	R3 - Hazardous Material at Dunnell Park Property	IF unknown Hazardous Material or contaminated soils located during excavation of structures and utilities	THEN additional costs will be incurred related to proper handling , removal and disposal	Accept	No action	4
7. Procurement Contracts	R4 - Tarriff	IF a government tariff is passed	THEN the cost of equipment will increase and may be a delay in material delivery	Accept	No action	4
11. Construction	R5 - Unknown Existing Conditions	IF unanticipated facilities or conditions are encountered	THEN additional engineering will be required and the construction schedule will be delayed	Reduce	Verify accurate and current as-built drawings	6
4. Permitting	R6 - Noise and visual impact mitigation	IF residents oppose noise/dust associated with demolition of the four story brick building at Pawtucket No 1	THEN additional permitting will be required, work hours will be restricted, and the schedule will be delayed.	Accept	No action	4
11. Construction	R7 - Equipment/Material Damage	IF equipment and/or material and new control house & switchgear are damaged due to congestion of the operational yard or building location	THEN additional equipment/material will need to be procured or repairs will be made and the schedule will be delayed.	Reduce	Construction methods and sequencing	4

Business Plan

Business Plan Name & Period	***Project Included in approved Business Plan?***	***(Over) / Under Business Plan***	***Project Cost relative to approved Business Plan ($M)***
NE Distribution FY20-24 Capital Plan	◉ Yes ○ No	◉ Over ○ Under ○ N/A	(7.348)
NE Transmission FY20-24 Capital Plan	◉ Yes ○ No	◉ Over ○ Under ○ N/A	(8.537)

If Cost > Approved

if costs > approved Business Plan how will this be funded?

Re-allocation of funds within the portfolio has been managed by Resource Planning to meet jurisdictional budgetary, statutory and regulatory requirements.

Drivers

This project is required to address safety, asset condition, and reliability concerns with the Pawtucket No.1 indoor substation. This project also addresses load at risk that exceeds the distribution planning criteria; feeder loading that exceeds summer normal ratings; and loading that exceeds the rated capacity of the station bus.

Cost Summary Table

Distribution

Project Number	C053657	Project Title	Southeast Sub (D -Sub)	Project Estimate Level	10%

Spend	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
Capex	2.101	4.150	3.713	0.718	0.002	0.000	0.000	10.684
Opex	0.003	0.000	0.049	0.030	0.000	0.000	0.000	0.082
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	2.104	4.150	3.762	0.748	0.002	0.000	0.000	10.766

Project Number	C053658	Project Title	Southeast Sub (D-Line)	Project Estimate Level	10%

Spend	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
Capex	0.330	2.100	6.270	1.107	0.002	0.000	0.000	9.809
Opex	0.003	0.111	0.400	0.078	0.000	0.000	0.000	0.592
Removal	0.000	0.108	0.092	0.017	0.000	0.000	0.000	0.217
Total	0.333	2.319	6.762	1.202	0.002	0.000	0.000	10.618

Project Number	C055683	Project Title	Pawtucket No 1 (D-Sub)			Project Estimate Level	10%	
Spend	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
Capex	0.129	0.065	0.100	0.264	0.002	0.000	0.000	0.560
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.065	0.045	1.450	1.936	0.000	0.000	0.000	3.496
Total	0.194	0.110	1.550	2.200	0.002	0.000	0.000	4.056

Transmission

Project Number	C055563	Project Title	Southeast Sub (T-Line)			Project Estimate Level	10%	
Spend	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
Capex	0.237	0.563	0.425	0.029	0.001	0.000	0.000	1.255
Opex	0.000	0.007	0.007	0.000	0.000	0.000	0.000	0.014
Removal	0.000	0.006	0.030	0.000	0.000	0.000	0.000	0.036
Total	0.237	0.576	0.462	0.029	0.001	0.000	0.000	1.305

Project Number	C056343	Project Title	Southeast Sub (T -Sub)			Project Estimate Level	10%	
Spend	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
Capex	0.252	0.867	1.910	0.064	0.001	0.000	0.000	3.094
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.252	0.867	1.910	0.064	0.001	0.000	0.000	3.094

Project Number	C055583	Project Title	Pawtucket No 1 (T-Sub)			Project Estimate Level	10%	
Spend	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
Capex	0.554	0.845	5.645	0.232	0.002	0.000	0.000	7.278
Opex	0.003	0.005	0.078	0.004	0.000	0.000	0.000	0.090
Removal	0.000	0.000	0.002	0.000	0.000	0.000	0.000	0.002
Total	0.557	0.850	5.725	0.236	0.002	0.000	0.000	7.370

Project Number	C061766	Project Title	Valley Sub P11 Upgrades			Project Estimate Level	10%	
Spend	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
Capex	0.142	0.180	0.630	0.010	0.000	0.000	0.000	0.962

Opex	0.000	0.000	0.003	0.000	0.000	0.000	0.000	0.003
Removal	0.000	0.000	0.000	0.008	0.000	0.000	0.000	0.008
Total	0.142	0.180	0.633	0.018	0.000	0.000	0.000	0.973

Total Project Sanction								
Capex	3.745	8.770	18.693	2.424	0.010	0.000	0.000	33.642
Opex	0.009	0.123	0.537	0.112	0.000	0.000	0.000	0.781
Removal	0.065	0.159	1.574	1.961	0.000	0.000	0.000	3.759
Total	3.819	9.052	20.804	4.497	0.010	0.000	0.000	38.182

Project Costs per Business Plan

Distribution

$M	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
Capex	2.560	6.250	4.400	0.350	0.000	0.000	0.000	13.560
Opex	0.006	0.111	0.087	0.006	0.000	0.000	0.000	0.210
Removal	0.065	1.608	2.616	0.033	0.000	0.000	0.000	4.322
Total Cost in Bus. Plan	2.631	7.969	7.103	0.389	0.000	0.000	0.000	18.092

Variance

$M	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
Capex	0.000	(0.065)	(5.683)	(1.739)	(0.006)	0.000	0.000	(7.493)
Opex	0.000	0.000	(0.362)	(0.102)	0.000	0.000	0.000	(0.464)
Removal	0.000	1.455	1.074	(1.920)	0.000	0.000	0.000	0.609
Total Variance	0.000	1.390	(4.971)	(3.761)	(0.006)	0.000	0.000	(7.348)

Project Costs per Business Plan

Transmission

$M	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
Capex	1.185	1.827	0.914	0.167	0.000	0.000	0.000	4.093
Opex	0.003	0.059	0.043	0.006	0.000	0.000	0.000	0.111
Removal	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.001
Total Cost in Bus. Plan	1.188	1.886	0.958	0.173	0.000	0.000	0.000	4.205

Variance

$M	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
Capex	0.000	(0.628)	(7.696)	(0.168)	(0.004)	0.000	0.000	(8.496)
Opex	0.000	0.047	(0.045)	0.002	0.000	0.000	0.000	0.004

Removal	0.000	(0.006)	(0.031)	(0.008)	0.000	0.000	0.000	(0.045)
Total Variance	0.000	(0.587)	(7.772)	(0.174)	(0.004)	0.000	0.000	(8.537)

Cost Assumptions

The accuracy level of estimate for the project is +/-10%.

Standard material procurement process to be followed, and there are no expected delivery delays.

Net Present Value / Cost Benefit Analysis

N/A

NPV Assumptions & Calculations

N/A

Additional Impacts

N/A

Statement of Support

Department	Individual	Responsibilities
Project Management	Arthur, David; Migdal, Sara A.;	Endorses resources, cost estimate and schedule
Electric Project Estimation	Lutz, Sara E.;	Endorses Cost Estimate
Investment Planning	Diconza, Glen L.; McColgan, Karen A.;	Endorses relative to 5-year business plan or emergent work
Engineering and Design	Hellmuth, Kevin; Larrabee, Mark A.; Swanson, Leonard G.;	Endorses scope, design, conformance with design standards
Asset Management / Planning	Ahern, Barry (US); Labarre, Alan T.;	Endorses scope, estimate, and schedule with the company's goals, strategies, and objectives
Resource Planning	Wyman, Anne; Phillips, Mark A.;	Endorses construction resources, cost estimate, schedule, and portfolio alignment

Reviewers

Function	Individual
Finance	Bostic, Christina ; Byrne, Andrew ;
Regulatory	Turieo, Edward ; Artuso, Michael V. ;
Jurisdictional Delegate(s)	Easterly, Patricia ; Hill, Terron P. ;
Procurement	Chevere, Diego ;
Control Centers (CC)	Lavallee, Phillip H. ; Gallagher, Michael W. ;

Decisions

The Senior Executive Sanctioning Committee (SESC) approved this paper at a meeting held on 07/22/2019:
(a) APPROVE the investment of $38.182M and a tolerance of +/-10% for full implementation.

(b) NOTED that Maximovich, George has the approved financial delegation

Signature Margaret M Smyth

Date 8/7/19

Margaret Smyth
US Chief Financial Officer
Chair, Senior Executive Sanctioning Committee

Appendix

N/A

US Sanction Paper

Title:	Dyer St Indoor Substation	**Sanction Paper #:**	USSC 16-305
Project #:	C051205, C051211	**Sanction Type:**	Partial Sanction
Operating Company:	The Narragansett Electric Co.	**Date of Request:**	02/08/2017
Author:	John Williams	**Sponsor:**	Carol Sedewitz. Vice President, Electric Asset Management
Utility Service:	Electricity T&D	**Project Manager:**	John Skrzypczak

1 Executive Summary

1.1 Sanctioning Summary

This paper requests partial sanction of *projects C051205 and C051211* in the amount $ 6.028 M with a tolerance of +/- 10% for the purposes of final engineering, city permitting and preliminary construction activities that may be required prior to the next planned sanction paper.

This sanction amount is $6.028 M broken down into:

$ 5.558 M Capex
$ 0.207 M Opex
$ 0.263 M Removal

NOTE: a potential investment of $ 14.154 M with a tolerance of +50 /- 25 %, is contingent upon submittal and approval of a Project Sanction paper following completion of permitting, final engineering and design activities. The cost breakdown for each of the associated projects is: C051205 (D-Sub) $12.982 M and C051211 (D-Line) $1.172 M.

1.2 Project Summary

Build a new 11 kV to 4.16 kV indoor distribution substation on National Grid's Dyer St site. Retire the existing Dyer St Indoor Substation. Remove all 11 kV and 4.16 kV equipment and demolish the Indoor building. This work will allow the retirement of a circa 1925 indoor substation. The dated substation presents a challenging work environment for National Grid personal as compared to a contemporary substation.

US Sanction Paper

1.3 Summary of Projects

Project Number	Project Type (Elec only)	Project Title	Estimate Amount ($M)
C051205	D Sub	Dyer St replace indoor substation	12.982
C051211	D line	Dyer St replace indoor Sub D- line	1.172
		Total	14.154

1.4 Associated Projects

Project Number	Project Title	Estimate Amount ($M)
C051213	South St Replc Indoor Subst D-Sub	38,645

1.5 Prior Sanctioning History

None

1.6 Next Planned Sanction Review

Date (Month/Year)	Purpose of Sanction Review
April 2019	Project Sanction

1.7 Category

Category	Reference to Mandate, Policy, NPV, or Other
☐ Mandatory ☒ Policy- Driven ☐ Justified NPV ☐ Other	National Grid Indoor Substation Strategy, December 21, 2011.

US Sanction Paper

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1.8 Asset Management Risk Score

Asset Management Risk Score: **45**

Primary Risk Score Driver: (Policy Driven Projects Only)

☐ Reliability ☐ Environment ☒ Health & Safety ☐ Not Policy Driven

1.9 Complexity Level

☒ High Complexity ☐ Medium Complexity ☐ Low Complexity ☐ N/A

Complexity Score: **27**

1.10 Process Hazard Assessment

A Process Hazard Assessment (PHA) is required for this project:

☒ Yes ☐ No

1.11 Business Plan

Business Plan Name & Period	Project included in approved Business Plan?	Over / Under Business Plan	Project Cost relative to approved Business Plan ($)
FY17-21 NEv Distribution and Transmission Capital Plan	☒ Yes ☐ No	☒ Over ☐ Under ☐ NA	$ 8.126 M

1.12 If cost > approved Business Plan how will this be funded?

Re-allocation of funds within the portfolio has been managed and approved by Resource Planning to meet jurisdictional budgetary, statutory and regulatory requirements

nationalgrid

US Sanction Paper

1.13 Current Planning Horizon

$M	Prior Yrs	Current Planning Horizon Yr. 1 2016/17	Yr. 2 2017/18	Yr. 3 2018/19	Yr. 4 2019/20	Yr. 5 2020/21	Yr. 6 + 2021/22	Total
CapEx	0.000	0.033	0.448	1.122	4.789	5.585	0.000	11.977
OpEx	0.000	0.004	0.031	0.065	0.373	0.433	0.000	0.905
Removal	0.000	0.004	0.050	0.098	0.517	0.603	0.000	1.272
CIAC/Reimbursement	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.041	0.529	1.284	5.679	6.621	0.000	14.154

1.14 Key Milestones

Milestone	Target Date: (Month/Year)
Partial Sanction	February 2017
Start Preliminary Engineering (Kickoff Meeting)	March 2017
Permitting	March 2018
Engineering Design Complete	March 2019
Construction Start	June 2019
Ready for load	November 2020
Construction Complete	December 2020
Project Closure Sanction	February 2021

1.15 Resources, Operations and Procurement

Resource Sourcing			
Engineering & Design Resources to be provided	☑ Internal	☑ Contractor	
Construction/Implementation Resources to be provided	☑ Internal	☑ Contractor	
Resource Delivery			
Availability of internal resources to deliver project:	☐ Red	☐ Amber	☒ Green
Availability of external resources to deliver project:	☐ Red	☐ Amber	☒ Green
Operational Impact			
Outage impact on network system:	☐ Red	☐ Amber	☒ Green
Procurement Impact			
Procurement impact on network system:	☐ Red	☐ Amber	☒ Green

US Sanction Paper

1.16 Key Issues (include mitigation of Red or Amber Resources)

1	Permitting, The Dyer St Site is in Providence's D-1 Zone. By zoning ordinance, the Downtown Design Review Committee reviews and approves of all exterior building alterations in the zone. This includes open landscapes, roof lines and demolition requests.
2	To rehabilitate the DC building the civil contractor will install a steel shoring system to stabilize load bearing walls, replace the roof, and reconstruct interior to accommodate a modern indoor substation.
3	Environmental costs of demolishing the existing Dyer St Indoor building are dependant on the findings of the pre-characterization assessment which is completed when the environmental engineering contractor is able to access to all de-energized parts of the existing indoor substation.

1.17 Climate Change

Contribution to National Grid's 2050 80% emissions reduction target:	☒ Neutral	☐ Positive	☐ Negative
Impact on adaptability of network for future climate change:	☒ Neutral	☐ Positive	☐ Negative

1.18 List References

1	National Grid Substation O&M Services Asset Condition Report – Dyer St Station, March 2011
2	Providence Area Long Term Supply and Distribution Study, May 2014
3	National Grid. Doc PR.02.00.004 Investment Grade Report of Substations. 'Dyer St –Existing Substation Retirement and New Substation Location, April 2016
4	Coneco Engineering 'Site Characterization Activities and remediation abatement and disposal of hazardous materials Cost Estimate, April 2016
5	Odeh Civil Engineers, Dyer St Substation Building - Summary of Construction Options, April 2016

US Sanction Paper

2 Decisions

The US Sanctioning Committee (USSC) at a meeting held on February 8, 2017

(a) APPROVED the investment of **$ 6.028 M** and a tolerance of +/- 10 % for design, procurement and final engineering.

(b) NOTED the potential investment **$ 14.154 M** to and a tolerance of +50 /-25 %, contingent upon submittal and approval of a Project Sanction paper following completion of final engineering and design.

(c) NOTED that **John Skrypczak** has the approved financial delegation to undertake the activities stated in (a).

Signature……………………………………………..Date………………
Christopher Kelly
Senior Vice President
Electric Process and Engineering

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US Sanction Paper

3 Sanction Paper Detail

Title:	Dyer St Indoor Substation Retirement	**Sanction Paper #:**	USSC 16-305
Project #:	C051205 , C051211	**Sanction Type:**	Select
Operating Company:	The Narragansett Electric Co.	**Date of Request:**	02/08/2017
Author:	John Williams	**Sponsor:**	Carol Sedewitz. Vice President, Electric Asset Management
Utility Service:	Electricity T&D	**Project Manager:**	John Skrzypczak

3.1 Background

Dyer St Indoor Substation is located in what is known as the AC building. This four story brick building, constructed in 1925, serves 13 MVA of summer peak load from it's nine 4.16 kV distribution circuits. The station also has an 11 kV bus that supports five supply circuits (three from South St and two from Franklin Square) one distribution circuit (1103), and two Network Circuits (1105 and 1109).

Located abt 50 ft west of the indoor substation is second brick structure known as the DC building. This building was the original structure on the 1.04 acre site that TNECo purchased in 1897 for $100. The building was used to generate DC power to supply street lights and the trolley line. The last DC circuits were retired in the early 1980s. Since then, the building has been used for general storage.

The Providence Area Long Term Supply and Distribution Study, completed in May 2014, recommended the replacement of Dyer St Indoor Substation.

3.2 Drivers

Asset Condition and Safety are the main drivers of this project.

National Grid's Network Asset Planning Group completed an Asset Condition Report on the Dyer St Indoor Station in March of 2011. After reviewing equipment test records, operating history, and applying industry knowledge it was concluded that the existing station presents operational, safety and maintenance challenges as compared to operating a modern indoor substation. Replacement of the indoor substation allows for the retirement of the breakers, reactors, and relay schemes that were identified in the

Asset condition report as deficient in performance and difficult to maintain. Pls see attachments 1 and 2 for an illustration of identified equipment.

In addition, this indoor substation ranked as the highest priority for replacement following the completion of the 2011 indoor substation replacement prioritization exercise performed by Distribution Asset Strategy.

3.3 Project Description

Tasks associated with C051205 ‘Dyer St Replace indoor subst D-Sub’ included:

Rehabilitation of the DC building.

- A new steel framed shoring system will be installed along the interior load bearing walls.
- The exterior brick will be repaired and repointed as needed.
- The building’s roof will be replaced.
- Non-load bearing interior walls that make up the south section transformer vaults will be removed.

Installation of a new indoor substation within the DC building

- A new six position 11 kV switchgear will be installed in the south section.
- A new 10 feeder breaker-and-a-half 4.16 kV indoor switchgear will be installed on the mezzanine
- Two 12.5 MVA 11.5 kV – 4.16 kV transformers will relocated from the outside of the Indoor building to the north face of the DC building.

Demolition of the existing Indoor Substation.

- All 11 kV and 4.16kV equipment will be removed from the building.
- All 15 kV and 5 kV electrical cables as will as relay and control wire will be removed.
- The 4 story circa 1925 brick building will be demolished.
- A green space / landscaped area will be created in place of the indoor substation building.

Tasks associated with C051211 ‘Dyer St Replace indoor subst D-Line’:

Cutover of 11kV and 4 kV circuits from the old indoor substation to the new indoor substation.

- Rebuild a new duct line from the cable vault inside the DC building.
- Relocate the three 11 kV supply circuits from South St (1102,1104 and 1106) from the indoor substation to the new 11 kV switchgear.
- Join the 11 kV Franklin Square 1149 circuit with the 1103 Dyer Circuit in the duct line outside Dyer St Substation

Relocate nine 4 kV distribution circuits from the existing Dyer St indoor substation to the new indoor switchgear.

3.4 Benefits Summary

This project will addresses safety and asset condition issues identified in the Dyer St Asset condition report. In addition, the new station will have status and control of the 11 KV and 4 kV breakers at the regional control center in Northboro.

The DC build will be rehabilitated, improving an asset the city of Providence deems historically significant.

3.5 Business and Customer Issues

Impact to Business and Customer Issues is expected to be minimal. Preservation of the DC building will be viewed favorably by the city of Providence.

3.6 Alternatives

Alternative 1: Install a new Outdoor Substation at Dyer St. Demolish the existing Indoor Substation.

The cost of this alternative was 10 % less than the recommended option. However this alternative involves knocking down the DC building, which the Providence Planning Board has identified as historically significant. It is extremely unlikely the city would grant the zoning variance required to demolish this structure.

Alternative 2: Install a new Outdoor Substation behind a Façade. Demolish the existing Indoor Substation

This alternative cost 3 % less than the recommended alternative. It involves creating a façade out of two sides of the historically significant DC building. An outdoor substation would then be constructed behind the façade. After initial contact with the Providence Planning Board, permitting for this alternative is also considered improbable. This option will be retained as part of the permitting strategy but has a low probability of success.

3.7 Safety, Environmental and Project Planning Issues

A health and safety plan will be developed to insure employees and contractors understand how to perform work that is compliant with the company's safety regulations.

US Sanction Paper

3.8 Execution Risk Appraisal

Number	Detailed Description of Risk / Opportunity	Probability	Impact		Score		Strategy	Pre-Trigger Mitigation Plan	Residual Risk	Post Trigger Mitigation Plan
			Cost	Schedule	Cost	Schedule				
1	City of Providence Permitting	3	5	1	15	3	Accept	Work with the City of Providence Planning Board to insure final design is both cost effective and has a high probability of being approved.	NGrid does not secure variances required to demolish existing indoor substation.	Rehabilitate the existing indoor substation building. Explore alternate uses for the building
2	Coordination of circuit cutover from existing indoor substation to new indoor substation	5	5	4	25	20	Mitigate	Perform detailed inspections of duct and manhole system in and around Dyer St. Choose circuit cutover locations that have the least cost and customer impacts. Determine the most effective cutover circuit sequence.	N/A	Work with designer and local underground department to change cable plan to minimize cost and customer outage time. Adjust schedule and spending forecast.
3	Hazardous Material (Asbestos wiring within substation)	3	2	2	6	6	Accept	Conduct pre- demolition walk through.	N/A	Properly dispose of contaminated materials.
4	Hazardous Material (Asbestos removal)	3	2	2	6	6	Accept	Closely inspect cables, inductors and ancillary electrical equipment when the facility is de-energized.	N/A	Properly dispose of contaminated materials.
5	Adjustment to scope is required due to Planning or Operations needs	2	5	2	10	4	Accept	Engage with planning and local stakeholders to silicate input before final sanction documentation is complete.	N/A	Confirm that engineering / design changes are justified. Adjust schedule and spending forecast.
6	Unknown cabling, underground structures or blocked duct lines	2	1	1	2	2	Mitigate	Mandrel suspect duct line or reroute cable through other duct lines.	N/A	Redesign, adjust schedule, confirm scope changes with the sponsor.
7	Engineering error or commissioning	2	1	1	2	2	Mitigate	Conduct regular progress meeting with engaged stakeholders to identify issues prior to beginning construction.	N/A	Confirm that engineering / design changes are justified. Adjust schedule and spending forecast.
8	Storm Duty / Emergency Response Efforts	2	1	1	2	2	Accept	Early engagement with OPR / Control Center to limit issues of temporary circuit configurations during storm emergencies.	N/A	Adjust schedule

US Sanction Paper

3.9 Permitting

Permit Name	Probability Required (Certain/ Likely/ Unlikely)	Duration To Acquire Permit	Status (Complete/ In Progress Not Applied For)	Estimated Completion Date
Providence Planning Board (DDRC)	Likely	15 moths	In progress	March 2018
State Environmental Permits	Likely	6 Month	Not Applied for	June 2019

3.10 Investment Recovery

3.10.1 Investment Recovery and Regulatory Implications

Investment recovery will be through standard rate recovery mechanisms approved by appropriate regulatory agencies.

3.10.2 Customer Impact

This project results in an indicative first full year revenue requirement when the asset is placed in service equal to approximately $ 2.082 M this is indicative only. The actual revenue requirement will differ, depending upon the timing of the next rate case and / or the timing of the next filing which the project is included in the rate base.

3.10.3 CIAC / Reimbursement

There is no CIAC / reimbursement associated with this project.

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US Sanction Paper

3.11 Financial Impact to National Grid

3.11.1 Cost Summary Table

Project Number	Project Title	Project Estimate Level (%)	Spend ($M)	Prior Yrs	Current Planning Horizon Yr. 1 2016/17	Yr. 2 2017/18	Yr. 3 2018/19	Yr. 4 2019/20	Yr. 5 2020/21	Yr. 6 + 2021/22	Total
C051205	Dyer St replace indoor substation	Est Lvl (e.g. +50 / -25%)	CapEx	0.000	0.020	0.210	0.829	4.529	5.254	0.000	10.842
			OpEx	0.000	0.004	0.031	0.065	0.373	0.433	0.000	0.905
			Removal	0.000	0.004	0.042	0.088	0.509	0.592	0.000	1.235
			Total	0.000	0.028	0.283	0.982	5.411	6.279	0.000	12.982
C051211	Dyer St replace indoor Sub D- line	Est Lvl (e.g. +50 / -25%)	CapEx	0.000	0.013	0.238	0.293	0.260	0.331	0.000	1.135
			OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Removal	0.000	0.000	0.008	0.010	0.008	0.011	0.000	0.037
			Total	0.000	0.013	0.246	0.303	0.268	0.342	0.000	1.172
Total Project Sanction			CapEx	0.000	0.033	0.448	1.122	4.789	5.585	0.000	11.977
			OpEx	0.000	0.004	0.031	0.065	0.373	0.433	0.000	0.905
			Removal	0.000	0.004	0.050	0.098	0.517	0.603	0.000	1.272
			Total	0.000	0.041	0.529	1.284	5.679	6.621	0.000	14.154

It is expected that the plant will be capitalized at the ready for load date, unless otherwise specified.

3.11.2 Project Budget Summary Table

Project Costs Per Business Plan

$M	Prior Yrs	Current Planning Horizon Yr. 1 2016/17	Yr. 2 2017/18	Yr. 3 2018/19	Yr. 4 2019/20	Yr. 5 2020/21	Yr. 6 + 2021/22	Total
CapEx	0.000	0.025	0.400	0.620	2.073	2.440	0.000	5.558
OpEx	0.000	0.001	0.028	0.037	0.064	0.077	0.000	0.207
Removal	0.000	0.002	0.032	0.043	0.084	0.102	0.000	0.263
Total Cost in Bus. Plan	0.000	0.028	0.460	0.700	2.221	2.619	0.000	6.028

Variance (Business Plan-Project Estimate)

$M	Prior Yrs	Current Planning Horizon Yr. 1 2016/17	Yr. 2 2017/18	Yr. 3 2018/19	Yr. 4 2019/20	Yr. 5 2020/21	Yr. 6 + 2021/22	Total
CapEx	0.000	(0.008)	(0.048)	(0.502)	(2.716)	(3.145)	0.000	(6.419)
OpEx	0.000	(0.003)	(0.003)	(0.028)	(0.309)	(0.356)	0.000	(0.698)
Removal	0.000	(0.002)	(0.018)	(0.055)	(0.433)	(0.501)	0.000	(1.009)
Total Cost in Bus. Plan	0.000	(0.013)	(0.069)	(0.584)	(3.458)	(4.002)	0.000	(8.126)

3.11.3 Cost Assumptions

Cost estimate accuracy is +50 / - 25 %. Project sanction cost estimates will be developed after final design is completed.

US Sanction Paper

3.11.4 Net Present Value / Cost Benefit Analysis
Not applicable

3.11.4.1 NPV Summary Table
Not applicable

3.11.4.2 NPV Assumptions and Calculations
Not applicable

3.11.5 Additional Impacts
Not applicable

3.12 Statements of Support
Not applicable

3.12.1 Supporters
The supporters listed have aligned their part of the business to support the project.

Department	Individual	Responsibilities
Investment Planning	Glen DiConza	Endorses relative to 5 year business plan or emergent work.
Resource Planning	Anne Wyman	Endorses construction resources, cost estimate. Schedule and portfolio alignment.
Resource Planning	Mark Phillips	Endorses construction resources, cost estimate. Schedule and portfolio alignment.
Asset Management / Planning	Alan Labarre	Endorses scope, estimate, and schedule with the company's goals, strategies and objectives.
Substation Engineering and Design	Suzan Martuscello	Endorses scope, design, conformance with design standards.
Protection Engineering	Leonard Swanson	Endorses scope, design conformance with design standards
Project Management	Andrew Schneller	Endorses resources, cost estimate and schedule.

US Sanction Paper

3.12.2 Reviewers

The reviewers have provided feedback on the content/language of the paper.

Function	Individual
Finance	Patricia Easterly
Regulatory	Peter Zschokke
Jurisdictional Delegate	Jim Patterson
Procurement	Arthur Curran
Control Center	Michael Gallagher

4 Appendices

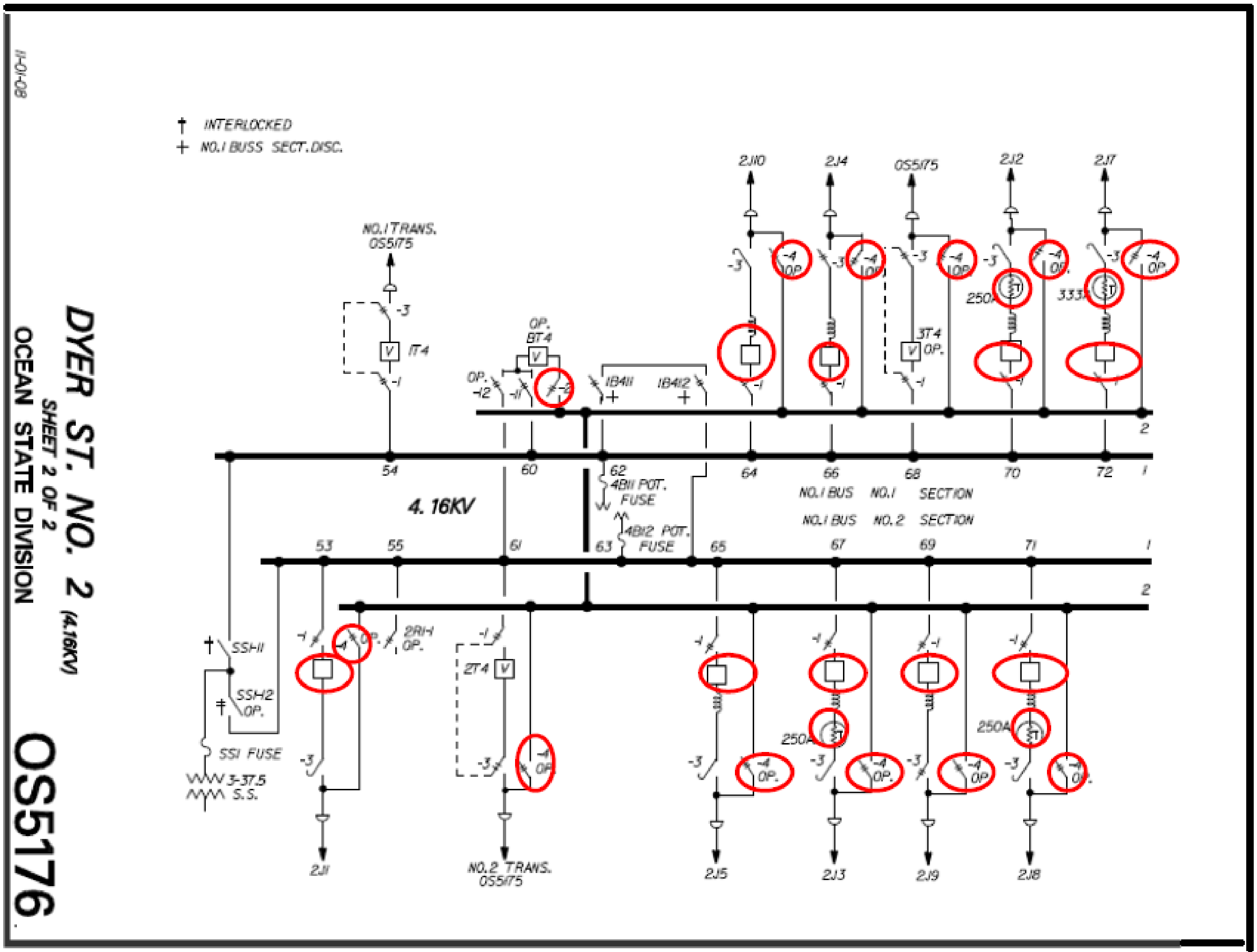
4.1 Sanction Request Breakdown by Project

$M	C051205	C051211	Total
CapEx	4.361	1.197	5.558
OpEx	0.087	0.098	0.207
Removal	0.131	0.132	0.263
Total	4.579	1.427	6.028

US Sanction Paper

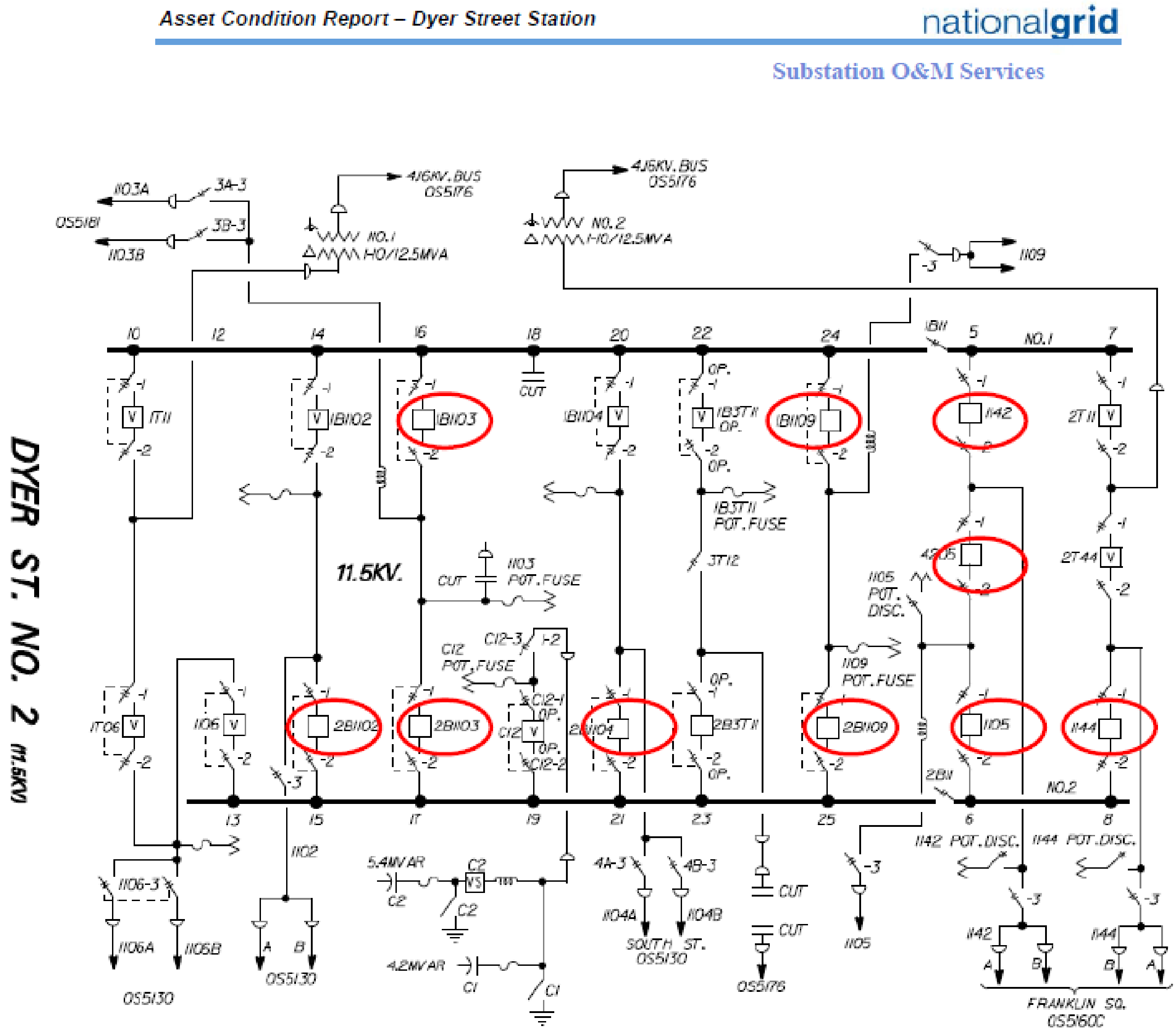
nationalgrid

4.2 Other Appendices



Equipment with red circle was identified for replacement in the O&M Services Asset Condition Report

US Sanction Paper



Equipment with red circle was identified for replacement in the O&M Services Asset Condition Report

Close up of H- Breakers that were recommend for replacement in the Asset Condition Report.

One of 7 Breaker Rooms with H-Type Breakers

US Sanction Paper

Dyer St Indoor Substation 1st row of switches off the 4 kV

Room with Gang operated disconnects and 4.16kV bus – Black doors on left wall provide access to each phase energized bus. 1 of 2 such rooms

US Sanction Paper

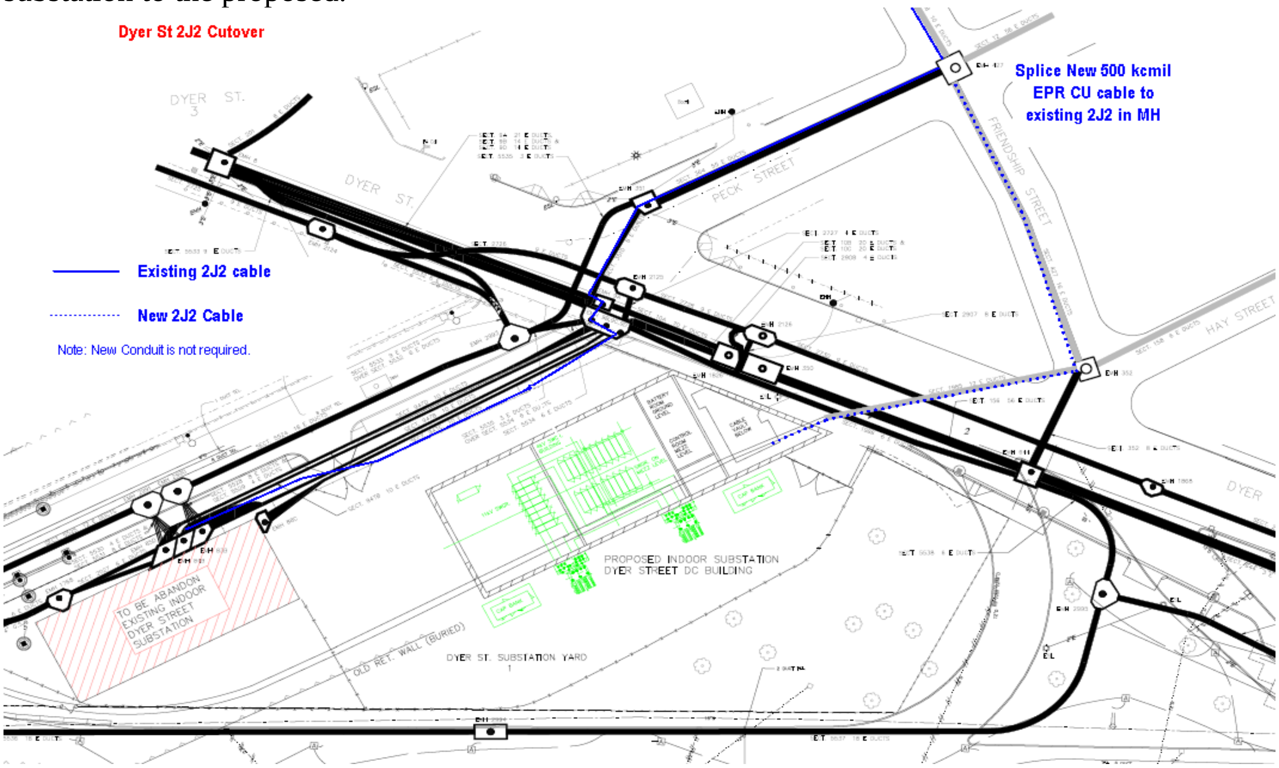
Dyer St Indoor Substation 2nd row of switches off the 4 kV bus

Substation O&M Services

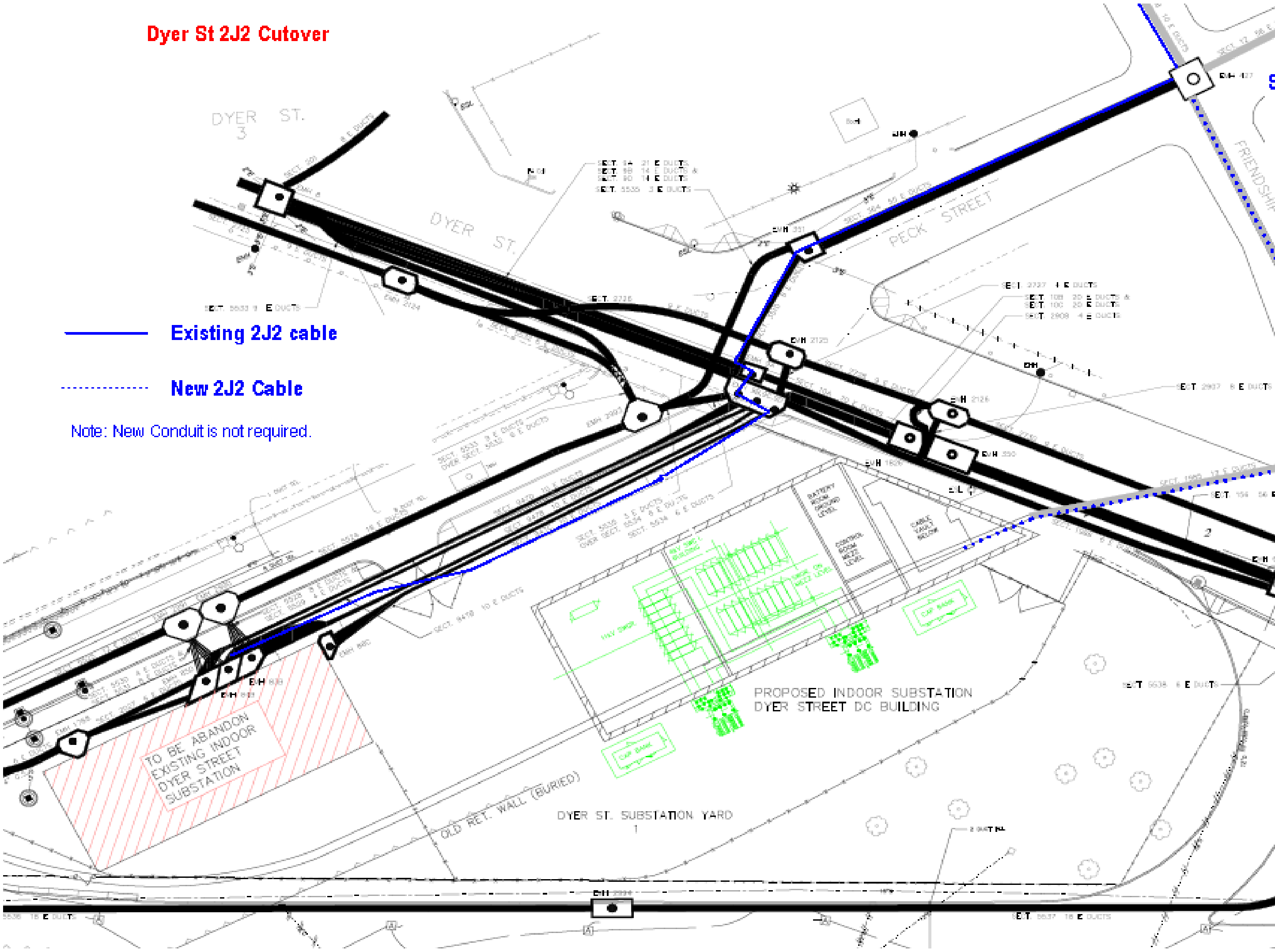
Room with 4.16kV -4 switches (left), -3 disconnects (ceiling)

US Sanction Paper

C051211 Distribution line work. Sample of 4 kV distribution circuit cutover from existing indoor substation to the proposed.



US Sanction Paper



R-I-19

Request:

Please confirm the FY2021 budget amount for Network Blower motors, and indicate if the work is planned as part of the Company's duct bank explosion remediation.

Response:

The FY2021 budget amount for Network Blower motors is $375,000.

The Company does not have a "duct bank explosion remediation" program. The Company undertakes actions to mitigate conditions that contribute to the likelihood of manhole explosions. The FY2021 investment in Network Blower motors proactively replaces existing vent blowers in below-grade network vaults with explosion-proof blowers and control systems. These replacements implement the Company's current construction standard, which requires that new installations in vents with forced-air ventilation use an explosion-proof blower and control system. Installation of explosion-proof blowers addresses one potential ignition source that is present in some underground structures.

Other manhole event mitigating activities include the sealing of service ducts as part of normal work activities, installing and assessing the efficacy of vented manhole covers, and programmatic underground cable replacement.

Prepared by or under the supervision of: Kathy Castro

R-I-20

Request:

The Company has proposed spending $4.9M for Asset Replacement as part of the I&M program, or nearly three times its forecasted spend in FY 2020.

a. Provide the rationale for the increase and cost/benefit analysis associated with the budget proposal.
b. How does the Company propose implementing a more aggressive I&M repair strategy while maximizing cost effectiveness? Will the Company require an increase in personnel to manage the additional work? Will internal, external, or both, labor resources be utilized?
c. For FY2015-FY2019, provide an annual summary of Asset Replacement-I&M for the following categories: Total spend; number of individual repairs completed; labor cost; material cost; and total man-hours.

Response:

a. The Company originally introduced spending for the I&M program to achieve a 5-year inspection and repair cycle. Through discussions with the Division and with the need to prioritize other projects the spend for the I&M program decreased throughout the past years.

   During last year's ISR planning the Company conducted an effort to determine how to best streamline the I&M Program. The result was to focus on the highest priority issues such as Level 1 and Level 9 urgent issues, potted porcelain cutouts, and certain guying issues. Using this streamlined method, the Company determined estimated repair cycles using mile based, structure based, and feeder-based metrics. With the streamlined program and a budget of approximately $1,700,000, the Company estimates a 26-28 -year repair cycle. The increase associated with the budget proposal is to return to a repair cycle towards a 10-15-year cycle.

   The I&M cost benefit analysis was provided as part of the pre-file documents. This analysis focuses on the cost of the program related to system indices reliability improvements. As detailed in the report, it is difficult to provide conclusive benefits due to all the other factors that impact system indices.

b. The Company conducted an effort to determine how to best streamline the I&M Program. The result was to focus on the highest priority issues and restructure work packets to only include Level 1 and Level 9 urgent issues, potted porcelain cutouts, and certain guying

R-I-20, page 2

issues. The restructured work packets have allowed the Company to be more feasible and more efficient.

No additional resources will be required to complete the additional work. The work would be managed both internally and externally, depending on workload and priority.

c. See following table for FY2015-FY2019 summary of Asset Replacement-I&M for the following categories: Total spend; number of individual repairs completed; labor cost; material cost; and total man-hours.

Fiscal Year	Number of Individual Repairs Completed	Total Spend	Labor Cost	Material Cost	Total Man Hours
FY2015	17,239.00	705,832.31	419,965.26	122,441.95	1,995.25
FY2016	8,939.00	6,548,231.91	4,795,401.25	302,552.16	18,768.32
FY2017	9,363.00	3,932,176.15	2,979,024.79	325,627.94	17,497.38
FY2018	2,248.00	1,507,459.48	1,046,023.80	189,691.52	4,167.25
FY2019	2,866.00	833,829.10	370,872.56	63,693.01	1,267.74

R-I-21

Request:

Referencing Section 2, page 34; the Company plans to invest in VVO expansion and, based on preliminary results from its VVO pilot, show a 3.3% demand reduction.

a. Explain why the VVO pilot is not considered a mature project, and why the actual demand reduction is not confirmed before investing in expansion.

b. Provide the specific impact on wholesale power cost reductions achieved through the VVO pilot.

Response:

a. The Company is transitioning to a "mature" program. As described in the Company's response to PUC Data Request 1-11 in the Fiscal Year 2020 Electric Infrastructure, Safety and Reliability Plan, Docket No. 4915, the Company had planned to develop a strategy and program for wider scale deployment as part of FY 2020; however, currently, the Company is executing on the final "pilot" VVO feeders to build on earlier successes and continue to refine the deployments and develop best practices. In particular, the Company continues to evaluate and learn from refinements to its communications approach.

   The Company continues the measurement and verification (M&V) effort to confirm the program value as it is expanded. For example, the Company's Putnam Pike substation VVO pilot averaged 3.15 percent energy savings (i.e., demand reduction) on one feeder and 3.50 percent energy savings on the other feeder; and the Langworthy Corner substation VVO pilot average 3.48 percent energy savings, but results ranged from 2.40 percent to 3.95 percent depending on the day of the week (i.e., weekdays versus weekends).[1]

   As can be seen from these early pilot projects, demonstrated results vary widely because VVO's effectiveness is highly dependent on the particular feeder configuration(s) and loads. The program expansion will be informed and revised by these results.

[1] VVO results are based on 90-day measurement and verification (M&V) analysis periods where the VVO technology was operated on alternating days (i.e., one day on, one day off).

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b. Energy savings from the VVO pilot expansion will reduce customer costs by reducing wholesale electricity costs and generation and transmission system capacity costs. While the Company cannot calculate the specific wholesale power cost reductions achieved through the VVO pilot, overall customer cost savings have been estimated using widely accepted Avoided Energy Supply Components (AESC) Study Group[2] methods and values based on the total energy savings estimated for the proposed VVO expansion in Rhode Island. Please also refer to the Company's response to PUC Data Request 2-6 and the related attachments from Docket No. 4915 for details on the Docket 4600 BCA calculations.

[2] Synapse Energy Economics, "Avoided Energy Supply Components in New England: 2018 Report", AESC 2018 Study Group.

R-I-22

Request:

Referencing Section 2, page 36; the Company provides information on a new program, Strategic DER Advancement, with a proposed budget of $5 million each year, beginning in FY 2021.

a. The Company states that "(w)ith the proliferation of Distributed Energy Resources (DER) the Company is experiencing rising complexity related to managing load, voltage, and protection systems that are the key to system reliability and safety." Please explain the complexities that the Company has experienced due to the proliferation of DER.

b. Provide specific examples of instances where the Company has been unable to maintain system reliability or has demonstrated safety issues due to DER including the issue encountered, the resulting reliability or safety impact, the methodologies deployed by the Company to resolve the reliability or safety issues, whether the solution provided only immediate relief or long term benefits, the cost to the DER to resolve the issue, and the cost incurred by the Company to implement the solution.

c. Provide all examples where the construction cost and timeline to integrate a DER resulted in negative economic impacts that resulted in a DER cancellation or significant size decrease. For each instance, is the Company aware of other factors contributing to the DER cancellation or size decrease?

d. Are the Company's proposed investments under the Strategic DER Advancement program shifting costs that would normally be borne by a DER owner to the Company?

e. Compare and contrast the Company's DER installations between Rhode Island and its New York and Massachusetts service areas in terms of total number and total capacity of interconnected DER projects and total number and capacity of DER projects in queue for each jurisdiction. Please explain issues or complexities the Company has experienced in Massachusetts and New York due to the proliferation of DER, a detailed description of the investments made by the company to resolve the issues, the timing of those investments, and the cost. Include any correlation of activities in Massachusetts and New York with those proposed in Rhode Island.

Response:

a. The Company is experiencing DER interconnections on the distribution system that are becoming increasingly complex stemming from hosting capacity limitations and compliance issues due to heavy saturation (aggregate impact of DER).

Issues include:

- Overloading of conductor, line equipment, station regulators, and supply transformers.
- Increase of over voltage during minimum load conditions and in some cases low voltage during peak conditions.
- Power quality and voltage fluctuation concerns in rural areas with less robust electric systems.
- Ground fault overvoltage concerns.
- Islanding concerns with mix of rotating and inverter-based generation with different islanding algorithms.
- Protection coordination concerns, specifically desensitization of ground fault protection.
- Exceeding equipment short circuit ratings.

b. The following are several examples of instances where the Company experienced aftercare issues or identified system reliability issues during System Impact Studies (SIS).

Example 1: During witness test of a 1,250kW photovoltaic solar project measurements of the primary system line to ground voltage exceeded 105%. Per Company requirements DER restoration schemes are set to only reclose for voltages within +/-5% of nominal. In order to ensure auto-restoration would occur system voltage needed to be reduced.

Resolution: In order to reduce system voltage a feeder capacitor was taken offline and seasonal settings were implemented to avoid high voltage during minimum loads. Estimated cost incurred by the Company for the setting changes was <$5,000.

Example 2: During the analysis of a 216kW photovoltaic solar project proposing to interconnect to a circuit served by the Clarkson Street Substation it was determined that 3V0 was required yet triggered prior to this proposed interconnection.

Resolution: Leveraged existing 3V0 program to install required protection scheme at Clarkson Street substation. Estimated cost incurred by the Company for the Distribution Substation portion of 3V0 was $52,000.

Example 3: During analysis of a 2,000kW photovoltaic solar project proposing to interconnect to the Farnum Pike 23F6 a pre-existing high voltage condition was identified at minimum feeder loads that would be exasperated with the interconnection of the DER.

Resolution: Replace three capacitors with units integrated with advanced controls, update capacitor settings on two units, and change station load tap changer settings. Company was responsible for the costs associated with these specific modifications which were considered system improvements. The estimated cost incurred by the Company was in the range of $100k.

Example 4: Adverse impacts identified during analysis of a 9,750kW photovoltaic solar project proposing to the Hopkins Hill 63F3 (Sub-transmission supplied distribution line). Issues included high voltage, excessive voltage fluctuation and desensitizing of existing protective devices.

Resolution: Reduce site size to 3,500kW, Reconductor ~8,500' OH conductor, upgrade line recloser with advanced controls, install bi-directional regulator controls. The estimated cost for system modifications are being developed as part of the System Impact study.

c. The Company does not formally track reasons behind project cancellation and size reduction. The following are a list of projects that the Company recollects where the construction cost and timeline to integrate a DER resulted in negative economic impacts that resulted in a DER cancellation or significant size decrease:

Example 1:
Original Size: 9,750kW
Decreased Size: 3,500kW
Driver for Decrease: Power Quality – Voltage Fluctuation Concerns
Status: Study
Comments: Engineering analysis identified unacceptable voltage and fluctuation issues on the area electric power system. To accommodate the full 9.75MW substantial modifications such as a new circuit, substation, or major transmission project would be required. The major feeder modifications to interconnect a reduced site size of 3.5MW include reconductor ~8,500' of overhead conductor, upgrade existing line recloser with advanced controls, installation of 3V0 on substation transformer, install bi-directional regulator controls.

Example 2:
Original Size: 4,500kW
Decreased Size: 750kW
Driver for Decrease: Overload/Non-compliance with Voltage ANSI Range A/Protection Concerns
Status: Study
Comments: Site proposed to interconnect to a 23kV sub-transmission circuit which supplies several distribution substations. The study considered all proposed and interconnected DER on the sub-transmission network as well as the distribution system served by the 23kV network. Engineering analysis identified potential high voltage, conductor overload, and protection issues with the interconnection of 4,500kW. Major system modifications required to accommodate 4,500kW included replacing station recloser and control with hardware capable of load encroachment schemes, change existing protective device settings at multiple locations, install approximately 15,000 feet of underground cable, reconductor approximately 30,000 feet of overhead conductor. In order to avoid system upgrades project reduced to 750kW.

Example 3:
Original Size: 6,120kW
Decreased Size: 2,750kW
Driver for Decrease: Overload
Status: Project Cancelled
Comments: Engineering analysis identified potential conductor overloads with the interconnection of 6,120kW. To accommodate the full 6.12MW substantial modifications such as a new circuit, substation, or major transmission project would be required . Site reduction to 2,775 kW was found to be acceptable with ~12,000 ft. of reconductoring required to avoid overload. Customer was informed of required system modifications during the study and high-level costs of $1.4 to $1.8m for reconductoring were provided. during early stages study. Option to decrease site size to 2,000 kW to avoid conductor overload was also presented.

Example 4:
Original Size: 10,000kW
Decreased Size: 3,150kW
Driver for Decrease: Overload
Status: Project Cancelled
Comments: Engineering analysis identified potential conductor overloads with the interconnection of 10,000kW. To accommodate the full 10MW substantial modifications such as a new circuit, substation, or major transmission project would be required . Site reduction to 3,150 kW was found to be acceptable with ~17,160 ft. of reconductoring

required to avoid overload. Customer was informed of required system modifications during the study and high-level costs of $2 to $2.6m for reconductoring were provided. Option to decrease site size to 1,1000 kW to avoid conductor overload was also presented.

Example 5:
Original Size: 6,720kW
Decreased Size: 2,220kW
Driver for Decrease: Non-compliance with Voltage ANSI Range A/Power Quality/Overload/Protection Concerns
Status: Study
Comments: Engineering analysis identified unacceptable voltage and fluctuation issues, equipment overloads and saturation of equipment on the area electric power system. To accommodate the full 6.72MW substantial modifications such as a new circuit, substation, or major transmission project would be required. Site reduction to 2,200 kW was found to be acceptable with the following system modifications, replace 900 kVAR capacitor with advanced control unit, enable co-generation on circuit regulators, replace multiple reclosers with units integrated with advanced controls, install two new reclosers integrated with advanced controls, install zero sequence over voltage protection (3V0) on the substation transformer. Total estimates including cost to extend the area electric power system to the site are approximately $1.3 million.

Example 6:
Original Size: 3,000kW
Decreased Size: 200kW
Driver for Decrease: Protection Concerns
Status: Project Cancelled
Comments: Engineering analysis identified the need for 3V0 protection on the station transformer in order to accommodate 3,000kW.

Example 7:
Original Size: 6,360kW
Decreased Size: 2,180kW
Driver for Decrease: Overload/Non-compliance with Voltage ANSI Range A
Status: Study
Comments: Engineering analysis identified unacceptable voltage ranges on the area electric power system. To accommodate the full 6.36MW substantial modifications such as a new circuit, substation, or major transmission project would be required. Site reduction to 2,180 kW was found to be acceptable with the following system modifications, re-conductor approximately 8,500 ft. of overhead conductor and replace

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existing 167kVA line regulators with 333kVA units integrated with advanced controls. Estimated cost for these system modifications were approximately $2m. Option to reduce size to 1,040kW was presented in order to avoid 6,300' of re-conductoring. Reduced estimate for system modifications were approximately $1m.

d. National Grid's Distribution Planning and Asset Management engineers analyze the impact of Distributed Energy Resources (DER) on the electrical distribution power system's performance at commencement of discrete System Impact Study (SIS) agreements. The analysis conducted identifies potential concerns due to DER interconnections and provide system modifications required to maintain compliance. Studies consider all interconnected and proposed DER within the analysis. Existing system issues are addressed as system improvements. Currently issues due to DER are assigned to the project which upsets the balance of any compliance issue. Modifications range from significant infrastructure upgrades to DER project curtailment. As DER continues to develop and more components of the distribution, sub-transmission, and potentially transmission system become impacted, it is expected to become increasingly difficult to assign system costs to any one project.

   The Strategic Advancement of DER program is designed to proactively install required equipment and controls that are needed to enable the interconnection of DER while maintaining core compliance obligations. The program will determine the efficiency of installing equipment in preparation for DER versus when required by a particular project. While there would be a shift in costs that might be normally borne by a DER owner to customers, the desire is that proactively installed upgrades will help enable more DER connections by reducing electric system limitations and timelines to get DER on-line. In addition, there are existing programs, such as 3V0 and VVO, that advance technologies recommended as part of the Strategic DER Advancement programs. Also, these investments are in line with standard actions that the Company currently performs to maintain and address immediate system performance and reliability needs for all customers.

e. In the context of this response, "the Company" refers to National Grid as a whole.

   See following table for total number and total capacity of interconnected DER projects and total number and capacity of DER projects in queue for each jurisdiction:

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State	Connected		Pending MW	
	Number of Applications	Capacity (MW)	Number of Applications	Capacity (MW)
MA	52,963	1,273	5,243	1,583
NY	21,078	555	1,982	2,312
RI	7,409	250	1,471	746
Total	81,450	2,078	8,696	4,641

In relation to service territory size New York is approximately three times the size of RI, yet only has twice as much interconnected DG. In addition to the data provided above, system-wide we have received 13 GW capacity of DG applications and connected 2 GW to our system as of October 1, 2019. Developers in all jurisdictions continue to cancel or withdraw applications due to various issues. New York cancellation rates are notably higher than New England, attributed primarily to lower state incentive levels, anticipated higher interconnection cost and municipal imposed construction moratoriums. While small rooftop or "simple" applications account for most application volumes (90%), it is the larger (stand-alone) complex applications that account for the clear majority (94%) of the capacity proposed to be installed. Incentive Programs in all three states coupled with Federal Investment Tax Credit are expected to continue to drive application volumes over the next 3-5 years. In calendar year 2018 alone, the Company has received 3.3 GW of applications, a 107% year over year increase. The uptick has been attributed to the SMART (Solar MA Renewable Target) program in Massachusetts, a regulatory change in allowed system sizes from 2MW to 5MW in New York and an expansion of the Public Entity definition for remote net metering in Rhode Island. So far this calendar year, we have received 2.8GW of applications of which 2.3GW are received in UNY. This is 100% increase over CY 2018 for same duration. The main reason for increase in application intake is due to Energy Storage Systems being eligible for Value Stack Incentive program in NY. MA. Massachusetts SMART has prompted tremendous interest in larger standalone applications, the Company is reaching saturation in many of its rural areas in Central and Western Massachusetts. This saturation is resulting in a need for major system modifications to interconnect the DG, including upgrading existing substation transformers and constructing new substations. Moreover, the growth is requiring New England Power to undertake a detailed Transmission Study in collaboration with ISO-NE and other Affected System Operators, to understand the level of Transmission modifications that are going to be necessary to accommodate the interconnection of the large quantity of projects. Consequently, the Company is revisiting its interconnection tariff with Massachusetts Department of Public Utilities (DPU) and its ways of working with ISO-NE to be able to support these new market conditions. Along with volume increases, the Company is also seeing dramatic increases in the size of complex applications as developers attempt to realize greater economies of scale and pursue Community Solar incentive programs. On average, projects have essentially doubled in size since 2016 and in fact, Rhode Island is currently studying multiple projects in excess of 20MW's. Similar to MA, the Company is working with stakeholders in RI to review the interconnection tariff in light of increased requirements to study and upgrade the transmission system in RI to accommodate more and larger projects.

Generally speaking all jurisdictions are seeing a relatively high level of DER aggregation in rural areas where there is available land. Traditionally the electric system serving these areas are designed to serve small amounts of load for one-way power flow. The systems do not have the available hosting capacity and are not robust enough to interconnect larger DER sites that introduce multi-directional power flow. Issues resulting from these interconnections include voltage, power quality, and protection coordination. System modifications including substation modifications, line reconductoring, advanced control and monitoring, and advanced protection schemes are required to maintain compliance obligations. Substation and Distribution line and equipment modifications can be in the multi-millions and take in excess of 12- 24 months to execute.

As an example of correlation, New England Power (NEP) recently performed a transmission level cluster analysis of approximately 400MW in the Western area of the Massachusetts jurisdiction. Analysis identified unacceptable voltage concerns which could have required significant transmission infrastructure upgrades and installation of Dynamic Volt-Amp reactive compensation at several area substations prior to interconnection of any DER. Advanced capacitor and regulator programs (supported by the Massachusetts DPU) were leveraged to mitigate voltage concerns and avoid timely and expensive transmission upgrades. This experience highlighted the need for more extensive integrated transmission and distribution System Planning to appropriately leverage the most efficient solutions to resolve transmission system compliance issues due to the aggregation of DER. In the example above the efficient solution leveraged distribution advanced control technologies to avoid major transmission upgrades.

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All 3 jurisdictions have 3V0 protection scheme installation programs, Massachusetts and New York have procured mobile 3V0 units, and NY is considering acceleration of 3V0. In MA some of this work is being approved under the grid modernization program.

R-I-23

Request:

The Company discusses vegetation management in Section 3 of its proposed FY 2021 ISR Plan annual filing. Provide the following details and information:

a. The Company's detailed specifications for the cycle pruning program including, but not limited to, those which are provided to the contractors it engages for cycle pruning activities. This should include both distribution and subtransmission, as well as any drawings depicting the clearing specifications.

b. The Company's detailed specifications for the enhanced hazard tree mitigation ("EHTM") program including, but not limited to, those which are provided to the contractors it engages for hazard tree removal activities. This should include both distribution and subtransmission, as well as any drawings depicting the clearing specifications.

c. The latest cost benefit analysis for the cycle pruning program.

d. The latest cost benefit analysis for the EHTM program

e. What is status of Diplodia corticola and the Company's proposed work associated with infected oak trees in FY2021?

f. The Company has reduced its EHTM budget from $2.25M in FY2020 to $1.75M in FY2021. What is the rationale for the reduction?

g. The Company proposes a budget increase of $200,000 for core activity to focus on "pockets of poor performance"
   i. How will pockets of poor performance be identified and prioritized?
   ii. How did the Company derive the $200,000 budget?
   iii. How will the Company measure the cost/benefit of additional investment?
   iv. On page 7-the Company states that "our routine pruning and hazard tree programs have not proven effective." What vegetation management activities does the Company propose for the poor performing pockets? For the circuits receiving additional work, will the activities be continuously applied in the future, in addition to routine pruning and hazard tree removals?

Please see response on page 2.

Prepared by or under the supervision of: Ryan Moe

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Response:

a. Please see Attachment R-I-23-1 and Attachment R-I-23-2.

b. Please see Attachment R-I-23-3.

c. Please see Attachment R-I-23-4.

d. Please see Attachment R-I-23-5.

e. As mentioned in the FY 2020 ISR in Docket No. 4915, Diplodia corticola has been found in oak trees following Gypsy Moth infestation. The Company has not focused solely on Diplodia corticola, but on all oak mortality, largely due to the infestation of Gypsy Moth. The Company has not tracked whether these oak trees were killed by Gypsy Moth or if they died later due to a fungus such as Diplodia corticola.

f. The EHTM budget has more than doubled since FY 2017 in response to the Gypsy Moth infestation. The Company increased the EHTM budget by $300,000 in FY 2018, and by $1 million in FY 2020 to address large numbers of dead oak trees. In FY 2020, almost the entire EHTM budget will be spent on oak removals.

   Typically, the EHTM program would target circuits with a history of tree-related reliability issues. In FY 2021, the Company plans to begin shifting back to this approach. This does not mean that all the dead oak trees have been removed, just that it is not necessary to sustain the same level of investment toward oak removals. Dead oak trees will continue to be removed on circuits that are part of the EHTM program, and the Company will still be dedicating a significant portion of the $1.75 million EHTM budget to removing heavy concentrations of dead oak trees throughout the State of Rhode Island.

   In addition to this, the Company has also requested additional funds to address pockets of poor performance. Many of the areas that the Company plans to target have small pockets of dead oak trees as well as other tree-related issues.

Prepared by or under the supervision of: Ryan Moe

g.

i. Pockets of poor performance will be the areas that experience the most tree-related outages during FY 2021. These areas will be prioritized based on field surveys conducted by certified arborists. Areas that have the most imminent tree issues will be done first.

ii. The Company set the budget at $200,000 in order to have a measurable impact on reliability to test the effectiveness of the program, and also to not significantly increase the overall vegetation management budget. If the program proves the be effective, the Company may propose to expand it in future ISR plans.

iii. The Company will measure the effectiveness of this investment in a similar manner as the current cost/benefit analysis for both the cycle prune and EHTM programs. See Attachments R-I-23-4 and R-I-23-5.

iv. The Company will evaluate each tree in the pockets of poor performance to determine the appropriate prescription for them. This may include increased minimum clearances compared to the current specification, removal of all branches hanging over the wires, and extensive hazard tree removal. The Company is optimistic that this will be a one-time investment in each area. In future years, these areas will be maintained by routine vegetation management practices.

National Grid Rhode Island Distribution Line Clearance Specification Fiscal Year 2021	Revision No.	2
		Page 1 of 11
	Date:	7/2/2019

FOREWORD

This specification documents the objectives, practices and procedures for vegetation management on National Grid companies' distribution circuits in **Rhode Island only**. The specification also defines the responsibilities of National Grid vegetation management personnel and contractors, identifies procedures to be followed by contractors performing all work and defines the requirements to maintain vegetation acceptable to the Company.

Questions or inquiries regarding information provided in this document should be referred to the National Grid's Manager of Vegetation Strategy.

Bert Stewart III
Bert H Stewart III
Manager
Vegetation Strategy

*Anne Marie Moran*__________
Anne Marie Moran
Manager
T&D Forestry, New England

Date: 7/2/2019

Date of Review/Revision:		
Revision	**Date**	**Description**
0	April 20, 2015	Original Specification
1	June 22, 2017	Edited language regarding police details
2	July 2, 2019	Edited section regarding service drops

nationalgrid

RI DISTRIBUTION LINE CLEARANCE SPECIFICATIONS **Updated 7/2/2019**

I. Scope/Intent

1.1 These specifications cover the cutting, clearing, pruning, tree removal and herbicide treatment of vegetation along overhead electric distribution lines and the corresponding substations. The intent is to define the minimum clearances to be obtained between the overhead conductors and vegetation that will be acceptable to National Grid. These specifications are strictly for use on overhead line maintenance pruning projects. This is not a specification to be used for enhanced hazard tree removal, new construction clearing or rebuild construction clearing.

II. Program Objectives:

2.1 The goals and objectives of the NGRID Distribution Line Clearance program are to provide safe, reliable, electric service through a cost effective, integrated vegetation management program. NGRID acknowledges differences in the manner in which various landowners respond to the need for routine line clearance activities, together with occasional differences in easement rights. Therefore, these specifications are designed to address:

- the minimum clearance requirements necessary to sustain safe, reliable electric service while striving to satisfy the concerns of sensitive customers,
- and the optimum clearance requirements necessary to sustain an appropriate level of safety and reliability.

III. Definitions:

Maintained Area: Generally defined as an area where the landowner or occupant is mowing the lawn and/or caring for gardens, ornamental shrubs or trees in the area under and immediately adjacent to the distribution poles. It includes commercial land uses such as business areas, parking lot edges and the tree lawn areas along urban and suburban streets. Un-maintained areas, of course, hold the opposite of these characteristics. It should be noted that within residential (maintained) areas there may be small sections of un-maintained property between yards or along the roadside of residential front lawns, etc. These small sections shall be treated as maintained areas for the purposes of this specification.

Mature Tree Line: A generally straight and contiguous line of trees nine (9) inches d.b.h. or greater, that mark the boundary between the forested edge and the maintenance corridor. In the case of an existing mature tree line, there may be individual mature trees that are rooted closer to the pole centerline than the common mature tree line. In these instances the mature tree line continues behind those individual trees.

Maintenance Corridor: The area physically located under and alongside the overhead distribution feeder bounded by the mature tree line when one exists. In the absence of a mature tree line the maintenance corridor is defined as the area that is at least ten (10) feet either side of the pole centerline or equal to the previously maintained dimensions if greater than ten (10) feet.

Service Drop or Service Line: The last span of triplex or open three wire extending to the building or meter pole or a multi-span run of either triplex or open three wire that serves a single customer. This does not include street light services.

Secondary: The conductor, either triplex or open wire, which extends from the transformer to the Service Drop. Secondary spans may run along under primary spans or separately.

Street Light Secondary: The conductor, either triplex or open wire, which leaves the primary pole to pole configuration and extends out to service a street light or lights.

IV. <u>Scope of Work:</u>

4.1 Pruning Standards: All pruning shall be performed in accordance with ANSI A300 standards as well as the Best Management Practices – Tree Pruning publication. All cuts shall be made at a parent branch or limb, so that no stub shall remain. In cutting back a branch, the cut shall be made at a crotch or node where the branch being removed is at least one-third the diameter of the parent limb. All pruning cuts shall be made in accordance with proper collar cutting methods, utilizing drop crotch principles to minimize the number of pruning cuts, promote natural growth patterns, and maintain tree health and vigor (ANSI A300). Climbing irons or spurs shall not be used in pruning a shade/ornamental tree to be saved. Tree wound dressings shall not be applied.

4.2 Line Clearance within Maintained Areas: All overhead primary lines shall be pruned to provide a minimum of ten (10) feet of overhead clearance, a minimum of six (6) feet of side clearance from the outermost phase and a minimum of ten (10) feet of clearance below the wires. The contractor shall recognize that the use of ANSI A300 standards and techniques will result in clearances beyond the dimensions noted above.

4.2.1 The main trunk of the tree or major leads which are structurally sound and healthy may be left growing within these distances as long as none of the smaller diameter end branches are within the clearance dimensions. In that case the lead must be removed.

4.2.2 Where greater clearances have been achieved in previous cycles, the pruning shall be completed so as to re-establish the clearances in a manner that equals or exceeds the previous clearance conditions.

4.2.3 The contractor shall ground cut any new volunteer growth capable of growing into the wires from around poles, guys, fences, etc. within the maintained yard areas after notifying the property owner.

4.2.4 It is an objective of National Grid's program to continually strive to reduce the number of under-wire tree and branch growth that will continually require pruning, by removing as many stems and growth as possible on each cycle. The Contractor is expected to emphasize this type of removal through the landowner contacts made by their customer contact personnel.

4.2.5 Contractor shall exercise extreme care when pruning ornamental plantings. Species, growth rates and growth characteristics should be taken into account and may require differing clearances.

4.2.6 All slash from pruning in maintained areas shall be disposed of through chipping. Large diameter wood may remain on site provided it is cut into manageable lengths and piled neatly. Smaller debris shall be raked up and removed so as to leave the property in a condition equal to the start of work.

4.3 Line Clearance Outside of Maintained Areas: All overhead lines shall be pruned to provide a minimum of fifteen (15) feet of overhead clearance and six (6) feet of side clearance from the outermost phase.

4.3.1 Along off-road sections the contractor shall completely remove all side branches that extend into the maintenance corridor from below and beside the lines in order to "box out" the maintenance corridor. This practice will minimize future pruning efforts as well as improve storm restoration and line inspection efficiencies.

4.3.2 Where greater clearances have been achieved in previous cycles, the pruning shall be completed so as to re-establish the clearances in a manner that equals or exceeds the previous clearance conditions.

4.3.3 The contractor shall ground cut all trees and shrubs which have the ability to interfere with the conductor out to the limits of the existing maintenance corridor. Where a maintenance corridor does not already exist, ground cutting shall be performed for a minimum distance of ten (10) feet either side of centerline. Ground cutting shall include stems of eight (8) inches d.b.h. or less, all as part of the fixed price bid. Along individual spans that have been previously maintained using National Grid's past eight (8) foot targeted ground cutting specification (trimming and removal) the same approach shall be utilized.

4.3.4 Where trees beyond the limits of the maintenance corridor are extending into the corridor, the contractor shall either prune those limbs back or have the option to remove the tree as part of the fixed price bid. For trees, eight

(8) inches d.b.h. or less, where the top of the tree is leaning out into the corridor so that topping would be the only possible correction, the contractor shall ground cut that tree as part of the fixed price bid.

4.3.5 Stumps shall be cut flat and as close to grade as possible.

4.3.6 All slash along the roadway or near residences shall be disposed of by chipping or mowing/mulching. Where practical, chips may be blown back onto the site without creating large chip piles. On off-road, un-maintained sites, slash shall be mowed/mulched or neatly windrowed to the edge of the maintenance corridor and cut to lie close to the ground, away from sensitive locations. No debris shall be left anywhere that will potentially block access, significantly alter any drainage or water resource, or create any unsafe condition for the public. Alternatives to these practices must be approved by National Grid's Forestry representative and by the current landowner.

4.4 All dead or damaged overhead limbs, branches or leads that are capable of falling onto overhead primary wires from above or along side the right-of-way and potentially causing a tree outage, shall be removed at the time of pruning, and included in the fixed price bid.

4.5 For all pine species growing above the overhead clearance limits with boughs overhanging primary conductor - the contractor shall shorten all overhanging boughs so to reduce the length of the branch by approximately 1/3 without removing all needle growth from the entire branch. This shall be done in a progressive manner beginning at the upper clearance dimension (10 or 15 feet) and working upwards generally two (2) whorls in the tree as necessary to reduce the likelihood of a long pine bough loaded with ice or wet snow, drooping down or breaking onto the conductors.

4.6 Pruning Clearance for Secondary and Service Lines:

4.6.1 All secondary wire (triplex and open wire), other than that serving street lights only, shall be pruned to provide a minimum of eighteen inches of clearance from wire to vegetation.

4.6.2 All service wires (triplex or open wire) and street light secondary on the circuit shall be inspected at the time of scheduled vegetation maintenance. For branches that are either making hard contact with the service wire, pushing on or creating tension enough to force the wire out of a natural arc, or redirecting the wire out of a straight-line run, the vendor shall do whatever pruning is necessary to correct that situation. The entire service drop need not be pruned, only the point of conflict.

4.6.3 For open wire services, pruning is required for all the situations noted in 4.6.2 as well as anytime vegetative growth is forcing the three wires out of their normal configuration. The vendor must take extra care when pruning around open wire services so not to cause a service interruption to our customers.

4.7 Multiple Circuits and Under-builds: The contractor shall prune all distribution circuits on a pole unless otherwise called out on the bid documents. Where a distribution circuit is under-built below a sub-transmission the contactor is responsible for the pruning of both the distribution circuit as well as the over-built circuit utilizing the specification of the higher voltage circuit unless otherwise directed in the bid documents. The contractor is also responsible for work on any primary, secondary or service tap running off the sub-transmission line along that specific distribution circuit. Any exceptions to the above will be explained at the time of bidding. Reference the appropriate sections of either National Grid's Sub-T IVM and/or Sideline specifications depending on the under-built situation.

4.8 Circuits along Transmission Rights-of-Way: The contractor shall employ this specification on all sections of distribution circuits that run along segments of transmission rights-of-way except for areas where the distribution circuit is actually under-built on the same pole. In those cases the above section will apply. Any exceptions to the above will be explained at the time of bidding.

4.9 Substation Clearances: All vegetation within 10' of the substation fence shall be pruned, from ground to sky, removed and chipped and no overhanging branches shall be allowed to remain. Where shrubs and trees have been planted for screening purposes and are rooted within the 10' distance, only the fence side branches shall be removed. Any volunteer growth (natural regeneration) rooted within the 10' distance shall be removed.

4.10 Vine Control: All vines growing on poles, guy wires, stub poles or towers shall be cut so as to create a "growth gap" of 4 feet and treated (where appropriate) with a herbicide approved by the company.. Contactors should not attempt to remove vines from any structure.

4.11 Hazard Tree Inspection and Removal: Other than work required in previous sections, the removal of any tree over 8 inches d.b.h. within the maintenance corridor or outside the maintenance corridor shall be considered a hazard tree removal and is outside the fixed price bid.

4.11.1 While pruning the circuit, the contractor's personnel shall perform a visual inspection of each tree along the circuit in order to identify potential defects and determine the potential risk for the tree to cause an interruption over the length of the pruning cycle. The crew shall work closely with National Grid Forestry representative to determine potential hazard trees, preparing a list of trees in accordance with National Grid's Hazard Tree Reporting Form. The completed lists of potential hazard trees shall be regularly provided to the Forestry representative for review and approval prior to removing any of those specific trees. Exceptions to this procedure may be approved to enable removals of trees that have been pre-identified as hazard trees by National Grid representatives, trees that pose an imminent risk, or to authorize hazard tree removals in off-road areas where a skidder bucket is already on site.

4.11.2 Once a crew completes the removals on an approved list they shall note the completion details on the Hazard Tree Reporting Form. This form shall be submitted to the Forestry representative on a timely basis. Once the list is audited the contractor may submit an invoice for that specific work.

V. <u>Contractor Requirements</u>

5.1 The Contractor shall do all work and furnish all labor including supervision, tools, machinery and transportation necessary for the pruning, removal and herbicide treatment of trees to provide acceptable vegetation clearance for overhead lines of National Grid. Work at the fixed price rates will be designated on the distribution circuit maps, and identified in the pre-bid documents. Work at the fixed price is based on overhead primary miles of line, and includes pruning, tree and lead removal and herbicide treatment to all primary, secondary, service drops, and substation fence areas as clarified in the Work Scope section of this specification. Work at unit prices and/or hourly rates as also defined in the Work Scope section will be designated at the pre-bid meeting or by a National Grid Forestry representative as required.

VI. <u>Contractor's Responsibility</u>

6.1 The Contractor shall provide all necessary supervision, labor, material, tools and equipment for the safe execution of all work covered by these specifications.

6.2 The Contractor shall employ a competent field supervisor and customer contact person(s) acceptable to the Corporation, in addition to the crew Foreman and senior Company management. Notification personnel shall be qualified in tree identification including identification of "proper under powerline trees". The supervisor shall be available to the Corporation at all reasonable times during the entire extent of the project and/or contract. In addition, at least one member of each stand-alone crew or unit of crews shall be fluent in the English language and on-site.

6.3 The Contractor shall comply with all building and sanitary laws and all Federal, State, County, Town and Municipal laws, ordinances and regulations pertaining to the work. The contractor shall be responsible for obtaining all permits necessary to perform the work unless otherwise provided by National Grid.

6.4 The Contractor shall notify each landowner and inform them of the clearing, removal, pruning and herbicide work to be done, and where appropriate, agree on access point(s), before crossing the property and then abide by the same. The Contractor shall designate a Customer Contact Person(s) for each project they are awarded and communicate that name and phone contact information for that person to the National Grid forestry representative for that project.

6.5 In the event that the Contractor cannot locate the landowner after using all reasonable measures, or upon locating them is aware of an objection to the work to be performed, the Contractor shall document the landowners concern and then notify the National Grid's forestry representative within 24 hours in order to obtain specific instructions and/or their permission prior to commencing work on that property.

6.6 In addition to the above notifications, where herbicide applications will be made, the Contractor must follow any and all current notification requirements of any applicable regulations.

6.7 The Contractor shall be held solely liable and indemnify National Grid fully for any and all claims and legal expenses for damage to crops, land, trees or otherwise resulting from such violations, failure or damages arising out of the Contractor's negligence. The Contractor shall not be liable for claims or suits for damage to property if the work causing such damage is done under specific direction from NGRID.

6.8 The Contractor shall replace or make necessary repairs to all property destroyed or damaged in the course of the work and exercise due care and diligence in adequately protecting all properties, both real and personal, from damage of whatsoever nature whenever crossed over, on, or in the vicinity of the work. If the contractor neglects or fails to promptly make said repairs or make good of said destruction, the Corporation may make any and all necessary repairs to the satisfaction of the property owner and the Contractor agrees to promptly reimburse the Corporation the amount of its incurred cost and expenses.

6.9 The contractor shall inform the National Grid Forestry representative of their intent to start work at least two weeks prior to the start of any action on a feeder.

6.10 The Contractor shall implement and provide the required training and certification programs necessary to provide fully qualified Line Clearance Tree Trimmers or Line Clearance Tree Trimmer Trainees. A single Foreman may supervise multiple bucket trucks on the same project. In that case however, the minimum qualifications for the "lead" person on each of the other trucks shall be a certified qualified Line Clearance Tree Trimmer. At least one other employee on the truck shall be at least a qualifying Line Clearance Tree Trimmer Trainee, in accordance with all applicable OSHA requirements.

6.11 The Contractor shall submit a weekly time report to the National Grid Forestry representative, indicating the labor and equipment assigned to the project, amount of work accomplished, quantities and location of herbicide applications and location of the work.

6.12 The Contractor shall provide a monthly summary report to Distribution Forestry, identifying crew staffing and equipment by area as of the first of each month, to be submitted by the 5th of each month or the following Monday should the 5th fall on the weekend. The report shall also identify work type (e.g., such as hourly, new construction, danger trees, mowing; lump sum or unit price) by project, percentage complete for all fixed price projects, and anticipated completion dates.

6.13 The Contractor shall provide a monthly OSHA injury summary report in a format supplied by National Grid for the previous month, no later that the 10th of the month or the following Monday should the 10th fall on the weekend. The data in the report shall be separated by state as well as reported for the overall Contractor Company for any and all United States operations.

6.14 By April 10th of each year, the contractor shall provide a list of employees and Aerial lifts that could reasonably be expected to work on National Grid's property to Distribution Forestry. This listing shall include:

Employees:

- identify the current pay classification of each employee, together with their union certification level,
- the date of their progression to their current pay level,
- the dates each employee completed their required OSHA safety and other training, or retraining, including any annual refreshers,
- the date each employee last demonstrated their tree rescue and climbing proficiency
- the date each employee completed first aid and CPR training,
- identify each certified pesticide applicator and their certification number.

Aerial Lifts:

- The truck number and date of dielectric testing
- The next scheduled dielectric test date

6.15 The contractor shall provide a unit cost per tree for the removal of potential hazard trees from the three phase portions of the circuit, as well as “high risk target” hazard trees from the single-phase portions. See the attached Addendum # 1, Hazard Tree Tree Removal, Unit Price Schedule to be bid separately from the fixed price project. National Grid reserves the right to award**,** in whole or in part, the removal of hazard trees for each bid package on the basis of these unit price costs, or to do the work at the contractor’s current hourly rates.

VII. Acceptance of Work

7.1 At appropriate intervals, the Contractor shall report and review the work completed to date with National Grid’s Forestry representative. The Contractor may then invoice for the percentage of the work completed and approved by National Grid.

7.2 Near completion of the work, the Contractor shall notify the National Grid Forestry representative that the entire project has been reviewed by the contractor’s supervision and is now ready for inspection. Upon review and acceptance of all required work including the resolution of any and all required corrective actions as well as any outstanding damage claims, the NGRID Forestry representative will give the Contractor permission to submit a final invoice for payment.

7.2.1 Traffic detail costs associated with re-work or corrective action shall be borne by the Contractor.

7.2.2 Police detail costs for any work not completed by the end of the fiscal year (March 31st) shall be borne by the Contractor. National Grid has the discretion to make allowances for circumstances outside of the Contractor’s control. (Storms, requested outages, etc.)

7.3 The contractor shall understand, per their signed Master Purchase order with NGRID that time is of the essence with respect to the performance of this work. The contractor shall take all appropriate actions necessary to complete the work on schedule. Those actions shall include among other things, the use of overtime, the use of supplemental labor crew resources from outside areas, and the use of subcontractors, not withstanding the NGRID requirement for advanced approval of all subcontractors. All actions employed by the contractor to meet schedules are at their cost and shall not affect the lump sum contract amount. In the event of extenuating circumstances defined by NGRID, the company reserves the right to extend project completion dates.

FOREWORD

This specification documents the objectives, practices and procedures for vegetation management on National Grid companies' sub-transmission electric roadsides and rights-of-way in **New England only**, and specifically addresses sideline and hazard tree pruning and removal. The specification also defines the responsibilities of National Grid vegetation management personnel and contractors, identifies procedures to be followed by contractors performing all work and defines the requirements to maintain vegetation acceptable to the Company.

Questions or inquiries regarding information provided in this document should be referred to the National Grid's Manager of Vegetation Strategy.

Bert Stewart III
Bert H Stewart III
Manager
Vegetation Strategy

*Anne Marie Moran*________
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Manager
T&D Forestry, New England

Date: 5/9/2017

Date of Review/Revision:		
Revision	**Date**	**Description**
0	August 9, 2013	Original Specification
1	July 16, 2014	Updates for 2015 Procurement Event
2	April 21, 2015	Updates for 2016 Procurement Event
3	June 16, 2016	Date Updates for FY18 Procurement Event
4	May 9, 2017	Updates for FY19 Procurement Event

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LIST OF APPENDICES

1.0 Introduction

1.1 Purpose

The purpose of this specification is to document the requirements for sideline pruning, hazard tree removal and IVM on sub-transmission electric roadsides and rights-of-way for National Grid in New England. This specification defines:

- Objectives, strategies and approved practices and procedures for sideline pruning and hazard tree removal on sub-transmission electric roadsides and rights-of-way;
- Clearance requirements between conductors and vegetation acceptable to National Grid for maintaining reliable electric sub-transmission service;
- Responsibilities of National Grid Forestry personnel and contractors;
- Procedures to be followed by contractors performing all work within the scope of this specification.

The Vegetation Strategy group is responsible for preparation of this specification. Company Foresters will manage the work performed by the contractor.

1.2 Scope

The requirements of the specification apply to all National Grid companies sub-transmission electric roadsides and rights-of-way in New England.

2.0 Definitions

Buffer – Areas of vegetation preserved on the right-of-way, on both sides of selected improved road crossings, yards, for the purpose of minimizing the visual impacts and linear views of the right-of-way for motorists.

Capable – Tree, shrub, and vine species that have the ability to grow into within 1 foot of conductor.

Danger Tree – A tree on or off the right-of-way that if were cut or failed could contact electric lines.

Hand Cutting – Vegetation management method in which woody vegetation is felled through the use of hand tools, including chainsaws and brush saws.

Hazard Tree – Danger trees which due to species and/or structural defect are likely to fail and fall into the electric facility.

IVM – IVM is an adaptation of Integrated Pest Management (IPM) where the pest is tall growing, capable vegetation. IPM/IVM is a system of controlling pests in which pests are identified, action thresholds considered, all possible control options evaluated, and selective physical, biological controls are considered. When chemical controls become necessary to control and prevent the growth of capable, tall-growing woody species, The Company is committed to employing selective, targeted applications. These treatments shall use approved herbicide products and mixtures that target specific plants or plant communities in a manner calculated to control and eliminate the tall-growing, capable woody species, while preserving as much of the small, compatible woody shrub and herbaceous vegetation as is practical.

Pruning – the cutting and removal of tree branches to provide specified clearance distance between vegetation and the conductors. See ANSI A300 for additional detail.

Roadside – The area physically located under and alongside the sub-transmission line bounded by the mature tree line on the field phase side when one exists. In the absence of a mature tree line the maintenance corridor is defined as the area that is at least fifteen (16) feet either side of the pole centerline or equal to the previously maintained dimensions if greater than fifteen (16) feet.
Roadside may include areas: 1. where the landowner or occupant is mowing the lawn and/or caring for gardens, ornamental shrubs or trees in the area under and immediately adjacent to the sub-transmission line/poles; 2. commercial land uses such as business areas, parking lot edges and the tree lawn areas along urban and suburban streets.

Right-of-Way (ROW) (Off-Road definition) - For this VM Spec (Sub-Transmission) a ROW is a cleared corridor of land over which electric lines are located. The companies may own the land in fee, own an easement, or have certain franchise or license rights to construct and maintain electric facilities. This definition does not address the specific width of any ROW. Specific widths will be supplied by the Company where necessary.

Sensitive Area – Areas on rights-of-ways where legal, visual, or environmental impacts/concerns require compromises to the general Vegetation Management Program.

Slash – All branches, tops, small diameter main stems and debris resulting from any cutting operation.

Sub-transmission – Can include electric lines 13kV – 46kV in New EnglandIdentified in the sub-transmssion work plan..

Tree Removal – The cutting and felling of trees, including wood and brush disposal.
Water – Standing or running water, existing at the time of maintenance operations, which has impact outside the right-of-way.

Wire Zone/Border Zone – the wire zone is defined as that portion of the right-of-way floor that is situated directly beneath the conductor for a distance extending approximately ten (10) feet to either side of the conductor. The border zone is that portion of the right-of-way floor situated to the outside of the wire zone extending to the right-of-way edge. It is sometimes referred to as a transition zone between the wire zone and the adjacent forest edge. The wire zone mid-span is the portion of the span where the conductor is at or near its lowest ground clearance distance, generally 60-70% of the span length.

3.0 General Policy/Requirements

- All work will be completed in accordance with the Request for Proposal document, this specification and the maps provided for each sub-transmission line.

- The contractor shall furnish all materials, vehicles, equipment, supervision and labor necessary for the completion of the work described within the timeframe and within the conditions herein set forth.

- Both sides of a right-of-way shall be worked unless instructed otherwise by National Grid Forestry staff, or noted on the maps for the project. If there is a lower voltage circuit on one side of the right-of-way it must meet the minimum side clearance for the lower voltage unless otherwise noted on the maps for the project.

- If the sub transmission circuit is located on the same structure or within the same right of way as a transmission circuit , clearances must be obtained to at least the sub transmission specification. (These areas are not to be skipped, unless specified by National Grid Forestry Staff).

- All vegetation management operations shall be conducted in a safe, effective manner in conformity with Federal and State laws, regulations and permit conditions.

- All vegetation management operations shall be conducted in conformance with national and regional standards including but not limited to ISO 14001.

- All state permits necessary for any vegetation management operations shall be obtained.

- All applicable state notification procedures shall be followed.

- National Grid Forestry staff, in consultation with vegetation management contractors, shall establish procedures for notifying nearby residents of all vegetation management activities conducted within a right-of-way.

- National Grid Forestry staff and/or contractors shall respond quickly to any questions or complaints relating to vegetation management from the public and/or government agencies.

- Appropriately licensed, certified and qualified contractors shall be retained to implement National Grid's vegetation management programs. Contractors shall conduct all vegetation management operations consistent with National Grid safety requirements and the ANSI Z-133 safety standard.

- National Grid Forestry shall provide local supervision, coordination and enforcement of this specification for contractors.

The document control process for this specification is as follows: The document is generally updated annually and distributed as hard copy. The applicable hard copy cover date shall be for the current fiscal year.

4.0 Safety

As a contractual term, National Grid requires all contractors to comply with all appropriate state and federal safety laws and regulations. This includes applicable sections of the Occupational Safety and Health Act (OSHA) and all worker safety-related statements.

It shall be understood and agreed to by the Contractor that vegetation management activities conducted near existing sub-transmission lines shall be undertaken while lines are presumed to be energized and operating at voltages up to and including 46kV. The Contractor shall provide competent, trained personnel to perform the work.

In order to ensure the safety of their employees, the general public and continuity of service in the energized lines, the Contractor shall exercise extraordinary precautions when conducting vegetation management activities in close proximity to structures, poles, guy wires, and anchors on roadsides and rights-of-way.

5.0 National Grid Roles and Responsibilities

5.1 Sub-Transmission Owner

National Grid companies own and are responsible for ensuring proper clearance of their sub-transmission electric facilities on roadsides and rights-of-way.

5.2 Forestry Department

The Forestry Department is responsible for system-wide design, planning, coordination and supervision of all vegetation management operations conducted near electric lines on roadsides and rights-of-way.

5.3 Location of Work

The location of work sites will be provided by the Company Forester**.**

6.0 Contractor Duties and Responsibilities

Vegetation management operations must be conducted according to this specification and according to the written directives of the Company’s on-site representative or other contract documents.

6.1 Environmental and Safety Compliance

The Contractor shall comply with all applicable Federal, State and local laws and regulations and with the requirements of all permits and approvals obtained by National Grid.

National Grid is committed to minimizing its impacts to the environment and requires contractors to demonstrate the same level of commitment as National Grid in the management of the environment. National Grid’s commitment to the environment is communicated in the National Grid – Environmental Policy (Appendix 2).

The contractor shall immediately notify the Company of any release of any quantity of oil or hazardous material. The contractor is responsible to make all required notifications of releases to appropriate regulatory agencies and to ensure that the response to the release is prompt and done in a proper manner.

National Grid Contractor Safety Requirements establish safety requirements for contractors. This document has been provided during the contractor qualification and bidding process.

All safety incidents shall be reported to the Company. The first call should be to the Company Forester. All inquires will be entered into the National Grid Incident Management System.

6.2 Qualifications

Contractor shall utilize only experienced and/or trained workers who are appropriately licensed or certified. Workers must conduct themselves professionally at all times.

Contractor shall utilize appropriately licensed or certified supervisors who are knowledgeable with regard to all aspects of vegetation mowing, and who are responsive to the guidance of the Company Foresters. Each supervisor must be able to effectively communicate with the public. They must also effectively supervise contractor crews in order to insure the satisfactory completion of the treatment operation.

6.3 Training

Contractor shall provide their employees with training that includes, but is not limited to, recognition of electrical hazards, working in proximity to energized facilities, identification of operating voltages, minimum approach distances, and other applicable rules and regulations associated with worker safety.

6.4 Commencement of Operations

Contractor may not initiate activities without a Purchase Order. Contractor shall contact Company Forestry staff if a Purchase Order has not been received by the time vegetation management activities are scheduled to commence. The contractor must return the signed acknowledgement copy of the Purchase Order to the Procurement Department before any work is done.

6.6 Notifications to National Grid

At least one (1) week prior to the initiation of vegetation management activities, the contractor must specify to Company Forestry staff the date work will begin. The contractor will notify Company Forestry staff of the approximate work schedule the contractor's crew will follow during the project. The contractor must keep Company Forestry staff informed about; crew location, conditions encountered and problems that arise as work progresses. Work shall be completed on each sub-transmission line with as few work interruptions as possible.

At least one (1) week prior to the completion of vegetation management activities, the contractor must specify to National Grid Forestry staff the date work on that sub-transmission line will end.

When working on a sub-transmission right-of-way, the contractor must supply crew work locations on a daily basis by notifying the local forestry supervisor. The location information will include the sub-transmission line name, the contractor company and foreman name, the number of crew members, and the nearest sub-transmission line structure number. Each crew shall call the appropriate National Grid Forester at the completion of the workday and when relocating to another right-of-way.

Should a contractor cause an event on a sub-transmission line, the contractor must immediately notify the appropriate Control Center. Refer to Appendix 1 for a listing of National Grid Forestry staff and Control Center contact information.

The contractor must supply completed weekly time sheet(s) with information for all time and materials worked as per direction of National Grid Forestry staff.

The contractor shall notify and provide copies of any records/reports of any regulatory inspection by federal, state or municipal officials.

6.6 Notifications to Customers/Landowners

The Contractor shall make every reasonable effort to notify nearby residents of all vegetation management activities. They shall also notify any property owner where a yard tree requires pruning or removal. The property owner shall also be notified prior to extensive widening or danger tree removal, unless National Grid has provided prior notification or otherwise specified by the Company Forester. Refer to Appendix 3 for examples of notification materials. Documentation of notification shall be maintained by the contractor and provided to National Grid Forestry staff upon request and at the completion of the project.

6.7 Documentation

The Contractor shall provide supplemental or new information regarding site conditions that affect current or future treatment operations, such as new construction, encroachments, At Time of Vegetation Management (ATVM) clearance deficiencies, hazardous conditions, significantly eroded access or right-of-way, sensitive areas and landowner concerns/requirements to the Company Forester on a timely basis.

6.8 Interaction with Public

The Company strives in every way possible to maintain good relations with the property owner and general public. The actions of the Contractor reflect on the Company; therefore, the Contractor shall give diligent consideration to the interests of property owners, tenants, and the general public, whenever involved, and shall carry out the work in such a manner as to cause a minimum inconvenience.

The contractor, or his representative, will only respond to inquiries regarding what work they are performing, where they are working, and when they will be working.

Copies of appropriate plans or permits may be shown as well. Refer all other inquiries to National Grid Forestry Staff.

Landowner complaints must be forwarded immediately by telephone to Company Forestry staff. The contractor must provide the name, address and telephone number of the major people involved, as well as the complaint or question.

6.9 Demands to Cease Operations

Handle demands to cease operations as follows:

- Immediately make the work area safe to the public, then move all personnel, equipment and materials to another property and continue work.
- Notify National Grid Forestry staff as soon as practical, if not immediately, of a demand that operations cease. Upon contacting National Grid Forestry staff, relate the chain of events and current status of the situation.
- Do not return to that site until National Grid Forestry staff has notified the contractor when and under what circumstances the crew may return.

6.10 Access to a Right-of-Way

Enter a site through the right-of-way on established roadways whenever possible. Permission to enter by any other means must be obtained from the landowner by the contractor.

Access to the right-of-way shall be limited to public road crossings. Where this is not possible, the Contractor shall obtain permission for the use of private roads, driveways, and other access to the right-of-way from the property owners involved and shall be responsible for any damage thereto. When permission for off right-of-way access cannot be obtained from the property owners involved, and other ingress/egress is unavailable, the Contractor shall notify the Company Forester or their designee.

In general, vehicular traffic shall be restricted to a twenty (20) foot wide roadway into and along the right-of-way. When present, existing roads into and along the right-of-way shall be used as the primary access, and maintained in as good or better condition for the duration of the Contractor's use. Access to the overall right-of-way is allowed only for vehicles performing selective vegetation maintenance activities. Other vehicles must remain on the designated access roads. Appropriate efforts to minimize unnecessary or excessive environmental or vegetation damage are required. Repair or replacement of excessive or unnecessary damage shall be the responsibility of the Contractor.

6.11 Site Conditions

Unreasonable site damage or destruction during any phase of the vegetation management operation by the contractor, his agents or employees, must be repaired immediately to the satisfaction of Company Forestry staff at no cost to National Grid companies. Company Forestry staff will determine what constitutes unreasonable site damage. Contractor shall make reasonable efforts to complete work during favorable site conditions so as to prevent unnecessary damage.

The Contractor shall leave all culverts, stream fords, fences, gates, walls and roads in the same or better condition as when they commenced their work. Any trees to be removed that have fence wire attached, or that are part of a permanent functional fence, shall be cut off above the top strand of wire. Care shall be taken that all fences and gates are closed or left in such condition that livestock cannot escape. If fences or gates of an active pasture along the right-of-way are in a state of disrepair prior to the start of clearing and could allow livestock to escape, the contractor shall attempt to notify both the property owner and the Company Forester of this condition. Where movement of the Contractor's equipment is required through existing fences, the Contractor shall make appropriate openings and adequate facilities for closing these openings during and after their use.

6.12 Railroads

Where the Company's right-of-way parallels or crosses railroad property, and the Contractor elects to gain access to the right-of-way from railroad property, they shall be responsible for all applicable rules, regulations and fees pertaining thereto. All associated costs will be a pass-through to National Grid.

The contractor must:

- Coordinate with National Grid to obtain a permit, if required, from the railroad near whose tracks he or she will be executing vegetation maintenance.
- Check with each railroad near whose tracks he will be treating to ensure that the contractor carries all insurance which the railroad may require. Contact National Grid Forestry staff if any problems arise.
- Provide qualified railroad trained personnel.
- Refrain from beginning vegetation work whenever a railroad has failed to provide a flagman or remove the railroad from service. Contact National Grid Forestry staff immediately so that he or she can contact the railroad.

6.13 Native American Lands

Where required to complete work upon reservations, the contractor shall employ the designated Native American personnel for the successful completion of the project.

6.14 Chainsaw Bar Lubricants

When working within a sensitive area, chainsaw bar lubricants must be biodegradable products.

6.16 Equipment

The contractor crew supervisor or foreman must be equipped with a cellular telephone.

Clearing crews should carry with them at all times a shovel, a broom, heavy-duty plastic bags or other leak-proof container, absorptive clay and activated charcoal (Chemical Spill Kit or Universal Kit).

Contractor's equipment must be sufficient to maintain the highest practical level of efficiency and effectiveness. Equipment must be maintained in good visual and working condition.

6.16 Site Restoration

Work shall also include grading, mulching, and reseeding of rutted or scarified soils caused by the Contractor's operations when directed by the Company Forester. This shall include repair of all environmental damage, maintenance of stream crossings, wetlands, crop fields, fence lines, etc. which are adversely impacted by the Contractor so as to leave the right-of-way in as good or better condition than found.

Inclusion of the repair of any previously existing environmental damage, including grading, seeding, mulching, stream, culvert and ditch repair, etc. shall be specified at the time of bidding or completed on a Time and Material basis if required.

7.0 Sub-Transmission Scope of Work

7.1 Pruning Standards

All pruning shall be performed in accordance with ANSI A300 standards as well as the Best Management Practices – Tree Pruning publication. All cuts shall be made at a parent branch or limb, so that no stub shall remain. In cutting back a branch, the cut shall be made at a crotch or node where the branch being removed is at least one-third the diameter of the parent limb. All pruning cuts shall be made in accordance with proper collar cutting methods, utilizing drop crotch principles to minimize the number of pruning cuts, promote natural growth patterns, and maintain tree health and vigor (ANSI A300). Climbing irons or spurs shall not be used in pruning a shade/ornamental tree in a maintained area. Tree wound dressings shall not be applied.

7.2 Hazard Tree Inspection and Removal

Other than work required in previous sections, the removal of any tree 9 inches dbh and above, within a maintained, roadside or unmaintained area, shall be considered a hazard tree removal.

7.2.1 While pruning the circuit, the contractor shall perform a visual inspection of each tree along the circuit in order to identify potential defects and determine the potential risk for the tree to cause an interruption over the length of the pruning cycle. The National Grid Forester will work closely with the contractor to determine potential hazard trees, preparing a list of trees in accordance with National Grid's Hazard Tree Removal Form (Appendix 4). The contractor shall also submit, for approval by National Grid, an additional list of potential hazard trees found while performing the work.

7.2.2 Once a crew completes the removals on an approved list they shall note the completion details on the Hazard Tree Removal Form. This form shall be submitted to the Forestry representative on a timely basis.

7.3 Management of Wood and Brush (Slash)

Wood and brush slash may be generated during vegetation management activities. In general, where tree removal or pruning is required, the brush that has been cut may be left where it falls after being cut (diced) so as to lie close to the ground. Length of diced stems or branches should not exceed 10 feet; height of diced slash should not exceed two (2) feet. Stumps shall be cut flat and as close to grade as possible. (Contractor may choose to mow the floor, this is an option and should be discussed with the Company Forester before proceeding.)

Near public or private roads, residential or commercial areas, parks, streams, on access roads, in any sensitive area or otherwise managed properties, the brush shall be disposed of by either chipping or removal to a suitable location within the right-of-way and neatly piled, windrowed or dispersed.

When chipping is required, the chips may be disposed of by dispersing on site in non-sensitive areas. Chips shall be removed from areas of more intense landscape management such as lawns.

Where trees and limbs larger than four (4) inches in diameter at the small end are removed and the designated slash disposal is a windrow, the wood shall be neatly piled on the site, taking care not to block any access roads used by either the property owner or the Company. When the authorized slash disposal method is chipping, it may be necessary to remove the larger wood from the site to another approved area of the right-of-way and piled neatly, or moved to an approved off right-of-way disposal site.

No burning of wood or brush will be permitted unless specifically authorized by the National Grid Forester.

All species of wild cherry (Prunus serotina, P. virginiana, P. pennsylvanica) that are cut or treated during the growing season can become toxic to livestock during the wilting stage of the leaves. In addition, several species of Maple (Acer) have been identified as toxic to horses in the wilting stage. Therefore, Maple and Cherry stems, which are cut or treated in active pastures, shall be immediately removed from the pasture following clearing, or arrangements made with the farmer to utilize alternate pastures until the wilting stage and hazard has passed.

Contractors shall comply with all applicable laws and guidelines pertinent to invasive species and their management, as set forth by Government and National Grid.

7.4 Overhead Dead or Damaged Vegetation

All dead or damaged overhead limbs, branches or leads that are capable of falling onto overhead sub-transmission lines from above or along side the right-of-way and potentially causing a tree interruption, shall be removed at the time of pruning.

7.5 Pine Species

For all road-side pine species growing above the overhead clearance limits with boughs overhanging primary conductor, the contractor shall shorten all overhanging boughs so to reduce the length of the branch by approximately 1/3 without removing all needle growth from the entire branch. This shall be done in a progressive manner beginning at the upper clearance dimension (20 feet) and working upwards generally two whorls in the tree as necessary to reduce the likelihood of a long pine bough loaded with ice or wet snow, drooping down or breaking onto the conductors.

7.6 Vine Control

All vines growing on poles, guy wires, stub poles or towers shall be cut so as to create a “growth gap” of four feet and treated (where appropriate) with a herbicide approved by the company. Contactors should not attempt to remove vines from any structure.

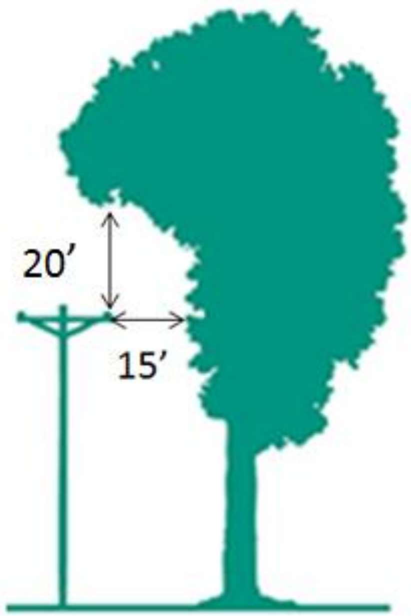
Sub-transmission work shall be carried out in a two-step process:

Step 1: Sideline pruning and floor cutting/mowing
Step 2: Follow-up herbicide treatments on off-road sections

7.7 Step 1: Sideline Pruning and Floor Cutting/Mowing

7.7.1 Vegetation Clearance - Road-side

All overhead sub-transmission lines shall be pruned to provide a minimum of 20 feet of overhead clearance, a minimum of 15 feet of side clearance from the outermost phase, or to the mature tree line and removal of capable species below the wires and within the clearance dimensions. The contractor shall recognize that the use of ANSI A300 standards and techniques will result in clearances beyond the dimensions noted above.



Where greater clearances have been achieved in previous cycles, the pruning shall be completed so as to re-establish the clearances in a manner that equals or exceeds the previous clearance conditions.

It is an objective of National Grid's vegetation program to continually strive to reduce the number of under-wire tree and branch growth that will continually require pruning, by removing as many stems and growth as possible on each cycle. The Contractor is expected to emphasize this type of removal through the landowner contacts made by their customer contact personnel unless they have signed documentation of refusal. National Grid must be notified upon refusal within 24 hours.

All slash from pruning in maintained areas shall be disposed of through chipping. The brush shall be disposed of by either chipping or removal to a suitable location within the right-of-way and neatly piled, windrowed or dispersed. Large diameter wood may remain on site provided it is cut into manageable lengths and piled neatly. Smaller debris shall be raked up and removed so as to leave the property in a condition equal to the start of work.

Herbicide treatments may be applied to road-side vegetation. This will be defined during the bidding process. **All herbicide applications MUST follow local state pesticide regulations.**

7.7.2 Vegetation Clearance - Off-Road

Prior to commencing vegetation maintenance activities in a right-of-way, the contractor MUST contact a National Grid Forester to discuss any sensitive areas within the right-of-way, which can include endangered species, wetlands, and drinking water wells. The presence of sensitive areas might

alter the type and timing of vegetation maintenance activities that will be conducted. A site specific work plan may be provided to the contractor by the National Grid Forester.

There should be no overhang above a sub-transmission line, unless there is an easement restriction or otherwise noted on the map, in which case follow Section 7.4 Overhead Dead or Damaged Vegetation. All sub-transmission lines shall be pruned to provide the maximum clearance allowed by easement. Where no easement has been obtained, prune to the established tree-line **unless an alternative clearance is approved by National Grid**.

Where greater clearances have been achieved in previous cycles, the pruning shall be completed so as to re-establish the clearances in a manner that equals or exceeds the previous clearance conditions.

Slash shall be mowed/mulched or neatly windrowed to the edge of the maintenance corridor and cut to lie close to the ground, away from sensitive locations. All slash near residences shall be disposed of by chipping or mowing/mulching. Where practical, chips may be blown back onto the site without creating large chip piles. No debris shall be left anywhere that will potentially block access, significantly alter any drainage or water resource, or create any unsafe conditions for the public. Stumps shall be cut flat and as close to grade as possible. (Contractor may choose to mow the floor, this is an option and should be discussed with the Company Forester before proceeding.) All mowing will be done in accordance with National Grid's Mowing Specification.

Alternatives to these practices must be approved by a National Grid Forester and by the current landowner.

As stated above, the contractor shall practice ANSI A300 pruning in choosing the pruning points within the tree which will often mean clearances greater than vertical/horizontal clearance distances will actually be obtained. Trees shall be directionally pruned to encourage growth away from the sub-transmission line. Pruning shall not leave any overhang over the right-of-way.

Prune or remove high risk hazard trees. Hazard trees found beyond the right-of-way and/or vertical/horizontal clearance distances that are judged to be an imminent threat to the conductors shall be brought to the attention of a National Grid Forester for approval prior to removing (see Section 6.7). Desirable species shall be retained along the edge of the right-of-way.

Any tree in the border zone that is within vertical/horizontal clearance distances shall be removed, not pruned.

Contractors shall comply with all applicable laws and guidelines pertinent to invasive species and their management, as set forth by Government and National Grid.

7.8 Step 2: Herbicide Treatments

Herbicide treatments will mainly be conducted in the off-road sections on the sub-transmission corridors. If a sub-transmission line shares a ROW with a Transmission line, then that corridor will be treated when the Transmission line is treated. This will be defined during the bidding process. All herbicide applications MUST follow local state pesticide regulations.

All treatment operations must be applied to the full specified width of the ROW. Vegetation Operations staff will determine whether the full specified width of the ROW has been treated. The contractor must, at his own expense, re-treat the site upon notification by Vegetation Operations staff that a treatment was not applied to the full specified width of the ROW. Re-treatment must be accomplished by using the application method and materials prescribed by Vegetation Operations staff. Refer to the National Grid ROW floor specification for additional details.

8.0 Management of Sensitive Areas & Wetlands

8.1 Sensitive Areas

Sensitive Areas are defined as areas on rights-of-way where legal, visual or environmental impacts/concerns require compromises to the general vegetation management program. Sensitive Areas include: public surface, public well and private well drinking water supplies; lakes, ponds, rivers, streams, and any other surface waters; wetlands; endangered species sites; agricultural areas including croplands, orchards, tree plantations and animal pastures; buffers at road crossings; buffers at residential and/or commercial yards; and easement restrictions and/or landowner agreements.

These sensitive areas have varying legal definitions in each of the states in which National Grid companies have sub-transmission facilities. Permits for vegetation management activities in these states vary as well. For purposes of this document, sensitive areas and vegetation management within them are discussed in a general way.

8.2 Wetlands

In wetlands, tall growing trees generally only occur in wooded swamps or areas that are dry for long enough periods each year to support tree growth. Generally equipment may not enter a wetland area. All tree felling in wetlands must be done by hand. Exceptions must be reviewed with the National Grid Forester prior to entering a wetland with equipment.

In remote areas, including remote wetlands, and with the National Grid Forester's approval, trees to be removed may be topped below conductor level to provide wildlife habitat and to reduce ground disturbance and clutter.

9.0 Mitigation of Impacts

If, during their operations, the Contractor causes any damage to occur to the land such as deep ruts or scarified areas, which in the opinion of the National Grid Forester could cause future erosion or interfere with access for line maintenance, the Contractor shall re-grade the site to original contours, and seed and mulch as required. Areas that do become rutted or where erosion occurs during sideline program operations will be restored per National Grid companies' policies.

The Contractor shall take reasonable precautions not to remove or damage existing low-growing vegetation, either natural or planted, which are to be preserved on the right-of-way. Where road crossing buffer vegetation, either natural or planted, has been damaged beyond reasonable repair because of the Contractor's negligence, this vegetation will be replaced at the Contractor's expense.

The Contractor shall take care not to rut or scarify the right-of-way for the duration of their operation. All environmental damage resulting from the Contractor's operation shall be permanently repaired at the Contractor's sole expense.

Mobile equipment shall not intrude into road crossing buffers, stream buffer zones or pruning and topping areas, except on designated access routes. When a tree that has been cut must be removed from such an area, it must first be limbed and the brush hand carried to the chipping location or pile site. The trunk wood may be removed by means of a winch line taking adequate care to avoid damaging residual vegetation.

In certain areas, where feasible and advantageous, the Forester may authorize the use of aerial lifts and other specialized equipment, in road crossing buffers for the purpose of pruning trees, and disposal. In no case, however, will any vegetation be cleared or any new road be authorized, other than the approved access road through the screen to facilitate the use of this equipment.

The Contractor shall take adequate precautions to protect the watercourses and wetlands from pollution and shall avoid disturbing streambeds and banks and the low-growing vegetation protecting them. Felling vegetation in or across a watercourse (such as a river, stream, or brook), should be avoided. Vegetation that is felled into a watercourse shall be removed as soon as possible and placed on high ground. Brush chipping shall be performed in such a manner that the chipped material shall not enter any watercourse or wetland area, nor accumulate in excess of four (4) inches in depth at any location.

Appendix 1
Contact Information

Vegetation Operations Staff, Control Center and Security Contact Information

SYSTEM WIDE		
Contact	**Location**	**Telephone Number**
Injury Hotline	System	866-322-5594
NEW ENGLAND		
Contact	**Location**	**Telephone Number**
NE Distribution Control Center	New England North New England South	(508)421-7879 (508)421-7885
Security	Northboro, MA	(508) 421-7970
Anne Marie Moran (Manager)	Worcester, MA	(508) 860-6925
Jason Magoon	Worcester, MA	(508) 860-6212
Eric Gemborys	Leominster, MA	(508) 614-0404
Jonathan Duval	Somerset, RI	(508) 730-4007
Seth Bernatchez	Leominster, MA	(978) 604-5308
Chris Rooney	Lincoln, RI	(401) 255-4439

Appendix 2
National Grid Environmental Policy

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Environment Policy

Our strategy is to be a recognised leader in the development and operation of safe, reliable and sustainable energy systems to meet the needs of our customers and communities and to generate value for our investors.

One of the ways we will achieve this is to protect and enhance the environment, always seeking new and innovative ways to lighten the environmental impact of our past, present and future activities.

J. Pettigrew.

John Pettigrew
Chief Executive

We commit to:

- Ensuring environmental sustainability is considered in our decision making and creating a sustainable thinking culture.
- Using resources more efficiently through good design, using sustainable materials, responsibly refurbishing existing assets, recovery and recycling.
- Ensuring our operations that have an impact on natural habitats are conducted in a manner to protect biodiversity and seeking ways to enhance the natural value of the area for the benefit of local communities and/or environment.
- Reducing greenhouse gas emissions: 45% by 2020 and 80% by 2050.
- Looking at ways to reduce the impact of climate change by implementing mitigation and adaptation measures.
- Openly reporting on our environmental and sustainability performance with employees, members of the public and other stakeholders.
- Actively working to prevent pollution which may result from our activities.
- Continually improving our environmental management system to protect the environment, reduce the risk of environmental incidents.
- Satisfying our compliance obligations.
- Actively managing the risks associated with sites where we have responsibility for dealing with contamination associated with past operations.
- Ensuring our employees have the training, skills, knowledge and resources necessary to meet our environmental commitments.
- Working with governments and regulators to help them develop and deliver more effective environmental policies and targets.
- Helping consumers reduce their dependency on fossil fuels by providing them with access to more sustainable energy and through innovative energy efficiency programmes.
- Ensuring those working on our behalf demonstrate the same commitment to the environment as we do.

For more details on this policy, visit the SSR Infonet homepage or nationalgrid.com

Appendix 3
Notification Materials

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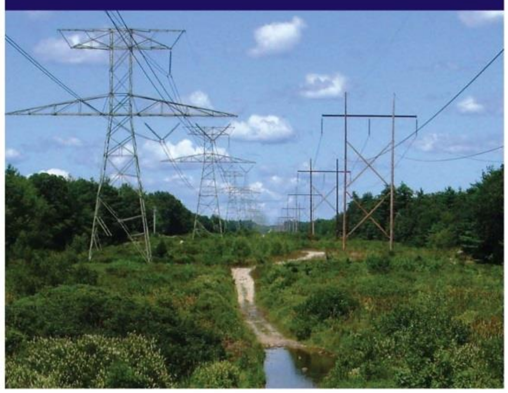
Notification of Vegetation Work



On behalf of National Grid's Vegetation Management department, ______________________ will soon conduct scheduled maintenance on the electric transmission right-of-way on or adjacent to your property.

The type of work to be done is indicated below:

❐ **Integrated Vegetation Management** (floor work—see back for details)

❐ **Sideline Maintenance** (see back for details)

Description of work:

____

____

____

____

If you have questions regarding this work, or a private water supply well on or within 100 feet of the right-of-way, please contact:

Name ____

Company ____

Phone ____

❐ **If this box is checked, a call back is needed**

Date: ROW #:

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Program Descriptions

Integrated Vegetation Management (IVM)
IVM focuses on the removal of tall-growing trees and shrubs to encourage the establishment of a low-growing shrub population on the right-of-way.

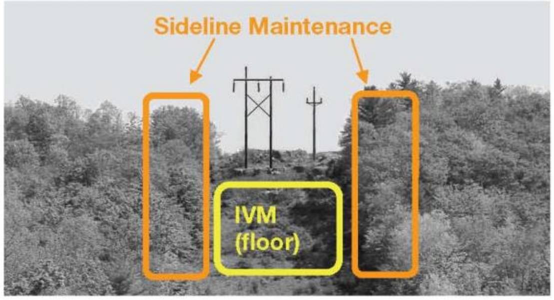
Methods used include:

- Hand cutting with chain saws
- Mowing
- Selective herbicide application (applied to foliage or cut stump surface)

Herbicide use is regulated by federal and state statutes and regulations, which protect sensitive areas, such as:

- Surface Water Supplies
- Wetlands
- Public & Private Wells

Sideline Maintenance
This work consists of removing or pruning danger trees along the sides or edges of transmission line corridors.



Methods used include:

- Skidder bucket or street bucket
- Climbers (for areas inaccessible by equipment)

For more information about our programs and work scheduled for the current year, click on "Operations Documentation" in the following link:

www.nationalgridus.com/transmission/index.asp

Enhanced Hazard Tree Mitigation – Process and Guideline

Purpose

This document outlines the hazard mitigation practices and specifications to be utilized on feeders designated by Asset Strategy and Performance (ASP) as requiring additional reliability work beyond routine circuit pruning. This hazard mitigation process may be prescribed for a circuit on cycle (during the routine circuit pruning process) or off-cycle also termed mid-cycle work. In practice, the specification will be employed in levels of intensity based on customers served downstream of the protective devices installed on a feeder.

It is well understood that National Grid would optimally like to clear all overhanging vegetation from above its main line, three phase facilities. However, it is also not practical to expect our customers, property owners, municipal officials and society members in general to be accepting of the abrupt change in the "treescape" that this would require. Instead we have adopted a risk assessment approach to removing just the overhanging vegetation on tree species that are documented to be problematic (weak wooded, frequent limb failure) along with the removal of trees exhibiting structural patterns and/or decay and disease conditions known for their failure potential. Additionally, as part of this risk assessment approach, the work will be prescribed by intensity levels based on a circuit location value which corresponds to the SAIFI impact of any future tree interruption at that point along the feeder also taking into account the pole top construction configuration and wire types installed.

Hazard Tree Inspection Specifications

This specification requires a tree by tree inspection by an arborist trained to recognize the potential defects in a tree based on species, structure, site characteristics and/or condition. In addition, the arborist must also understand the differences in the effect a tree or limb failure will have on different construction types – crossarm, candlestick or spacer cable as well as wire types - bare wire, covered wire and covered spacer cable. These different construction and wire types will affect the decisions made with regards to the hazard mitigation inspections and actual work prescribed. Lastly, although the elements of the hazard tree inspection process are broken out below in distinct categories the actual process is really an art form rather than a science as it requires the balancing of all the characteristics of the tree as well as those of the target. In other words, the inspecting arborists must consider all issues in determining whether a tree is to be removed, pruned or passed by.

1) Species and Overhang: Where bare three-phase construction exists, the goal is to completely remove the overhanging vegetation from the following weak-wooded and/or branch shedding species. With covered wire or spacer cable the focus is limited to larger leads that could potentially cause physical damage upon their failure.

Ash	Elm
Aspen/Poplar Family	Grey Birch
Basswood	Norway Maple
Black Cherry	Silver Maple
Black Locust	White Pine (shorten bows)
Boxelder	Willow

2) Tree Structure: The mitigation step may include pruning or full removal depending on the location of the defect in the tree and the line construction. The following items need to be addressed:

a) Co-dominate stems and limb attachments (especially with included bark and visible ribs). Some of the worst performers in this category are the maples, especially red and silver maple as well as white pine.

b) Poor branch attachments such as those with a small angle (tight V crotch) at the point of attachment. Also, look for epicormic branching from previous pruning or storm damage as this is a weak form of branch attachment.

c) Longer limbs growing more horizontal than usual, appearing to be longer than should be supportable, limbs that have been pruned leaving the majority of growth out at the end (lions tailing).

d) Open cracks or splits in the stem or leads through the bark and extending into the wood. These may be vertical or horizontal with horizontal cracks being a higher risk for failure. Seams, frost cracks or small ribs that are not open are a low risk and generally will require no action.

e) Hollows or cavities in the stem or large leader that encompasses a significant percentage of the stem area or circumference. Other factors such as location of the opening on the tension side of the tree and species wood strength characteristics must be integrated into the inspection decision. Animal infestations like squirrels are indications of potentially larger hollows within the tree structure.

f) Trees with a lean greater than 30 degrees shall be inspected carefully. In addition, the tree may show signs of stem buckling on the compression side and horizontal cracking on the tension side. High risk leaners may also show soil mounding or lifting on the backside including cracks or openings in the soil surface. Finally, note the presence of soil moisture on the site during the inspection.

3) Tree health and vigor issues – the mitigation step may include pruning or full removal depending on the location of the defect in the tree and the line construction. The following items need to be addressed:

a) Basal injury from such things as snow plows, construction and excavation or log skidding will require closer inspection to determine if removal is necessary. Part of the decision will depend on the species decay compartmentalizing abilities.

a) Stem decay at any position affecting a significant portion of the stem cross section. Conks and fruiting bodies on the stem or lead are a signal that the interior decay is significant, and the tree or lead must be removed. Visible decay in any overhead lead shall require removal of that lead. Past pruning wounds are important points to inspect.

c) Cankers showing significant progress in the tree shall indicate that removal is necessary. Cankers become a notable risk as they affect more than 1/3 of the stem cross section. High risk cankers may include horizontal cracks within the canker face. Aspen with Hypoxylon canker along side our lines must always be removed.

d) Dead and dying trees, tops or branches overhanging or alongside the conductor shall be addressed either by complete removal or by pruning off the section that threatens our facilities.

4) Tree position or micro site issues – the mitigation step may include pruning or full removal depending on the location of the defect in the tree and the line construction. The following items need to be addressed:

a) Trees on wet sites or sites with very shallow soil or rock outcrops especially with evidence of recent uprooting in that area.

b) Taller trees on open, exposed sites subject to high winds or isolated edge trees left standing on previously wooded sites (from logging, clearing or site work) especially with evidence of recent failures in that area.

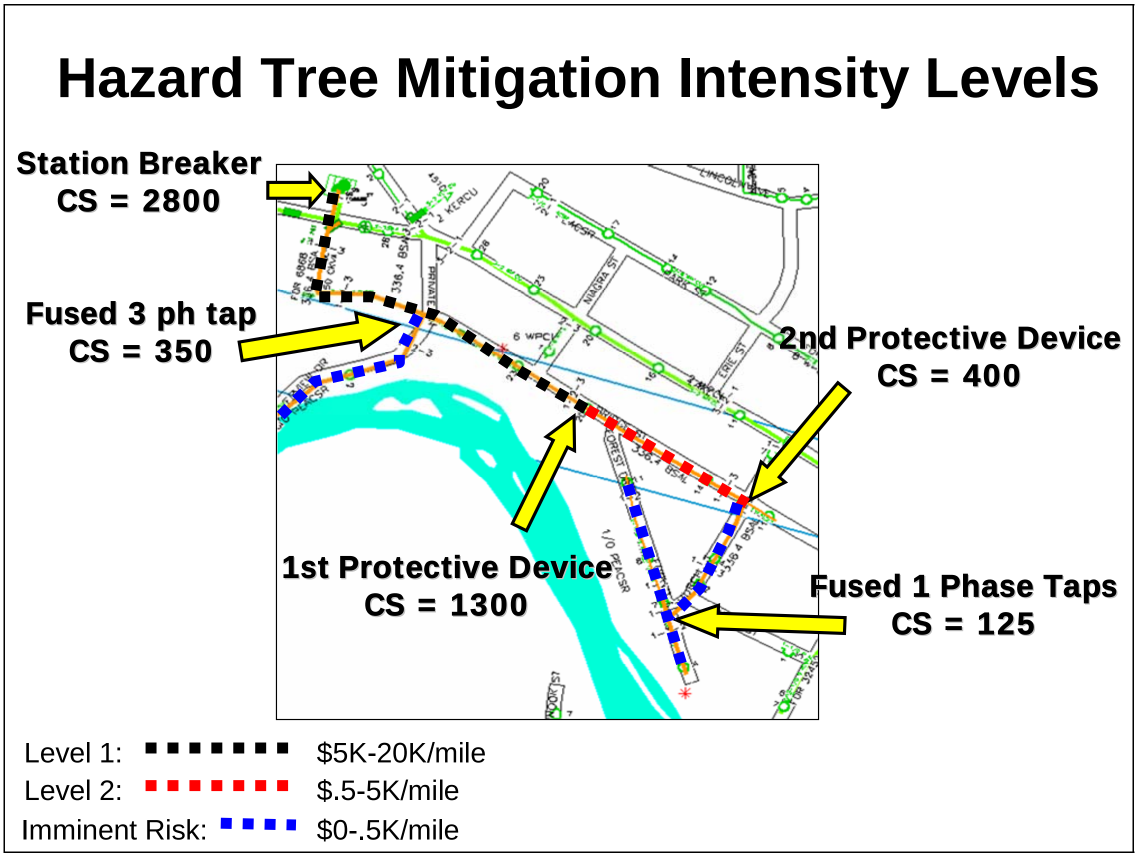
c) Evidence of recent beaver activity in the area must be considered when inspecting trees for failure.

<u>Determining Intensity Levels using Calculated Customer Served Points</u>

An important concept and process to understand in this approach is the development of the Calculated Customer Served (CCS) Point. The CCS points are protection positions (reclosers, sectionalizers, fuse points) on the distribution the feeder where the number of customers served drops below a pre-determined number such as 1500 or 500. The location and customers served (CS) for each point can be determined using the trace out –

downstream function on Smallworld GIS. The downstream trace is performed at each protective device working away from the substation and noting the number of customers served at each protection device. These customer service points will serve as adjustment points for the intensity of the reliability targeted pruning and removal process.

With each protection device along the feeder labeled with the number of customers served downstream of that point it is possible to then assign the intensity levels to the different circuit segments beginning with the lockout portion or Level 1 intensity. The intensity level will generally step down for the circuit segments beyond the lockout portion unless the number of customers served is still above a predetermined number like 1500. In that case the intensity level remains as on the lockout section. Once below 1500 but above 500 the intensity level will drop to the next lowest or second level of intensity. Finally, at points along the feeder below 500 customers the hazard mitigation intensity level will be employed at its lowest level. For an example a study circuit (see diagram on next page) may serve 2800 customers from the station. Along the three-phase mainline there are two protection devices, the first serving 1300 downstream and the second serving 400 downstream. In addition, there is a fused three-phase tap that serves 350 customers downstream and fused single phase taps serving 125 people all together. The first segment from the station to the first protective device (lockout section) would get a Level One intensity (the highest) for hazard tree mitigation. Every element of the hazard tree mitigation specification would be inspected for and prescribed on this portion of the feeder. From the 1st protection device serving 1300 customers down to the second device the arborists would utilize a Level Two intensity in their prescriptions. In the Level Two areas we are willing to increase our risk tolerance and employee less of the elements in the hazard tree specifications as the consequences of a tree interruption are reduced. As the inspection progresses past the 2nd protection device on the mainline where only 400 customers are served downstream, the risk tolerance again increases, and our inspection criteria again adjusts to limit the hazard mitigation prescribed and hazard dollars spent. Finally, the same is true of the fused-three phase tap as it only serves 350 customers downstream and so our risk tolerance is relatively high compared to the lockout section of the feeder.



Of course, tree interruption locations also play a role in the intensity level decision as well. Concurrent with the establishment of the CCS points, five years worth of tree interruptions shall also be plotted to determine if there are any concentrated areas of historic tree outage activity that when grouped together may have had a significant impact on SAIFI for that circuit. We are specifically looking for problem areas that may exist beyond a CCS point, thus potentially overriding the CCS point process and calling for a higher level of enhanced hazard tree mitigation to be employed on this section of the circuit. As an example, a study circuit may serve 2700 customers and over five years has had 3800 customers interrupted due to tree outages. At the first set of reclosers the CS drops to 1800 and past the second set of reclosers the CS drops down to 700. However, in review of the five-year tree interruption history, it is determined that a single three phase section out past the second set of reclosers (350 CS) has had 7 events totaling 2450 customers over the five years. A detailed review of that area to determine and perform the appropriate mitigation for that outage activity is certainly warranted even though this past the last CCS point.

<u>Using the Hazard Tree Specification on each Intensity Level</u>

1) Level 1 – Highest or Premium Inspection Intensity – Generally utilized on the lockout section (station to 1st protective device) of all feeders designated and prioritized by ASP. Level 1 may extend beyond the 1st protective device depending on the

customers served at each CCS point generally to a protective point serving less than 1500 customers however each circuit configuration will have relative CS numbers for CSS target values. All aspects of the hazard tree mitigation specification shall be employed in an effort to provide the highest level of reliability.

2) Level 2 – Moderate Inspection Intensity – Utilized beyond the lockout section down to the next determined CCS point (generally 500 CS) for all feeders designated and prioritized by ASP. Risk tolerance is increased from Level 1 and so fewer elements of the hazard tree mitigation specification are utilized. As an example, a basal injury on a tree without signs of decay may mean removal of that tree in Level 1 however in the Level 2 section of the circuit that tree only is removed with a basal injury and significant signs of decay. The arborist uses their expertise to determine the higher risk issues for removal. This level also requires a tree by tree inspection by a trained arborist. For Level 2 the list of inspection items to be addressed doesn't change specifically. Instead it's the amount of risk we are willing to endure that increases. For example, rather than removing all overhanging vegetation from above the bare three phase conductors the arborist may only choose specific trees from the species list that have a higher potential to fail based on crown dieback or just height above the conductor. Other trees, although on the species list, may appear less likely to fail due to their general health or structure. Another approach would be to consider how long the tree condition may exist before ultimate failure. Any condition that will eventually fail would be mitigated under the Level 1 intensity level but in Level 2 sections of the feeder the arborist eye should be tuned to conditions they believe may fail within the next 2 to 4 years for example.

3) Level 3 - Imminent Risk Inspection – Utilized on all sections of the feeder beyond the last CCS point. The intent is to mitigate only the most critical visible and obvious conditions. This level will also be utilized on all annual distribution inspections and as a guide for all post storm damage sweeps as well. This level includes the removal of all obvious critical risk issues with the ability to cause an outage in the near future (within 1 year) including, but not limited to:
    1) Broken overhanging branches
    2) Dead overhanging branches or dead trees alongside the lines that will not be picked up through routine pruning performed that current year
    3) Trees with visible open cracks and splits
    4) Severally bowed trees from recent weather affects
    5) Uprooted trees showing actual root plate and soil lifting
    6) Trees showing little or no sound wood due to decay in the stem or lead

Cycle Pruning - Reliability

Fiscal Year 2007				1st Year After Project			2nd Year After Project			3rd Year After Project		
Feeder ID	Total CI 4/1/03-3/31/06	Average CI	Project Year 4/1/06-3/31/07	Total CI 4/1/07-3/31/08	Difference	% Improved	Total CI 4/1/08-3/31/09	Difference	% Improved	Total CI 4/1/09-3/31/10	Difference	% Improved
49_53_102W44	508	169		0	-169	-100.0%	0	-169	-100.0%	0	-169	-100.0%
49_53_102W51	24,357	8,119		553	-7,566	-93.2%	838	-7,281	-89.7%	15	-8,104	-99.8%
49_53_108W51	0	0		0	0	0.0%	1	1	0.0%	0	0	0.0%
49_53_108W53	3,743	1,248		1	-1,247	-99.9%	77	-1,171	-93.8%	101	-1,147	-91.9%
49_53_108W55	0	0		0	0	0.0%	0	0	0.0%	2	2	0.0%
49_53_108W61	76	25		0	-25	-100.0%	0	-25	-100.0%	86	61	239.5%
49_53_108W62	16,197	5,399		0	-5,399	-100.0%	1,586	-3,813	-70.6%	1,592	-3,807	-70.5%
49_53_108W63	22	7		0	-7	-100.0%	7,908	7,901	107736.4%	5	-2	-31.8%
49_53_108W65	3	1		3	2	200.0%	0	-1	-100.0%	1	0	0.0%
49_53_126W40	20	7		0	-7	-100.0%	3	-4	-55.0%	34	27	410.0%
49_53_126W50	5,493	1,831		19,108	17,277	943.6%	220	-1,611	-88.0%	1,846	15	0.8%
49_53_127W40	1,618	539		548	9	1.6%	262	-277	-51.4%	8,195	7,656	1419.5%
49_53_127W42	513	171		0	-171	-100.0%	0	-171	-100.0%	0	-171	-100.0%
49_53_15F2	6,151	2,050		8,790	6,740	328.7%	10,634	8,584	418.6%	596	-1,454	-70.9%
49_53_17W43	2,635	878		0	-878	-100.0%	0	-878	-100.0%	0	-878	-100.0%
49_53_18F1	97	32		225	193	595.9%	3,883	3,851	11909.3%	196	164	506.2%
49_53_18F2	9	3		0	-3	-100.0%	0	-3	-100.0%	79	76	2533.3%
49_53_18F3	372	124		203	79	63.7%	1	-123	-99.2%	63	-61	-49.2%
49_53_18F7	108	36		9	-27	-75.0%	9	-27	-75.0%	0	-36	-100.0%
49_53_18F8	20	7		0	-7	-100.0%	60	53	800.0%	106	99	1490.0%
49_53_18F9	0	0		0	0	0.0%	0	0	0.0%	51	51	0.0%
49_53_20F1	0	0		0	0	0.0%	1,284	1,284	0.0%	0	0	0.0%
49_53_20F2	10,027	3,342		1,985	-1,357	-40.6%	10	-3,332	-99.7%	2	-3,340	-99.9%
49_53_21F1	12,841	4,280		554	-3,726	-87.1%	65	-4,215	-98.5%	170	-4,110	-96.0%
49_53_21F2	79	26		34	8	29.1%	37	11	40.5%	1,182	1,156	4388.6%
49_53_21F4	18	6		16	10	166.7%	109	103	1716.7%	22	16	266.7%
49_53_23F1	3,229	1,076		2,465	1,389	129.0%	2,707	1,631	151.5%	54	-1,022	-95.0%
49_53_23F4	15	5		0	-5	-100.0%	0	-5	-100.0%	0	-5	-100.0%
49_53_27F1	11,283	3,761		49	-3,712	-98.7%	2,599	-1,162	-30.9%	182	-3,579	-95.2%
49_53_34F1	10,609	3,536		1,388	-2,148	-60.8%	907	-2,629	-74.4%	3,098	-438	-12.4%
49_53_37J1	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_37J2	28	9		17	8	82.1%	12	3	28.6%	140	131	1400.0%
49_53_37J3	43	14		0	-14	-100.0%	0	-14	-100.0%	0	-14	-100.0%
49_53_37J4	32	11		0	-11	-100.0%	0	-11	-100.0%	0	-11	-100.0%
49_53_38F1	9,921	3,307		4,846	1,539	46.5%	449	-2,858	-86.4%	724	-2,583	-78.1%
49_53_38F3	7,844	2,615		67	-2,548	-97.4%	3,989	1,374	52.6%	248	-2,367	-90.5%
49_53_77J1	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_77J2	29	10		1	-9	-89.7%	0	-10	-100.0%	0	-10	-100.0%
49_53_77J3	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_77J4	518	173		0	-173	-100.0%	0	-173	-100.0%	0	-173	-100.0%
49_53_9J2	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_9J3	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_56_16F2	515	172		419	247	144.1%	197	25	14.8%	5	-167	-97.1%
49_56_16J2	14	5		0	-5	-100.0%	0	-5	-100.0%	0	-5	-100.0%
49_56_17F1	342	114		4	-110	-96.5%	34	-80	-70.2%	31	-83	-72.8%
49_56_30F2	3,086	1,029		321	-708	-68.8%	360	-669	-65.0%	9,122	8,093	786.8%
49_56_33F3	2,881	960		1,864	904	94.1%	1,480	520	54.1%	973	13	1.3%
49_56_36W41	99	33		3	-30	-90.9%	52	19	57.6%	128	95	287.9%
49_56_36W42	206	69		12	-57	-82.5%	1	-68	-98.5%	27	-42	-60.7%
49_56_36W43	34	11		12	1	5.9%	39	28	244.1%	7	-4	-38.2%
49_56_36W44	1,516	505		151	-354	-70.1%	1	-504	-99.8%	13	-492	-97.4%
49_56_3F1	9,631	3,210		9	-3,201	-99.7%	198	-3,012	-93.8%	6,876	3,666	114.2%
49_56_42F1	183	61		14,361	14,300	23442.6%	204	143	234.4%	223	162	265.6%
49_56_45J2	0	0		148	148	0.0%	0	0	0.0%	9	9	0.0%
49_56_45J6	32	11		198	187	1756.3%	124	113	1062.5%	0	-11	-100.0%
49_56_46F1	1,191	397		175	-222	-55.9%	14	-383	-96.5%	647	250	63.0%
49_56_46F2	7,023	2,341		975	-1,366	-58.4%	1,109	-1,232	-52.6%	503	-1,838	-78.5%
49_56_46F3	5,393	1,798		540	-1,258	-70.0%	230	-1,568	-87.2%	231	-1,567	-87.2%
49_56_46F4	512	171		18	-153	-89.5%	8	-163	-95.3%	288	117	68.8%
49_56_59F2	312	104		1	-103	-99.0%	681	577	554.8%	10	-94	-90.4%
49_56_59F3	542	181		533	352	195.0%	5,004	4,823	2669.7%	834	653	361.6%
49_56_63F2	360	120		2	-118	-98.3%	620	500	416.7%	10	-110	-91.7%
49_56_65J2	2,393	798		72	-726	-91.0%	0	-798	-100.0%	2	-796	-99.7%
49_56_68F4	1,291	430		188	-242	-56.3%	90	-340	-79.1%	204	-226	-52.6%
49_56_72F2	469	156		0	-156	-100.0%	25	-131	-84.0%	282	126	80.4%
Totals	**166,483**	**55,494**		**60,868**	**5,374**	**9.7%**	**48,121**	**-7,373**	**-13.3%**	**39,215**	**-16,279**	**-29.3%**

Fiscal Year 2008				1st Year After Project			2nd Year After Project			3rd Year After Project		
Feeder ID	Total CI 4/1/04-3/31/07	Average CI	Project Year 4/1/07-3/31/08	Total CI 4/1/08-3/31/09	Difference	% Improved	Total CI 4/1/09-3/31/10	Difference	% Improved	Total CI 4/1/10-3/31/11	Difference	% Improved
49_53_102K22	18	6		0	-6	-100.0%	0	-6	-100.0%	0	-6	-100.0%
49_53_102W41	1,186	395		0	-395	-100.0%	0	-395	-100.0%	0	-395	-100.0%
49_53_102W42	0	0		0	0	0.0%	0	0	0%	0	0	0%
49_53_102W50	0	0		14	14	0.0%	0	0	0%	0	0	0%
49_53_102W52	0	0		0	0	0.0%	0	0	0%	0	0	0%
49_53_12J6	87	29		0	-29	-100.0%	62	33	113.8%	0	-29	-100.0%
49_53_13F2	7,710	2,570		1	-2,569	-100.0%	60	-2,510	-97.7%	0	-2,570	-100.0%
49_53_13F3	194	65		0	-65	-100.0%	0	-65	-100.0%	0	-65	-100.0%
49_53_13F4	160	53		99	46	85.6%	1	-52	-98.1%	19	-34	-64.4%
49_53_13F9	53	18		0	-18	-100.0%	133	115	652.8%	11	-7	-37.7%
49_53_15F1	228	76		242	166	218.4%	7	-69	-90.8%	149	73	96.1%
49_53_27F5	46	15		0	-15	-100.0%	393	378	2463.0%	70	55	356.5%
49_53_28J1	120	40		89	49	122.5%	0	-40	-100.0%	22	-18	-45.0%
49_53_2J7	0	0		0	0	0.0%	0	0	0%	1	1	0%
49_53_34F2	8,160	2,720		200	-2,520	-92.6%	1,150	-1,570	-57.7%	757	-1,963	-72.2%
49_53_34F3	3,015	1,005		2,541	1,536	152.8%	8,074	7,069	703.4%	4,327	3,322	330.5%
49_53_37J5	748	249		32	-217	-87.2%	17	-232	-93.2%	0	-249	-100.0%
49_53_47J1	0	0		0	0	0.0%	0	0	0%	0	0	0%
49_53_47J2	0	0		0	0	0.0%	1	1	0%	2	2	0%
49_53_47J3	0	0		0	0	0.0%	0	0	0%	0	0	0%
49_53_47J4	49	16		2,225	2,209	13522.4%	0	-16	-100.0%	50	34	206.1%
49_53_48F1	3,631	1,210		0	-1,210	-100.0%	0	-1,210	-100.0%	179	-1,031	-85.2%
49_53_48F2	0	0		0	0	0.0%	0	0	0%	0	0	0%
49_53_48F5	202	67		2	-65	-97.0%	40	-27	-40.6%	71	4	5.4%
49_53_48F6	132	44		0	-44	-100.0%	1	-43	-97.7%	2,826	2,782	6322.7%
49_53_4F1	1,718	573		589	16	2.9%	45	-528	-92.1%	3,390	2,817	492.0%
49_53_51F1	1,624	541		97	-444	-82.1%	358	-183	-33.9%	1	-540	-99.8%
49_53_51F2	576	192		0	-192	-100.0%	430	238	124.0%	209	17	8.9%
49_53_51F3	6,785	2,262		713	-1,549	-68.5%	218	-2,044	-90.4%	867	-1,395	-61.7%
49_53_5F1	13,329	4,443		1,068	-3,375	-76.0%	33	-4,410	-99.3%	192	-4,251	-95.7%
49_53_5F2	905	302		7,385	7,083	2348.1%	109	-193	-63.9%	495	193	64.1%
49_53_5F3	11,557	3,852		3	-3,849	-99.9%	2	-3,850	-99.9%	507	-3,345	-86.8%
49_53_5F4	3,414	1,138		0	-1,138	-100.0%	0	-1,138	-100.0%	0	-1,138	-100.0%
49_53_66J2	43	14		0	-14	-100.0%	0	-14	-100.0%	0	-14	-100.0%
49_53_66J4	20	7		0	-7	-100.0%	807	800	12005.0%	0	-7	-100.0%
49_53_69F1	7,942	2,647		223	-2,424	-91.6%	0	-2,647	-100.0%	3	-2,644	-99.9%
49_53_69F3	12,432	4,144		37	-4,107	-99.1%	1	-4,143	-100.0%	16	-4,128	-99.6%
49_53_6J6	0	0		0	0	0.0%	0	0	0%	59	59	0%
49_53_71J1	764	255		2	-253	-99.2%	37	-218	-85.5%	0	-255	-100.0%
49_53_71J2	0	0		0	0	0.0%	0	0	0%	0	0	0%
49_53_71J3	0	0		0	0	0.0%	0	0	0%	0	0	0%
49_53_71J4	62	21		1	-20	-95.2%	0	-21	-100.0%	0	-21	-100.0%
49_53_71J5	25	8		0	-8	-100.0%	0	-8	-100.0%	0	-8	-100.0%
49_53_76F1	1,981	660		28	-632	-95.8%	1	-659	-99.8%	5	-655	-99.2%
49_53_78F3	938	313		1	-312	-99.7%	1	-312	-99.7%	2,082	1,769	565.9%

		Post-Project Year 1		Post-Project Year 2		Post-Project Year 3	
Project Year	**Cycle Prune Cost**	**Δ CI**	**$ / Δ CI**	**Average Δ CI**	**$ / Δ CI**	**Average Δ CI**	**$ / Δ CI**
2009	$ 5,144,193	12,035	$ 427	2,709	$ 1,899	2,348	$ 2,191
2010	$ 4,365,639	4,543	$ 961	7,106	$ 614	16,297	$ 268
2011	$ 3,956,357	51,463	$ 77	47,966	$ 82	52,324	$ 76
2012	$ 3,919,065	8,799	$ 445	11,629	$ 337	11,507	$ 341
2013	$ 4,764,000	6,482	$ 735	4,612	$ 1,033	(341)	$ (13,958)
2014	$ 5,180,000	4,025	$ 1,287	(3,152)	$ (1,643)	(3,157)	$ (1,641)
2015	$ 4,475,000	(8,275)	$ (541)	(2,473)	$ (1,810)	(8,199)	$ (546)
2016	$ 5,414,000	(11,556)	$ (469)	(8,905)	$ (608)	(42,709)	$ (127)
2017	$ 5,050,000	2,084	$ 2,423	(16,050)	$ (315)	-	-
2018	$ 5,458,000	(14,128)	$ (386)	-	-	-	-
Totals	**$ 47,726,254**	**55,473**	**$ 860**	**43,442**	**$ 973**	**28,070**	**$ 1,326**

49_53_78F4	154	51		0	-51	-100.0%	2	-49	-96.1%	8,302	8,251	16072.7%
49_53_79F1	0	0		0	0	0.0%	0	0	0%	0	0	0%
49_53_79F2	6	2		0	-2	-100.0%	49	47	2350.0%	0	-2	-100.0%
49_53_7F1	7,509	2,503		14	-2,489	-99.4%	1	-2,502	-100.0%	0	-2,503	-100.0%
49_53_7F2	60	20		0	-20	-100.0%	0	-20	-100.0%	0	-20	-100.0%
49_56_122J4	5,894	1,965		0	-1,965	-100.0%	0	-1,965	-100.0%	0	-1,965	-100.0%
49_56_131J2	227	76		0	-76	-100.0%	0	-76	-100.0%	0	-76	-100.0%
49_56_131J4	1,573	524		0	-524	-100.0%	0	-524	-100.0%	0	-524	-100.0%
49_56_146J14	712	237		1,437	1,200	505.5%	0	-237	-100.0%	0	-237	-100.0%
49_56_146J2	657	219		130	-89	-40.6%	0	-219	-100.0%	0	-219	-100.0%
49_56_14F2	2,340	780		0	-780	-100.0%	108	-672	-86.2%	9,680	8,900	1141.0%
49_56_14F3	926	309		0	-309	-100.0%	2	-307	-99.4%	6,168	5,859	1898.3%
49_56_16J1	2	1		0	-1	-100.0%	0	-1	-100.0%	0	-1	-100.0%
49_56_16J3	0	0		0	0	0.0%	0	0	0%	0	0	0%
49_56_17F2	156	52		22	-30	-57.7%	16	-36	-69.2%	234	182	350.0%
49_56_17F3	124	41		5,230	5,189	12553.2%	99	58	139.5%	39	-2	-5.6%
49_56_19J16	0	0		0	0	0.0%	0	0	0%	0	0	0%
49_56_21J4	5,155	1,718		0	-1,718	-100.0%	923	-795	-46.3%	0	-1,718	-100.0%
49_56_22F1	145	48		1	-47	-97.9%	1	-47	-97.9%	86	38	77.9%
49_56_22F3	150	50		1	-49	-98.0%	18	-32	-64.0%	140	90	180.0%
49_56_22F4	936	312		154	-158	-50.6%	35	-277	-88.8%	298	-14	-4.5%
49_56_23J2	1,314	438		0	-438	-100.0%	0	-438	-100.0%	4,576	4,138	944.7%
49_56_23J4	0	0		0	0	0.0%	1	1	0%	4,566	4,566	0%
49_56_29F1	2,268	756		75	-681	-90.1%	1	-755	-99.9%	108	-648	-85.7%
49_56_29F2	0	0		0	0	0.0%	3	3	0%	0	0	0%
49_56_31J1	0	0		0	0	0.0%	0	0	0%	0	0	0%
49_56_33F1	128	43		101	58	136.7%	31	-12	-27.3%	8,067	8,024	18807.0%
49_56_33F2	4,061	1,354		45	-1,309	-96.7%	49	-1,305	-96.4%	11,320	9,966	736.2%
49_56_36W42	207	69		1	-68	-98.6%	27	-42	-60.9%	0	-69	-100.0%
49_56_37J2	555	185		0	-185	-100.0%	0	-185	-100.0%	0	-185	-100.0%
49_56_37W41	975	325		5	-320	-98.5%	1	-324	-99.7%	14	-311	-95.7%
49_56_37W42	200	67		73	6	9.5%	1	-66	-98.5%	435	368	552.5%
49_56_37W43	563	188		376	188	100.4%	28	-160	-85.1%	64	-124	-65.9%
49_56_40F1	3,020	1,007		101	-906	-90.0%	1,010	3	0.3%	14	-993	-98.6%
49_56_52F1	165	55		684	629	1143.6%	323	268	487.3%	54	-1	-1.8%
49_56_52F2	163	54		16	-38	-70.6%	3,390	3,336	6139.3%	72	18	32.5%
49_56_57J3	23	8		117	109	1426.1%	0	-8	-100.0%	2	-6	-73.9%
49_56_61F1	657	219		0	-219	-100.0%	0	-219	-100.0%	4	-215	-98.2%
49_56_61F3	94	31		283	252	803.2%	83	52	164.9%	1,598	1,567	5000.0%
49_56_63F3	1,223	408		593	185	45.5%	6,819	6,411	1572.7%	3,066	2,658	652.1%
49_56_63F4	113	38		25	-13	-33.6%	208	170	452.2%	24	-14	-36.3%
49_56_63F5	206	69		54	-15	-21.4%	12	-57	-82.5%	122	53	77.7%
49_56_63F6	5,631	1,877		2,830	953	50.8%	2,897	1,020	54.3%	6,659	4,782	254.8%
49_56_65J12	16	5		78	73	1362.5%	0	-5	-100.0%	2	-3	-62.5%
49_56_72F1	21	7		0	-7	-100.0%	15	8	114.3%	0	-7	-100.0%
49_56_72F4	358	119		107	-12	-10.3%	201	82	68.4%	220	101	84.4%
49_56_83F2	1,924	641		1,811	1,170	182.4%	18	-623	-97.2%	64	-577	-90.0%
49_56_84T1	1,529	510		0	-510	-100.0%	0	-510	-100.0%	0	-510	-100.0%
49_56_85T1	403	134		377	243	180.6%	3	-131	-97.8%	91	-43	-32.3%
49_56_87F1	0	0		0	0	0.0%	0	0	0%	1	1	0%
Totals	**142,397**	**47,466**		**30,333**	**-17,133**	**-36.1%**	**28,356**	**-19,110**	**-40.3%**	**82,400**	**34,934**	**73.6%**

Fiscal Year 2009				1st Year After Project			2nd Year After Project			3rd Year After Project		
Feeder ID	Total CI 4/1/05-3/31/08	Average CI	Project Year 4/1/08-3/31/09	Total CI 4/1/09-3/31/10	Difference	% Improved	Total CI 4/1/10-3/31/11	Difference	% Improved	Total CI 4/1/11-3/31/12	Difference	% Improved
49_53_102W54	13,821	4,607		0	-4,607	-100.0%	66	-4,541	-98.6%	1	-4,606	-100.0%
49_53_104J1	593	198		0	-198	-100.0%	0	-198	-100.0%	0	-198	-100.0%
49_53_104J5	1,077	359		0	-359	-100.0%	0	-359	-100.0%	0	-359	-100.0%
49_53_106J1	32	11		0	-11	-100.0%	0	-11	-100.0%	0	-11	-100.0%
49_53_107W43	593	198		28	-170	-85.8%	0	-198	-100.0%	0	-198	-100.0%
49_53_107W50	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_107W53	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_107W60	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_107W61	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_107W62	82	27		0	-27	-100.0%	0	-27	-100.0%	0	-27	-100.0%
49_53_107W63	562	187		1,392	1,205	643.1%	0	-187	-100.0%	0	-187	-100.0%
49_53_107W65	0	0		0	0	0.0%	0	0	0.0%	10	10	0.0%
49_53_107W66	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_107W81	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_107W83	18	6		1	-5	-83.3%	0	-6	-100.0%	0	-6	-100.0%
49_53_107W84	5	2		0	-2	-100.0%	0	-2	-100.0%	0	-2	-100.0%
49_53_108W60	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_109J5	3,420	1,140		0	-1,140	-100.0%	0	-1,140	-100.0%	1,506	366	32.1%
49_53_112W43	21	7		58	51	728.6%	32	25	357.1%	2,878	2,871	41014.3%
49_53_112W44	8,171	2,724		11,165	8,441	309.9%	1,034	-1,690	-62.0%	795	-1,929	-70.8%
49_53_126W41	6,770	2,257		454	-1,803	-79.9%	686	-1,571	-69.6%	11,646	9,389	416.1%
49_53_127W41	3,782	1,261		23	-1,238	-98.2%	442	-819	-64.9%	142	-1,119	-88.7%
49_53_12J1	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_12J2	0	0		0	0	0.0%	3	3	0.0%	0	0	0.0%
49_53_12J3	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_12J4	58	19		0	-19	-100.0%	0	-19	-100.0%	0	-19	-100.0%
49_53_12J5	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_13F5	136	45		0	-45	-100.0%	0	-45	-100.0%	97	52	114.0%
49_53_17W42	84	28		0	-28	-100.0%	0	-28	-100.0%	0	-28	-100.0%
49_53_18F5	52	17		0	-17	-100.0%	0	-17	-100.0%	0	-17	-100.0%
49_53_18F6	749	250		1,389	1,139	456.3%	280	30	12.1%	225	-25	-9.9%
49_53_23F2	2,520	840		19	-821	-97.7%	259	-581	-69.2%	407	-433	-51.5%
49_53_23F3	455	152		83	-69	-45.3%	246	94	62.2%	696	544	358.9%
49_53_23F4	15	5		0	-5	-100.0%	82	77	1540.0%	0	-5	-100.0%
49_53_23F5	3	1		0	-1	-100.0%	0	-1	-100.0%	0	-1	-100.0%
49_53_27F6	26	9		0	-9	-100.0%	1	-8	-88.5%	1	-8	-88.5%
49_53_36J1	1	0		0	0	-100.0%	0	0	-100.0%	0	0	-100.0%
49_53_36J2	0	0		0	0	0.0%	0	0	0.0%	2	2	0.0%
49_53_36J4	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_36J5	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_38F2	54	18		0	-18	-100.0%	82	64	355.6%	21	3	16.7%
49_53_38F4	379	126		28	-98	-77.8%	29	-97	-77.0%	70	-56	-44.6%
49_53_38F5	1,203	401		34	-367	-91.5%	2,987	2,586	644.9%	513	112	27.9%
49_53_38F6	12	4		63	59	1475.0%	55	51	1275.0%	369	365	9125.0%
49_53_45F2	3,344	1,115		75	-1,040	-93.3%	150	-965	-86.5%	768	-347	-31.1%
49_53_48F3	8,350	2,783		97	-2,686	-96.5%	91	-2,692	-96.7%	2,697	-86	-3.1%
49_53_48F4	268	89		46	-43	-48.5%	81	-8	-9.3%	185	96	107.1%
49_53_4F2	9,373	3,124		3,086	-38	-1.2%	348	-2,776	-88.9%	902	-2,222	-71.1%
49_53_50J1	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_50J3	102	34		0	-34	-100.0%	0	-34	-100.0%	0	-34	-100.0%
49_53_66J1	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_66J3	0	0		0	0	0.0%	0	0	0.0%	1	1	0.0%
49_53_66J5	387	129		0	-129	-100.0%	0	-129	-100.0%	50	-79	-61.2%
49_53_6J2	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_6J5	1,584	528		0	-528	-100.0%	0	-528	-100.0%	0	-528	-100.0%
49_53_73J1	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_73J2	37	12		0	-12	-100.0%	0	-12	-100.0%	0	-12	-100.0%
49_53_73J3	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_73J4	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_73J5	24	8		0	-8	-100.0%	0	-8	-100.0%	1	-7	-87.5%
49_53_76F2	70	23		2	-21	-91.4%	0	-23	-100.0%	2	-21	-91.4%
49_53_76F4	43	14		0	-14	-100.0%	0	-14	-100.0%	75	61	423.3%
49_53_76F6	114	38		0	-38	-100.0%	0	-38	-100.0%	0	-38	-100.0%
49_53_76F7	57	19		0	-19	-100.0%	2,205	2,186	11505.3%	22	3	15.8%
49_53_9J1	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_9J5	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%

49_56_122J2	6,179	2,060		0	-2,060	-100.0%	0	-2,060	-100.0%	0	-2,060	-100.0%
49_56_122J6	4,252	1,417		0	-1,417	-100.0%	0	-1,417	-100.0%	0	-1,417	-100.0%
49_56_131J12	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_56_131J14	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_56_131J6	692	231		0	-231	-100.0%	1	-230	-99.6%	0	-231	-100.0%
49_56_154J14	14	5		0	-5	-100.0%	0	-5	-100.0%	0	-5	-100.0%
49_56_154J16	26	9		0	-9	-100.0%	0	-9	-100.0%	0	-9	-100.0%
49_56_154J18	0	0		0	0	0.0%	47	47	0.0%	0	0	0.0%
49_56_154J2	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_56_154J6	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_56_154J8	0	0		0	0	0.0%	0	0	0.0%	220	220	0.0%
49_56_19J14	0	0		0	0	0.0%	537	537	0.0%	0	0	0.0%
49_56_19J2	4,252	1,417		0	-1,417	-100.0%	4,558	3,141	221.6%	42	-1,375	-97.0%
49_56_21J2	4,277	1,426		0	-1,426	-100.0%	0	-1,426	-100.0%	0	-1,426	-100.0%
49_56_21J6	4,253	1,418		0	-1,418	-100.0%	0	-1,418	-100.0%	0	-1,418	-100.0%
49_56_23J12	0	0		0	0	0.0%	5,032	5,032	0.0%	0	0	0.0%
49_56_23J14	9	3		0	-3	-100.0%	6,055	6,052	201733.3%	0	-3	-100.0%
49_56_23J6	0	0		0	0	0.0%	4,558	4,558	0.0%	0	0	0.0%
49_56_31J2	8	3		0	-3	-100.0%	0	-3	-100.0%	0	-3	-100.0%
49_56_32J12	6,174	2,058		0	-2,058	-100.0%	4	-2,054	-99.8%	0	-2,058	-100.0%
49_56_32J14	0	0		28	28	0.0%	1	1	0.0%	0	0	0.0%
49_56_32J2	926	309		0	-309	-100.0%	0	-309	-100.0%	0	-309	-100.0%
49_56_32J4	2,111	704		0	-704	-100.0%	0	-704	-100.0%	0	-704	-100.0%
49_56_33F4	7,613	2,538		1,345	-1,193	-47.0%	404	-2,134	-84.1%	544	-1,994	-78.6%
49_56_37J4	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_56_38J2	35	12		0	-12	-100.0%	0	-12	-100.0%	0	-12	-100.0%
49_56_38J4	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_56_41F1	1,529	510		654	144	28.3%	127	-383	-75.1%	263	-247	-48.4%
49_56_49J1	60	20		216	196	980.0%	0	-20	-100.0%	0	-20	-100.0%
49_56_49J2	224	75		50	-25	-33.0%	0	-75	-100.0%	0	-75	-100.0%
49_56_49J3	0	0		0	0	0.0%	0	0	0.0%	20	20	0.0%
49_56_49J4	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_56_51J12	0	0		0	0	0.0%	4,558	4,558	0.0%	0	0	0.0%
49_56_51J14	0	0		0	0	0.0%	4,558	4,558	0.0%	0	0	0.0%
49_56_51J16	34	11		21	10	85.3%	4,558	4,547	40117.6%	0	-11	-100.0%
49_56_51J2	6	2		26	24	1200.0%	4,558	4,556	227800.0%	0	-2	-100.0%
49_56_54F1	20,426	6,809		1,667	-5,142	-75.5%	1,389	-5,420	-79.6%	2,439	-4,370	-64.2%
49_56_57J2	13	4		0	-4	-100.0%	0	-4	-100.0%	1	-3	-76.9%
49_56_57J4	0	0		0	0	0.0%	0	0	0.0%	1	1	0.0%
49_56_57J5	80	27		0	-27	-100.0%	8	-19	-70.0%	2	-25	-92.5%
49_56_59F1	467	156		443	287	184.6%	444	288	185.2%	264	108	69.6%
49_56_59F4	5,324	1,775		747	-1,028	-57.9%	362	-1,413	-79.6%	2	-1,773	-99.9%
49_56_61F2	195	65		75	10	15.4%	4,613	4,548	6996.9%	24	-41	-63.1%
49_56_61F4	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_56_64F1	105	35		4	-31	-88.6%	201	166	474.3%	2,044	2,009	5740.0%
49_56_64F2	68	23		0	-23	-100.0%	443	420	1854.4%	176	153	676.5%
49_56_68F3	3,031	1,010		5,857	4,847	479.7%	162	-848	-84.0%	13,089	12,079	1195.5%
49_56_72F5	9,563	3,188		16	-3,172	-99.5%	56	-3,132	-98.2%	231	-2,957	-92.8%
49_56_72F6	35	12		140	128	1100.0%	35	23	200.0%	6	-6	-48.6%
49_56_83F1	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_56_83F3	4	1		0	-1	-100.0%	0	-1	-100.0%	0	-1	-100.0%
49_56_84T2	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_56_84T4	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_56_85T3	635	212		8,995	8,783	4149.6%	551	339	160.3%	4,949	4,737	2238.1%
49_56_87F2	18	6		0	-6	-100.0%	0	-6	-100.0%	0	-6	-100.0%
49_56_87F4	0	0		0	0	0.0%	0	0	0.0%	335	335	0.0%
Totals	**151,085**	**50,362**		**38,327**	**-12,035**	**-23.9%**	**56,979**	**6,617**	**13.1%**	**48,734**	**-1,628**	**-3.2%**

Fiscal Year 2010				1st Year After Project			2nd Year After Project			3rd Year After Project		
Feeder ID	Total CI 4/1/06-3/31/09	Average CI	Project Year 4/1/09-3/31/10	Total CI 4/1/10-3/31/11	Difference	% Improved	Total CI 4/1/11-3/31/12	Difference	% Improved	Total CI 4/1/12-3/31/13	Difference	% Improved
49_53_104J3	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_104J7	0	0		0	0	0.0%	0	0	0.0%	1,140	1,140	0.0%
49_53_106J3	1,886	629		0	-629	-100.0%	0	-629	-100.0%	0	-629	-100.0%
49_53_106J7	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_107W51	84	28		0	-28	-100.0%	0	-28	-100.0%	1	-27	-96.4%
49_53_107W80	0	0		0	0	0.0%	0	0	0.0%	1	1	0.0%
49_53_108W61	1,491	497		34	-463	-93.2%	0	-497	-100.0%	0	-497	-100.0%
49_53_108W62	1,633	544		18	-526	-96.7%	1	-543	-99.8%	0	-544	-100.0%
49_53_108W63	7,916	2,639		1	-2,638	-100.0%	21	-2,618	-99.2%	122	-2,517	-95.4%
49_53_109J1	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_109J3	0	0		0	0	0.0%	28	28	0.0%	1,273	1,273	0.0%
49_53_1119	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_111J1	0	0		0	0	0.0%	0	0	0.0%	1	1	0.0%
49_53_111J3	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_1123	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_1125	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_112W41	127	42		5,284	5,242	12381.9%	800	758	1789.8%	68	26	60.6%
49_53_112W42	14,150	4,717		2,642	-2,075	-44.0%	11,421	6,704	142.1%	3,440	-1,277	-27.1%
49_53_1131	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_1133	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_113J1	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_113J2	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_126W42	7	2		0	-2	-100.0%	16	14	585.7%	7	5	200.0%
49_53_126W51	1,054	351		44	-307	-87.5%	260	-91	-26.0%	10	-341	-97.2%
49_53_127W40	2,511	837		1,198	361	43.1%	1,049	212	25.3%	262	-575	-68.7%
49_53_148J1	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_148J3	0	0		1,560	1,560	0.0%	40	40	0.0%	0	0	0.0%
49_53_148J5	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_148J7	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_18F3	8,741	2,914		360	-2,554	-87.6%	70	-2,844	-97.6%	22	-2,892	-99.2%
49_53_21F1	905	302		490	188	62.4%	266	-36	-11.8%	228	-74	-24.4%
49_53_23F1	11,875	3,958		174	-3,784	-95.6%	130	-3,828	-96.7%	1	-3,957	-100.0%
49_53_23F2	2,559	853		259	-594	-69.6%	407	-446	-52.3%	217	-636	-74.6%
49_53_23F3	730	243		246	3	1.1%	696	453	186.0%	95	-148	-61.0%
49_53_23F6	13,842	4,614		128	-4,486	-97.2%	121	-4,493	-97.4%	2,500	-2,114	-45.8%
49_53_24J1	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_28J2	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_2J1	0	0		17	17	0.0%	31	31	0.0%	0	0	0.0%
49_53_2J3	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_2J4	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_2J5	0	0		0	0	0.0%	0	0	0.0%	1	1	0.0%
49_53_30J1	0	0		0	0	0.0%	883	883	0.0%	0	0	0.0%
49_53_30J3	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_30J5	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_34F1	2,879	960		1,265	305	31.8%	9,409	8,449	880.4%	2,173	1,213	126.4%
49_53_50F2	1,660	553		1	-552	-99.8%	0	-553	-100.0%	47	-506	-91.5%
49_53_50J2	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_60J1	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_60J3	0	0		0	0	0.0%	0	0	0.0%	1	1	0.0%
49_53_60J5	0	0		0	0	0.0%	0	0	0.0%	11	11	0.0%
49_53_67J1	0	0		4	4	0.0%	0	0	0.0%	395	395	0.0%
49_53_6J1	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_6J3	3	1		0	-1	-100.0%	0	-1	-100.0%	0	-1	-100.0%
49_53_6J7	1	0		0	0	-100.0%	0	0	-100.0%	5	5	1400.0%
49_53_6J8	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_73J6	8	3		0	-3	-100.0%	0	-3	-100.0%	1	-2	-62.5%
49_53_76F5	19	6		0	-6	-100.0%	1	-5	-84.2%	0	-6	-100.0%
49_53_7F4	2	1		15	14	2150.0%	0	-1	-100.0%	58	57	8600.0%
49_56_14F1	612	204		12,405	12,201	5980.9%	5	-199	-97.5%	7	-197	-96.6%
49_56_14F4	858	286		6,170	5,884	2057.3%	10	-276	-96.5%	0	-286	-100.0%

49_56_16F1	15,979	5,326		52	-5,274	-99.0%	1,650	-3,676	-69.0%	17	-5,309	-99.7%
49_56_16F3	107	36		33	-3	-7.5%	0	-36	-100.0%	4	-32	-88.8%
49_56_16F4	10	3		2,199	2,196	65870.0%	27	24	710.0%	54	51	1520.0%
49_56_22F2	6,673	2,224		24	-2,200	-98.9%	20	-2,204	-99.1%	64	-2,160	-97.1%
49_56_30F1	14,760	4,920		2,639	-2,281	-46.4%	364	-4,556	-92.6%	567	-4,353	-88.5%
49_56_30F2	7,188	2,396		44	-2,352	-98.2%	207	-2,189	-91.4%	299	-2,097	-87.5%
49_56_42F1	14,855	4,952		19	-4,933	-99.6%	1	-4,951	-100.0%	1,659	-3,293	-66.5%
49_56_43F1	8,329	2,776		1,208	-1,568	-56.5%	1,657	-1,119	-40.3%	1,161	-1,615	-58.2%
49_56_46F2	5,621	1,874		756	-1,118	-59.7%	261	-1,613	-86.1%	1,643	-231	-12.3%
49_56_46F3	1,808	603		10	-593	-98.3%	99	-504	-83.6%	560	-43	-7.1%
49_56_52F3	6,754	2,251		288	-1,963	-87.2%	251	-2,000	-88.9%	103	-2,148	-95.4%
49_56_57J1	0	0		0	0	0.0%	0	0	0.0%	9	9	0.0%
49_56_68F1	4,755	1,585		1,032	-553	-34.9%	708	-877	-55.3%	1,305	-280	-17.7%
49_56_68F2	5,094	1,698		680	-1,018	-60.0%	960	-738	-43.5%	645	-1,053	-62.0%
49_56_68F4	399	133		319	186	139.8%	16	-117	-88.0%	57	-76	-57.1%
49_56_86F1	163	54		0	-54	-100.0%	6,930	6,876	12654.6%	111	57	104.3%
49_56_88F1	709	236		645	409	172.9%	472	236	99.7%	217	-19	-8.2%
49_56_88F3	1,026	342		754	412	120.5%	7,899	7,557	2209.6%	2,506	2,164	632.7%
49_56_88F5	4,245	1,415		10,449	9,034	638.4%	1,153	-262	-18.5%	264	-1,151	-81.3%
Totals	**174,028**	**58,009**		**53,466**	**-4,543**	**-7.8%**	**48,340**	**-9,669**	**-16.7%**	**23,332**	**-34,677**	**-64.9%**

Fiscal Year 2011				1st Year After Project			2nd Year After Project			3rd Year After Project		
Feeder ID	Total CI 4/1/07-3/31/10	Average CI	Project Year 4/1/10-3/31/11	Total CI 4/1/11-3/31/12	Difference	% Improved	Total CI 4/1/12-3/31/13	Difference	% Improved	Total CI 4/1/13-3/31/14	Difference	% Improved
49_53_102W44	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_102W51	1,406	469		0	-469	-100.0%	255	-214	-45.6%	89	-380	-81.0%
49_53_107W85	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_108W51	1	0		0	0	-100.0%	33	33	9800.0%	0	0	-100.0%
49_53_108W53	179	60		303	243	407.8%	86	26	44.1%	0	-60	-100.0%
49_53_108W55	2	1		845	844	126650.0%	0	-1	-100.0%	0	-1	-100.0%
49_53_108W65	4	1		0	-1	-100.0%	0	-1	-100.0%	0	-1	-100.0%
49_53_126W40	37	12		34	22	175.7%	0	-12	-100.0%	8	-4	-35.1%
49_53_126W50	21,174	7,058		346	-6,712	-95.1%	20	-7,038	-99.7%	1,076	-5,982	-84.8%
49_53_126W54	8,128	2,709		0	-2,709	-100.0%	0	-2,709	-100.0%	0	-2,709	-100.0%
49_53_127W42	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_15F2	20,020	6,673		859	-5,814	-87.1%	2,189	-4,484	-67.2%	197	-6,476	-97.0%
49_53_17W43	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_18F1	4,304	1,435		45	-1,390	-96.9%	430	-1,005	-70.0%	75	-1,360	-94.8%
49_53_18F7	18	6		4,036	4,030	67166.7%	183	177	2950.0%	10	4	66.7%
49_53_18F8	166	55		31	-24	-44.0%	164	109	196.4%	2	-53	-96.4%
49_53_18F9	51	17		3	-14	-82.4%	60	43	252.9%	0	-17	-100.0%
49_53_20F1	1,284	428		0	-428	-100.0%	1	-427	-99.8%	757	329	76.9%
49_53_20F2	1,997	666		1	-665	-99.8%	0	-666	-100.0%	0	-666	-100.0%
49_53_21F2	1,253	418		67	-351	-84.0%	46	-372	-89.0%	94	-324	-77.5%
49_53_21F4	147	49		2	-47	-95.9%	2,358	2,309	4712.2%	0	-49	-100.0%
49_53_27F1	2,830	943		13	-930	-98.6%	7	-936	-99.3%	2	-941	-99.8%
49_53_27F2	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_27F3	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_27F4	1	0		0	0	-100.0%	1	1	200.0%	86	86	25700.0%
49_53_2J7	0	0		0	0	0.0%	828	828	0.0%	825	825	0.0%
49_53_2J8	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_2J9	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_37J1	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_37J2	169	56		0	-56	-100.0%	0	-56	-100.0%	0	-56	-100.0%
49_53_37J3	0	0		0	0	0.0%	0	0	0.0%	21	21	0.0%
49_53_37J4	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_37J5	65	22		1	-21	-95.4%	0	-22	-100.0%	0	-22	-100.0%
49_53_38F1	6,019	2,006		486	-1,520	-75.8%	1,840	-166	-8.3%	259	-1,747	-87.1%
49_53_38F3	4,304	1,435		230	-1,205	-84.0%	1,663	228	15.9%	52	-1,383	-96.4%
49_53_51F1	1,968	656		3	-653	-99.5%	293	-363	-55.3%	162	-494	-75.3%
49_53_51F2	695	232		441	209	90.4%	1	-231	-99.6%	0	-232	-100.0%
49_53_51F3	1,063	354		0	-354	-100.0%	861	507	143.0%	2,178	1,824	514.7%
49_53_5F1	7,565	2,522		1,031	-1,491	-59.1%	142	-2,380	-94.4%	135	-2,387	-94.6%
49_53_5F2	34,936	11,645		319	-11,326	-97.3%	2,549	-9,096	-78.1%	106	-11,539	-99.1%
49_53_5F3	14,607	4,869		161	-4,708	-96.7%	6	-4,863	-99.9%	244	-4,625	-95.0%
49_53_5F4	9,588	3,196		3,294	98	3.1%	27	-3,169	-99.2%	5	-3,191	-99.8%
49_53_76F1	29	10		22	12	127.6%	93	83	862.1%	0	-10	-100.0%
49_53_77J1	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_77J2	1	0		0	0	-100.0%	0	0	-100.0%	0	0	-100.0%
49_53_77J3	0	0		0	0	0.0%	238	238	0.0%	0	0	0.0%
49_53_77J4	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_79F1	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_79F2	57	19		0	-19	-100.0%	0	-19	-100.0%	71	52	273.7%
49_56_14F1	556	185		5	-180	-97.3%	7	-178	-96.2%	0	-185	-100.0%
49_56_14F2	286	95		25	-70	-73.8%	91	-4	-4.5%	0	-95	-100.0%
49_56_14F3	15	5		1,186	1,181	23620.0%	3	-2	-40.0%	1,013	1,008	20160.0%
49_56_16F2	621	207		244	37	17.9%	2,677	2,470	1193.2%	93	-114	-55.1%
49_56_17F1	69	23		17	-6	-26.1%	2,778	2,755	11978.3%	0	-23	-100.0%
49_56_17F2	11,028	3,676		8,790	5,114	139.1%	22	-3,654	-99.4%	133	-3,543	-96.4%
49_56_17F3	5,608	1,869		12	-1,857	-99.4%	1,138	-731	-39.1%	7	-1,862	-99.6%
49_56_22F1	26	9		49	40	465.4%	123	114	1319.2%	0	-9	-100.0%
49_56_22F4	2,598	866		26	-840	-97.0%	24	-842	-97.2%	165	-701	-80.9%
49_56_29F1	77	26		0	-26	-100.0%	72	46	180.5%	1,417	1,391	5420.8%
49_56_29F2	3	1		0	-1	-100.0%	1	0	0.0%	0	-1	-100.0%
49_56_30F2	9,803	3,268		207	-3,061	-93.7%	299	-2,969	-90.8%	135	-3,133	-95.9%
49_56_36W41	183	61		31	-30	-49.2%	22	-39	-63.9%	2,158	2,097	3437.7%
49_56_36W42	40	13		9	-4	-32.5%	22	9	65.0%	2,158	2,145	16085.0%
49_56_36W43	58	19		27	8	39.7%	10	-9	-48.3%	25	6	29.3%
49_56_36W44	165	55		2	-53	-96.4%	162	107	194.5%	0	-55	-100.0%
49_56_3F1	7,083	2,361		77	-2,284	-96.7%	437	-1,924	-81.5%	0	-2,361	-100.0%
49_56_3F2	170	57		1	-56	-98.2%	164	107	189.4%	55	-2	-2.9%
49_56_42F1	14,788	4,929		1	-4,928	-100.0%	1,659	-3,270	-66.3%	23	-4,906	-99.5%
49_56_45J2	157	52		46	-6	-12.1%	682	630	1203.2%	0	-52	-100.0%
49_56_45J4	58	19		10	-9	-48.3%	824	805	4162.1%	6	-13	-69.0%
49_56_45J6	322	107		4	-103	-96.3%	464	357	332.3%	65	-42	-39.4%
49_56_46F1	836	279		105	-174	-62.3%	52	-227	-81.3%	27	-252	-90.3%
49_56_46F4	314	105		307	202	193.3%	13	-92	-87.6%	1,529	1,424	1360.8%
49_56_52F1	1,007	336		1	-335	-99.7%	21	-315	-93.7%	30	-306	-91.1%
49_56_52F2	3,406	1,135		1	-1,134	-99.9%	35	-1,100	-96.9%	1	-1,134	-99.9%
49_56_59F2	692	231		606	375	162.7%	65	-166	-71.8%	127	-104	-44.9%
49_56_59F3	6,371	2,124		1,293	-831	-39.1%	2,254	130	6.1%	633	-1,491	-70.2%
49_56_65J12	78	26		3	-23	-88.5%	8	-18	-69.2%	0	-26	-100.0%
49_56_65J2	74	25		14	-11	-43.2%	10	-15	-59.5%	8	-17	-67.6%
49_56_72F1	15	5		1	-4	-80.0%	2	-3	-60.0%	80	75	1500.0%
49_56_72F2	307	102		327	225	219.5%	24	-78	-76.5%	5	-97	-95.1%
49_56_72F3	21,520	7,173		3	-7,170	-100.0%	4,625	-2,548	-35.5%	183	-6,990	-97.4%
49_56_72F4	500	167		168	1	0.8%	2	-165	-98.8%	62	-105	-62.8%
49_56_64F5	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
Totals	**232,902**	**77,634**		**26,171**	**-51,463**	**-66.3%**	**33,166**	**-44,468**	**-57.3%**	**16,592**	**-61,042**	**-78.6%**

Fiscal Year 2012				1st Year After Project			2nd Year After Project			3rd Year After Project		
Feeder ID	Total CI 4/1/08-3/31/11	Average CI	Project Year 4/1/11-3/31/12	Total CI 4/1/12-3/31/13	Difference	% Improved	Total CI 4/1/13-3/31/14	Difference	% Improved	Total CI 4/1/14-3/31/15	Difference	% Improved
49_53_102W41	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_102W42	0	0		1	1	0.0%	0	0	0.0%	0	0	0.0%
49_53_102W50	14	5		0	-5	-100.0%	0	-5	-100.0%	0	-5	-100.0%
49_53_102W52	34	11		698	687	6058.8%	0	-11	-100.0%	0	-11	-100.0%
49_53_102W54	867	289		24	-265	-91.7%	99	-190	-65.7%	40	-249	-86.2%
49_53_107W85	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%

49_53_108W51	1	0		33	33	9800.0%	0	0	-100.0%	0	0	-100.0%
49_53_108W53	179	60		86	26	44.1%	0	-60	-100.0%	304	244	409.5%
49_53_108W55	2	1		0	-1	-100.0%	0	-1	-100.0%	0	-1	-100.0%
49_53_108W65	4	1		0	-1	-100.0%	0	-1	-100.0%	0	-1	-100.0%
49_53_112W43	58	19		223	204	1053.4%	1	-18	-94.8%	60	41	210.3%
49_53_112W44	7,414	2,471		728	-1,743	-70.5%	37	-2,434	-98.5%	445	-2,026	-82.0%
49_53_126W41	3,409	1,136		978	-158	-13.9%	211	-925	-81.4%	302	-834	-73.4%
49_53_127W42	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_13F2	112	37		3	-34	-92.0%	8	-29	-78.6%	162	125	333.9%
49_53_13F3	21	7		12	5	71.4%	58	51	728.6%	26	19	271.4%
49_53_13F4	309	103		58	-45	-43.7%	328	225	218.4%	773	670	650.5%
49_53_13F9	133	44		0	-44	-100.0%	88	44	98.5%	72	28	62.4%
49_53_15F1	395	132		3	-129	-97.7%	11	-121	-91.6%	189	57	43.5%
49_53_17W43	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_20F1	642	214		1	-213	-99.5%	757	543	253.7%	0	-214	-100.0%
49_53_20F2	1,997	666		0	-666	-100.0%	0	-666	-100.0%	1	-665	-99.8%
49_53_21F2	686	229		46	-183	-79.9%	94	-135	-58.9%	2	-227	-99.1%
49_53_21F4	147	49		2,358	2,309	4712.2%	0	-49	-100.0%	1,761	1,712	3493.9%
49_53_27F1	2,830	943		7	-936	-99.3%	2	-941	-99.8%	1,612	669	70.9%
49_53_27F2	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_27F3	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_27F4	1	0		1	1	200.0%	86	86	25700.0%	0	0	-100.0%
49_53_27F5	1,796	599		26	-573	-95.7%	25	-574	-95.8%	13	-586	-97.8%
49_53_34F2	2,549	850		2,784	1,934	227.7%	2,115	1,265	148.9%	1,702	852	100.3%
49_53_34F3	4,749	1,583		18	-1,565	-98.9%	263	-1,320	-83.4%	333	-1,250	-79.0%
49_53_37J1	0	0		0	0	0.0%	0	0	0.0%	1	1	0.0%
49_53_47J1	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_47J2	1	0		0	0	-100.0%	3	3	800.0%	0	0	-100.0%
49_53_47J3	43	14		1	-13	-93.0%	1	-13	-93.0%	0	-14	-100.0%
49_53_47J4	1,120	373		2	-371	-99.5%	109	-264	-70.8%	1	-372	-99.7%
49_53_4F1	2,806	935		10	-925	-98.9%	34	-901	-96.4%	146	-789	-84.4%
49_53_4F2	6,676	2,225		318	-1,907	-85.7%	199	-2,026	-91.1%	656	-1,569	-70.5%
49_53_69F1	250	83		0	-83	-100.0%	194	111	132.8%	101	18	21.2%
49_53_69F3	38	13		21	8	65.8%	197	184	1455.3%	93	80	634.2%
49_53_71J1	728	243		0	-243	-100.0%	0	-243	-100.0%	0	-243	-100.0%
49_53_71J2	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_71J3	550	183		0	-183	-100.0%	0	-183	-100.0%	0	-183	-100.0%
49_53_71J4	1	0		0	0	-100.0%	0	0	-100.0%	0	0	-100.0%
49_53_71J5	0	0		0	0	0.0%	66	66	0.0%	0	0	0.0%
49_53_79F1	0	0		0	0	0.0%	0	0	0.0%	0	0	0.0%
49_53_79F2	57	19		0	-19	-100.0%	71	52	273.7%	3	-16	-84.2%
49_53_7F1	4,081	1,360		56	-1,304	-95.9%	52	-1,308	-96.2%	0	-1,360	-100.0%
49_53_7F2	4	1		0	-1	-100.0%	0	-1	-100.0%	2,606	2,605	195350.0%
49_56_30F2	5,555	1,852		299	-1,553	-83.9%	135	-1,717	-92.7%	608	-1,244	-67.2%
49_56_33F1	3,899	1,300		115	-1,185	-91.2%	215	-1,085	-83.5%	177	-1,123	-86.4%
49_56_33F2	218	73		2,626	2,553	3513.8%	112	39	54.1%	19	-54	-73.9%
49_56_36W41	119	40		22	-18	-44.5%	2,158	2,118	5340.3%	92	52	131.9%
49_56_36W42	40	13		22	9	65.0%	120	107	800.0%	51	38	282.5%
49_56_36W43	58	19		10	-9	-48.3%	25	6	29.3%	40	21	106.9%
49_56_36W44	165	55		162	107	194.5%	0	-55	-100.0%	0	-55	-100.0%
49_56_45J2	157	52		682	630	1203.2%	0	-52	-100.0%	0	-52	-100.0%
49_56_45J4	58	19		824	805	4162.1%	6	-13	-69.0%	0	-19	-100.0%
49_56_45J6	322	107		464	357	332.3%	65	-42	-39.4%	0	-107	-100.0%
49_56_46F1	559	186		52	-134	-72.1%	27	-159	-85.5%	1,604	1,418	760.8%
49_56_46F4	189	63		13	-50	-79.4%	1,529	1,466	2327.0%	60	-3	-4.8%
49_56_52F1	1,007	336		21	-315	-93.7%	30	-306	-91.1%	169	-167	-49.7%
49_56_52F2	1,711	570		35	-535	-93.9%	1	-569	-99.8%	0	-570	-100.0%
49_56_59F1	640	213		426	213	99.7%	563	350	163.9%	85	-128	-60.2%
49_56_59F4	2,193	731		84	-647	-88.5%	338	-393	-53.8%	6	-725	-99.2%
49_56_63F3	1,733	578		77	-501	-86.7%	88	-490	-84.8%	1,733	1,155	200.0%
49_56_63F4	69	23		11	-12	-52.2%	38	15	65.2%	0	-23	-100.0%
49_56_63F5	332	111		317	206	186.4%	27	-84	-75.6%	107	-4	-3.3%
49_56_63F6	6,903	2,301		562	-1,739	-75.6%	1,948	-353	-15.3%	1,237	-1,064	-46.2%
49_56_65J12	64	21		8	-13	-62.5%	0	-21	-100.0%	3	-18	-85.9%
49_56_65J2	56	19		10	-9	-46.4%	8	-11	-57.1%	346	327	1753.6%
49_56_68F3	9,287	3,096		788	-2,308	-74.5%	163	-2,933	-94.7%	154	-2,942	-95.0%
49_56_72F1	15	5		2	-3	-60.0%	80	75	1500.0%	0	-5	-100.0%
49_56_72F2	232	77		24	-53	-69.0%	5	-72	-93.5%	18	-59	-76.7%
49_56_72F3	7,214	2,405		4,625	2,220	92.3%	183	-2,222	-92.4%	453	-1,952	-81.2%
49_56_72F4	462	154		2	-152	-98.7%	62	-92	-59.7%	13	-141	-91.6%
49_56_85T3	3,006	1,002		744	-258	-25.7%	2,829	1,827	182.3%	679	-323	-32.2%
Totals	**90,967**	**30,322**		**21,523**	**-8,799**	**-29.0%**	**15,864**	**-14,458**	**-47.7%**	**19,058**	**-11,264**	**-37.1%**

	Fiscal Year 2013			1st Year After Project			2nd Year After Project			3rd Year After Project		
Feeder ID	**Total CI 4/1/09-3/31/12**	**Average CI**	**Project Year 4/1/12-3/31/13**	**Total CI 4/1/13-3/31/14**	**Difference**	**% Improved**	**Total CI 4/1/14-3/31/15**	**Difference**	**% Improved**	**Total CI 4/1/15-3/31/16**	**Difference**	**% Improved**
49_53_107W43	28	9		0	-9	-100.0%	0	-9	-100.0%	0	9	-100.0%
49_53_107W50	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_53_107W53	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_53_107W60	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_53_107W61	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_53_107W62	15	5		35	30	600.0%	0	-5	-100.0%	2,258	-2,253	-7510.0%
49_53_107W63	1,392	464		4	-460	-99.1%	0	-464	-100.0%	0	464	-100.9%
49_53_107W65	10	3		0	-3	-100.0%	0	-3	-100.0%	36	-33	980.0%
49_53_107W66	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_53_107W81	0	0		0	0	0.0%	59	59	0.0%	0	0	-
49_53_107W83	1	0		4	4	1100.0%	0	0	-100.0%	1,460	-1,460	-39809.1%
49_53_107W84	0	0		1,376	1,376	0.0%	0	0	0.0%	0	0	0.0%
49_53_1123	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_53_1125	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_53_127W41	607	202		247	45	22.1%	1,049	847	418.5%	270	-68	-151.5%
49_53_17W42	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_53_18F5	0	0		0	0	0.0%	14	14	0.0%	22	-22	-
49_53_18F6	1,527	509		100	-409	-80.4%	245	-264	-51.9%	1,086	-577	141.1%
49_53_23F2	684	228		47	-181	-79.4%	6	-222	-97.4%	287	-59	32.6%
49_53_23F4	82	27		2	-25	-92.7%	55	28	101.2%	22	5	-21.1%
49_53_23F5	98	33		0	-33	-100.0%	0	-33	-100.0%	0	33	-100.0%
49_53_27F6	2	1		0	-1	-100.0%	442	441	66200.0%	0	1	-100.0%
49_53_2J1	48	16		1	-15	-93.8%	0	-16	-100.0%	0	16	-106.7%
49_53_34F1	7,611	2,537		502	-2,035	-80.2%	1,037	-1,500	-59.1%	1,056	1,481	-72.8%
49_53_36J1	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_53_36J2	2	1		0	-1	-100.0%	0	-1	-100.0%	0	1	-100.0%
49_53_36J4	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_53_36J5	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_53_38F2	103	34		30	-4	-12.6%	5	-29	-85.4%	32	2	-53.8%
49_53_38F4	127	42		41	-1	-3.1%	0	-42	-100.0%	187	-145	10850.0%
49_53_38F5	3,207	1,069		202	-867	-81.1%	299	-770	-72.0%	1,183	-114	13.1%
49_53_38F6	487	162		0	-162	-100.0%	0	-162	-100.0%	54	108	-66.7%
49_53_45F2	680	227		44	-183	-80.6%	52	-175	-77.1%	59	168	-91.8%
49_53_48F1	181	60		0	-60	-100.0%	1	-59	-98.3%	768	-708	1172.9%
49_53_48F2	0	0		0	0	0.0%	552	552	0.0%	1	-1	-
49_53_48F3	2,885	962		37	-925	-96.2%	16	-946	-98.3%	3,384	-2,422	262.0%
49_53_48F4	312	104		0	-104	-100.0%	1	-103	-99.0%	12	92	-88.5%
49_53_48F5	111	37		1	-36	-97.3%	0	-37	-100.0%	0	37	-102.8%
49_53_48F6	963	321		0	-321	-100.0%	8	-313	-97.5%	0	321	-100.0%
49_53_66J1	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_53_66J3	1	0		0	0	-100.0%	16	16	4700.0%	0	0	-100.0%
49_53_66J5	50	17		0	-17	-100.0%	0	-17	-100.0%	13	4	-22.0%
49_53_73J1	0	0		0	0	0.0%	0	0	0.0%	8	-8	-
49_53_73J2	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_53_73J3	0	0		0	0	0.0%	0	0	0.0%	0	0	-

49_53_73J4	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_53_73J5	1	0		0	0	-100.0%	0	0	-100.0%	0	0	-100.0%
49_53_73J6	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_53_76F2	4	1		217	216	16175.0%	100	99	7400.0%	199	-198	-91.7%
49_53_76F4	75	25		99	74	296.0%	0	-25	-100.0%	21	4	5.4%
49_53_76F5	1	0		53	53	15800.0%	0	0	-100.0%	2	-2	-3.2%
49_53_76F6	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_53_76F7	2,227	742		1	-741	-99.9%	0	-742	-100.0%	81	661	-89.2%
49_53_76F8	0	0		0	0	0.0%	1	1	0.0%	0	0	-
49_53_78F3	1,292	431		944	513	119.2%	0	-431	-100.0%	45	386	75.1%
49_53_78F4	799	266		0	-266	-100.0%	32	-234	-88.0%	734	-468	175.6%
49_53_7F4	15	5		0	-5	-100.0%	13	8	160.0%	0	5	-100.0%
49_53_9J1	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_53_9J5	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_56_122J4	10	3		0	-3	-100.0%	7	4	110.0%	0	3	-100.0%
49_56_131J12	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_56_131J14	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_56_131J2	0	0		0	0	0.0%	9	9	0.0%	0	0	-
49_56_131J4	1	0		0	0	-100.0%	0	0	-100.0%	90	-90	26900.0%
49_56_131J6	1	0		0	0	-100.0%	0	0	-100.0%	0	0	-100.0%
49_56_154J14	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_56_154J16	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_56_154J18	0	0		0	0	0.0%	0	0	0.0%	1	-1	-
49_56_154J2	0	0		0	0	0.0%	5	5	0.0%	0	0	-
49_56_154J6	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_56_154J8	110	37		0	-37	-100.0%	22	-15	-40.0%	0	37	-100.0%
49_56_23J12	376	125		13	-112	-89.6%	0	-125	-100.0%	0	125	-111.6%
49_56_23J14	1,055	352		0	-352	-100.0%	0	-352	-100.0%	0	352	-100.0%
49_56_23J2	477	159		0	-159	-100.0%	10	-149	-93.7%	17	142	-89.3%
49_56_23J4	1,045	348		0	-348	-100.0%	0	-348	-100.0%	0	348	-100.0%
49_56_23J6	256	85		34	-51	-60.2%	308	223	260.9%	0	85	-166.2%
49_56_32J12	4	1		0	-1	-100.0%	0	-1	-100.0%	40	-39	2900.0%
49_56_32J14	29	10		0	-10	-100.0%	0	-10	-100.0%	0	10	-100.0%
49_56_32J2	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_56_32J4	0	0		8	8	0.0%	0	0	0.0%	0	0	0.0%
49_56_33F4	2,241	747		1,900	1,153	154.4%	513	-234	-31.3%	8,807	-8,060	-699.0%
49_56_37W41	2,577	859		759	-100	-11.6%	1	-858	-99.9%	718	141	-141.0%
49_56_37W42	436	145		0	-145	-100.0%	189	44	30.0%	76	69	-47.7%
49_56_37W43	147	49		0	-49	-100.0%	4,805	4,756	9706.1%	52	-3	6.1%
49_56_38J2	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_56_38J4	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_56_40F1	1,036	345		175	-170	-49.3%	1,066	721	208.7%	20	325	-191.0%
49_56_41F1	1,044	348		304	-44	-12.6%	438	90	25.9%	926	-578	1313.6%
49_56_49J1	216	72		0	-72	-100.0%	46	-26	-36.1%	0	72	-100.0%
49_56_49J2	50	17		24	7	44.0%	0	-17	-100.0%	0	17	227.3%
49_56_49J3	20	7		0	-7	-100.0%	14	7	110.0%	0	7	-100.0%
49_56_49J4	0	0		0	0	0.0%	0	0	0.0%	0	0	-
49_56_51J12	258	86		0	-86	-100.0%	0	-86	-100.0%	0	86	-100.0%
49_56_51J14	89	30		0	-30	-100.0%	0	-30	-100.0%	0	30	-100.0%
49_56_51J16	876	292		1	-291	-99.7%	0	-292	-100.0%	269	23	-7.9%
49_56_51J2	656	219		0	-219	-100.0%	0	-219	-100.0%	0	219	-100.0%
49_56_54F1	4,634	1,545		1,789	244	15.8%	624	-921	-59.6%	1,853	-308	-126.2%
49_56_57J2	1	0		0	0	-100.0%	0	0	-100.0%	20	-20	5900.0%
49_56_57J4	1	0		0	0	-100.0%	0	0	-100.0%	0	0	-100.0%
49_56_57J5	10	3		0	-3	-100.0%	0	-3	-100.0%	2	1	-40.0%
49_56_61F1	4	1		293	292	21875.0%	0	-1	-100.0%	291	-290	-99.3%
49_56_61F2	1,658	553		248	-305	-55.1%	129	-424	-76.7%	186	367	-120.4%
49_56_61F3	1,831	610		198	-412	-67.6%	985	375	61.4%	321	289	-70.2%
49_56_63F2	297	99		15	-84	-84.8%	3	-96	-97.0%	8	91	-108.3%
49_56_64F1	2,247	749		2,146	1,397	186.5%	11	-738	-98.5%	26	723	51.8%
49_56_64F2	399	133		130	-3	-2.3%	1	-132	-99.2%	0	133	-4433.3%
49_56_68F2	2,159	720		26	-694	-96.4%	2,567	1,847	256.7%	1,806	-1,086	156.6%
49_56_72F5	303	101		97	-4	-4.0%	3	-98	-97.0%	44	57	-1425.0%
49_56_72F6	181	60		4	-56	-93.4%	1	-59	-98.3%	27	33	-59.2%
49_56_83F2	170	57		1	-56	-98.2%	0	-57	-100.0%	0	57	-101.8%
49_56_87F2	0	0		0	0	0.0%	0	0	0.0%	18	-18	-
49_56_87F4	335	112		0	-112	-100.0%	0	-112	-100.0%	0	112	-100.0%
49_56_88F3	3,900	1,300		289	-1,011	-77.8%	420	-880	-67.7%	273	1,027	-101.6%
Totals	**56,768**	**18,923**		**12,441**	**-6,482**	**-34.3%**	**16,180**	**-2,743**	**-14.5%**	**29,171**	**10,248**	**54.2%**

Fiscal Year 2014				1st Year After Project			2nd Year After Project			3rd Year After Project		
Feeder ID	**Total CI 4/1/10-3/31/13**	**Average CI**	**Project Year 4/1/13-3/31/14**	**Total CI 4/1/14-3/31/15**	**Difference**	**% Improved**	**Total CI 4/1/15-3/31/16**	**Difference**	**% Improved**	**Total CI 4/1/16-3/31/17**	**Difference**	**% Improved**
49_53_102W51	263	88		403	315	0.0%	1	-87	-98.9%	698	-610	-696.2%
49_53_104J1	1	0		0	0	0.0%	0	0	-	0	0	100.0%
49_53_104J3	0	0		0	0	0.0%	0	0	-	0	0	#DIV/0!
49_53_104J5	750	250		0	-250	-100.0%	0	-250	-100.0%	0	250	100.0%
49_53_104J7	1,140	380		0	-380	-100.0%	0	-380	-100.0%	617	-237	-62.4%
49_53_106J1	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_53_106J3	0	0		0	0	-	0	0	-	845	-845	#DIV/0!
49_53_106J7	0	0		0	0	0.0%	0	0	-	0	0	#DIV/0!
49_53_107W51	1	0		0	0	0.0%	3	3	800.0%	0	0	100.0%
49_53_107W80	1	0		0	0	-100.0%	0	0	-100.0%	0	0	100.0%
49_53_108W61	34	11		0	-11	-100.0%	0	-11	-100.0%	0	11	100.0%
49_53_108W62	19	6		0	-6	-100.0%	0	-6	-100.0%	1	5	84.2%
49_53_108W63	177	59		0	-59	-100.0%	1	-58	-98.3%	0	59	100.0%
49_53_109J1	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_53_109J3	1,287	429		0	-429	-100.0%	0	-429	-100.0%	0	429	100.0%
49_53_109J5	1,506	502		0	-502	-100.0%	0	-502	-100.0%	0	502	100.0%
49_53_1119	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_53_111J1	0	0		0	0	0.0%	460	460	-	0	0	#DIV/0!
49_53_111J3	0	0		0	0	0.0%	1,129	1,129	-	0	0	#DIV/0!
49_53_112W41	3,065	1,022		23	-999	-97.7%	0	-1,022	-100.0%	93	929	90.9%
49_53_112W42	9,191	3,064		0	-3,064	0.0%	146	-2,918	-95.2%	1,064	2,000	65.3%
49_53_1131	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_53_113J1	1	0		36	36	10700.0%	0	0	-100.0%	0	0	100.0%
49_53_113J2	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_53_126W42	23	8		38	30	395.7%	29	21	278.3%	1	7	87.0%
49_53_126W51	314	105		3	-102	-97.1%	2,807	2,702	2581.8%	2,804	-2,699	-2579.0%
49_53_127W40	1,851	617		251	-366	-59.3%	1,828	1,211	196.3%	1,044	-427	-69.2%
49_53_12J1	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_53_12J2	3	1		0	-1	-100.0%	0	-1	-100.0%	0	1	100.0%
49_53_12J3	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_53_12J4	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_53_12J5	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_53_12J6	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_53_13F5	103	34		27	-7	-21.4%	339	305	887.4%	0	34	100.0%
49_53_148J1	0	0		938	938	-	0	0	-	0	0	#DIV/0!
49_53_148J3	820	273		0	-273	0.0%	434	161	58.8%	0	273	100.0%
49_53_148J5	0	0		0	0	0.0%	331	331	-	0	0	#DIV/0!
49_53_148J7	0	0		1,085	1,085	-	0	0	-	0	0	#DIV/0!
49_53_18F2	0	0		0	0	0.0%	0	0	-	0	0	#DIV/0!
49_53_18F3	0	0		0	0	0.0%	0	0	-	0	0	#DIV/0!
49_53_21F1	909	303		5	-298	0.0%	848	545	179.9%	738	-435	-143.6%
49_53_23F1	305	102		54	-48	0.0%	34	-68	-66.6%	0	102	100.0%
49_53_23F3	1,037	346		1,509	1,163	336.5%	330	-16	-4.5%	153	193	55.7%
49_53_23F6	2,726	909		2,518	1,609	177.1%	87	-822	-90.4%	27	882	97.0%
49_53_24J1	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_53_26W3	448	149		42	-107	-71.9%	719	570	381.5%	278	-129	-86.2%
49_53_26W5	5,950	1,983		2,805	822	41.4%	307	-1,676	-84.5%	2,801	-818	-41.2%
49_53_28J1	108	36		613	577	1602.8%	0	-36	-100.0%	0	36	100.0%

49_53_28J2	0	0		1,120	1,120	-	81	81	-	0	0	#DIV/0!
49_53_2J3	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_53_2J4	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_53_2J5	1	0		0	0	-100.0%	0	0	-100.0%	0	0	100.0%
49_53_30J1	883	294		0	-294	-100.0%	0	-294	-100.0%	19	275	93.5%
49_53_30J3	0	0		0	0	-	0	0	-	5	-5	#DIV/0!
49_53_30J5	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_53_34F1	7,905	2,635		1,037	-1,598	-60.6%	1,056	-1,579	-59.9%	1,841	794	30.1%
49_53_50F2	48	16		27	11	68.8%	0	-16	-100.0%	864	-848	-5300.0%
49_53_50J1	0	0		0	0	-	18	18	-	1	-1	#DIV/0!
49_53_50J2	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_53_50J3	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_53_60J1	0	0		74	74	-	0	0	-	0	0	#DIV/0!
49_53_60J3	1	0		0	0	0.0%	0	0	-100.0%	0	0	100.0%
49_53_60J5	11	4		0	-4	-100.0%	476	472	12881.8%	0	4	100.0%
49_53_66J2	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_53_66J4	1	0		0	0	-100.0%	0	0	-100.0%	0	0	100.0%
49_53_67J1	399	133		0	-133	-100.0%	0	-133	-100.0%	0	133	100.0%
49_53_6J1	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_53_6J2	4	1		0	-1	-100.0%	0	-1	-100.0%	1	0	25.0%
49_53_6J3	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_53_6J5	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_53_6J6	59	20		0	-20	-100.0%	0	-20	-100.0%	0	20	100.0%
49_53_6J8	183	61		0	-61	-100.0%	187	126	206.6%	0	61	100.0%
49_53_9J2	55	18		0	-18	-100.0%	0	-18	-100.0%	0	18	100.0%
49_56_16F1	1,716	572		80	-492	-86.0%	122	-450	-78.7%	12	560	97.9%
49_56_16F2	2,936	979		109	-870	-88.9%	2,797	1,818	185.8%	1,544	-565	-57.8%
49_56_16F3	37	12		7	-5	-43.2%	1,014	1,002	8121.6%	0	12	100.0%
49_56_16F4	2,280	760		75	-685	0.0%	332	-428	-56.3%	52	708	93.2%
49_56_22F2	108	36		0	-36	0.0%	57	21	58.3%	1	35	97.2%
49_56_22F3	2,269	756		0	-756	-100.0%	888	132	17.4%	355	401	53.1%
49_56_30F1	2,298	766		225	-541	0.0%	2,759	1,993	260.2%	1,498	-732	-95.6%
49_56_30F2	2,351	784		608	-176	0.0%	7,462	6,678	852.2%	3,614	-2,830	-361.2%
49_56_42F1	1,679	560		161	-399	0.0%	22	-538	-96.1%	136	424	75.7%
49_56_43F1	3,973	1,324		584	-740	0.0%	494	-830	-62.7%	941	383	28.9%
49_56_46F2	2,157	719		112	-607	-84.4%	378	-341	-47.4%	1,294	-575	-80.0%
49_56_46F3	669	223		1,949	1,726	774.0%	3,890	3,667	1644.4%	339	-116	-52.0%
49_56_52F3	642	214		86	-128	-59.8%	210	-4	-1.9%	95	119	55.6%
49_56_68F1	3,045	1,015		1,534	519	51.1%	2,468	1,453	143.2%	345	670	66.0%
49_56_68F4	392	131		193	62	47.7%	564	433	331.6%	478	-347	-265.8%
49_56_68F5	1	0		0	0	-100.0%	0	0	-100.0%	29	-29	-8600.0%
49_56_85T1	2,119	706		137	-569	-80.6%	64	-642	-90.9%	69	637	90.2%
49_56_86F1	2,545	848		2,923	2,075	244.6%	380	-468	-55.2%	4,411	-3,563	-420.0%
49_56_87F1	49	16		0	-16	-100.0%	6	-10	-63.3%	0	16	100.0%
49_56_88F1	991	330		274	-56	-17.1%	1,356	1,026	310.5%	654	-324	-98.0%
49_56_88F5	5,796	1,932		1,258	-674	-34.9%	219	-1,713	-88.7%	369	1,563	80.9%
49_56_31J1	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_56_31J2	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_56_21J2	1	0		0	0	-100.0%	0	0	-100.0%	0	0	100.0%
49_56_21J6	0	0		0	0	-	20	20	-	0	0	#DIV/0!
49_56_19J2	316	105		0	-105	-100.0%	0	-105	-100.0%	0	105	100.0%
49_56_19J14	314	105		0	-105	-100.0%	0	-105	-100.0%	0	105	100.0%
49_56_37J4	0	0		1	1	-	0	0	-	0	0	#DIV/0!
49_56_23J12	376	125		0	-125	-100.0%	0	-125	-100.0%	0	125	100.0%
49_56_61F4	249	83		15	-68	-81.9%	141	58	69.9%	0	83	100.0%
49_56_84T1	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_56_83F1	0	0		0	0	-	0	0	-	0	0	#DIV/0!
49_56_83F3	1	0		0	0	-100.0%	0	0	-100.0%	0	0	100.0%
Totals	**80,893**	**26,964**		**22,939**	**-4,025**	**-14.93%**	**37,294**	**10,330**	**38.3%**	**30,131**	**3,167**	**11.7%**

	Fiscal Year 2015			1st Year After Project			2nd Year After Project			3rd Year After Project		
Feeder ID	Total CI 4/1/11-3/31/14	Average CI	Project Year 4/1/14-3/31/15	Total CI 4/1/15-3/31/16	Difference	% Improved	Total CI 4/1/16-3/31/17	Difference	% Improved	Total CI 4/1/17-3/31/18	Difference	% Improved
49_53_102W44	0	0		1	1	0.0%	61	61	#DIV/0!	25	-25	#DIV/0!
49_53_1117	0	0		0	0	0.0%	0	0	#DIV/0!	0	0	#DIV/0!
49_53_1121	0	0		0	0	0.0%	0	0	#DIV/0!	0	0	#DIV/0!
49_53_126W40	42	14		1	-13	-92.9%	0	-14	-100.0%	0	14	100.0%
49_53_126W50	1,442	481		221	-260	-54.0%	247	-234	-48.6%	147	334	69.4%
49_53_126W54	0	0		706	706	-	9	9	#DIV/0!	224	-224	#DIV/0!
49_53_15F2	2,760	920		1,033	113	12.3%	287	-633	-68.8%	2,526	-1,606	-174.6%
49_53_18F1	0	0		0	0	0.0%	0	0	#DIV/0!	0	0	#DIV/0!
49_53_18F4	0	0		0	0	0.0%	0	0	#DIV/0!	0	0	#DIV/0!
49_53_18F7	814	271		65	-206	-76.0%	22	-249	-91.9%	3	268	98.9%
49_53_18F8	197	66		1,965	1,899	2892.4%	69	3	5.1%	5	61	92.4%
49_53_18F9	63	21		0	-21	-100.0%	0	-21	-100.0%	0	21	100.0%
49_53_20F1	758	253		1	-252	-99.6%	0	-253	-100.0%	0	253	100.0%
49_53_20F2	1	0		0	0	-100.0%	3	3	800.0%	0	0	100.0%
49_53_26W1	2,886	962		1,926	964	100.2%	2,022	1,060	110.2%	4,995	-4,033	-419.2%
49_53_26W7	121	40		215	175	433.1%	289	249	616.5%	330	-290	-718.2%
49_53_2J7	1,653	551		31	-520	-94.4%	0	-551	-100.0%	0	551	100.0%
49_53_2J8	0	0		0	0	0.0%	0	0	#DIV/0!	0	0	#DIV/0!
49_53_2J9	0	0		0	0	0.0%	0	0	#DIV/0!	0	0	#DIV/0!
49_53_34F3	1,405	468		481	13	2.7%	734	266	56.7%	993	-525	-112.0%
49_53_37J1	0	0		0	0	0.0%	1	1	#DIV/0!	0	0	#DIV/0!
49_53_37J2	0	0		0	0	-	0	0	#DIV/0!	34	-34	#DIV/0!
49_53_37J3	21	7		16	9	128.6%	60	53	757.1%	0	7	100.0%
49_53_37J4	0	0		881	881	-	0	0	#DIV/0!	0	0	#DIV/0!
49_53_37J5	1	0		1	1	200.0%	0	0	-100.0%	0	0	100.0%
49_53_38F1	2,335	778		2,547	1,769	227.2%	578	-200	-25.7%	3,705	-2,927	-376.0%
49_53_38F3	1,944	648		4,165	3,517	542.7%	819	171	26.4%	199	449	69.3%
49_53_51F1	458	153		984	831	544.5%	255	102	67.0%	708	-555	-363.8%
49_53_51F2	442	147		12	-135	-91.9%	0	-147	-100.0%	3,578	-3,431	-2328.5%
49_53_51F3	3,039	1,013		178	-835	-82.4%	0	-1,013	-100.0%	29	984	97.1%
49_53_5F1	868	289		665	376	129.8%	152	-137	-47.5%	4,624	-4,335	-1498.2%
49_53_5F2	2,974	991		61	-930	-93.8%	0	-991	-100.0%	1,440	-449	-45.3%
49_53_5F3	411	137		1,961	1,824	1331.4%	187	50	36.5%	79	58	42.3%
49_53_5F4	3,326	1,109		79	-1,030	-92.9%	230	-879	-79.3%	419	690	62.2%
49_53_76F1	115	38		102	64	166.1%	16	-22	-58.3%	16	22	58.3%
49_53_77J1	0	0		0	0	0.0%	0	0	#DIV/0!	0	0	#DIV/0!
49_53_77J2	0	0		1	1	0.0%	0	0	#DIV/0!	0	0	#DIV/0!
49_53_77J3	238	79		0	-79	-100.0%	0	-79	-100.0%	1,683	-1,604	-2021.4%
49_53_77J4	0	0		0	0	0.0%	0	0	#DIV/0!	0	0	#DIV/0!
49_53_79F1	0	0		0	0	0.0%	0	0	#DIV/0!	0	0	#DIV/0!
49_53_79F2	71	24		0	-24	0.0%	0	-24	-100.0%	4	20	83.1%
49_53_9J3	57	19		0	-19	0.0%	0	-19	-100.0%	0	19	100.0%
49_56_14F1	13	4		400	396	9130.8%	2,477	2,473	57061.5%	43	-39	-892.3%
49_56_14F2	116	39		42	3	8.6%	1,794	1,755	4539.7%	226	-187	-484.5%
49_56_14F3	2,203	734		63	-671	-91.4%	1,541	807	109.9%	0	734	100.0%
49_56_14F4	258	86		11	-75	-87.2%	1	-85	-98.8%	0	86	100.0%
49_56_17F1	2,795	932		2,090	1,158	124.3%	5	-927	-99.5%	283	649	69.6%
49_56_17F2	3,164	1,055		1,986	931	88.3%	4	-1,051	-99.6%	43	1,012	95.9%
49_56_17F3	1,157	386		977	591	153.3%	985	599	155.4%	112	274	71.0%
49_56_22F1	172	57		11	-46	-80.8%	1,509	1,452	2532.0%	2,406	-2,349	-4096.5%
49_56_22F4	215	72		382	310	433.0%	0	-72	-100.0%	0	72	100.0%
49_56_29F1	1,488	496		1	-495	-99.8%	0	-496	-100.0%	84	412	83.1%
49_56_29F2	1	0		0	0	-100.0%	176	176	52700.0%	0	0	100.0%
49_56_33F1	377	126		2,470	2,344	1865.5%	1,396	1,270	1010.9%	107	19	14.9%
49_56_33F2	5,299	1,766		2,527	761	43.1%	17	-1,749	-99.0%	1,063	703	39.8%
49_56_33F3	6,061	2,020		813	-1,207	-59.8%	215	-1,805	-89.4%	4,738	-2,718	-134.5%
49_56_3F1	379	126		210	84	66.2%	235	109	86.0%	1,803	-1,677	-1327.2%
49_56_3F2	219	73		18	-55	-75.3%	50	-23	-31.5%	1,979	-1,906	-2611.0%

49_56_45J2	0	0		0	0	-	0	0	#DIV/0!	0	0	#DIV/0!
49_56_45J4	833	278		4	-274	-98.6%	3	-275	-98.9%	17	261	93.9%
49_56_45J6	464	155		0	-155	-100.0%	0	-155	-100.0%	0	155	100.0%
49_56_57J1	1	0		0	0	-100.0%	0	0	-100.0%	0	0	100.0%
49_56_57J3	1,163	388		1	-387	-99.7%	0	-388	-100.0%	12	376	96.9%
49_56_59F2	534	178		285	107	60.1%	2	-176	-98.9%	118	60	33.7%
49_56_59F3	4,180	1,393		659	-734	-52.7%	2,439	1,046	75.0%	3,332	-1,939	-139.1%
49_56_65J12	22	7		14	7	90.9%	3	-4	-59.1%	18	-11	-145.5%
49_56_65J2	28	9		0	-9	-100.0%	12	3	28.6%	684	-675	-7228.6%
49_56_68F3	10,770	3,590		463	-3,127	-87.1%	1,217	-2,373	-66.1%	268	3,322	92.5%
Totals	**70,354**	**23,451**		**31,726**	**8,275**	**35.28%**	**20,122**	**-3,329**	**-14.2%**	**43,102**	**19,651**	**83.8%**

Fiscal Year 2016				1st Year After Project			2nd Year After Project			3rd Year After Project		
Feeder ID	Total CI 4/1/12-3/31/15	Average CI	Project Year 4/1/15-3/31/16	Total CI 4/1/16-3/31/17	Difference	% Improved	Total CI 4/1/17-3/31/18	Difference	% Improved	Total CI 4/1/18-3/31/19	Difference	% Improved
49_53_102W41	0	0		0	0	0.0%	29	29	#DIV/0!	0	0	#DIV/0!
49_53_102W42	1	0		0	0	0.0%	0	0	-100.0%	0	0	100.0%
49_53_102W50	0	0		0	0	0.0%	0	0	#DIV/0!	0	0	#DIV/0!
49_53_102W52	698	233		11	-222	-95.3%	0	-233	-100.0%	0	233	100.0%
49_53_102W54	163	54		270	216	396.9%	0	-54	-100.0%	1266	-1,212	-2230.1%
49_53_107W85	0	0		16	16	-	0	0	#DIV/0!	0	0	#DIV/0!
49_53_108W51	0	0		0	0	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!
49_53_108W53	390	130		783	653	0.0%	453	323	248.5%	0	130	100.0%
49_53_108W55	0	0		536	536	0.0%	0	0	#DIV/0!	0	0	#DIV/0!
49_53_108W65	0	0		791	791	#DIV/0!	166	166	#DIV/0!	210	-210	#DIV/0!
49_53_112W43	284	95		577	482	509.5%	39	-56	-58.8%	1151	-1,056	-1115.8%
49_53_112W44	1,210	403		642	239	59.2%	398	-5	-1.3%	7374	-6,971	-1728.3%
49_53_126W41	1,491	497		298	-199	-40.0%	430	-67	-13.5%	695	-198	-39.8%
49_53_127W42	1,236	412		1,990	1,578	383.0%	158	-254	-61.7%	573	-161	-39.1%
49_53_13F2	28	9		0	-9	-100.0%	0	-9	-100.0%	0	9	100.0%
49_53_13F3	70	23		0	-23	-100.0%	0	-23	-100.0%	45	-22	-92.9%
49_53_13F4	1,167	389		2,743	2,354	605.1%	18	-371	-95.4%	1276	-887	-228.0%
49_53_13F8	0	0		0	0	0.0%	0	0	#DIV/0!	0	0	#DIV/0!
49_53_13F9	603	201		2	-199	0.0%	15	-186	-92.5%	0	201	100.0%
49_53_15F1	200	67		72	5	8.0%	216	149	224.0%	239	-172	-258.5%
49_53_21F2	142	47		10	-37	0.0%	95	48	100.7%	1482	-1,435	-3031.0%
49_53_21F4	4,118	1,373		46	-1,327	-	48	-1,325	-96.5%	94	1,279	93.2%
49_53_27F1	472	157		283	126	79.9%	0	-157	-100.0%	11	146	93.0%
49_53_27F2	72	24		70	46	-	35	11	45.8%	0	24	100.0%
49_53_27F3	0	0		0	0	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!
49_53_27F4	86	29		0	-29	-100.0%	0	-29	-100.0%	0	29	100.0%
49_53_27F5	1,622	541		2,939	2,398	443.6%	55	-486	-89.8%	2945	-2,404	-444.7%
49_53_34F2	6,601	2,200		3,195	995	45.2%	1,287	-913	-41.5%	16618	-14,418	-655.2%
49_53_47J1	0	0		0	0	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!
49_53_47J2	3	1		62	61	6100.0%	17	16	1600.0%	0	1	100.0%
49_53_47J3	2	1		0	-1	-100.0%	0	-1	-100.0%	0	1	100.0%
49_53_47J4	112	37		0	-37	-100.0%	0	-37	-100.0%	0	37	100.0%
49_53_4F1	190	63		1,881	1,818	2870.0%	84	21	32.6%	1994	-1,931	-3048.4%
49_53_4F2	1,173	391		214	-177	-45.3%	1,763	1,372	350.9%	3594	-3,203	-819.2%
49_53_69F1	295	98		50	-48	-49.2%	0	-98	-100.0%	84	14	14.6%
49_53_69F3	325	108		2	-106	0.0%	0	-108	-100.0%	0	108	100.0%
49_53_6J7	6	2		0	-2	0.0%	0	-2	-100.0%	0	2	100.0%
49_53_71J1	0	0		0	0	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!
49_53_71J2	0	0		0	0	0.0%	0	0	#DIV/0!	0	0	#DIV/0!
49_53_71J3	0	0		0	0	0.0%	122	122	#DIV/0!	551	-551	#DIV/0!
49_53_71J4	0	0		0	0	0.0%	0	0	#DIV/0!	0	0	#DIV/0!
49_53_71J5	66	22		0	-22	0.0%	0	-22	-100.0%	0	22	100.0%
49_56_36W41	2,272	757		8	-749	-98.9%	35	-722	-95.4%	90	667	88.1%
49_56_36W42	193	64		0	-64	-100.0%	542	478	742.5%	356	-292	-453.4%
49_56_36W43	75	25		2	-23	-92.0%	51	26	104.0%	42	-17	-68.0%
49_56_36W44	162	54		9	-45	-83.3%	108	54	100.0%	251	-197	-364.8%
49_56_46F1	1,683	561		68	-493	-87.9%	793	232	41.4%	849	-288	-51.3%
49_56_46F4	2,079	693		339	-354	-51.1%	5,024	4,331	625.0%	123	570	82.3%
49_56_52F1	221	74		102	28	38.5%	232	158	214.9%	966	-892	-1211.3%
49_56_52F2	36	12		2	-10	-83.3%	0	-12	-100.0%	0	12	100.0%
49_56_54F1	3,996	1,332		5,158	3,826	287.2%	3,914	2,582	193.8%	4494	-3,162	-237.4%
49_56_59F1	1,074	358		26	-332	-92.7%	155	-203	-56.7%	1356	-998	-278.8%
49_56_59F4	428	143		529	386	270.8%	263	120	84.3%	724	-581	-407.5%
49_56_63F3	2,021	674		2,503	1,829	271.5%	256	-418	-62.0%	2576	-1,902	-282.4%
49_56_63F4	134	45		102	57	128.4%	0	-45	-100.0%	1711	-1,666	-3730.6%
49_56_63F5	451	150		147	-3	-2.2%	522	372	247.2%	362	-212	-140.8%
49_56_63F6	3,747	1,249		317	-932	-74.6%	1,060	-189	-15.1%	2777	-1,528	-122.3%
49_56_64F5	0	0		0	0	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!
49_56_72F1	1	0		0	0	-	0	0	-100.0%	0	0	100.0%
49_56_72F2	47	16		302	286	1827.7%	0	-16	-100.0%	77	-61	-391.5%
49_56_72F3	5,294	1,765		2	-1,763	-99.9%	3,392	1,627	92.2%	956	809	45.8%
49_56_72F4	77	26		63	37	145.5%	84	58	227.3%	403	-377	-1470.1%
Totals	**46,817**	**15,606**		**27,162**	**11,556**	**74.05%**	**21,859**	**6,253**	**40.1%**	**58,315**	**-42,709**	**-273.7%**

Fiscal Year 2017				1st Year After Project			2nd Year After Project		
Feeder ID	Total CI 4/1/13-3/31/16	Average CI	Project Year 4/1/16-3/31/17	Total CI 4/1/17-3/31/18	Difference	% Improved	Total CI 4/1/18-3/31/19	Difference	% Improved
49_53_107W43	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_53_107W50	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_53_107W53	3	1		0	-1	-100.0%	2	1	100.0%
49_53_107W60	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_53_107W61	0	0		0	0	#DIV/0!	1888	1,888	#DIV/0!
49_53_107W62	2,258	753		0	-753	-100.0%	0	-753	-100.0%
49_53_107W63	0	0		3,065	3,065	#DIV/0!	20	20	#DIV/0!
49_53_107W65	36	12		0	-12	-100.0%	0	-12	-100.0%
49_53_107W66	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_53_107W81	104	35		0	-35	-100.0%	0	-35	-100.0%
49_53_107W83	1,464	488		125	-363	-74.4%	45	-443	-90.8%
49_53_107W84	1,457	486		0	-486	-100.0%	4	-482	-99.2%
49_53_108W60	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_53_127W41	560	187		45	-142	-75.9%	1005	818	438.4%
49_53_127W43	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_53_18F5	22	7		39	32	431.8%	7	0	-4.5%
49_53_18F6	1,335	445		43	-402	-90.3%	911	466	104.7%
49_53_23F2	338	113		396	283	251.5%	1277	1,164	1033.4%
49_53_23F4	78	26		0	-26	-100.0%	25	-1	-3.8%
49_53_23F5	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_53_27F2	2	1		35	34	5150.0%	0	-1	-100.0%
49_53_2J1	0	0		0	0	#DIV/0!	558	558	#DIV/0!
49_53_36J1	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_53_36J2	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_53_36J4	0	0		3	3	#DIV/0!	0	0	#DIV/0!
49_53_36J5	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_53_38F2	67	22		32	10	43.3%	162	140	625.4%
49_53_38F4	226	75		12	-63	-84.1%	39	-36	-48.2%
49_53_38F5	264	88		250	162	184.1%	1168	1,080	1227.3%
49_53_38F6	54	18		0	-18	-100.0%	53	35	194.4%
49_53_45F2	1,645	548		695	147	26.7%	1734	1,186	216.2%
49_53_48F1	767	256		0	-256	-100.0%	897	641	250.8%
49_53_48F2	552	184		0	-184	-100.0%	0	-184	-100.0%
49_53_48F3	3,436	1,145		91	-1,054	-92.1%	150	-995	-86.9%
49_53_48F4	12	4		9	5	125.0%	6	2	50.0%
49_53_48F5	0	0		0	0	#DIV/0!	3202	3,202	#DIV/0!
49_53_48F6	8	3		3	0	12.5%	0	-3	-100.0%

49_53_66J1	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_53_66J3	16	5		0	-5	-100.0%	0	-5	-100.0%
49_53_66J5	13	4		0	-4	-100.0%	0	-4	-100.0%
49_53_73J1	8	3		0	-3	-100.0%	0	-3	-100.0%
49_53_73J2	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_53_73J3	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_53_73J4	0	0		0	0	#DIV/0!	47	47	#DIV/0!
49_53_73J5	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_53_73J6	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_53_76F2	516	172		50	-122	-70.9%	0	-172	-100.0%
49_53_76F4	119	40		0	-40	-100.0%	0	-40	-100.0%
49_53_76F5	53	18		0	-18	-100.0%	42	24	137.7%
49_53_76F6	0	0		19	19	#DIV/0!	109	109	#DIV/0!
49_53_76F7	77	26		774	748	2915.6%	38	12	48.1%
49_53_76F8	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_53_78F3	989	330		18	-312	-94.5%	0	-330	-100.0%
49_53_78F4	765	255		0	-255	-100.0%	827	572	224.3%
49_53_7F1	53	18		2	-16	-88.7%	2757	2,739	15505.7%
49_53_7F2	2,606	869		172	-697	-80.2%	4020	3,151	362.8%
49_53_7F4	13	4		16	12	269.2%	2725	2,721	62784.6%
49_53_9J1	0	0		0	0	#DIV/0!	9	9	#DIV/0!
49_53_9J5	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_53_1123	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_53_1125	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_100F1	770	257		1,183	926	360.9%	1259	1,002	390.5%
49_56_122J4	7	2		0	-2	-100.0%	327	325	13914.3%
49_56_131J12	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_131J14	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_131J2	9	3		57	54	1800.0%	0	-3	-100.0%
49_56_131J4	90	30		3	-27	-90.0%	0	-30	-100.0%
49_56_131J6	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_154J16	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_154J18	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_154J2	5	2		0	-2	-100.0%	0	-2	-100.0%
49_56_154J8	22	7		32	25	336.4%	0	-7	-100.0%
49_56_23J14	0	0		28	28	#DIV/0!	0	0	#DIV/0!
49_56_23J2	27	9		0	-9	-100.0%	0	-9	-100.0%
49_56_23J4	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_23J6	265	88		0	-88	-100.0%	0	-88	-100.0%
49_56_32J12	40	13		0	-13	-100.0%	0	-13	-100.0%
49_56_32J14	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_32J2	0	0		0	0	#DIV/0!	3	3	#DIV/0!
49_56_32J4	8	3		0	-3	-100.0%	0	-3	-100.0%
49_56_33F4	11,097	3,699		4,419	720	19.5%	1035	-2,664	-72.0%
49_56_37W41	1,473	491		24	-467	-95.1%	155	-336	-68.4%
49_56_37W42	265	88		44	-44	-50.2%	73	-15	-17.4%
49_56_37W43	4,760	1,587		0	-1,587	-100.0%	0	-1,587	-100.0%
49_56_38J2	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_38J4	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_40F1	1,028	343		0	-343	-100.0%	0	-343	-100.0%
49_56_41F1	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_49J1	46	15		89	74	480.4%	0	-15	-100.0%
49_56_49J2	24	8		0	-8	-100.0%	0	-8	-100.0%
49_56_49J3	14	5		0	-5	-100.0%	0	-5	-100.0%
49_56_49J4	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_51J12	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_51J14	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_51J16	269	90		0	-90	-100.0%	0	-90	-100.0%
49_56_51J2	0	0		26	26	#DIV/0!	0	0	#DIV/0!
49_56_57J2	20	7		0	-7	-100.0%	0	-7	-100.0%
49_56_57J5	0	0		0	0	#DIV/0!	44	44	#DIV/0!
49_56_61F1	584	195		0	-195	-100.0%	304	109	56.2%
49_56_61F2	615	205		238	33	16.1%	1760	1,555	758.5%
49_56_61F3	1,503	501		521	20	4.0%	192	-309	-61.7%
49_56_63F2	22	7		803	796	10850.0%	93	86	1168.2%
49_56_64F1	2,180	727		0	-727	-100.0%	1284	557	76.7%
49_56_64F2	130	43		0	-43	-100.0%	122	79	181.5%
49_56_68F2	4,391	1,464		68	-1,396	-95.4%	140	-1,324	-90.4%
49_56_72F5	140	47		132	85	182.9%	79	32	69.3%
49_56_72F6	26	9		16	7	84.6%	106	97	1123.1%
49_56_83F2	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_84T3	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_87F2	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_87F3	55	18		47	29	156.4%	18	0	-1.8%
49_56_87F4	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_88F3	977	326		211	-115	-35.2%	277	-49	-14.9%
49_56_2230	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_2232	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_122J2	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_122J6	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_23J12	13	4		0	-4	-100.0%	0	-4	-100.0%
49_56_146J14	203	68		1,079	1,011	1494.6%	0	-68	-100.0%
49_56_146J2	67	22		0	-22	-100.0%	0	-22	-100.0%
49_56_37J2	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_37J4	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_38W2	138	46		68	22	47.8%	2118	2,072	4504.3%
49_56_83F1	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_83F3	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_84T1	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_84T2	0	0		0	0	#DIV/0!	0	0	#DIV/0!
49_56_84T4	0	0		0	0	#DIV/0!	0	0	#DIV/0!
Totals	**51,199**	**17,066**		**14,982**	**-2,084**	**-12.2%**	**33,116**	**16,050**	**94.0%**

Fiscal Year 2018				1st Year After Project		
Feeder ID	**Total CI 4/1/14-3/31/17**	**Average CI**	**Project Year 4/1/17-3/31/18**	**Total CI 4/1/18-3/31/19**	**Difference**	**% Improved**
49_53_102C43	0	0		0	0	#DIV/0!
49_53_102W51	1099	366		297	-69	-18.9%
49_53_112W41	116	39		0	-39	-100.0%
49_53_112W42	1194	398		531	133	33.4%
49_53_126W42	67	22		0	-22	-100.0%
49_53_126W51	5614	1,871		2620	749	40.0%
49_53_127W40	3111	1,037		3574	2,537	244.6%
49_53_12J1	0	0		0	0	#DIV/0!
49_53_12J2	0	0		0	0	#DIV/0!
49_53_12J3	0	0		0	0	#DIV/0!
49_53_12J4	0	0		0	0	#DIV/0!
49_53_12J5	0	0		0	0	#DIV/0!
49_53_12J6	0	0		0	0	#DIV/0!
49_53_13F5	365	122		0	-122	-100.0%
49_53_21F1	1582	527		4488	3,961	751.1%
49_53_2228	3	1		0	-1	-100.0%
49_53_23F1	88	29		203	174	592.0%
49_53_23F3	1986	662		1823	1,161	175.4%
49_53_23F6	2412	804		328	-476	-59.2%
49_53_26W3	1038	346		2357	2,011	581.2%
49_53_26W5	5913	1,971		72	-1,899	-96.3%
49_53_2J3	0	0		0	0	#DIV/0!
49_53_2J4	0	0		0	0	#DIV/0!
49_53_2J5	0	0		0	0	#DIV/0!
49_53_34F1	3886	1,295		4099	2,804	216.4%

49_53_50F2	891	297		52	-245	-82.5%
49_53_50J1	18	6		0	-6	-100.0%
49_53_50J2	0	0		0	0	#DIV/0!
49_53_50J3	0	0		6	6	#DIV/0!
49_53_66J2	0	0		0	0	#DIV/0!
49_53_66J4	0	0		0	0	#DIV/0!
49_53_67J1	0	0		0	0	#DIV/0!
49_53_6J1	0	0		0	0	#DIV/0!
49_53_6J2	0	0		0	0	#DIV/0!
49_53_6J3	0	0		0	0	#DIV/0!
49_53_6J5	0	0		0	0	#DIV/0!
49_53_6J6	0	0		0	0	#DIV/0!
49_53_6J8	187	62		0	-62	-100.0%
49_53_9J2	0	0		0	0	#DIV/0!
49_53_2207	0	0		0	0	#DIV/0!
49_53_2213	0	0		0	0	#DIV/0!
49_53_2221	0	0		0	0	#DIV/0!
49_53_2227	0	0		1	1	#DIV/0!
49_53_2229	0	0		0	0	#DIV/0!
49_53_2228 ELM	0	0		0	0	#DIV/0!
49_53_2254	0	0		0	0	#DIV/0!
49_56_16F1	208	69		2072	2,003	2888.5%
49_56_16F2	4448	1,483		8	-1,475	-99.5%
49_56_16F3	1020	340		40	-300	-88.2%
49_56_16F4	457	152		25	-127	-83.6%
49_56_16F4MOBIL	0	0		0	0	#DIV/0!
49_56_19J14	0	0		0	0	#DIV/0!
49_56_19J16	0	0		0	0	#DIV/0!
49_56_19J2	0	0		0	0	#DIV/0!
49_56_21J2	0	0		0	0	#DIV/0!
49_56_21J4	9	3		0	-3	-100.0%
49_56_21J6	20	7		0	-7	-100.0%
49_56_30F1	4479	1,493		1514	21	1.4%
49_56_30F2	11671	3,890		4895	1,005	25.8%
49_56_42F1	314	105		32	-73	-69.4%
49_56_43F1	632	211		0	-211	-100.0%
49_56_46F2	1777	592		260	-332	-56.1%
49_56_46F3	6175	2,058		0	-2,058	-100.0%
49_56_68F1	4327	1,442		6144	4,702	326.0%
49_56_68F4	1226	409		777	368	90.1%
49_56_68F5	29	10		0	-10	-100.0%
49_56_86F1	7706	2,569		248	-2,321	-90.3%
49_56_88F1	2279	760		522	-238	-31.3%
49_56_88F5	1839	613		762	149	24.3%
49_56_88F7	746	249		2252	2,003	805.6%
49_56_85T1	265	88		409	321	363.0%
49_56_85T2	0	0		116	116	#DIV/0!
49_56_2266	0	0		0	0	#DIV/0!
Totals	**79,197**	**26,399**		**40,527**	**14,128**	**53.5%**

	Total CI	Average CI Before Project Year	Project Year	Average CI After Project Year	Difference	% Improved	Average CI 2 Years After	Difference	% Improved	Average CI 3 Years After	Difference	% Improved
Program Totals	**-**	**447,697**		**380,465**	**-67,232**	**-15.0%**	**359,397**	**-88,300**	**-19.7%**	**390,050**	**-57,647**	**-12.9%**

Cycle Pruning Project Year	AVG Annual CI Pre-Project	Total CI 1st Year Post-Project	% Improved	Total CI 2nd Year Post-Project	% Improved	Total CI 3rd Year Post-Project	% Improved
2007	55,494	60,868	-10%	48,121	13%	39,215	29%
2008	47,466	30,333	36%	28,356	40%	82,400	-74%
2009	50,362	38,327	24%	56,979	-13%	48,734	3%
2010	58,009	53,466	8%	48,340	17%	23,332	60%
2011	77,634	26,171	66%	33,166	57%	16,592	79%
2012	30,322	21,523	29%	15,864	48%	19,058	37%
2013	18,923	12,441	34%	16,180	14%	29,171	-54%
2014	26,964	22,939	15%	37,294	-38%	30,131	-12%
2015	23,451	31,726	-35%	20,122	14%	43,102	-84%
2016	15,606	27,162	-74%	21,859	-40%	58,315	-274%
2017	17,066	14,982	12%	33,116	-94%	-	-
2018	26,399	40,527	-54%	-	-	-	-
Totals	**447,697**	**380,465**	**15%**	**359,397**	**20%**	**390,050**	**13%**

EHTM - Reliability

Fiscal Year 2007				1st Year After Project		
Feeder ID	**Total CI 4/1/03-3/31/06**	**Average CI**	**Project Year 4/1/06-3/31/07**	**Total CI 4/1/07-3/31/08**	**Difference**	**% Improved**
No EHTM for FY '07	-	-		-	-	-
Totals	-	-		-	-	-

Fiscal Year 2008				1st Year After Project			2nd Year After Project			3rd Year After Project		
Feeder ID	**Total CI 4/1/04-3/31/07**	**Average CI**	**Project Year 4/1/07-3/31/08**	**Total CI 4/1/08-3/31/09**	**Difference**	**% Improved**	**Total CI 4/1/09-3/31/10**	**Difference**	**% Improved**	**Total CI 4/1/10-3/31/11**	**Difference**	**% Improved**
49_53_13F2	7,710	2,570		1	-2,569	-100.0%	60	-2,510	-97.7%	0	-2,570	-100.0%
49_53_34F2	8,160	2,720		200	-2,520	-92.6%	1,150	-1,570	-57.7%	757	-1,963	-72.2%
49_53_51F1	1,624	541		97	-444	-82.1%	358	-183	-33.9%	1	-540	-99.8%
49_53_69F1	7,942	2,647		223	-2,424	-91.6%	0	-2,647	-100.0%	3	-2,644	-99.9%
49_56_33F4	4,346	1,449		3,818	2,369	163.6%	1,345	-104	-7.2%	404	-1,045	-72.1%
49_56_54F1	30,968	10,323		5,344	-4,979	-48.2%	1,667	-8,656	-83.9%	1,389	-8,934	-86.5%
49_56_63F6	5,631	1,877		2,830	953	50.8%	2,897	1,020	54.3%	6,659	4,782	254.8%
Total	**66,381**	**22,127**		**12,513**	**-9,614**	**-43.4%**	**7,477**	**-14,650**	**-66.2%**	**9,213**	**-12,914**	**-58.4%**

Fiscal Year 2009				1st Year After Project			2nd Year After Project			3rd Year After Project		
Feeder ID	**Total CI 4/1/05-3/31/08**	**Average CI**	**Project Year 4/1/08-3/31/09**	**Total CI 4/1/09-3/31/10**	**Difference**	**% Improved**	**Total CI 4/1/10-3/31/11**	**Difference**	**% Improved**	**Total CI 4/1/11-3/31/12**	**Difference**	**% Improved**
49_53_102W51	17,532	5,844		15	-5,829	-99.7%	8	-5,836	-99.9%	0	-5,844	-100.0%
49_53_112W42	15,617	5,206		629	-4,577	-87.9%	2,642	-2,564	-49.2%	11,421	6,215	119.4%
49_53_2291	0	0		0	0	-	0	0	-	0	0	-
49_53_23F1	12,397	4,132		54	-4,078	-98.7%	174	-3,958	-95.8%	130	-4,002	-96.9%
49_53_38F1	9,353	3,118		724	-2,394	-76.8%	2,964	-154	-4.9%	486	-2,632	-84.4%
49_53_5F4	13,002	4,334		0	-4,334	-100.0%	0	-4,334	-100.0%	3,294	-1,040	-24.0%
49_56_22F4	3,271	1,090		35	-1,055	-96.8%	298	-792	-72.7%	26	-1,064	-97.6%
49_56_30F1	13,810	4,603		4,851	248	5.4%	2,639	-1,964	-42.7%	364	-4,239	-92.1%
49_56_52F3	11,293	3,764		240	-3,524	-93.6%	288	-3,476	-92.3%	251	-3,513	-93.3%
Total	**96,275**	**32,092**		**6,548**	**-25,544**	**-79.6%**	**9,013**	**-23,079**	**-71.9%**	**15,972**	**-16,120**	**-50.2%**

Fiscal Year 2010				1st Year After Project			2nd Year After Project			3rd Year After Project		
Feeder ID	**Total CI 4/1/06-3/31/09**	**Average CI**	**Project Year 4/1/09-3/31/10**	**Total CI 4/1/10-3/31/11**	**Difference**	**% Improved**	**Total CI 4/1/11-3/31/12**	**Difference**	**% Improved**	**Total CI 4/1/12-3/31/13**	**Difference**	**% Improved**
49_53_108W62	1,633	544		18	-526	-96.7%	1	-543	-99.8%	0	-544	-100.0%
49_53_20F2	3,983	1,328		0	-1,328	-100.0%	1	-1,327	-99.9%	0	-1,328	-100.0%
49_53_38F5	3,668	1,223		2,987	1,764	144.3%	186	-1,037	-84.8%	425	-798	-65.2%
49_53_5F2	35,343	11,781		495	-11,286	-95.8%	319	-11,462	-97.3%	2,549	-9,232	-78.4%
49_53_5F3	21,442	7,147		507	-6,640	-92.9%	161	-6,986	-97.7%	6	-7,141	-99.9%
49_53_7F1	14,814	4,938		0	-4,938	-100.0%	0	-4,938	-100.0%	56	-4,882	-98.9%
49_56_16F1	15,979	5,326		52	-5,274	-99.0%	1,650	-3,676	-69.0%	17	-5,309	-99.7%
49_56_17F2	11,037	3,679		234	-3,445	-93.6%	8,790	5,111	138.9%	22	-3,657	-99.4%
49_56_42F1	14,855	4,952		19	-4,933	-99.6%	1	-4,951	-100.0%	1,659	-3,293	-66.5%
49_56_43F1	7,505	2,502		1,208	-1,294	-51.7%	1,657	-845	-33.8%	1,161	-1,341	-53.6%
49_56_46F2	5,621	1,874		756	-1,118	-59.7%	261	-1,613	-86.1%	1,643	-231	-12.3%
49_56_59F4	2,223	741		362	-379	-51.1%	2	-739	-99.7%	84	-657	-88.7%
49_56_72F3	12,332	4,111		93	-4,018	-97.7%	3	-4,108	-99.9%	4,625	514	12.5%
Total	**150,435**	**50,145**		**6,731**	**-43,414**	**-86.6%**	**13,032**	**-37,113**	**-74.0%**	**12,247**	**-37,898**	**-75.6%**

Fiscal Year 2011				1st Year After Project			2nd Year After Project			3rd Year After Project		
Feeder ID	**Total CI 4/1/07-3/31/10**	**Average CI**	**Project Year 4/1/10-3/31/11**	**Total CI 4/1/11-3/31/12**	**Difference**	**% Improved**	**Total CI 4/1/12-3/31/13**	**Difference**	**% Improved**	**Total CI 4/1/13-3/31/14**	**Difference**	**% Improved**
49_53_38F5	3,399	1,133		186	-947	-83.6%	425	-708	-62.5%	202	-931	-82.2%
Total	**3,399**	**1,133**		**186**	**-947**	**-83.6%**	**425**	**-708**	**-62.5%**	**202**	**-931**	**-82.2%**

Fiscal Year 2012				1st Year After Project			2nd Year After Project			3rd Year After Project		
Feeder ID	**Total CI 4/1/08-3/31/11**	**Average CI**	**Project Year 4/1/11-3/31/12**	**Total CI 4/1/12-3/31/13**	**Difference**	**% Improved**	**Total CI 4/1/13-3/31/14**	**Difference**	**% Improved**	**Total CI 4/1/14-3/31/15**	**Difference**	**% Improved**
49_53_112W44	7,862	2,621		728	-1,893	-72.2%	37	-2,584	-98.6%	445	-2,176	-83.0%
49_53_126W41	1,202	401		978	577	144.1%	211	-190	-47.3%	302	-99	-24.6%
49_53_15F1	398	133		3	-130	-97.7%	11	-122	-91.7%	189	56	42.5%
49_53_34F3	7,350	2,450		18	-2,432	-99.3%	263	-2,187	-89.3%	333	-2,117	-86.4%
49_56_43F1	7,909	2,636		1,161	-1,475	-56.0%	0	-2,636	-100.0%	584	-2,052	-77.8%
49_56_59F4	1,083	361		84	-277	-76.7%	0	-361	-100.0%	6	-355	-98.3%
Total	**25,804**	**8,601**		**2,972**	**-5,629**	**-65.4%**	**522**	**-8,079**	**-93.9%**	**1,859**	**-6,742**	**-78.4%**

Fiscal Year 2013				1st Year After Project			2nd Year After Project			3rd Year After Project		
Feeder ID	**Total CI 4/1/09-3/31/12**	**Average CI**	**Project Year 4/1/12-3/31/13**	**Total CI 4/1/13-3/31/14**	**Difference**	**% Improved**	**Total CI 4/1/14-3/31/15**	**Difference**	**% Improved**	**Total CI 4/1/15-3/31/16**	**Difference**	**% Improved**
49_53_107W83	1	0		4	4	1100.0%	0	0	-100.0%	1,460	1,460	437900.0%
49_53_126W41	6,092	2,031		211	-1,820	-89.6%	302	-1,729	-85.1%	930	-1,101	-54.2%
49_53_15F1	2,769	923		11	-912	-98.8%	189	-734	-79.5%	158	-765	-82.9%
49_53_18F6	1,527	509		100	-409	-80.4%	245	-264	-51.9%	1,086	577	113.4%
49_53_27F1	273	91		2	-89	-97.8%	1,612	1,521	1671.4%	69	-22	-24.2%
49_53_38F4	127	42		41	-1	-3.1%	0	-42	-100.0%	187	145	341.7%
49_53_4F1	1,565	522		34	-488	-93.5%	146	-376	-72.0%	11	-511	-97.9%
49_53_4F2	4,122	1,374		199	-1,175	-85.5%	656	-718	-52.3%	97	-1,277	-92.9%
49_56_14F1	4,443	1,481		0	-1,481	-100.0%	85	-1,396	-94.3%	400	-1,081	-73.0%
49_56_22F2	2,571	857		977	120	14.0%	0	-857	-100.0%	57	-800	-93.3%
49_56_57J2	1	0		0	0	-100.0%	0	0	-100.0%	20	20	5900.0%
49_56_57J5	10	3		0	-3	-100.0%	0	-3	-100.0%	2	-1	-40.0%
49_56_68F3	15,917	5,306		163	-5,143	-96.9%	154	-5,152	-97.1%	463	-4,843	-91.3%
49_56_88F5	5,909	1,970		2,074	104	5.3%	1,258	-712	-36.1%	219	-1,751	-88.9%
Total	**45,327**	**15,109**		**3,816**	**-11,293**	**-74.7%**	**4,647**	**-10,462**	**-69.2%**	**5,159**	**-9,950**	**-65.9%**

Fiscal Year 2014				1st Year After Project			2nd Year After Project			3rd Year After Project		
Feeder ID	**Total CI 4/1/10-3/31/13**	**Average CI**	**Project Year 4/1/13-3/31/14**	**Total CI 4/1/14-3/31/15**	**Difference**	**% Improved**	**Total CI 4/1/15-3/31/16**	**Difference**	**% Improved**	**Total CI 4/1/16-3/31/17**	**Difference**	**% Improved**

49_53_112W42	12,044	4,015		0	-4,015	-100.0%	146	-3,869	-96.4%	1,064	-2,951	-73.5%
49_53_112W41	3,065	1,022		23	-999	-97.7%	0	-1,022	-100.0%	93	-929	-90.9%
49_53_18F7	5,169	1,723		0	-1,723	-100.0%	315	-1,408	-81.7%	22	-1,701	-98.7%
49_56_33F3	5,586	1,862		409	-1,453	-78.0%	813	-1,049	-56.3%	215	-1,647	-88.5%
49_56_33F1	4,294	1,431		177	-1,254	-87.6%	4,996	3,565	249.0%	1,396	-35	-2.5%
49_56_33F2	8,985	2,995		19	-2,976	-99.4%	3,518	523	17.5%	17	-2,978	-99.4%
49_56_38K23	0	0		0	0	-	0	0	-	0	0	#DIV/0!
Total	**39,143**	**13,048**		**628**	**-12,420**	**-95.2%**	**9,788**	**-3,260**	**-25.0%**	**2,807**	**-10,241**	**-78.5%**

Fiscal Year 2015				1st Year After Project			2nd Year After Project			3rd Year After Project		
Feeder ID	**Total CI 4/1/11-3/31/14**	**Average CI**	**Project Year 4/1/14-3/31/15**	**Total CI 4/1/15-3/31/16**	**Difference**	**% Improved**	**Total CI 4/1/16-3/31/17**	**Difference**	**% Improved**	**Total CI 4/1/17-3/31/18**	**Difference**	**% Improved**
49_53_21F1	462	154		848	694	450.6%	738	584	379.2%	157	3	1.9%
49_53_21F2	315	105		87	-18	-17.1%	10	-95	-90.5%	95	-10	-9.5%
49_53_21F4	2,359	786		67	-719	-91.5%	46	-740	-94.2%	48	-738	-93.9%
49_53_34F2	9,043	3,014		6,448	3,434	113.9%	3,195	181	6.0%	1,287	-1,727	-57.3%
49_53_38F1	2,461	820		2,593	1,773	216.1%	578	-242	-29.5%	3,705	2,885	351.6%
49_56_54F1	4,937	1,646		1,853	207	12.6%	5,158	3,512	213.4%	3,914	2,268	137.8%
49_56_63F3	3,539	1,180		181	-999	-84.7%	2,503	1,323	112.2%	256	-924	-78.3%
49_56_63F6	3,214	1,071		503	-568	-53.0%	317	-754	-70.4%	1,060	-11	-1.1%
49_56_85T3	6,377	2,126		218	-1,908	-89.7%	3,200	1,074	50.5%	310	-1,816	-85.4%
Total	**32,707**	**10,902**		**12,798**	**1,896**	**17.4%**	**15,745**	**4,843**	**44.4%**	**10,832**	**-70**	**-0.6%**

Fiscal Year 2016				1st Year After Project			2nd Year After Project			3rd Year After Project		
Feeder ID	**Total CI 4/1/12-3/31/15**	**Average CI**	**Project Year 4/1/15-3/31/16**	**Total CI 4/1/16-3/31/17**	**Difference**	**% Improved**	**Total CI 4/1/17-3/31/18**	**Difference**	**% Improved**	**Total CI 4/1/18-3/31/19**	**Difference**	**% Improved**
49_56_40F1	1,028	343		0	-343	-100.0%	0	-343	-100.0%	0	-343	-100.0%
49_56_41F1	2,092	697		595	-102	-14.7%	0	-697	-100.0%	0	-697	-100.0%
49_56_88F3	3,215	1,072		123	-949	-88.5%	211	-861	-80.3%	277	-795	-74.2%
49_56_37W41	800	267		26	-241	-90.3%	24	-243	-91.0%	155	-112	-41.9%
49_56_37W42	294	98		0	-98	-100.0%	44	-54	-55.1%	73	-25	-25.5%
49_56_37W43	4,751	1,584		31	-1,553	-98.0%	0	-1,584	-100.0%	0	-1,584	-100.0%
Total	**12,180**	**4,060**		**775**	**-3,285**	**-80.9%**	**279**	**-3,781**	**-93.1%**	**505**	**-3,555**	**-87.6%**

Fiscal Year 2017				1st Year After Project			2nd Year After Project		
Feeder ID	**Total CI 4/1/13-3/31/16**	**Average CI**	**Project Year 4/1/16-3/31/17**	**Total CI 4/1/17-3/31/18**	**Difference**	**% Improved**	**Total CI 4/1/18-3/31/19**	**Difference**	**% Improved**
49_53_34F1	2,556	852		1,350	498	58.5%	4099	3,247	381.1%
49_56_30F1	3,302	1,101		309	-792	-71.9%	1514	413	37.6%
49_56_30F2	10,979	3,660		361	-3,299	-90.1%	4895	1,235	33.8%
49_56_46F3	5,848	1,949		387	-1,562	-80.1%	0	-1,949	-100.0%
49_56_88F1	3,899	1,300		787	-513	-39.4%	522	-778	-59.8%
Total	**26,584**	**8,861**		**3,194**	**-5,667**	**-64.0%**	**11,030**	**2,169**	**24.5%**

Fiscal Year 2018				1st Year After Project		
Feeder ID	**Total CI 4/1/14-3/31/17**	**Average CI**	**Project Year 4/1/17-3/31/18**	**Total CI 4/1/18-3/31/19**	**Difference**	**% Improved**
49_56_33F1	4,040	1,347		1,382	35	2.6%
49_56_33F2	2,601	867		205	-662	-76.4%
49_56_33F3	1,437	479		1,569	1,090	227.6%
49_56_33F4	13,523	4,508		1,035	-3,473	-77.0%
49_56_88F1	2,279	760		522	-238	-31.3%
49_56_88F5	1,839	613		762	149	24.3%
Total	**25,719**	**8,573**		**5,475**	**-3,098**	**-36.1%**

				1st Year After Project			2nd Year After Project			3rd Year After Project		
	Total CI	**Average CI Before Project Year**	**Project Year**	**Average CI After Project Year**	**Difference**	**% Improved**	**Average CI 2 Years After**	**Difference**	**% Improved**	**Average CI 3 Years After**	**Difference**	**% Improved**
Program Totals	**-**	**174,652**		**55,636**	**-119,016**	**-68.1%**	**71,958**	**-102,694**	**-58.8%**	**58,796**	**-115,856**	**-66.3%**

EHTM Project Year	Average Annual CI Pre-Project	CI - First Year Post-Project	% Improved	CI - Second Year Post-Project	% Improved	CI - Third Year Post-Project	% Improved
2008	22,127	12,513	43%	7,477	66%	9,213	58%
2009	32,092	6,548	80%	9,013	72%	15,972	50%
2010	50,145	6,731	87%	13,032	74%	12,247	76%
2011	1,133	186	84%	425	62%	202	82%
2012	8,601	2,972	65%	522	94%	1,859	78%
2013	15,109	3,816	75%	4,647	69%	5,159	66%
2014	13,048	628	95%	9,788	25%	2,807	78%
2015	10,902	12,798	-17%	15,745	-44%	10,832	1%
2016	4,060	775	81%	279	93%	505	88%
2017	8,861	3,194	64%	11,030	-24%	-	-
2018	8,573	5,475	36%	-	-	-	-
Totals	**174,652**	**55,636**	**68%**	**71,958**	**59%**	**58,796**	**66%**

Division Set 2

nationalgrid

Jennifer Brooks Hutchinson
Acting Assistant General Counsel and Director

November 14, 2019

VIA HAND DELIVERY & ELECTRONIC MAIL

Rhode Island Division of Public Utilities and Carriers
c/o Luly E. Massaro
89 Jefferson Boulevard
Warwick, RI 02888

RE: National Grid's Proposed FY 2021 Electric Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – Set 2

Dear Ms. Massaro:

I have enclosed National Grid's[1] responses to the Division's Second Set of Data Requests in the above-referenced matter.

Please be advised that the Company's response to data request Division R-II-5 is pending.

Thank you for your attention to this transmittal. If you have any questions, please contact me at 401-784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosure

cc: Leo Wold, Esq.
John Bell, Division
Greg Booth, Division
Linda Kushner, Division
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R-II-1

Request:

Provide a copy of the Company's Delegation of Authority governance policy as discussed in Section 2, page 17 of 38, of the Proposed FY 2021 ISR Plan Annual Filing.

Response:

Please see Attachment R-II-1-1 for policy for projects less than $1 million.
Please see Attachment R-II-1-2 for policy for projects greater than $1 million.

nationalgrid

Sanction Procedure for Projects < $1M

Authorized by

Date: 14 August 2019.

Kathleen Geraghty, Vice President
National Grid USA

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1.0 VERSION HISTORY

Version	Date	Modification	Author(s)	Reviews and Approvals by
Issue 1	May 16, 2013	Implementation of new procedures	R.Morey	Approved by Mary Fuller
Issue 2	January 7, 2015	Annual Review	M. Carlino & M. Roby	Mary Fuller
Issue 3	March 25, 2016	Annual Review	M. Carlino	Mary Fuller
Issue 4	May 8, 2017	Annual Review	D. Monteiro	Mary Fuller
Issue 5	June 7, 2018	Annual Review	D. Monteiro	Suzan Martuscello
Issue 6	July 29, 2019	Annual Review	D. Monteiro	Suzan Martuscello

2.0 INTRODUCTION

2.1 This procedure applies to capital specific projects, programs and blankets less than $1 million regardless of complexity levels for all US Utility Services.

2.2 The purpose of this document is to provide:

2.2.1 Guidance in obtaining Sanctioning and Delegations of Authority ("DoA") for applicable blanket funding projects, program funding projects, and specific funding projects;

2.2.2 Guidance in obtaining re-sanctioning when applicable specific, programs, and gas blankets funding projects over-run their approved DoA or have the potential to do so, and;

2.2.3 PowerPlant Operations is excluded from this procedure since the utility service does not use PowerPlan.

3.0 REFERENCES

3.1 Supporting policies and procedures are available on the Infonet and reviewed on an annual basis. Note: The links below may bring the reader to where the document is located.

3.1.1 National Grid Statement of Delegations of Authority (DoA)

3.1.2 National Grid US Sanctioning Committee Procedure

3.1.3 Business Review Process Job Aide

3.1.4 US Tertiary Delegation Matrix (DoA Limits)

3.1.5 Cost Overrun Procedure (Under Development)

4.0 SANCTION (DoA)

4.1 DoA is obtained at the funding project level not at the work order level.

4.2 Funding project sanctioning is obtained electronically in PowerPlan for specific projects, programs and blankets that are less than $1M.

4.3 The funding project DoA to be requested shall be the gross expected expenditure. Any CIAC or other contributions shall not reduce the gross amount. For example, if a $500K funding project is initiated and a $100K customer contribution is expected, DoA shall be requested for $500K not $400K.

4.4 The funding project will remain in "initiated" status and unable to accept charges until the initiator routes it for, and receives, DoA approval.

4.5 Once the funding project DoA is approved, it moves to an "open" status and charges will be accepted from work orders generated under the funding project.

4.6 The initiator shall include the following class codes / justification within PowerPlan for reporting and controls purposes.

4.6.1 Responsible person shall proactively maintain / update the class codes to ensure relevant information including alignment with P6 dates (if applicable).

Key Fields: PowerPlan Reporting Purposes		
Class Code Tab		**Justification Tab**
Budget Classification	USSC Fiscal Yr Sanction	Project Risk Score
Capex Program Name	USSC Utility Service	Project Complexity Score
DoA Type	CAPEX Category	Project Scope
Funding Type	Investment Number (IT)	Risk Identification
Department	Authorization Workflow Type	
Region	Gas Capital by Category (Gas)	
Resource Planning Region	Program Code (Gas)	
Responsible Director	Estimated Close Date	
Responsible Person	In-Service Date	
Spending Rationale		

5.0 SPECIFICS, BLANKET AND PROGRAMS

5.1 Specifics

5.1.1 Specific Funding Projects shall be sanctioned as necessary based on the estimated costs to bring it to completion and shall be routed for DoA approval.

5.1.2 Specific Funding Projects are assigned a complexity score reflective of the project.

5.2 Blanket

5.2.1 Blanket Funding Projects are assigned a default complexity score of 15.

5.2.2 Blanket Funding projects shall be sanctioned at the start of each fiscal year to reflect the upcoming budget and routed for DoA Approval.

5.2.3 (This section applies to Electric Only) Gross expenditures against an Electric blanket funding project work order are not to exceed $100,000. If a work order is estimated to exceed those amounts, then a specific funding project must be created and all charges accumulated under the work order shall be transferred to the new funding project or the appropriate steps are taken to ensure the DoA is reconciled.

5.3 Programs

5.3.1 Program funding projects shall be sanctioned at the start of each fiscal year to reflect the upcoming budget and shall be routed for DoA Approval.

5.3.2 Gas Programs are considered “low complexity” and should default to 15 similar to Blankets.

5.3.3 Electric Programs are an average of the program projects and are scored accordingly.

6.0 RE-SANCTIONING

Re-sanctioning is the process for obtaining additional DoA Approval if the project is, or forecasted to exceed the originally sanctioned amount.

It is the responsibility and accountability of the person managing the project(s) to proactively avoid any cost overruns above the sanctioned amount.

6.1 Re-Sanctioning Requirements

6.1.1 Specific funding projects must be re-sanctioned as soon as the actual spend is greater than or equal to $100,000 or is forecasted to be, above the authorized expenditure (sanctioned amount +/- 10%) or $25,000 whichever is greater. For example, if the Sanctioning is for $500K, the project can spend $550k. Additionally, a $100K project can spend $125K.

6.1.2 In the event a funding project is originally estimated to be under $1M but the forecasted or actual costs exceed $1M, the funding project must be re-sanctioned per the National Grid US Sanctioning Committee Procedure.

6.1.3 If a funding project is sanctioned for less than $100,000 the funding project does not require re-sanctioning until the spending is greater than $100,000

6.2 Electric and Gas Blankets < $1M

(1) Electric Blankets less than $1M, the responsible person is required to submit the "Change in DoA < $1M" form no later than 60 calendar days after the end of the fiscal year.

(2) Gas Blankets require re-authorization if DoA is exceeded within 60 calendar days from notification.

6.3 Electric and Gas Programs < $1M and other Utility Services as applicable.

6.3.1 If the total spend of the program at the end of the year is less than $100,000, a "Change in DoA <$1M" form does not need to be submitted for approval.

6.3.2 If the total spend of the program, or a suite of related programs within a jurisdiction, exceeds $1M in the fiscal year, the program must be re-sanctioned per the National Grid US Sanctioning Committee Procedure.

6.4 Project schedule and scope changes:

6.4.1 Project schedule and scope variances are not governed by this process. Variances are documented and approved in accordance with the applicable Utility Services procedures.

7.0 RE-SANCTIONING PROCESS

7.1 Electric and Gas utilize the "Change in DoA <$1M Form". All Other Utility Services shall input respective Change in DoA directly into PowerPlan under the Justification & Scope tab "Additional Notes".

7.1.1 The funding project re-sanction request shall take into consideration the funding project's total estimated costs including capital, cost of removal and O&M which shall support and justify the prudent increase.

7.1.2 The justification must be clear, concise and accurate. It should contain enough information to allow a full understanding of the reasons for the increase.

7.2 For all Utility Services the revised funding project estimate will be routed through the business (via PowerPlan Business Review Process) and DoA review cycle for approval. Once approval is obtained, the funding project DoA in PowerPlan will be updated.

8.0 COST OVERRUN REPORT (Detailed Procedure Under Development)

On a monthly basis, each Utility Service shall prepare and distribute the Cost Overrun Report to responsible business stakeholders for action.

8.1 The Cost Overrun report identifies capital funding projects that have exceeded the sanctioned / authorized amount.

8.2 All Utility Services (Electric, Gas, Generation, Property, and IT) shall provide Investment Management with comprehensive / high level data utilized to compile the 30 Day DoA Awareness Scorecard

8.3 Within 10 business days from notification date, the responsible person must provide a driver for overrun in addition to a written plan to bring the affected funding project back into DoA compliance.

8.3.1 The actions may be a transfer of some of the costs to a different work order, re-sanctioning the sanctioned amount i.e. writing a paper or submitting a "Change in DoA Request Form".

8.3.2 Each Utility Service responsible person will follow up within their respective Utility Service if no action plan is received within 10 business days:

8.3.3 If no action plan is received – Projects that are at risk of becoming a 60 day overrun will be escalated to the Director of Investment Strategy and VP of Investment Strategy and Resource Planning at the 45 calendar day mark.

8.4 Responsible individual must seek management re-sanction of all funding projects that exceed the authorized spending limit on a timely basis but in no case later than 60 calendar days after notification.

8.4.1 Within 60 calendar days from notification date, the responsible person(s) must ensure stated action is completed, this includes all aspects of the process.

8.4.2 If the re-sanction cannot be attained in 60 calendar days from notification of date, the Vice President of Investment Strategy and Resource Planning must be notified and must approve the exception. The re-sanction will be noted as an exception on the cost overrun report.

8.4.3 The person requesting the exception must provide a plan to obtain compliance.

9.0 GOVERANCE

Governance refers to the activities that ensure Policies and Procedures are being executed according to how they have been designed. The governance structure also defines accountability and responsibility for ownership of the processes stated in this document.

9.1 The activities to ensure the Re-sanctioning process is operating effectively are listed below.

Governance Activities			
Activities	**Description**	**Accountable**	**Responsible**
Documentation Retention	Each Utility Service will keep all the responses for the respective department within the Cost Overrun file and stored in a deemed designated area by Utility Services.	Each Utility Service	Manager of respective Utility Service
Monthly presentation of overrun report at USSC meeting	At each USSC monthly meeting, the Vice President of Investment Strategy & Resource Planning will present the 30 Day DoA Awareness Scorecard, which highlights projects that have not been re-sanctioned timely for each Utility Service.	Investment Strategy & Resource Planning VP	Investment Strategy & Resource Planning VP
Monthly presentation of overrun report at SESC meeting	At each SESC monthly meeting, the Vice President of Investment Strategy & Regulatory Compliance will present the 60 Day DoA Awareness Scorecard, which highlights projects that have not been re-sanctioned timely for all Utility Services	Investment Strategy & Resource Planning VP	Investment Strategy & Resource Planning VP

10.0 DEFINITIONS

Term / Acronym	Definition
Authorized Expenditure	The authorized expenditure (sanctioned amount) represents the amount approved by an authorized individual(s) to spend on a funding project(s).
Blanket Funding Project	Blanket funding projects consist of many work orders that are typically standard construction and of short duration. Both Gas and Electric blanket work orders are typically externally–driven, i.e., reactive in nature. Blankets are intended to have duration of a single year and must be re-authorized each fiscal year. Examples of blanket funding projects may be New Business, Damage/Failure, etc. Gross expenditures under an electric blanket funding project work order shall not exceed $100,000.
Blanket Funding Project Work Order	Work orders initiated and linked to Blanket Funding Projects.
Class Code	A field in PowerPlan that identifies a particular attribute about the funding project. Class codes are usually selected during the funding project initiation. Most class codes are available in PowerPlan via a drop-down although a class code field may be freeform. Examples include budget class, funding type, and responsible person.
Delegations of Authority (DOA)	A hierarchy of authorization that empowers individual(s) to enter into contracts, other external commitments or take (or not take) other actions which might result in an obligation by National Grid. DOA is obtained at the funding project level.
Funding Project	A funding project is a method of tracking work charges in the PowerPlan system and is assigned an alpha numeric value. Work orders are generated in the appropriate work management system and linked to the funding project. A funding project may have one or more work orders linked to it. A separate funding project is generally assigned for different types of work or for work in different major locations.
In-Service Date	This is the date when the facility is placed in operation or is ready for service. The cost of the facility becomes part of the Company's asset base and is no longer eligible for AFUDC. The date is tracked in PowerPlan and P6 where applicable.
Program Funding Project	A program is generally a group of similar proactive work that is done on the assets such as breakers, main replacement, etc. There is a start and end date. Programs are re-authorized each fiscal year.

Program Funding Project Work Order	Work orders initiated and linked to Program Funding Projects.
Project	A funding project is a method of tracking work-related charges in the PowerPlan system. Funding Projects are assigned a 7-digit, alpha-numeric value (e.g. C000001). Funding projects must have at least one work order assigned to them for cost
Re-sanction	The process of receiving authorization to revise the existing approved cost for funding projects. Re-sanction could include re-authorization in PowerPlan i.e. a change in DOA request form.
Specific Funding Project	A specific project is defined as an undertaking representing an investment in time and resources with a specified plan and budget, generally in a specific location, over a discrete period of time, intended to achieve a long-term outcome for assets.
Specific Funding Project Work Order	Work orders initiated and linked to specific funding projects.

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National Grid US Sanctioning Committee Procedure

Authorized by

Date: 14 August 19

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1.0 Change Control

Version	Date	Modification	Author(s)	Reviews and Approvals by
Issue 1	March 7, 2012	Implementation of new procedures for all US utility services.	M. Carlino	Approved by Mary Fuller
Issue 2	May 8, 2013	Revision to incorporate changes to procedure	R. Morey	Mary Fuller
Issue 3	January 7, 2015	Annual Review	M. Carlino & M. Roby	Mary Fuller
Issue 4	March 25, 2016	Annual Review	M. Carlino	Mary Fuller
Issue 5	May 08, 2017	Annual Review	D. Monteiro	Mary Fuller
Issue 6	May 30, 2018	Annual Review	MJ Barry	Sue Martuscello
Issue 7	July 29, 2019	Annual Review	MJ Barry	Sue Martuscello

2.0 Introduction

2.1 This procedure is intended to provide guidance for sanctioning and re-sanctioning capital investments greater than or equal to $1 million.

2.2 The purpose of this document is to establish a formal review and approval process for all National Grid utility services.

2.3 All investments must receive proper Delegation of Authority ("DoA") prior to that expenditure being committed, except in emergency situations as outlined in Section 11.5. Approval will be based on maximum risk-range (tolerance) cost including capital, Operations and Maintenance ("O&M"), removal, and salvage costs.

2.4 This document shall be reviewed annually and amended as needed.

2.5 The sanction process utilizes several key digital templates:

2.5.1 Sanction Templates will be used for partial sanctions, full sanctions, re-sanctions and project development.

2.5.2 The Closure Template is used to close out the funding project after all the work has been completed. The Spending Review Template is used for annual Blankets/Programs and Project Development at fiscal year-end.

3.0 Applicability

3.1 This procedure is applicable to the following Utility Services:

- Power Plant Operations
- Property
- Gas
- LNG
- Electricity Transmission and Distribution
- Fleet
- Information Technology

3.2 Site Investigation and Remediation (SIR) will be subject to the US Environmental Oversight Committee's Terms of Reference

3.3 The Executive Sanctioning Committees may require any other Utility Services to occur before it is permitted for approval.

4.0 Exceptions

4.1 This procedure does not apply to:
- Energy Procurement
- Regulatory DoA

5.0 References

5.1 Supporting policies and procedures are available on the Infonet and reviewed on an annual basis. Terms of Reference link is set to the main page where both documents can be located.

5.1.1 National Grid USA Delegations of Authority (DoA) Site
5.1.2 Terms of Reference (US Sanctioning Committee and Senior Executive Sanctioning Committee)
5.1.3 Cost Overrun Procedure (Under Development)

6.0 Sanction Paper – General:

6.1 Investment proposals may progress as a partial sanction paper or full sanction paper.

6.2 A sanction paper shall be used to approve any expenditure as required in the Executive Sanctioning Committee's Terms of Reference and provides the financial DoA to deliver the funding project as detailed within the proposal.

6.2.1 The funding project amount to be sanctioned and for which DoA is requested shall be the gross expected expenditure. Any CIAC or other contributions are not to be used to reduce the gross amount. For example, if a $5.0M funding project is initiated and a $1.0M customer contribution is expected, DoA shall be requested for $5.0M. It would not amount to $4.0M.

6.3 Sanction paper numbers are obtained from the USSC Technical Secretary prior to submitting the paper as an agenda item for the Sanctioning Committee meetings.

6.4 Land purchases must have their own funding project number.

6.5 A partial sanction paper shall be submitted to advance a funding project when a request for full authorization cannot be submitted due to the lack of a complete scope and final cost (except as noted in section 8.0). The author should ask for enough DoA in their first partial sanction paper to get them through all the activities prior to construction, when possible. DoA under a partial sanction provides authority for items such as, but not limited to:

- Engineering and design
- Land purchase
- Services procurement from consultants, attorneys, etc. to obtain permitting and licensing ahead of construction
- Long lead-time material procurement
- In emergencies, when approval is required immediately
- Preliminary field work
- Other steps necessary to move a funding project towards execution
- An increase in scope, schedule or cost from a previously approved partial sanction

6.6 Generally, only one operating company is to be included in a sanction paper. Exceptions to this include sanctions initiated by

6.6.1 Papers involving New England Power and another New England distribution or transmission companies where multiple funding projects may be included in the same paper.

6.7 Committee Approval is determined by the potential investment at the time the paper is presented for approval.

6.7.1 For example, if a Partial Sanction was approved at the Senior Executive Sanctioning Committee (SESC) due to the potential investment being greater than $25M (including tolerance). If the full sanction potential investment becomes less than $25M (including tolerance), then United States Sanctioning Committee (USSC) shall approve the paper.

6.7.2 Determination of Committee Approval between Weekly Tuesday Committee and USSC does not includes tolerance.

6.7.3 The final spend for Closures and Spending Reviews shall determine which sanctioning committee it is presented to for approval.

6.8 Related funding projects can cross lines of business (e.g. Transmission and Distribution Electric, Gas, Property, IS, SIR or Generation investments) and companies. These related funding projects should be identified in a Sanction Paper with a very brief scope and total cost by line of business and company

7.0 Sanction Paper: Specific Projects, Blankets, and Programs greater than or equal to $1M

7.1 **Gas and Electric** DoA requests for investments greater than or equal to $1M and less than $8M, whether high, medium or low complexity, to use the short form digital template.

7.1.1 These papers will be approved and signed by the USSC Chair and placed on the USSC agenda on a quarterly basis for noting.

7.2 **Gas and Electric** DoA requests for high or medium complexity funding projects with total costs of $8M or greater to use the USSC sanction digital template which will be presented to the USSC for approval.

7.3 **Gas and Electric** DoA requests for low complexity funding projects with total costs of $8M or greater to use the short form digital template which will be presented to the USSC for approval

7.3.1 In the event a Gas or Electric funding project is estimated to be below $8M but the tolerance raises the DoA above $8M, a short form digital template can be used and signed by the USSC chair, however:

- If the forecast is expected to reach or exceed $8M and is above the allowable tolerance; the paper must be re-sanctioned and submitted to the USSC on the appropriate form as described above.
- The paper must clearly explain that the original sanction was for under $8M.

7.4 **SIR** contracts with total costs that are:

- Between $1M and $5M with a low complexity may be completed using SIR DoA procedure with appropriate documentation.
- Between $1M and $5M with a medium or high complexity will be completed using the USSC sanction digital template and will be presented to the Environmental Oversight Committee for approval.
- Greater than $5M with a medium or high complexity will use the USSC sanction digital template and will be presented to the Environmental Oversight Committee for approval.
- Greater than $5M with a low complexity will use the short form digital template and will be presented to the Environmental Oversight Committee for approval.

7.5 **LNG** projects with total costs that are:

- Equal to or greater than $8M with a low complexity will use the short form digital template.
- Equal to or greater than $8M with a medium or high complexity will use the standard sanction digital template which will be presented to USSC for approval.

7.6 **IT** funding projects that are:

- Greater than or equal to $1M and less than $5M with a low complexity, will use the short form digital template.
- Greater than or equal to $1M and less than $5M with a medium or high complexity, will use the USSC sanction digital template.
- Greater than $5M with a low complexity will use the short form digital template and will be presented to the USSC for approval
- Greater than $5M with a medium or high complexity will use the USSC sanction digital template and will be presented to the USSC for approval

7.7 **Property** funding projects that are:

- Greater than or equal to $1M and less than $3M with a low complexity, will use the short form digital template.

- Greater than or equal to $1M and less than $3M with a medium or high complexity, will use the USSC sanction digital template.
- Greater than $3M with a low complexity will use the short form digital template and will be presented to the USSC for approval.
- Greater than $3M with a medium or high complexity will use the USSC sanction digital template and will be presented to the USSC for approval.

7.8 Power Plant Operations (Generation) funding projects that are:

- Greater than $1M with a low complexity will use the short form digital template and will be presented to the USSC for approval.
- Greater than $1M with a medium or high complexity will use the USSC sanction digital template and will be presented to the USSC for approval.

7.9 All Utility Services

- DoA requests for all utility services funding projects with total costs greater than $25M to use the USSC sanction digital template which will be presented and noted for recommendation by the USSC, to move forward to the SESC for approval. If a project is less than $25M but the tolerance puts the project greater than $25M, then the project will go to the USSC for noting and to the SESC for approval. An overview presentation is also required for SESC.

7.10 Blanket Funding Projects

- Each fiscal year the blanket funding projects are presented to the Sanctioning Committees for approval using the short form digital template.
- Blanket funding projects have a complexity score of 15
- An overview presentation of the blanket funding paper is required when presented at the Senior Executive Sanctioning Committee. (For USSC, a one-page slide highlighting total blanket spend when multiple operating companies are involved).
- Blanket funding projects may not be segmented into smaller pieces to sanction the spending at a lower level of authority than would otherwise be required.
- A spending review document is presented at the end of each fiscal year no later than the July sanction approval.
- Senior Executive Sanctioning Committee (SESC) has authorization to approve Blanket funding projects exceeding the SESC approval limit.

7.11 Programs

- Each fiscal year the program(s) is/are presented to the Sanctioning Committees for approval using the short form digital template.
- Program complexity scores should reflect an average of the program.
- An overview presentation of the program is required when presented at the Senior Executive Sanctioning Committee. (For USSC, a one-page slide highlighting total program spend when multiple operating companies are involved).
- Program funding projects may not be segmented into smaller pieces to sanction the spending at a lower level of authority than would otherwise be required.

- A spending review document is presented at the end of each fiscal year no later than the July sanction approval.
- Senior Executive Sanctioning Committee (SESC) has authorization to approve Program funding project(s) exceeding the SESC approval limit.

7.12 Project Development

- Each fiscal year specific capital project development costs are aggregated in a single sanction paper for each Operating Company ("OpCo").
- The utilization of the single paper approval for portfolio project development costs supports the new capital delivery process.
- Project Development Funding Papers will be presented to the Sanctioning committee.
- An overview presentation of the Project Development is required when presented at the SESC.
- A spending review document is presented at the end of each fiscal year no later than the July sanction approval.

8.0 Sanction Paper: Engineering / Design

8.1 If a project is requesting funds for engineering/design only, it may be done using the short form template or by using the appropriate personal DoA in PowerPlant to approve a Project Funding number.

8.1.1 All sanctions following the engineering/design partial sanction will abide by the requirements listed above.

9.0 Re-Sanctioning:

9.1 All specific, blanket and program funding projects, for all Utility Services (excluding electric blankets) must be re-sanctioned within 60 calendar days of notification that the cost is outside of the tolerance approved in the sanction template.

- Partial sanctions are not re-sanctioned using the re-sanction template. In the event the funding project scope or cost has changed since a partial sanction paper was approved, another partial sanction would be presented using the appropriate template until the investment has been sanctioned at the full sanction at +/-10%.

9.2 Funding project schedule and scope variances are not governed by this process. Variances are documented and approved in accordance with the applicable Utility Services procedures.

9.3 If DoA was obtained for a funding project originally estimated to be below $1M, but the forecasted total cost or the actual spend subsequently equals or exceeds $1M, then the funding project must be re-sanctioned by the Program Manager and presented to the appropriate committee.

- The paper must clearly explain that the original sanction was for under $1M and explain what drove the variance.

9.4 A cost is incurred at the moment the payment obligation is incurred. Non-payment of valid invoices is not an acceptable method of remaining within DoA.

9.5 If there are any outstanding contractual claims in an investment (contractor, land owner, etc.) that may push costs over the upper sanction range, the Sanctioning Committees and responsible executive sponsor shall be notified with an explanation of the issue along with a description of potential outcomes. The investment should be re-sanctioned for cost when the value of the claim is known.

9.6 An investment must also be re-sanctioned if the project scope fundamentally changes, there is a material increase or decrease in project scope, or changes occur in the actual work even though the operational outcome remains the same. The decision as to whether changes in a project are "material" rests with the Sponsor.

9.7 Summary of Re-sanction thresholds:

Re-sanction for:	Re-sanction Threshold
Cost	Once forecasted to be above the DoA authorized in the Sanction Paper **it must be re-sanctioned** (requested amount plus tolerance)
Scope	Fundamental or material increase or decrease in scope – determined by Sponsor

9.8 Re-sanction papers should not re-state the original need case. Rather the paper must include a detailed explanation of the new sanction requirements and why they have changed from that which was originally approved. In addition, the re-sanction paper should include details of lessons learned including an explanation of any significant variances in cost. If they are not fully known at the time, they must be included in the closure or spending review paper.

9.9 If the original investment drivers change during the course of a funding project, but the investment costs and scope remain as sanctioned, the funding project must be re-sanctioned.

9.10 Re-sanction papers must be presented through the full DoA chain until it reaches the authority that can approve the revised total amount.

9.11 In the event there is a personnel change to the project or program manager following approval of a sanction paper, the funding project does not have to be re-sanctioned.

Closure Paper:

9.12 Funding project closure papers shall be required for all funding projects $1M or greater. All annual Program and Blanket closure papers shall use the Spending Review template and be presented at the appropriate sanction committee by July of the next fiscal year.

9.13 Specific funding project closure papers shall be submitted to the Sanctioning Committee's Secretary as soon as possible after all work orders and projects are closed.

9.14 Investment Management will circulate the Closure report quarterly for any updates to the project closure dates. The project sponsor/owner will have 10 business days to respond back with any changes to project closure dates.

9.15 Re-sanction for under spend may be combined with the closure paper if the under spend is not forecasted until late in the construction phase.

10.0 Fast-Track Approval Process

10.1 Where the needs of the business demand it, papers may be approved via a fast-track process administered by the Technical Secretary.

10.2 Under this process, papers must be submitted to the Business Director and Sponsor for an abbreviated review and support cycle prior to being circulated to the Committee members as appropriate.

10.3 Fast-track process approval for any paper shall be in written form (which may include, without limitation, electronic form) and will require approval of at least three Committee members.

10.4 Papers approved by the fast-track process will be presented for noting by the full Committee at its earliest convenience or at the next Committee meeting.

10.5 This fast-track process should only be used in exceptional circumstances, e.g., where a delay will impair safety, reputation and/or incur financial losses. The reason for the fast-track approval request must be clearly stated. The Investment Planning Director may use this process at his/her discretion as deemed necessary.

11.0 Delegations of Authority

11.1 In the event that an individual's DoA is used in-lieu of the sanctioning process; the Manual DoA form must be submitted to the Investment Strategy Director for auditing purposes. Electric

Investment Management will retain all Executive Sanctioning Committee's documentation. This individual DoA must be followed up with a sanction paper. Approvals must align to the DoA Tertiary Matrix and a sanction must be written for the full project expenditure.

11.2 The Sanctioning Committee's DoA will be authorized in PowerPlan by a proxy in Investment Management.

- The proxy will verify that the Sanctioning Committees approved amount for each funding project matches the DoA requested in PowerPlan prior to authorizing it.

11.3 Funding projects may not be segmented into smaller pieces to sanction the spending at a lower level of authority than otherwise would be required. Related funding projects shall be included in one investment document. A funding project is related to another funding project if it cannot fully accomplish its intended purpose unless the other funding project is also carried out.

11.4 DoA cannot be given to contract personnel.

11.5 In certain circumstances, it may not be practical to seek a proper delegated authority approval prior to entering a commitment. This is acceptable if the spend is nondiscretionary and following the delegated authority approval process would hinder operations in an emergency (e.g., response to storms, damage failures).

- DoA for full project expenditures must be obtained within 7 business days.

12.0 Special Meeting for Specific Projects ≥ 100M

12.1 Managing a complex project presents a series of challenges of greater magnitude, as a result an expanded reviewers and supporters meeting will prioritize the focus, drive continuous engagement while ensuring content and accuracy of the sanction request prior to presentation to USSC.

12.2 Include Project Sponsor, Vice Presidents of Asset Management, Business Development, Gas Resource Planning, Investment Strategy, and Project Management, as applicable.

13.0 NY Distributed Generation (DG) Sanction Process

13.1 This process shall only be used to expedite the funding project creation / approval for NY Distributed Generation (DG) projects $1M or greater.

13.2 Initially, the abbreviated NY DG digital form will be utilized to achieve the authorization to advance the project. If at any point, additional funds are needed, a re-sanction digital form shall be submitted while adhering to the sanction guidelines / process in place.

13.3 Signatory shall be the Vice President of Electric Asset Management and Planning.

14.0 Cost Overrun Report (Detailed Procedure Under Development)

On a monthly basis, each Utility Service shall prepare and distribute the Cost Overrun Report to responsible business stakeholders for action.

14.1 The Cost Overrun report identifies capital funding projects that have exceeded the sanctioned / authorized amount.

14.2 All Utility Services (Electric, Gas, Generation, Property and IT) shall provide Investment Management with comprehensive / high level data utilized to compile the 30 Day DoA Awareness Scorecard.

14.3 Within 10 business days from notification date, the responsible person must provide a driver for overrun in addition to a written plan to bring the affected funding project back into DoA compliance.

14.3.1 The actions may be a transfer of some of the costs to a different work order, re-sanctioning the sanctioned amount i.e. writing a paper or submitting a "Change in DoA Request Form".

14.3.2 Each Utility Service responsible person will follow up within their respective Utility Service if no action plan is received within 10 business days:

14.3.3 If no action plan is received – Projects that are at risk of becoming a 60 day overrun will be escalated to the Director of Investment Planning and VP of Investment Strategy and Regulatory Compliance at the 45 calendar day mark.

15.0 Responsibilities

15.1 *Director* - The *Director of Electric Investment Strategy* is the owner of the sanctioning process. The Director is responsible for developing, revising and maintaining the sanction templates, processes, procedures and ensuring that all changes are communicated to the corporation.

15.2 *Investment Management* – Revising and maintaining sanction templates, training, oversight of the Business Review Process within PowerPlan and sanction approval committees. Maintains approved sanction papers to PowerPlan and the USSC library while retaining approved sanction papers, and monitoring compliance with DoA.

15.3 *Investment Planning* – Ensures the funding projects described in the sanction papers are included, where applicable, in the budget and forecast. Facilitates annual sanctions for Blankets and Programs

15.4 *Program / Project Manager* – An individual responsible for implementing all aspects of a funding project including, planning, coordinating, and controlling a funding project. The Program / Project Manager, who is supported by a cross-functional project team, is accountable for delivering the funding project in accordance with the approved scope, cost, schedule and quality parameters.

15.5 *Reviewer* – A reviewer is an individual that reviews a proposal for content, language and recommends edits as necessary. A reviewer may or may not be a project team member but typically has expertise in one or several areas of a proposal. A reviewer's approval is required to advance a proposal.

15.6 *Sponsor* – The sponsor must be a vice-president or above and is ultimately responsible for assuring that a project delivers its proposed scope, cost, schedule and benefits. The sponsor works in conjunction with the project manager getting commitment from and managing cross-functional support and resource needs and clarifies business priorities and strategy. Also, the sponsor provides a route to escalate any issues and acts as a decision maker for issues beyond the project team's scope of authority. The sponsor (or designee) attends team meetings, as required, and regularly reviews project timelines, key milestones and outstanding issues. The sponsor is responsible for the quality and content of the sanction papers presented to the USSC or other governance committees.

15.7 *Supporter* – A supporter is typically a manager, director or vice-president. The supporter endorses a project or proposal when he or she is in agreement with the overall scope, cost, schedule and methodology incorporated in the proposal as it relates to his or her area of responsibility. The supporter also agrees that they have aligned, or will align, their part of the business to support the project. If a supporter does not endorse a project, then the project sponsor and the supporter must resolve any issues before the project can move forward.

15.8 *USSC – United States Sanctioning Committee* - Approves, endorses or notes investment papers for DOA within its authority. The USSC Terms of Reference (TOR) is posted on the Investment Planning Infonet site.

15.9 *SESC – Senior Executive Sanctioning Committee* - Approves, endorses or notes investment papers for DOA within its authority. The SESC Terms of Reference (TOR) is posted on the Investment Planning Infonet site.

15.10 *Sanction Committee Secretary* – Coordinates the investment proposals to be presented at the sanction committee meetings. Issues action items for US Sanctioning Committee and Senior Executive Sanctioning Committee meetings. Prepares and circulates the minutes associated with Committee meetings. Manages the Fast Track Sanction process, and progresses papers to the NGUSA Board for approval, as required.

16.0 Considerations in Preparation of Investment Papers

16.1 Authors are responsible to post papers to the USSC Sanction SharePoint site that are complete and ready for presentation to the Committees *per the due dates posted on SharePoint*.

- Any paper that has not been properly reviewed will be sent back to the author and rescheduled.
- Papers received after this deadline will not be accepted on the current month's USSC, and SESC agendas or weekly sanction review agenda.

16.2 Authors shall allow adequate time to incorporate reviewer and supporter comments prior to submittal to the USSC SharePoint site. Papers shall be sent to all supporters and reviewers listed on the paper allowing at least 5 business days for review.

- The reviewer and supporter list is posted on the US Sanctioning Committee's (USSC) SharePoint site.

16.3 If the investment paper includes Critical Energy Infrastructure Information (CEII) it should not be viewed by anyone not trained on procedures regarding CEII. Training is provided and tracked in MyHub prior to posting papers, the approved (signed) paper is sent to the Transmission Planning Department to determine if the paper contains CEII. If it does, the paper is processed accordingly before posting. The distribution of papers within and outside of National Grid shall follow CEII procedures.

17.0 Retention and Notification of Approval of Investment Papers

17.1 Final investment papers shall be posted by the author to the USSC SharePoint site as major version 3 with all edits requested by the Approving committee incorporated. The Investment Management Department will circulate sanction papers for signature approval. Investment Management will retain all Executive Sanctioning Committee's approved sanction papers and alternate forms requesting DoA (i.e. Manual DoA form, etc.)

17.2 All Executive Sanctioning Committee's approved sanction papers will be saved electronically to the USSC SharePoint library and as a hardcopy by Investment Management.

18.0 Definitions

Term / Acronym	Definition
Approved Amount	The approved amount represents the estimated project cost requested for approval. The authorizing individual or committee must have DoA equal to or greater than the dollars being requested. The estimated project cost plus the tolerance would be the DoA amount.
Blanket Funding project	Blanket funding projects consist of many work orders that are typically standard construction and are of short duration. Both, Gas and Electric blanket funding projects are work that are typically externally driven (reactive in nature). Blankets are intended to have a duration of a single year and must be re-authorized each fiscal year. Examples of blanket funding projects may be New Business, Damage/Failure, etc. Electric blanket funding project work order gross expenditures shall not exceed $100,000. Multiple blanket funding projects may be sanctioned together on a single sanction paper. Close-out papers are written for each blanket funding project on an annual basis, either individually or as a group, similar to how the blankets were originally sanctioned.
Blanket Funding Project Work Order:	Work orders initiated and linked to Blanket Funding Projects
Closure Paper	A closure paper is a paper prepared for noting to the Executive Sanctioning Committees at the completion of a funding project that details the financial and objective outcomes of the funding project. A closure paper shall be prepared using the Closure Paper template. A closure paper must be prepared for all funding projects approved by the Sanctioning Committees, including canceled funding projects.
Conflict of Interest	Federal law prohibits the disclosure of non-public transmission function information or non-public information acquired from unaffiliated transmission customers to employees in our Marketing function.

Noting	Noting consists of items that, because of their nature, can be decided by the USSC based on written reviews and analyses previously made available to the committee and do not require discussion. Any item under the Noting section requiring discussion may be resolved via email or added to the following month's sanction meeting agenda.
Critical Energy Infrastructure Information (CEII)	Critical Energy Infrastructure Information (CEII) is defined as "specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure" that: • Relates details about the production, generation, transportation, transmission, or distribution of energy; • Could be useful to a person in planning an attack on critical infrastructure; • Is exempt from mandatory disclosure under the Freedom of Information Act; and • Does not simply give the general location of the critical infrastructure.
Deferred Work	A funding project that was originally scheduled to begin within the fiscal year, but it did not start, and it was not canceled.
Delegations of Authority (DoA)	A hierarchy of authorization that empowers individual(s) to enter into contracts, other external commitments or take (or not take) other actions which might result in an obligation by National Grid. DoA is obtained at the funding project level.
Emergent Work	Unidentified work that arises within a fiscal year (or after the business plan has been sent to Resource Planning).
Executive Sanctioning Committees	The Executive Sanctioning Committees consists of the US Sanctioning Committee (USSC) and/or the Senior Executive Sanctioning Committee (SESC). See definitions below for each committee. • Weekly Sanction Review Meeting
Fast Track Approval Process (as related to Executive Sanctioning Committee's sanctioning)	Where the needs of the business demand it, papers may be approved via a fast track process administered by the Executive Sanctioning Committee's Technical Secretary. Under this process, papers must be submitted to the Director for an abbreviated review and support cycle prior to being circulated to the Committee members. Three members of the Executive Sanctioning Committees must approve the paper and the paper must be presented to the full Committee where the full committee will endorse the action.

Funding Project	A funding project is a method of tracking work charges in the PowerPlan system and is assigned an alpha numeric value. Work orders are generated in the appropriate work management system and linked to the funding project. A funding project may have one or more work orders linked to it. A separate funding project is generally assigned for different types of work or for work in different major locations. Several different funding projects may be included in a single project. For example, a $10M project to build a new substation may have three funding projects under it, one funding project for Transmission Line, one for Substation, and one for Distribution Line.
In-Service Date	This is the date when the facility is placed in operation or is ready for service. The cost of the facility becomes part of the Company's asset base and is no longer eligible for AFUDC. The date is tracked in PowerPlan and P6 where applicable.
Mandatory	There is an explicit external obligation to do this specific project immediately. There is no discretion on the spend, such as with statutory regulatory or damage failure type work (referred to as non-discretionary).
Partial Sanction	A Partial Sanction paper may be submitted when full authorization cannot be submitted due to the lack of a full scope or final cost, but approval must be obtained to progress the funding project. For examples, refer to section 6.5
Policy-driven	The driver for these will be either a general external guideline, including statutory and regulatory obligations, or an internal policy. Either way, the company will usually have choices as to how and when it makes such investments, i.e. there is some discretion about scope and timing such as with system capacity and performance, asset condition and non-infrastructure type work.
Program Funding Project	A program is generally proactive work that is done on the assets such as breakers, main replacement, etc. There is a start and end date. Programs are re-authorized each fiscal year.
Program Funding Project Work Order	Work orders initiated and linked to Program Funding Projects.

Project	Project can be either complex and non-complex (see distinction below) Complex Project – Major modifications, large, complex projects (or multiple related projects) generally with a high dollar value, typically spanning multiple fiscal years, involve complex permitting and extensive stakeholder interactions and are critical to the business are designated "Complex". The full Network Delivery Process (formally known as the Complex Capital Delivery Process) shall be applied. Non-Complex Project – Small configuration changes, low risk and low dollar values are designated Non-Complex with fewer project management process steps applied. The processes and steps for these projects are described in the Project Management Playbook Level 3.
Project Development	Ensure complex electric and gas capital projects are fully scoped, budgeted and scheduled in a timely manner to meet to customer, operational, safety and regulatory requirements.
Project Schedule and Scope Changes	Project schedule and scope variances are not governed by this process. Variances are documented and approved in accordance with the applicable Utility Services procedures.
Property	Property is defined as Facilities and/or Real Estate.
Re-sanction	The process of receiving authorization to revise the existing approved cost, for specific funding projects, gas blankets and all programs. Re-sanction is required for all complexity levels and all estimated costs. Re-sanction will include resubmittal of the paper and presentation at the committee meeting (e.g. USSC, SESC, PLC, etc.).
Reviewer	A Reviewer is an individual that reviews a proposal for content and language and recommends edits as necessary. A Reviewer may or may not be a project team member but typically has expertise in one or several areas of a proposal. Refer to section 13.5 for additional details.
Ready for Load / Ready for Use	The date when a facility's construction is complete and is ready for electricity/gas service.

Sanction (as in Sanction paper)	A Sanction Paper is the document submitted to the appropriate Sanctioning Committee for project approval. A Sanction, as opposed to a partial sanction, is generally prepared for the full scope and cost of the funding project. Generally, the costs are expected to have a tolerance of +/-10%. This is considered the final approval to undertake the funding project.
Spending Review paper	A spending review paper is a paper prepared for presentation to the appropriate Sanctioning Committees at the completion of a program or blanket that details the financial and objective outcomes of the program or blanket. A spending review paper shall be prepared using the Spending Review template. A Spending review paper must be prepared for all programs, blankets and project development approved by the appropriate Sanctioning Committees, including canceled programs and blankets.
Sponsor	The Sponsor must be a vice-president or above and is ultimately responsible for assuring that a funding project delivers its proposed scope, cost, schedule, and benefits. Refer to section 13.6 for additional details.
Supporter	A Supporter is an individual, typically a manager, director, or vice-president, that represents an area of the business that is affected by the proposed project. Refer to section 13.7 for additional details.
Tolerance and Accuracy	The permissible upper and lower limit of variation in expected funding project spending is expressed in percent (e.g. +/- 10%). Do not confuse accuracy with tolerance. The more accurate the estimate the less of a contingency should be built in. • The tolerance for the request for money should always be (+/- 10%), unless it can be justified otherwise by the author. (E.g. Bids not in, Permitting, etc.). • The accuracy for the total funding project cost on a partial sanction should be in line with the Capital Delivery process, unless otherwise justified by the author. • Full Sanction tolerances should always be at the project grade estimate (+/-10%), unless it can be justified otherwise by the author.

Technical Secretary (as relates to Executive Sanctioning Committees)	The Executive Sanctioning Committee's Technical Secretary provides all materials to the members, produces the agenda, and keeps track of all action items. Refer to section 13.10 for additional details.
Executive Sanctioning Committee's Secretary	The Executive Sanctioning Committee's Secretary is responsible for preparing and circulating minutes of the meetings.
US Sanctioning Committee (USSC)	The purpose of the Committee is to provide executive management review of proposed major capital funding projects and other proposed commitments deemed appropriate candidates for such review, and to administer a consistent and comprehensive sanctioning process for such funding projects and commitments across the organization. See USSC Terms of Reference for details.
Senior Executive Sanctioning Committee (SESC)	The purpose of the Committee is to provide executive management review of proposed major capital funding projects and other proposed commitments deemed appropriate candidates for such review, and to administer a consistent and comprehensive sanctioning process for such funding projects and commitments across the organization. See SESC Terms of Reference for details.
Template (as in Sanction Template, Closure Paper and Spending Review Template)	A template is an outline for a paper to be presented to the US Sanction Committees. The digital template shall be used for all partial sanctions, sanctions, project development and re-sanctions. The Closure digital Template shall be used for all specific project closure papers. The Spending Review digital Template shall be used for all program and blanket closure papers.

Utility Service	A Utility Service is one of the main operational/functional areas of the company. There are seven Utility Services: • Electricity T&D • Gas • LNG • Power Plant Operations • Property • Environmental • IT
Utility Service Technical Secretary	The Utility Service liaison is an individual designated to assist the Executive Sanctioning Committee's Technical Secretary in coordinating with the related activities for a particular Utility Service Area.
Weekly Sanction Review Meeting	Approves sanction papers with a potential investment below a specific dollar value as outlined in the USSC Terms of reference e.g. Electric sanction papers less than $8M can be approved at the weekly sanction review meeting. See Section 5 - USSC Terms of Reference for dollar value cut off by Utility Service.

R-II-2

Request:

Provide a full and detailed explanation of the project complexity scoring system as discussed in Section 2, pages 17 and 18 of 38, of the Proposed 2021 ISR Plan Annual Filing.

Response:

Please see response to R-I-15a for a detailed description of the project complexity scoring system, which is attached to this response as Attachment R-II-2 for reference.

Prepared by or under the supervision of: Patricia C. Easterly

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R-I-15

Request:

Referencing Section 2, page 17; The Company states that projects over $1.0 million require a Project Sanctioning Paper (PSP). Further, the Project Development group writes the PSP for complex projects that have a complexity score of 19 or greater, while the project sponsor writes the PSP for non-complex projects, or those with a complexity score of 18 or lower:

a. Provide additional information on how the Company derives a complexity score, including the risk factors evaluated.
b. Describe the differences in the PSP required for complex vs. non-complex projects.
c. Describe how the PSP process differs from that described in previous ISR filings.
d. Describe the anticipated impacts to ISR budget estimates due to any changes.

Response:

a. The Company scores each project based on nine separate factors detailed below. Each factor is given a 1, 2 or 3 [lower complexity to higher] and added up to determine overall complexity:
    - Cost – Projects are scored on a scale based on three thresholds >$8M, <$8M/>$1M and <$1M. Projects with greater costs are scored higher. It is understood that lower costs does not always equal lower complexity, which is why there are more factors considered as detailed below.
    - Project Components – If the project has multiple components to be installed, then the project receives a higher complexity score.
    - Outage Requirements – Assets requiring significant outage coordination are scored higher. A scoring matrix was developed to capture and rank issues such as a mobile substation requirement, if customer outages needed, if circuit cut overs are required, and if critical service lines are affected.
    - Duration – The duration component is scored differently depending upon if the project is on a company standard driven timeline or customer (internal or external) driven timeline.
        - Standard company timeline driven projects are scored higher if there is an overall longer duration of the project timeline which would include large projects with significant spend over multiple years.
        - Customer Drive Projects are scored higher if there is a timeline compression needed to meet an internal or external deliverable requiring exceptions and waivers to the standard company processes and procedures.

R-I-15, page 2

- Stakeholder Management – Projects that require significant involvement managing customers, area residents, local / federal governments and communities with significant vocal interest are scored higher.
- Asset Complexity – A matrix was developed to determine the overall complexity of the project based on assets being replaced or added. For example, a project which requires the replacement of one asset with the exact same type (i.e. one-to-one replacement) is scored lower than the expansion of a substation with new equipment.
- Land Rights – Projects requiring land rights that involve the Company's Real Estate Department are scored higher than projects that do not have land rights issues.
- Permits – Permitting is scored on three levels. The lowest is a project that either requires existing permits to be utilized or requires no permits. The next level is projects that require permitting, which is done on a regular basis by the Company. The highest score is given to projects requiring significant permitting and legal representation.
- Procurement – Material /Labor Procurement is scored on three levels. The lowest is a project that only requires Stock material, which can be obtained from the Company's local stores, and labor being performed by local resources or existing contractor agreements. The next level is projects requiring non-stock material, which have short duration timelines to obtain. The highest score is given to projects requiring unique material bids and labor contracts of significant value.

b. The project sanction paper process does not change dependent upon complex vs. non-complex. The process only changes dependent on overall costs, as detailed below.
   - <$1M – Electronic DOA [no sanction paper]
   - <$8M->$1M – Short form sanction process
   - <$25M-$>8M – Long form sanction, full United States Sanction Committee (USSC) Process
   - >$25M – Long form sanction, USSC Approval and Senior Executive Sanction Committee (SESC) approval

It is more likely that a complex project would require moving through the higher costs sanctioning process, but it is not a rule. There could be a high cost non-complex project depending upon overall score.

R-I-15, page 3

c. The project sanction process differs from the previous ISR filings based on the timing of the Project Sanction. The new Complex Capital Delivery process requires Project Sanction after preliminary engineering has been completed. The old process required Project Sanction after final design was completed and final contractor bids were received. In addition, the new Complex Capital Delivery process aims to reduce or eliminate partial sanctions.

d. There are no major anticipated impacts as to how the ISR budget estimates are set due to the timing of the Project Sanction Paper. The new Complex Capital Delivery process will improve the visibility and reasons for changes in projects cost.

Prepared by or under the supervision of: David Arthur

R-II-3

Request:

In Section 2, page 23 of 38, the Company discusses the Admiral Street substation project and the distribution system conversion projects associated with this project.

a. Provide a detailed analysis of the first year's power loss savings associated with this project including demand reduction, energy reduction, and power cost savings for the first year after the project is completed, including, but not necessarily limited to, the loss savings associated with the substation changes, line voltage and conductor changes, and elimination of high loss distribution transformers with low loss distribution transformers.
b. Provide an estimate of the capital investment this project's power loss savings will amortize.

Response:

a. The loss analysis is divided into two components based on the tools utilized to model the distribution and sub-transmission systems. The distribution feeder analysis is completed using CYME distribution software and the transmission, sub-transmission, and substation loss analysis is completed using power system simulator for engineering (PSSE) loadflow software.

   Attachment R-II-3-1 shows the results of the analysis for the comprehensive substation and distribution system conversion projects that were proposed as part of the Providence Area Study. The loss saving analysis was calculated for year 2030, the expected projected year of completion. The total demand reduction is estimated at 2.75 megawatts. Using a yearly load loss factor of .2, gives 4,818 megawatt*hours of energy reduction.

   The Company does not currently calculate a power cost savings for losses, although it is investigating methods, such as use of Synapse's Avoided Energy Supply Components in New England: 2018 Report (AESC), as part of its adoption of a benefit-cost framework. An example using the AESC avoided energy costs is shown in Attachment R-II-3-2.

b. As stated above, the Company does not currently calculate a power cost savings for losses and, therefore, does not have a standard agreed upon method for doing such calculations. However, one possible method for doing that would be to use the AESC values. Attachment R-II-3-2 shows an example power cost saving of losses using AESC values (AESC-2018-07-080, October 2018 Update) with a net present value of approximately $1.14M.

Prepared by or under the supervision of: Kathy Castro

Attachments R-II-3

Please see the Excel versions of Attachments R-II-3-1 and R-II-3-2

Prepared by or under the supervision of: Kathy Castro

R-II-6

Request:

For the VVO/CVR program discussed in Section 2, pages 33, 34 and 35 of 38, provide the estimated annual power loss savings after the completion of the work proposed for FY 2021 in kilowatt demand reduction, energy reduction and power cost savings associated with the power loss reduction. Identify how long it will take for the power loss savings to amortize the cost of the VVO/CVR program implemented through 2021.

Response:

The estimated annual power loss savings from completion of the work proposed for FY 2021 is 1,870 kW demand reduction, 6.87 GWh annual energy reduction, and $394,000 annual power cost savings. The Company estimates it would take 8 years for the Company's net cost savings to amortize the cost of the VVO/CVR program, including CAPEX, OPEX, and Cost of Removal (COR). This analysis does not take into account the full revenue requirement, in which case the Company estimates it would take 13 years to amortize the cost of the VVO/CVR program.

Prepared by or under the supervision of: Stephen Lasher

R-II-7

Request:

For each proposed project which is based on thermal capacity or voltage reasons, provide a copy of the CYME model substation and feeder one line color coded output showing the areas of thermal and voltage deficiency before the project is implemented, and after the project is implemented.

Response:

The response for this question focused on the following projects:

a) Aquidneck Island
b) South County East (New Lafayette)
c) East Bay Study (East Providence & Warren Sub)

Feeder one-lines provided below represent thermal capacity and voltage issues for normal configuration. CYME is not used to analyze loading and voltage performance of substation assets. Additionally, while these projects have loading and voltage conditions it is important to note that asset condition was also a main driver, which informed the solutions and projects.

The following chart provides thermal loading color coding, based on percentage of summer normal rating:

Greater than (%)	Lower than or equal (%)	Color
0	80	
80	90	
90	95	
95	105	
105	150	
150	9999	

Figure 1: Thermal Loading Color Coding

R-II-7, page 2

The following chart provides voltage level color coding, based on percentage of nominal voltage:

Greater than (%)	Lower than or equal (%)	Color
0	85	
85	90	
90	95	
95	105	
105	9999	

Figure 2: Voltage Levels Color Coding

Voltage orange color coding reflects 95-105% of nominal voltage which corresponds to the ANSI A definition of acceptable delivery voltage.

a) Aquidneck Island:

The projects related to Aquidneck Island were mainly proposed to address transformer contingency and asset condition issues. While there were some distribution feeder thermal overloads noted, these projects are considered legacy, and were completed such that Distribution Planning did not create CYME models at the original time of the study.

As projects progress into Design and Construction, CYME models are created. Below are images related to the Newport Substation project circuits. As other area projects move into design and construction, additional models will be created (i.e. Jepson Substation).

Once all projects stemming from this legacy study are complete, the Company will conduct a new comprehensive area study, at which point Distribution Planning will create detailed CYME models that can be shared with the Division during the Area Study process.

R-II-7, page 3

The following figures outline the Newport Substation's associated feeders' thermal levels, pre- and post- project implementation:

Figure 3: Newport Substation Thermal Loading: Pre- Project Implementation

R-II-7, page 4

Figure 4: Newport Substation Thermal Loading: Post- Project Implementation

R-II-7, page 5

The following figures outline the Newport Substation's associated feeders' voltage levels, pre- and post-project implementation:

Figure 5:Newport Substation Voltage Levels: Pre-Project Implementation

R-II-7, page 6

Figure 6: Newport Substation Voltage Levels: Post-Project Implementation

b) South County East:

The following figures outline the South County East Area Study's associated feeders' thermal levels, pre and post project implementation:

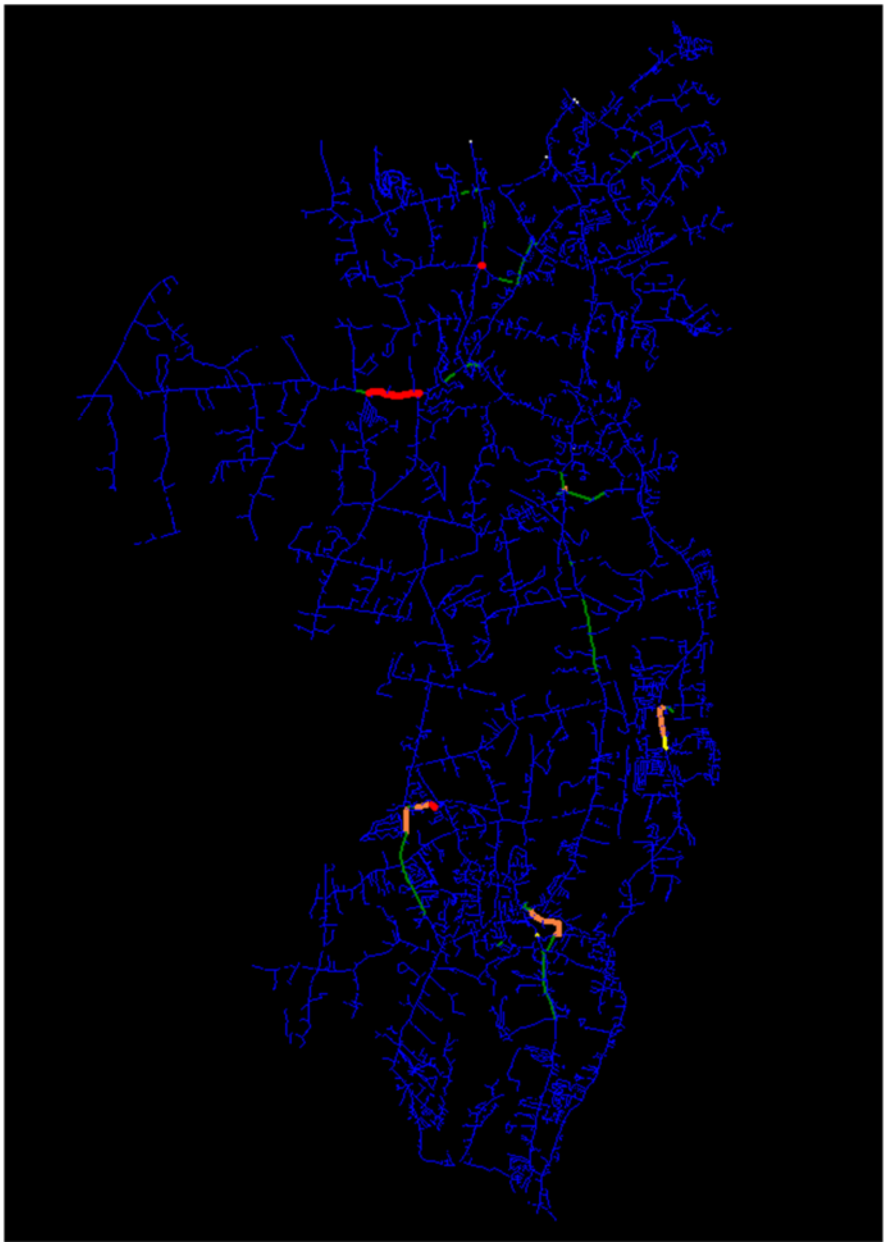

Figure 7: SCE Thermal Loading: Pre- Project Implementation

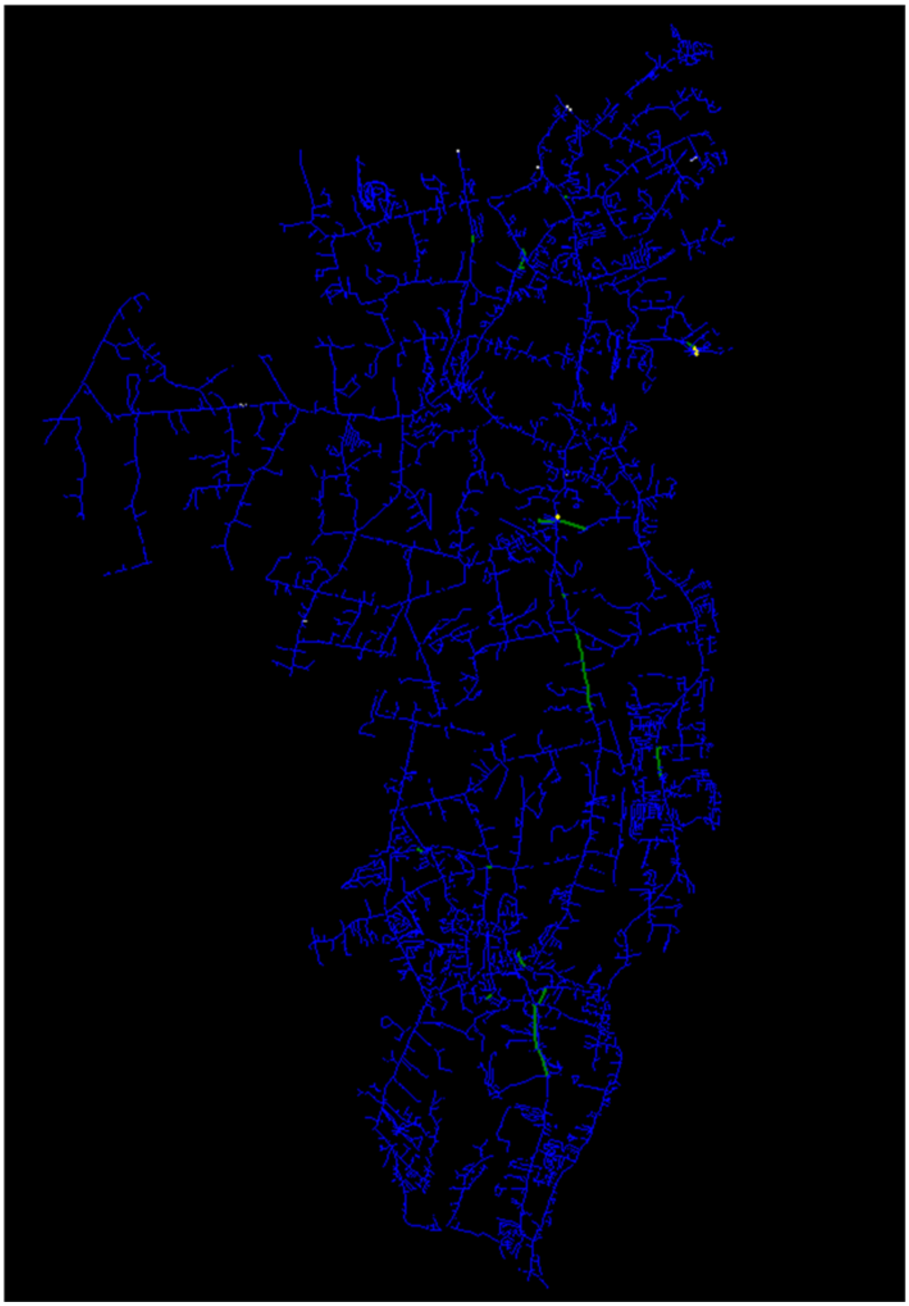

Figure 8: SCE Thermal Loading: Post-Project Implementation

R-II-7, page 9

The following figures outline the South County East Area Study's associated feeders' voltage levels, pre- and post-project implementation:

Figure 9: SCE Voltage Levels: Pre-Project Implementation

R-II-7, page 10

Figure 10: SCE Voltage Levels: Post-Project Implementation

Prepared by or under the supervision of: Kathy Castro

R-II-7, page 11

c) East Bay Study (East Providence & Warren Sub):

The following figures outline the East Bay Study's associated feeders' thermal levels, pre- and post-project implementation:

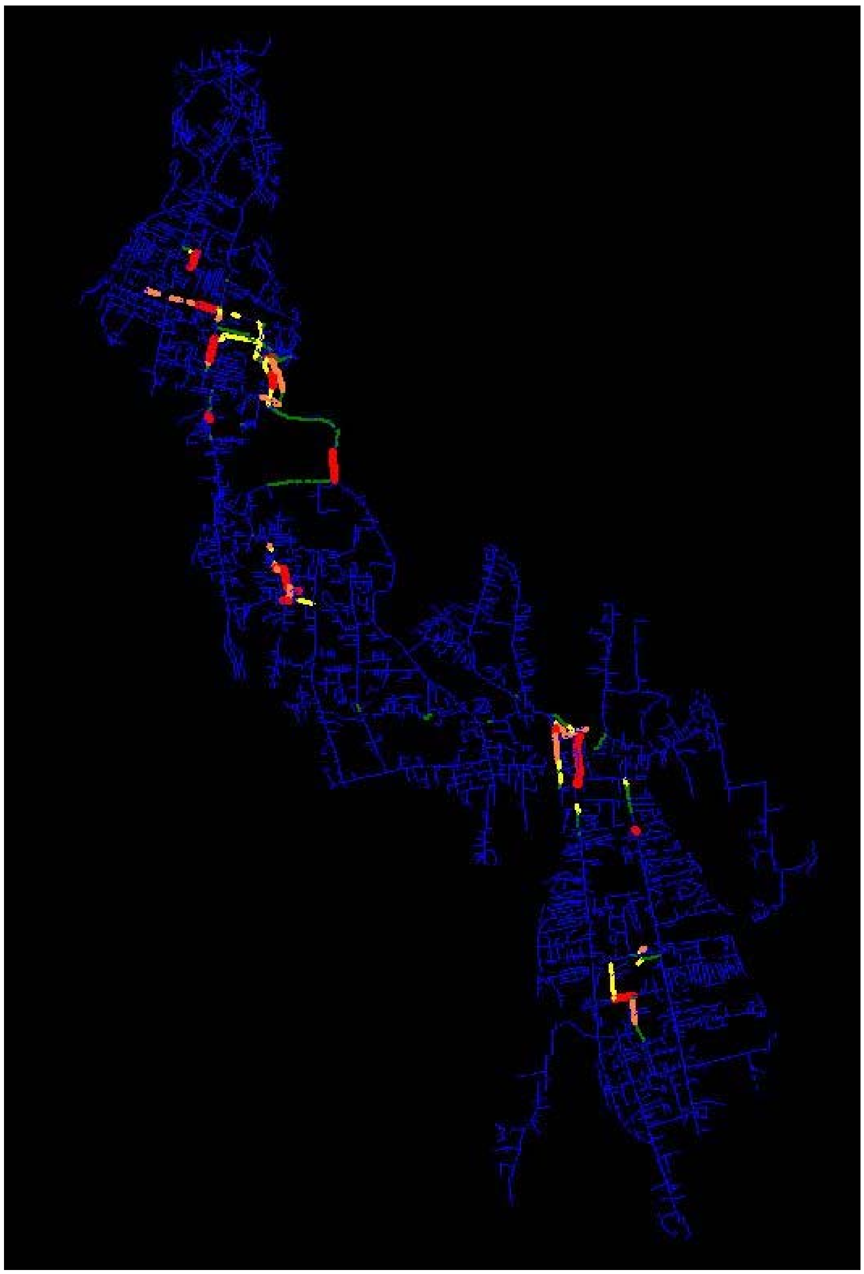
Figure 11: East Bay Thermal Loading: Pre- Project Implementation

R-II-7, page 12

Figure 12: East Bay Thermal Loading: Post- Project Implementation

R-II-7, page 13

The following figures outline the East Bay Study's associated feeders' voltage levels, pre- and post-project implementation:

Figure 13: East Bay Voltage Levels: Pre-Project Implementation

R-II-7, page 14

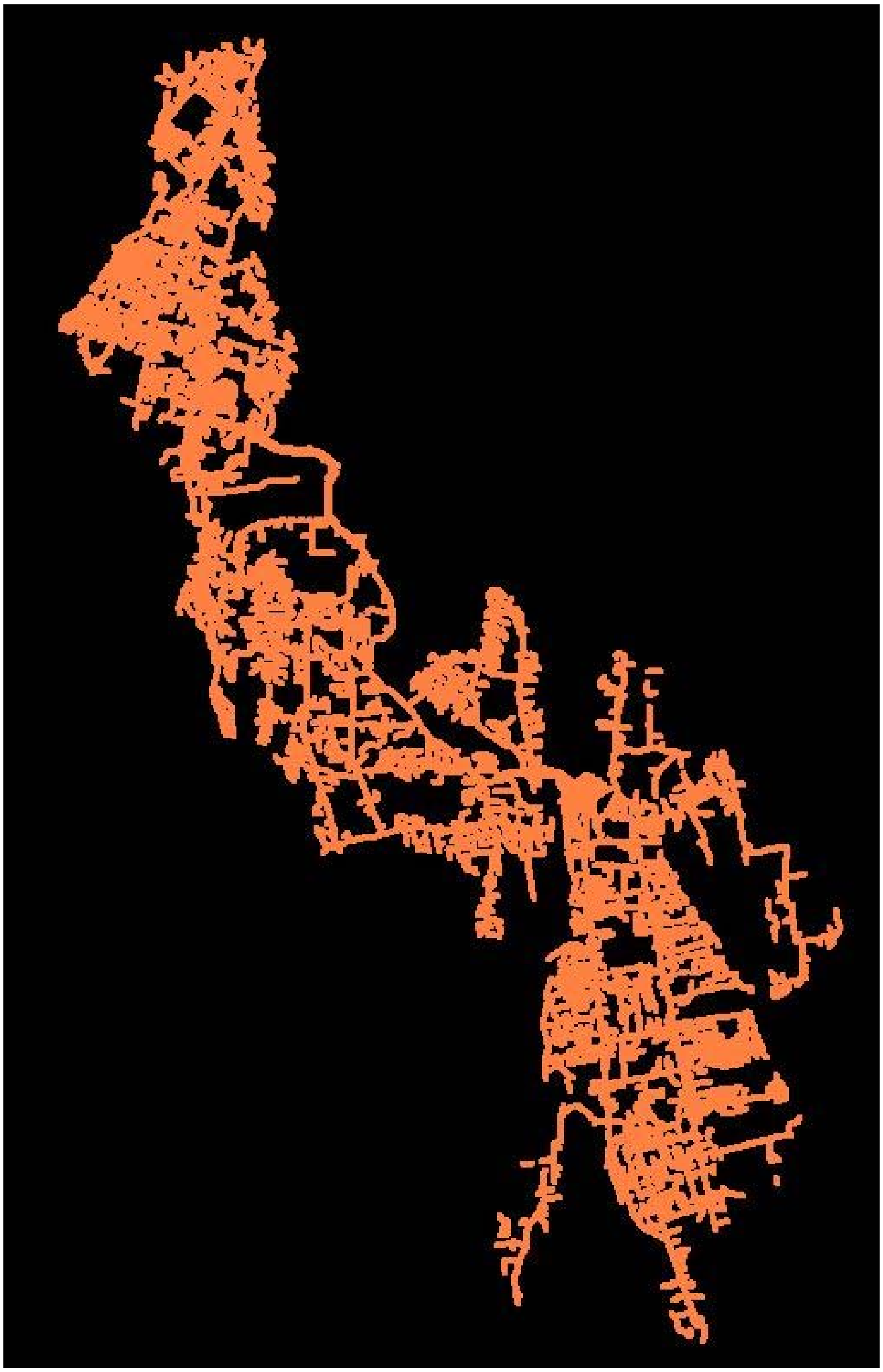

Figure 14: East Bay Voltage Levels: Post-Project Implementation

Prepared by or under the supervision of: Kathy Castro

R-II-8

Request:

Provide a comparison of load projects by substation used for the FY 2018 and 2019 ISR Plans and the area studies, versus the actuals which have occurred both in peak kW and percent growth rate.

Response:

Please refer to the following attachments for feeder and transformer load actuals and projections for 2016, 2017, and 2018:

- Attachment R-II-8-1 Feeder Load Actuals
- Attachment R-II-8-2 Feeder Load Projections
- Attachment R-II-8-3 Transformer Load Actuals
- Attachment R-II-8-4 Transformer Load Projections

The actual loads included in these attachments are the peak loads, at the feeder and transformer levels, for each year. Note that switching recommendations are typically made in a given year based on actual or projected loading exceeding 100% of the Summer normal rating to avoid overload in the following summer. The projected loads included in these attachments are from the Annual Plan of 2016, where the projected load is based off the 2015 actual peak loads, with forecasted growth rates and weather adjustment applied for 2016, 2017 and 2018.

Study Area	Substation	Voltage (kV)	Feeder ID	Rating (Amps)		2016		2017			2018		
				Normal Rating	Emergency Rating	Load (Amps)	% SN	Load (Amps)	% SN	% Load Growth	Load (Amps)	% SN	% Load Growth
Blackstone Valley North	FARNUM	23	105K1	515	515	40	8%	44	9%	11%	47	9%	5%
Blackstone Valley North	NASONVILLE	13.8	127W40	484	515	329	68%	258	53%	-22%	281	58%	9%
Blackstone Valley North	NASONVILLE	13.8	127W41	515	515	77	15%	82	16%	6%	86	17%	5%
Blackstone Valley North	NASONVILLE	13.8	127W42	459	515	277	60%	284	62%	2%	332	72%	17%
Blackstone Valley North	NASONVILLE	13.8	127W43	559	585	543	97%	502	90%	-8%	553	99%	10%
Blackstone Valley North	RIVERSIDE 8	13.8	108W51	499	631	197	39%	306	61%	55%	333	67%	9%
Blackstone Valley North	RIVERSIDE 8	13.8	108W53	499	631	425	85%	372	74%	-13%	402	81%	8%
Blackstone Valley North	RIVERSIDE 8	13.8	108W55	510	600	390	82%	174	37%	-55%	199	39%	14%
Blackstone Valley North	RIVERSIDE 8	13.8	108W60	365	365	259	50%	225	44%	-13%	181	50%	-19%
Blackstone Valley North	RIVERSIDE 8	13.8	108W61	500	500	94	19%	172	34%	82%	197	39%	15%
Blackstone Valley North	RIVERSIDE 8	13.8	108W62	515	515	66	13%	98	19%	47%	130	25%	33%
Blackstone Valley North	RIVERSIDE 8	13.8	108W63	515	515	502	97%	187	36%	-63%	222	43%	19%
Blackstone Valley North	RIVERSIDE 8	13.8	108W65	520	520	283	55%	269	52%	-5%	319	61%	18%
Blackstone Valley North	STAPLES 112	13.8	112W41	515	515	245	47%	186	36%	-24%	201	39%	8%
Blackstone Valley North	STAPLES 112	13.8	112W42	500	599	372	74%	349	70%	-6%	385	77%	10%
Blackstone Valley North	STAPLES 112	13.8	112W43	515	515	140	27%	170	33%	21%	184	36%	9%
Blackstone Valley North	STAPLES 112	13.8	112W44	406	484	343	85%	320	79%	-7%	369	91%	15%
Blackstone Valley North	HIGHLAND PARK #200	13.8	200W1	465	570	88	19%	210	45%	138%	213	46%	1%
Blackstone Valley North	HIGHLAND PARK #200	13.8	200W2	530	705	178	34%	120	23%	-33%	132	25%	10%
Blackstone Valley North	HIGHLAND PARK #200	13.8	200W3	530	705	166	31%	153	29%	-8%	155	29%	1%
Blackstone Valley North	HIGHLAND PARK #200	13.8	200W4	530	705	25	5%	90	17%	263%	93	18%	4%
Blackstone Valley North	HIGHLAND PARK #200	13.8	200W5	530	650	0	0%	222	42%	0%	254	48%	14%
Blackstone Valley North	HIGHLAND PARK #200	13.8	200W6	515	515	0	0%	171	33%	0%	199	39%	16%
Blackstone Valley North	WOONSOCKET	13.8	26W1	505	515	224	44%	204	40%	-9%	204	40%	0%
Blackstone Valley North	WOONSOCKET	13.8	26W3	507	612	337	66%	334	66%	-1%	351	69%	5%
Blackstone Valley North	WOONSOCKET	13.8	26W5	513	612	283	55%	269	53%	-5%	274	53%	2%
Blackstone Valley North	WOONSOCKET	13.8	26W7	515	515	217	42%	212	41%	-2%	233	45%	10%
Blackstone Valley South	VALLEY SUB	23	102K23	9999	9999	126	1%	64	1%	-49%	63	1%	-2%
Blackstone Valley South	PAWTUCKET #1	13.8	107W1	9999	9999	63	1%	67	1%	7%	63	1%	-6%
Blackstone Valley South	PAWTUCKET #1	13.8	107W2	9999	9999	18	0%	19	0%	4%	32	0%	68%
Blackstone Valley South	PAWTUCKET #1	13.8	107W3	9999	9999	65	1%	66	1%	1%	70	1%	6%
Blackstone Valley South	PAWTUCKET #1	13.8	107W43	365	365	289	79%	302	83%	5%	302	83%	0%
Blackstone Valley South	PAWTUCKET #1	13.8	107W49	202	250	183	91%	192	95%	5%	235	116%	22%
Blackstone Valley South	PAWTUCKET #1	13.8	107W50	356	365	267	75%	244	69%	-9%	339	95%	39%
Blackstone Valley South	PAWTUCKET #1	13.8	107W51	365	365	248	68%	227	62%	-9%	257	70%	13%
Blackstone Valley South	PAWTUCKET #1	13.8	107W53	407	540	190	47%	227	56%	20%	238	58%	5%
Blackstone Valley South	PAWTUCKET #1	13.8	107W60	334	449	320	96%	285	85%	-11%	359	107%	26%
Blackstone Valley South	PAWTUCKET #1	13.8	107W61	343	411	317	92%	308	90%	-3%	244	71%	-21%
Blackstone Valley South	PAWTUCKET #1	13.8	107W62	480	480	282	59%	280	58%	-1%	325	68%	16%
Blackstone Valley South	PAWTUCKET #1	13.8	107W63	515	515	260	51%	240	47%	-8%	272	53%	13%
Blackstone Valley South	PAWTUCKET #1	13.8	107W65	345	360	290	84%	233	68%	-20%	203	59%	-13%
Blackstone Valley South	PAWTUCKET #1	13.8	107W66	389	389	152	39%	149	38%	-2%	158	41%	6%
Blackstone Valley South	PAWTUCKET #1	13.8	107W80	279	406	220	79%	202	72%	-8%	229	82%	13%
Blackstone Valley South	PAWTUCKET #1	13.8	107W81	395	557	404	102%	360	91%	-11%	302	76%	-16%

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Blackstone Valley South	PAWTUCKET #1	13.8	107W83	367	591	230	63%	297	81%	29%	233	63%	-22%
Blackstone Valley South	PAWTUCKET #1	13.8	107W84	350	365	165	47%	168	48%	2%	232	66%	38%
Blackstone Valley South	PAWTUCKET #1	13.8	107W85	335	365	219	65%	188	56%	-14%	225	67%	20%
Blackstone Valley South	VALLEY	13.8	102W41	500	515	168	34%	123	25%	-27%	116	23%	-6%
Blackstone Valley South	VALLEY	13.8	102W42	463	515	291	63%	302	65%	4%	276	60%	-9%
Blackstone Valley South	VALLEY	13.8	102W44	328	460	220	67%	220	67%	0%	239	73%	9%
Blackstone Valley South	VALLEY	13.8	102W50	364	375	166	46%	84	23%	-49%	17	5%	-80%
Blackstone Valley South	VALLEY	13.8	102W51	341	497	183	54%	292	86%	60%	330	**97%**	13%
Blackstone Valley South	VALLEY	13.8	102W52	306	355	130	43%	93	31%	-29%	105	34%	13%
Blackstone Valley South	VALLEY	13.8	102W54	334	444	215	74%	208	71%	-3%	305	**91%**	47%
Blackstone Valley South	WASHINGTON	13.8	126W40	515	645	227	44%	241	47%	6%	257	50%	7%
Blackstone Valley South	WASHINGTON	13.8	126W41	520	535	387	75%	406	78%	5%	423	81%	4%
Blackstone Valley South	WASHINGTON	13.8	126W42	525	600	362	69%	356	68%	-2%	339	65%	-5%
Blackstone Valley South	WASHINGTON	13.8	126W50	528	645	448	85%	407	77%	-9%	431	82%	6%
Blackstone Valley South	WASHINGTON	13.8	126W51	515	515	403	78%	396	77%	-2%	430	83%	9%
Blackstone Valley South	WASHINGTON	13.8	126W53	583	750	28	5%	28	5%	1%	26	4%	-7%
Blackstone Valley South	WASHINGTON	13.8	126W54	530	645	465	88%	333	63%	-28%	388	73%	17%
Blackstone Valley South	CENTRAL FALLS	4.16	104J1	350	350	226	65%	183	52%	-19%	122	35%	-33%
Blackstone Valley South	CENTRAL FALLS	4.16	104J3	350	350	0	0%	0	0%	0%	0	0%	0%
Blackstone Valley South	CENTRAL FALLS	4.16	104J5	350	350	20	6%	26	7%	26%	26	7%	0%
Blackstone Valley South	CENTRAL FALLS	4.16	104J7	350	350	128	37%	71	20%	-45%	111	32%	57%
Blackstone Valley South	CENTRE ST	4.16	106J1	350	350	170	49%	119	34%	-30%	57	16%	-52%
Blackstone Valley South	CENTRE ST	4.16	106J3	350	350	178	51%	179	51%	0%	176	50%	-2%
Blackstone Valley South	CENTRE ST	4.16	106J7	350	350	37	11%	30	9%	-20%	45	13%	51%
Blackstone Valley South	COTTAGE STREET	4.16	109J1	408	408	231	57%	150	37%	-35%	228	56%	52%
Blackstone Valley South	COTTAGE STREET	4.16	109J3	408	408	224	55%	196	48%	-13%	218	53%	11%
Blackstone Valley South	COTTAGE STREET	4.16	109J5	408	408	308	75%	302	74%	-2%	285	70%	-6%
Blackstone Valley South	CROSSMAN STREET	4.16	111J1	340	340	234	69%	267	79%	14%	285	84%	7%
Blackstone Valley South	CROSSMAN STREET	4.16	111J3	340	340	222	65%	198	58%	-11%	262	77%	33%
Blackstone Valley South	DAGGETT	4.16	113J1	390	390	144	37%	0	0%	-100%	0	0%	0%
Blackstone Valley South	DAGGETT	4.16	113J2	390	390	296	76%	0	0%	-100%	0	0%	0%
Blackstone Valley South	FRONT ST	4.16	24J1	400	400	181	45%	170	42%	-6%	151	38%	-11%
Blackstone Valley South	HYDE	4.16	28J1	400	400	173	43%	0	0%	-100%	0	0%	0%
Blackstone Valley South	HYDE	4.16	28J2	400	400	46	12%	0	0%	-100%	0	0%	0%
Blackstone Valley South	LEE STREET	4.16	30J1	380	380	225	59%	222	58%	-1%	122	32%	-45%
Blackstone Valley South	LEE STREET	4.16	30J3	380	380	237	62%	158	42%	-33%	89	23%	-44%
Blackstone Valley South	LEE STREET	4.16	30J5	380	380	221	58%	167	44%	-24%	167	44%	0%
Blackstone Valley South	PAWTUCKET #2	4.16	148J1	370	370	140	38%	249	67%	78%	279	75%	12%
Blackstone Valley South	PAWTUCKET #2	4.16	148J3	290	290	93	32%	210	72%	125%	236	81%	12%
Blackstone Valley South	PAWTUCKET #2	4.16	148J5	370	370	168	45%	263	71%	56%	332	90%	26%
Blackstone Valley South	PAWTUCKET #2	4.16	148J7	370	370	139	37%	209	56%	51%	264	71%	26%
Blackstone Valley South	SOUTHEAST	4.16	60J1	408	408	97	24%	0	0%	-100%	0	0%	0%
Blackstone Valley South	SOUTHEAST	4.16	60J3	408	408	156	38%	0	0%	-100%	0	0%	0%
Blackstone Valley South	SOUTHEAST	4.16	60J5	380	380	135	36%	0	0%	-100%	0	0%	0%
Central RI East	APPONAUG 3	12.47	3F1	526	612	328	62%	260	49%	-21%	284	54%	9%

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Central RI East	APPONAUG 3	12.47	3F2	515	515	277	54%	287	56%	4%	281	55%	-2%
Central RI East	DRUMROCK 14	12.47	14F1	530	612	334	63%	318	60%	-5%	325	61%	2%
Central RI East	DRUMROCK 14	12.47	14F2	530	595	373	70%	325	61%	-13%	363	68%	12%
Central RI East	DRUMROCK 14	12.47	14F3	515	515	372	72%	354	69%	-5%	426	83%	20%
Central RI East	DRUMROCK 14	12.47	14F4	515	515	332	64%	334	65%	1%	335	65%	0%
Central RI East	KILVERT STREET 87	12.47	87F1	530	645	371	70%	317	60%	-15%	347	65%	9%
Central RI East	KILVERT STREET 87	12.47	87F2	570	662	294	52%	293	51%	-1%	330	58%	13%
Central RI East	KILVERT STREET 87	12.47	87F3	530	645	337	64%	319	60%	-5%	366	69%	15%
Central RI East	KILVERT STREET 87	12.47	87F4	530	650	237	45%	313	59%	32%	234	44%	-25%
Central RI East	KILVERT STREET 87	12.47	87F5	530	650	280	53%	291	55%	4%	294	56%	1%
Central RI East	KILVERT STREET 87	12.47	87F6	530	650	243	46%	231	44%	-5%	249	47%	7%
Central RI East	LINCOLN AVENUE 72	12.47	72F1	530	650	200	38%	190	36%	-5%	194	37%	2%
Central RI East	LINCOLN AVENUE 72	12.47	72F2	530	650	369	70%	338	64%	-8%	340	64%	0%
Central RI East	LINCOLN AVENUE 72	12.47	72F3	530	650	435	82%	396	75%	-9%	431	81%	9%
Central RI East	LINCOLN AVENUE 72	12.47	72F4	530	650	408	77%	388	73%	-5%	414	78%	7%
Central RI East	LINCOLN AVENUE 72	12.47	72F5	515	515	468	**91%**	409	79%	-13%	439	85%	7%
Central RI East	LINCOLN AVENUE 72	12.47	72F6	567	645	414	73%	491	87%	19%	527	**93%**	7%
Central RI East	PONTIAC 27	12.47	27F1	530	650	349	66%	335	63%	-4%	352	66%	5%
Central RI East	PONTIAC 27	12.47	27F2	530	650	494	**93%**	380	72%	-23%	404	76%	6%
Central RI East	PONTIAC 27	12.47	27F3	460	515	147	32%	145	32%	-1%	156	34%	7%
Central RI East	PONTIAC 27	12.47	27F4	460	515	379	82%	334	73%	-12%	340	74%	2%
Central RI East	PONTIAC 27	12.47	27F5	530	650	459	87%	443	84%	-4%	478	**90%**	8%
Central RI East	PONTIAC 27	12.47	27F6	530	645	223	42%	219	41%	-2%	153	29%	-30%
Central RI East	WARWICK 52	12.47	52F1	485	490	224	46%	220	45%	-2%	228	47%	4%
Central RI East	WARWICK 52	12.47	52F2	485	490	122	25%	146	30%	20%	133	27%	-9%
Central RI East	WARWICK 52	12.47	52F3	526	560	412	78%	352	67%	-14%	389	74%	10%
Central RI East	AUBURN 73	4.16	73J1	369	408	120	33%	100	27%	-17%	137	37%	37%
Central RI East	AUBURN 73	4.16	73J2	385	385	117	30%	110	29%	-6%	111	29%	1%
Central RI East	AUBURN 73	4.16	73J3	385	385	272	71%	256	66%	-6%	283	73%	10%
Central RI East	AUBURN 73	4.16	73J4	385	385	160	42%	140	36%	-13%	156	41%	11%
Central RI East	AUBURN 73	4.16	73J5	408	408	268	66%	235	58%	-12%	248	61%	5%
Central RI East	AUBURN 73	4.16	73J6	381	408	168	44%	172	45%	2%	149	39%	-13%
Central RI East	LAKEWOOD 57	4.16	57J1	369	441	138	37%	200	54%	45%	79	21%	-61%
Central RI East	LAKEWOOD 57	4.16	57J2	452	556	230	51%	232	51%	1%	125	28%	-46%
Central RI East	LAKEWOOD 57	4.16	57J3	408	408	262	64%	136	33%	-48%	158	39%	16%
Central RI East	LAKEWOOD 57	4.16	57J5	492	510	360	73%	132	27%	-63%	154	31%	17%
Central RI West	ANTHONY	12.47	64F1	361	374	252	70%	193	54%	-23%	211	58%	9%
Central RI West	ANTHONY	12.47	64F2	361	374	322	89%	279	77%	-13%	221	61%	-21%
Central RI West	COVENTRY	12.47	54F1	526	560	428	81%	352	67%	-18%	441	84%	25%
Central RI West	DIVISION ST	12.47	61F1	450	515	300	67%	314	70%	5%	299	66%	-5%
Central RI West	DIVISION ST	12.47	61F2	450	667	320	71%	281	62%	-12%	293	65%	4%
Central RI West	DIVISION ST	12.47	61F3	450	476	319	71%	312	69%	-2%	337	75%	8%
Central RI West	DIVISION ST	12.47	61F4	450	645	352	78%	329	73%	-7%	331	73%	0%
Central RI West	HOPE	12.47	15F1	348	394	313	90%	282	81%	-10%	317	**91%**	12%
Central RI West	HOPE	12.47	15F2	476	476	423	89%	360	76%	-15%	417	88%	16%

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Central RI West	HOPKINS HILL	12.47	63F1	538	650	214	40%	258	48%	21%	240	45%	-7%
Central RI West	HOPKINS HILL	12.47	63F2	530	650	190	36%	318	60%	68%	357	67%	12%
Central RI West	HOPKINS HILL	12.47	63F3	530	650	294	55%	262	49%	-11%	281	53%	7%
Central RI West	HOPKINS HILL	12.47	63F4	530	650	359	68%	308	58%	-14%	346	65%	12%
Central RI West	HOPKINS HILL	12.47	63F5	530	650	431	81%	410	77%	-5%	421	79%	3%
Central RI West	HOPKINS HILL	12.47	63F6	530	650	452	85%	430	81%	-5%	428	81%	-1%
Central RI West	HUNT RIVER	12.47	40F1	274	327	204	74%	0	0%	-100%	0	0%	0%
Central RI West	KENT COUNTY	12.47	22F1	530	650	334	63%	326	61%	-2%	359	68%	10%
Central RI West	KENT COUNTY	12.47	22F2	530	650	365	69%	355	67%	-3%	383	72%	8%
Central RI West	KENT COUNTY	12.47	22F3	530	650	383	72%	393	74%	3%	410	77%	4%
Central RI West	KENT COUNTY	12.47	22F4	510	650	447	76%	262	51%	-41%	266	52%	2%
Central RI West	KENT COUNTY	12.47	22F6	510	650	0	0%	354	69%	0%	353	69%	0%
Central RI West	NATICK	12.47	29F1	385	385	352	92%	319	83%	-10%	329	85%	3%
Central RI West	NATICK	12.47	29F2	409	489	249	61%	234	57%	-6%	242	59%	4%
Central RI West	WARWICK MALL	12.47	28F1	390	412	129	33%	115	29%	-11%	118	30%	2%
Central RI West	WARWICK MALL	12.47	28F2	390	422	83	21%	78	20%	-7%	74	19%	-5%
Central RI West	ARCTIC	4.16	49J1	295	352	224	76%	214	73%	-4%	232	79%	8%
Central RI West	ARCTIC	4.16	49J2	295	352	179	61%	122	41%	-32%	92	31%	-25%
Central RI West	ARCTIC	4.16	49J3	295	315	214	73%	188	64%	-12%	200	68%	6%
Central RI West	ARCTIC	4.16	49J4	295	352	293	99%	268	91%	-9%	245	83%	-8%
Central RI West	TIOGUE AVE	12.47	100F1	570	612	445	78%	402	71%	-10%	434	76%	8%
Central RI West	NEW LONDON AVE	12.47	150F1	645	645	0	0%	0	0%	0%	0	0%	0%
Central RI West	NEW LONDON AVE	12.47	150F3	530	650	0	0%	0	0%	0%	0	0%	0%
Central RI West	NEW LONDON AVE	12.47	150F5	530	650	0	0%	0	0%	0%	0	0%	0%
Central RI West	NEW LONDON AVE	12.47	150F7	645	645	0	0%	0	0%	0%	0	0%	0%
East Bay	BARRINGTON 4	12.47	4F1	515	515	376	73%	265	51%	-30%	361	70%	36%
East Bay	BARRINGTON 4	12.47	4F2	510	510	428	84%	323	63%	-25%	426	83%	32%
East Bay	BRISTOL 51A	12.47	51F1	645	645	467	72%	376	58%	-19%	455	70%	21%
East Bay	BRISTOL 51A	12.47	51F2	530	612	467	88%	400	75%	-14%	465	88%	16%
East Bay	BRISTOL 51A	12.47	51F3	502	567	352	70%	326	65%	-7%	382	76%	17%
East Bay	PHILLIPSDALE 20	12.47	20F1	425	450	309	73%	285	67%	-8%	289	68%	1%
East Bay	PHILLIPSDALE 20	12.47	20F2	425	450	294	69%	284	67%	-3%	309	73%	9%
East Bay	WAMPANOAG 48	12.47	48F1	502	507	411	82%	369	74%	-10%	423	84%	15%
East Bay	WAMPANOAG 48	12.47	48F2	515	515	392	76%	370	72%	-6%	370	72%	0%
East Bay	WAMPANOAG 48	12.47	48F3	510	515	464	91%	432	85%	-7%	449	88%	4%
East Bay	WAMPANOAG 48	12.47	48F4	530	612	451	85%	425	80%	-6%	454	86%	7%
East Bay	WAMPANOAG 48	12.47	48F5	530	612	553	114%	423	80%	-24%	364	69%	-14%
East Bay	WAMPANOAG 48	12.47	48F6	530	612	409	77%	347	66%	-15%	377	71%	8%
East Bay	WARREN 5	12.47	5F1	425	520	377	89%	303	71%	-20%	340	80%	12%
East Bay	WARREN 5	12.47	5F2	434	434	355	82%	335	77%	-6%	365	84%	9%
East Bay	WARREN 5	12.47	5F3	515	515	356	69%	335	65%	-6%	349	68%	4%
East Bay	WARREN 5	12.47	5F4	510	510	409	80%	357	70%	-13%	396	78%	11%
East Bay	WATERMAN AVENUE 78	12.47	78F3	409	489	264	65%	196	48%	-26%	216	53%	10%
East Bay	WATERMAN AVENUE 78	12.47	78F4	409	489	245	60%	199	49%	-19%	210	51%	6%
East Bay	KENT CORNERS 47	4.16	47J1	408	408	0	0%	0	0%	0%	0	0%	0%

Study Area	Substation	Voltage (kV)	Feeder ID	Normal Rating	Emergency Rating	Load (Amps)	% SN	Load (Amps)	% SN	% Load Growth	Load (Amps)	% SN	% Load Growth
East Bay	KENT CORNERS 47	4.16	47J2	408	408	264	65%	230	56%	-13%	326	80%	42%
East Bay	KENT CORNERS 47	4.16	47J3	408	408	308	75%	247	60%	-20%	312	76%	26%
East Bay	KENT CORNERS 47	4.16	47J4	408	408	332	81%	252	62%	-24%	296	72%	17%
East Bay	EAST PROVIDENCE SUB	12.47	F1	0	0	0	0%	0	0%	0%	0	0%	0%
East Bay	EAST PROVIDENCE SUB	12.47	F2	0	0	0	0%	0	0%	0%	0	0%	0%
East Bay	EAST PROVIDENCE SUB	12.47	F3	0	0	0	0%	0	0%	0%	0	0%	0%
East Bay	EAST PROVIDENCE SUB	12.47	F4	0	0	0	0%	0	0%	0%	0	0%	0%
East Bay	WARREN 5	12.47	5F5	0	0	0	0%	0	0%	0%	0	0%	0%
East Bay	WARREN 5	12.47	5F6	0	0	0	0%	0	0%	0%	0	0%	0%
East Bay	PHILLIPSDALE 20	12.47	F1	0	0	0	0%	0	0%	0%	0	0%	0%
East Bay	PHILLIPSDALE 20	12.47	F2	0	0	0	0%	0	0%	0%	0	0%	0%
East Bay	PHILLIPSDALE 20	12.47	F3	0	0	0	0%	0	0%	0%	0	0%	0%
East Bay	PHILLIPSDALE 20	12.47	F4	0	0	0	0%	0	0%	0%	0	0%	0%
East Bay	BRISTOL 51A	12.47	51F4	0	0	0	0%	0	0%	0%	0	0%	0%
Newport	DEXTER	13.8	36W41	464	566	283	61%	260	56%	-8%	273	59%	5%
Newport	DEXTER	13.8	36W42	464	515	224	48%	203	44%	-9%	228	49%	12%
Newport	DEXTER	13.8	36W43	464	566	145	31%	133	29%	-8%	162	35%	22%
Newport	DEXTER	13.8	36W44	464	566	286	62%	274	59%	-4%	299	64%	9%
Newport	JEPSON	13.8	37W41	560	560	292	52%	289	52%	-1%	309	55%	7%
Newport	JEPSON	13.8	37W42	560	560	438	78%	411	73%	-6%	427	76%	4%
Newport	JEPSON	13.8	37W43	560	560	342	61%	334	60%	-2%	364	65%	9%
Newport	BAILEY BROOK	4.16	19J2	447	476	221	49%	203	45%	-8%	184	41%	-9%
Newport	BAILEY BROOK	4.16	19J14	476	476	210	44%	157	33%	-25%	169	36%	8%
Newport	BAILEY BROOK	4.16	19J16	476	476	20	4%	20	4%	0%	20	4%	0%
Newport	CLARKE STREET	4.16	65J2	570	595	375	66%	340	60%	-9%	346	61%	2%
Newport	CLARKE STREET	4.16	65J12	575	575	335	58%	288	50%	-14%	307	53%	6%
Newport	ELDRED	4.16	45J3	560	668	502	90%	419	75%	-16%	466	83%	11%
Newport	ELDRED	4.16	45J4	560	668	253	45%	214	38%	-16%	234	42%	10%
Newport	ELDRED	4.16	45J6	448	476	0	0%	0	0%	0%	0	0%	0%
Newport	GATE 2	4.16	38J2	440	476	63	14%	58	13%	-8%	66	15%	14%
Newport	GATE 2	4.16	38J4	440	476	317	72%	296	67%	-7%	345	78%	17%
Newport	HARRISON	4.16	32J2	350	420	288	82%	240	69%	-17%	277	79%	16%
Newport	HARRISON	4.16	32J4	300	380	172	57%	120	40%	-30%	147	49%	23%
Newport	HARRISON	4.16	32J12	372	380	332	89%	276	74%	-17%	262	70%	-5%
Newport	HARRISON	4.16	32J14	366	500	313	86%	294	80%	-6%	213	58%	-28%
Newport	HOSPITAL	4.16	146J2	300	357	56	19%	49	16%	-11%	178	59%	260%
Newport	HOSPITAL	4.16	146J4	434	434	204	47%	241	56%	18%	255	59%	6%
Newport	HOSPITAL	4.16	146J12	434	434	152	35%	126	29%	-17%	136	31%	8%
Newport	HOSPITAL	4.16	146J14	307	365	157	51%	142	46%	-10%	157	51%	10%
Newport	JEPSON	4.16	37J2	380	380	67	18%	53	14%	-21%	54	14%	3%
Newport	JEPSON	4.16	37J4	380	380	201	53%	189	50%	-6%	188	50%	0%
Newport	KINGSTON	4.16	131J2	397	510	234	59%	227	57%	-3%	234	59%	3%
Newport	KINGSTON	4.16	131J4	510	510	320	63%	275	54%	-14%	327	64%	19%
Newport	KINGSTON	4.16	131J6	380	380	156	41%	140	37%	-10%	153	40%	9%
Newport	KINGSTON	4.16	131J12	380	380	336	88%	316	83%	-6%	354	**93%**	12%

Study Area	Substation	Voltage (kV)	Feeder ID	Normal Rating	Emergency Rating	Load (Amps)	% SN	Load (Amps)	% SN	% Load Growth	Load (Amps)	% SN	% Load Growth
Newport	KINGSTON	4.16	131J14	307	365	212	69%	237	77%	12%	212	69%	-11%
Newport	MERTON	4.16	51J2	310	333	301	97%	243	78%	-19%	200	64%	-18%
Newport	MERTON	4.16	51J12	356	408	128	36%	120	34%	-6%	132	37%	10%
Newport	MERTON	4.16	51J14	310	368	124	40%	128	41%	3%	136	44%	6%
Newport	MERTON	4.16	51J16	380	380	256	67%	240	63%	-6%	267	70%	11%
Newport	NO. AQUIDNECK	4.16	21J2	480	480	236	49%	163	34%	-31%	152	32%	-7%
Newport	NO. AQUIDNECK	4.16	21J4	480	480	204	43%	160	33%	-22%	168	35%	5%
Newport	NO. AQUIDNECK	4.16	21J6	480	480	180	38%	156	33%	-13%	152	32%	-3%
Newport	SO. AQUIDNECK	4.16	122J2	481	510	311	65%	424	88%	36%	348	72%	-18%
Newport	SO. AQUIDNECK	4.16	122J4	480	510	340	71%	364	76%	7%	367	76%	1%
Newport	SO. AQUIDNECK	4.16	122J6	480	480	0	0%	0	0%	0%	120	25%	0%
Newport	VERNON	4.16	23J2	384	408	63	16%	59	15%	-6%	67	17%	14%
Newport	VERNON	4.16	23J4	384	408	234	61%	206	54%	-12%	239	62%	16%
Newport	VERNON	4.16	23J6	384	408	104	27%	102	27%	-2%	93	24%	-9%
Newport	VERNON	4.16	23J12	384	408	135	35%	133	35%	-1%	153	40%	15%
Newport	VERNON	4.16	23J14	384	408	10	3%	47	12%	370%	47	12%	0%
Newport	WEST HOWARD	4.16	154J2	480	688	356	74%	263	55%	-26%	273	57%	4%
Newport	WEST HOWARD	4.16	154J4	290	350	140	48%	137	47%	-2%	130	45%	-5%
Newport	WEST HOWARD	4.16	154J6	268	346	36	13%	36	13%	0%	36	13%	0%
Newport	WEST HOWARD	4.16	154J8	380	380	336	88%	312	82%	-7%	341	90%	9%
Newport	WEST HOWARD	4.16	154J14	290	350	22	8%	193	67%	777%	197	68%	2%
Newport	WEST HOWARD	4.16	154J16	270	340	189	70%	168	62%	-11%	186	69%	11%
Newport	WEST HOWARD	4.16	154J18	380	380	255	67%	261	69%	2%	287	76%	10%
Newport	GATE 2	13.8	38W1	515	515	220	43%	202	39%	-8%	223	43%	10%
North Central RI	CENTREDALE 50	12.47	50F2	367	386	300	82%	260	71%	-13%	288	78%	11%
North Central RI	CHOPMIST 34	12.47	34F1	530	544	466	88%	378	71%	-19%	422	80%	12%
North Central RI	CHOPMIST 34	12.47	34F2	415	415	332	80%	266	64%	-20%	304	73%	14%
North Central RI	CHOPMIST 34	12.47	34F3	385	385	197	51%	228	59%	16%	221	57%	-3%
North Central RI	FARNUM PIKE 23	12.47	23F1	530	650	293	55%	279	53%	-5%	280	53%	0%
North Central RI	FARNUM PIKE 23	12.47	23F2	515	515	385	75%	363	70%	-6%	398	77%	10%
North Central RI	FARNUM PIKE 23	12.47	23F3	530	640	459	87%	406	77%	-12%	458	86%	13%
North Central RI	FARNUM PIKE 23	12.47	23F4	530	612	263	50%	248	47%	-6%	204	38%	-18%
North Central RI	FARNUM PIKE 23	12.47	23F5	515	515	101	20%	109	21%	8%	100	19%	-8%
North Central RI	FARNUM PIKE 23	12.47	23F6	515	515	372	72%	344	67%	-7%	368	72%	7%
North Central RI	JOHNSTON 18	12.47	18F1	526	626	0	0%	0	0%	0%	0	0%	0%
North Central RI	JOHNSTON 18	12.47	18F2	452	515	0	0%	0	0%	0%	0	0%	0%
North Central RI	JOHNSTON 18	12.47	18F3	515	515	0	0%	0	0%	0%	0	0%	0%
North Central RI	JOHNSTON 18	12.47	18F4	530	560	0	0%	0	0%	0%	0	0%	0%
North Central RI	JOHNSTON 18	12.47	18F5	530	612	434	82%	415	78%	-4%	446	84%	8%
North Central RI	JOHNSTON 18	12.47	18F6	515	515	460	89%	393	76%	-15%	360	70%	-8%
North Central RI	JOHNSTON 18	12.47	18F7	530	612	305	58%	273	51%	-11%	295	56%	8%
North Central RI	JOHNSTON 18	12.47	18F8	530	612	271	51%	249	47%	-8%	259	49%	4%
North Central RI	JOHNSTON 18	12.47	18F9	530	612	384	72%	338	64%	-12%	389	73%	15%
North Central RI	JOHNSTON 18	12.47	18F10	531	612	387	73%	354	67%	-8%	385	73%	9%
North Central RI	JOHNSTON 18	12.47	18F11	526	612	350	67%	348	66%	-1%	351	67%	1%

Study Area	Substation	Voltage (kV)	Feeder ID	Normal Rating	Emergency Rating	Load (Amps)	% SN	Load (Amps)	% SN	% Load Growth	Load (Amps)	% SN	% Load Growth
North Central RI	JOHNSTON 18	12.47	18F12	507	612	141	28%	144	28%	2%	151	30%	5%
North Central RI	JOHNSTON 18	12.47	18F13	460	515	276	60%	313	68%	14%	345	75%	10%
North Central RI	JOHNSTON 18	12.47	18F14	515	612	199	39%	180	35%	-10%	186	36%	3%
North Central RI	MANTON 69	12.47	69F1	515	515	440	85%	376	73%	-15%	420	82%	12%
North Central RI	MANTON 69	12.47	69F3	502	515	448	89%	396	79%	-12%	416	83%	5%
North Central RI	PUTNAM PIKE 38	12.47	38F1	530	650	473	89%	419	79%	-11%	489	92%	17%
North Central RI	PUTNAM PIKE 38	12.47	38F2	530	650	187	35%	189	36%	1%	190	36%	1%
North Central RI	PUTNAM PIKE 38	12.47	38F3	530	650	386	73%	321	61%	-17%	299	56%	-7%
North Central RI	PUTNAM PIKE 38	12.47	38F4	515	515	233	45%	246	48%	6%	344	67%	40%
North Central RI	PUTNAM PIKE 38	12.47	38F5	530	395	372	70%	334	63%	-10%	252	47%	-25%
North Central RI	PUTNAM PIKE 38	12.47	38F6	530	612	331	62%	364	69%	10%	406	77%	11%
North Central RI	WEST CRANSTON 21	12.47	21F1	515	515	508	99%	413	80%	-19%	459	89%	11%
North Central RI	WEST CRANSTON 21	12.47	21F2	515	515	372	72%	355	69%	-4%	358	70%	1%
North Central RI	WEST CRANSTON 21	12.47	21F4	515	515	448	87%	392	76%	-13%	416	81%	6%
North Central RI	WEST GREENVILLE 45	12.47	45F2	425	520	93	22%	76	18%	-18%	344	81%	350%
North Central RI	CENTREDALE 50	4.16	50J1	285	313	129	45%	154	54%	19%	160	56%	4%
North Central RI	CENTREDALE 50	4.16	50J2	295	352	0	0%	0	0%	0%	0	0%	0%
North Central RI	CENTREDALE 50	4.16	50J3	408	408	208	51%	196	48%	-6%	244	60%	24%
North Central RI	SHUN PIKE	13.2	128L1	1039	1321	1025	99%	659	63%	-36%	736	71%	12%
Providence	CLARKSON STREET 13	12.47	13F1	400	533	146	37%	123	31%	-16%	141	35%	15%
Providence	CLARKSON STREET 13	12.47	13F2	540	612	173	32%	163	30%	-6%	173	32%	6%
Providence	CLARKSON STREET 13	12.47	13F3	425	612	333	78%	311	73%	-7%	323	76%	4%
Providence	CLARKSON STREET 13	12.47	13F4	520	612	432	83%	388	75%	-10%	451	87%	16%
Providence	CLARKSON STREET 13	12.47	13F5	455	612	408	90%	372	82%	-9%	402	88%	8%
Providence	CLARKSON STREET 13	12.47	13F6	415	542	167	40%	152	37%	-9%	228	55%	50%
Providence	CLARKSON STREET 13	12.47	13F7	436	571	351	81%	274	63%	-22%	339	78%	24%
Providence	CLARKSON STREET 13	12.47	13F8	437	563	268	61%	315	72%	18%	307	70%	-2%
Providence	CLARKSON STREET 13	12.47	13F9	530	612	483	91%	411	77%	-15%	453	85%	10%
Providence	CLARKSON STREET 13	12.47	13F10	315	315	215	68%	205	65%	-5%	240	76%	17%
Providence	ELMWOOD 7 - OUTDOOR	12.47	7F1	530	612	329	62%	300	57%	-9%	351	66%	17%
Providence	ELMWOOD 7 - OUTDOOR	12.47	7F2	530	612	364	69%	344	65%	-6%	358	68%	4%
Providence	ELMWOOD 7 - OUTDOOR	12.47	7F4	530	612	367	69%	368	69%	0%	400	75%	9%
Providence	LIPPITT HILL 79	12.47	79F1	459	579	376	82%	349	76%	-7%	350	76%	0%
Providence	LIPPITT HILL 79	12.47	79F2	459	579	383	84%	389	85%	2%	424	92%	9%
Providence	POINT STREET 76	12.47	76F1	484	490	395	82%	386	80%	-2%	418	86%	8%
Providence	POINT STREET 76	12.47	76F2	500	612	453	91%	433	87%	-4%	504	101%	16%
Providence	POINT STREET 76	12.47	76F3	546	600	224	41%	225	41%	0%	251	46%	12%
Providence	POINT STREET 76	12.47	76F4	530	612	475	90%	445	84%	-6%	469	89%	6%
Providence	POINT STREET 76	12.47	76F5	448	570	398	89%	369	82%	-7%	397	89%	8%
Providence	POINT STREET 76	12.47	76F6	518	612	412	80%	427	82%	4%	464	90%	9%
Providence	POINT STREET 76	12.47	76F7	525	612	401	76%	372	71%	-7%	415	79%	12%
Providence	POINT STREET 76	12.47	76F8	530	612	300	57%	275	52%	-8%	261	49%	-5%
Providence	ADMIRAL STREET 9	11.5	1115	9999	0	107	1%	100	1%	-6%	103	1%	3%
Providence	ADMIRAL STREET 9	11.5	1117	9999	0	50	1%	60	1%	20%	60	1%	0%
Providence	ADMIRAL STREET 9	11.5	1119	9999	0	73	1%	117	1%	60%	170	2%	46%

Study Area	Substation	Voltage (kV)	Feeder ID	Normal Rating	Emergency Rating	Load (Amps)	% SN	Load (Amps)	% SN	% Load Growth	Load (Amps)	% SN	% Load Growth
Providence	DYER STREET 2	11.5	1103	9999	0	170	2%	170	2%	0%	170	2%	0%
Providence	FRANKLIN SQUARE 11	11.5	1112	280	280	65	23%	67	24%	4%	71	25%	5%
Providence	FRANKLIN SQUARE 11	11.5	1121	363	455	96	26%	96	27%	0%	102	28%	6%
Providence	FRANKLIN SQUARE 11	11.5	1123	404	404	0	0%	0	0%	0%	0	0%	0%
Providence	FRANKLIN SQUARE 11	11.5	1125	696	834	129	18%	127	18%	-1%	105	15%	-18%
Providence	FRANKLIN SQUARE 11	11.5	1126	327	450	234	72%	238	73%	2%	237	72%	-1%
Providence	FRANKLIN SQUARE 11	11.5	1149	249	0	52	21%	200	80%	282%	93	37%	-54%
Providence	FRANKLIN SQUARE 11	11.5	1153	313	350	139	45%	146	47%	5%	142	45%	-3%
Providence	HARRIS AVENUE 12	11.5	1129	290	290	104	36%	110	38%	6%	80	28%	-27%
Providence	HARRIS AVENUE 12	11.5	1131	290	290	79	27%	60	21%	-24%	47	16%	-22%
Providence	HARRIS AVENUE 12	11.5	1133	290	290	93	32%	90	31%	-4%	90	31%	0%
Providence	HARRIS AVENUE 12	11.5	1137	290	290	203	70%	232	80%	14%	203	70%	-13%
Providence	HARRIS AVENUE 12	11.5	1145	9999	0	83	1%	100	1%	21%	80	1%	-20%
Providence	HARRIS AVENUE 12	11.5	1147	290	290	60	21%	60	21%	0%	55	19%	-9%
Providence	SOUTH STREET 1	11.5	1101	9999	0	221	2%	238	2%	8%	239	2%	0%
Providence	SOUTH STREET 1	11.5	1151	322	375	233	72%	234	73%	1%	201	63%	-14%
Providence	SOUTH STREET 1	11.5	1152	326	389	165	51%	173	53%	4%	174	53%	1%
Providence	SOUTH STREET 1	11.5	1169	9999	0	189	2%	157	2%	-17%	151	2%	-4%
Providence	SOUTH STREET 1	11.5	1171	9999	0	47	0%	43	0%	-7%	43	0%	0%
Providence	ADMIRAL STREET 9	4.16	9J1	408	472	313	77%	287	70%	-9%	353	87%	23%
Providence	ADMIRAL STREET 9	4.16	9J2	408	408	197	48%	177	43%	-10%	198	49%	12%
Providence	ADMIRAL STREET 9	4.16	9J3	255	255	140	55%	163	64%	17%	187	73%	14%
Providence	ADMIRAL STREET 9	4.16	9J5	408	408	83	20%	93	23%	12%	100	25%	7%
Providence	DYER STREET 2	4.16	2J1	408	408	272	67%	250	61%	-8%	300	74%	20%
Providence	DYER STREET 2	4.16	2J2	354	354	123	35%	117	33%	-5%	120	34%	3%
Providence	DYER STREET 2	4.16	2J3	285	313	43	15%	75	26%	73%	80	28%	7%
Providence	DYER STREET 2	4.16	2J4	297	326	130	44%	150	51%	15%	133	45%	-11%
Providence	DYER STREET 2	4.16	2J5	340	340	133	39%	80	24%	-40%	160	47%	100%
Providence	DYER STREET 2	4.16	2J7	354	354	220	62%	243	69%	11%	238	67%	-2%
Providence	DYER STREET 2	4.16	2J8	354	354	170	48%	173	49%	2%	187	53%	8%
Providence	DYER STREET 2	4.16	2J9	354	354	233	66%	212	60%	-9%	267	75%	26%
Providence	DYER STREET 2	4.16	2J10	340	340	163	48%	153	45%	-6%	153	45%	0%
Providence	EAST GEORGE ST 77	4.16	77J1	371	408	250	67%	247	66%	-1%	273	74%	11%
Providence	EAST GEORGE ST 77	4.16	77J2	364	495	283	78%	300	82%	6%	317	87%	6%
Providence	EAST GEORGE ST 77	4.16	77J3	371	385	297	80%	267	72%	-10%	327	88%	23%
Providence	EAST GEORGE ST 77	4.16	77J4	364	495	283	78%	277	76%	-2%	303	83%	10%
Providence	GENEVA 71	4.16	71J1	274	274	192	70%	184	67%	-4%	208	76%	13%
Providence	GENEVA 71	4.16	71J2	274	274	132	48%	80	29%	-39%	86	31%	7%
Providence	GENEVA 71	4.16	71J3	274	274	200	73%	205	75%	2%	166	61%	-19%
Providence	GENEVA 71	4.16	71J4	274	274	204	74%	208	76%	2%	165	60%	-21%
Providence	GENEVA 71	4.16	71J5	408	408	312	76%	272	67%	-13%	301	74%	11%
Providence	HARRIS AVENUE 12	4.16	12J1	425	425	93	22%	80	19%	-14%	93	22%	17%
Providence	HARRIS AVENUE 12	4.16	12J2	425	425	217	51%	203	48%	-6%	220	52%	8%
Providence	HARRIS AVENUE 12	4.16	12J3	425	425	0	0%	0	0%	0%	0	0%	0%
Providence	HARRIS AVENUE 12	4.16	12J4	425	425	257	60%	247	58%	-4%	310	73%	26%

Study Area	Substation	Voltage (kV)	Feeder ID	Normal Rating	Emergency Rating	Load (Amps)	% SN	Load (Amps)	% SN	% Load Growth	Load (Amps)	% SN	% Load Growth
Providence	HARRIS AVENUE 12	4.16	12J5	340	340	100	29%	100	29%	0%	120	35%	20%
Providence	HARRIS AVENUE 12	4.16	12J6	408	408	130	32%	120	29%	-8%	140	34%	17%
Providence	HUNTINGTON PARK 67	4.16	67J1	274	274	231	84%	229	84%	-1%	252	92%	10%
Providence	KNIGHTSVILLE 66	4.16	66J1	248	353	208	84%	210	85%	1%	244	98%	16%
Providence	KNIGHTSVILLE 66	4.16	66J2	315	408	260	83%	276	88%	6%	304	97%	10%
Providence	KNIGHTSVILLE 66	4.16	66J3	379	408	293	77%	236	62%	-20%	300	79%	27%
Providence	KNIGHTSVILLE 66	4.16	66J4	379	408	268	71%	236	62%	-12%	278	73%	18%
Providence	KNIGHTSVILLE 66	4.16	66J5	379	408	170	45%	208	55%	22%	164	43%	-21%
Providence	OLNEYVILLE 6	4.16	6J1	306	354	188	61%	166	54%	-12%	166	54%	0%
Providence	OLNEYVILLE 6	4.16	6J2	306	354	227	74%	221	72%	-2%	240	78%	8%
Providence	OLNEYVILLE 6	4.16	6J3	306	354	107	35%	99	32%	-7%	101	33%	3%
Providence	OLNEYVILLE 6	4.16	6J5	306	354	1	0%	1	0%	0%	1	0%	0%
Providence	OLNEYVILLE 6	4.16	6J6	306	354	100	33%	96	31%	-4%	102	33%	6%
Providence	OLNEYVILLE 6	4.16	6J7	306	354	216	71%	182	59%	-16%	221	72%	22%
Providence	OLNEYVILLE 6	4.16	6J8	306	354	87	28%	85	28%	-2%	85	28%	0%
Providence	ROCHAMBEAU AVENUE 37	4.16	37J1	329	408	196	60%	172	52%	-12%	180	55%	5%
Providence	ROCHAMBEAU AVENUE 37	4.16	37J2	291	349	220	76%	184	63%	-16%	197	68%	7%
Providence	ROCHAMBEAU AVENUE 37	4.16	37J3	303	408	250	83%	223	74%	-11%	243	80%	9%
Providence	ROCHAMBEAU AVENUE 37	4.16	37J4	278	371	228	82%	190	68%	-17%	244	88%	28%
Providence	ROCHAMBEAU AVENUE 37	4.16	37J5	347	408	272	78%	307	88%	13%	244	70%	-20%
Providence	SPRAGUE STREET 36	4.16	36J1	236	283	163	69%	157	66%	-4%	157	66%	0%
Providence	SPRAGUE STREET 36	4.16	36J2	252	299	190	75%	183	73%	-4%	200	79%	9%
Providence	SPRAGUE STREET 36	4.16	36J4	344	405	200	58%	225	65%	13%	193	56%	-14%
Providence	SPRAGUE STREET 36	4.16	36J5	315	315	242	77%	227	72%	-6%	253	80%	12%
South County East	BONNET 42	12.47	42F1	525	566	468	89%	392	75%	-16%	431	82%	10%
South County East	LAFAYETTE 30	12.47	30F1	350	398	237	68%	204	58%	-14%	250	71%	22%
South County East	LAFAYETTE 30	12.47	30F2	530	612	416	78%	345	65%	-17%	373	70%	8%
South County East	OLD BAPTIST ROAD 46	12.47	46F1	530	612	383	72%	345	65%	-10%	382	72%	11%
South County East	OLD BAPTIST ROAD 46	12.47	46F2	530	612	341	64%	276	52%	-19%	277	52%	1%
South County East	OLD BAPTIST ROAD 46	12.47	46F3	565	612	329	58%	309	55%	-6%	346	61%	12%
South County East	OLD BAPTIST ROAD 46	12.47	46F4	594	612	490	83%	457	77%	-7%	492	83%	8%
South County East	PEACEDALE 59	12.47	59F1	409	489	150	37%	134	33%	-11%	142	35%	6%
South County East	PEACEDALE 59	12.47	59F2	492	515	297	60%	263	53%	-11%	285	58%	8%
South County East	PEACEDALE 59	12.47	59F3	492	650	434	88%	372	76%	-14%	426	87%	15%
South County East	PEACEDALE 59	12.47	59F4	425	515	173	41%	159	37%	-8%	193	45%	21%
South County East	QUONSET 83	12.47	83F1	645	645	150	23%	126	20%	-16%	102	16%	-19%
South County East	QUONSET 83	12.47	83F2	490	650	282	58%	304	62%	8%	286	58%	-6%
South County East	QUONSET 83	12.47	83F3	645	645	240	37%	280	43%	16%	0	0%	-100%
South County East	WAKEFIELD 17	12.47	17F1	602	612	428	71%	387	64%	-10%	403	67%	4%
South County East	WAKEFIELD 17	12.47	17F2	510	510	461	90%	425	83%	-8%	456	89%	7%
South County East	WAKEFIELD 17	12.47	17F3	597	626	443	74%	417	70%	-6%	447	75%	7%
South County East	TOWER HILL 88	12.47	88F1	530	650	370	70%	349	66%	-6%	377	71%	8%
South County East	TOWER HILL 88	12.47	88F3	550	645	403	73%	358	65%	-11%	371	68%	4%
South County East	TOWER HILL 88	12.47	88F5	530	650	373	70%	350	66%	-6%	368	69%	5%
South County East	TOWER HILL 88	12.47	88F7	530	650	367	69%	318	60%	-13%	351	66%	10%

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South County East	QUONSET 83	12.47	83F4	600	600	0	0%	0	0%	0%	264	44%	0%
South County West	ASHAWAY 43	12.47	43F1	388	423	339	87%	311	80%	-8%	0	0%	-100%
South County West	HOPE VALLEY 41	12.47	41F1	347	430	297	86%	271	78%	-9%	0	0%	-100%
South County West	KENYON 68	12.47	68F1	512	612	352	69%	309	60%	-12%	328	64%	6%
South County West	KENYON 68	12.47	68F2	511	612	456	89%	392	77%	-14%	444	87%	13%
South County West	KENYON 68	12.47	68F3	512	515	379	74%	323	63%	-15%	341	67%	5%
South County West	KENYON 68	12.47	68F4	514	612	294	57%	268	52%	-9%	288	56%	7%
South County West	KENYON 68	12.47	68F5	612	612	184	30%	179	29%	-3%	190	31%	6%
South County West	LANGWORTHY 86	12.47	86F1	600	612	525	88%	498	83%	-5%	495	83%	-1%
South County West	WESTERLY 16	12.47	16F1	515	515	450	87%	403	78%	-10%	445	86%	11%
South County West	WESTERLY 16	12.47	16F2	515	515	431	84%	496	96%	15%	438	85%	-12%
South County West	WESTERLY 16	12.47	16F3	515	515	398	77%	374	73%	-6%	419	81%	12%
South County West	WESTERLY 16	12.47	16F4	645	645	264	41%	245	38%	-7%	271	42%	11%
South County West	CHASE HILL	12.47	155F2	530	650	0	0%	0	0%	0%	289	55%	0%
South County West	CHASE HILL	12.47	155F4	530	650	0	0%	0	0%	0%	269	51%	0%
South County West	CHASE HILL	12.47	155F6	530	650	0	0%	0	0%	0%	268	50%	0%
South County West	CHASE HILL	12.47	155F8	530	612	0	0%	0	0%	0%	247	47%	0%
TIVERTON	TIVERTON	12.47	33F1	478	515	298	62%	252	53%	-15%	407	85%	61%
TIVERTON	TIVERTON	12.47	33F2	456	515	355	78%	346	76%	-3%	381	84%	10%
TIVERTON	TIVERTON	12.47	33F3	478	600	390	82%	337	71%	-14%	335	70%	-1%
TIVERTON	TIVERTON	12.47	33F4	456	576	463	102%	375	82%	-19%	416	91%	11%

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				Normal Rating	Emergency Rating	Projected Load (Amps)	%SN	Growth Rate	Projected Load (Amps)	%SN	Growth Rate	Projected Load (Amps)	%SN	Growth Rate
Blackstone Valley North	FARNUM	23	105K1	515	515	46	9%	15.0%	46	9%	-0.2%	46	9%	-0.2%
Blackstone Valley North	NASONVILLE	13.8	127W40	484	515	363	75%	15.0%	363	75%	-0.2%	362	75%	-0.2%
Blackstone Valley North	NASONVILLE	13.8	127W41	515	515	422	82%	15.0%	421	82%	-0.2%	420	82%	-0.2%
Blackstone Valley North	NASONVILLE	13.8	127W42	459	515	0	0%	15.0%	0	0%	-0.2%	0	0%	-0.2%
Blackstone Valley North	NASONVILLE	13.8	127W43	559	585	627	112%	15.0%	597	107%	2.0%	609	109%	2.0%
Blackstone Valley North	RIVERSIDE 8	13.8	108W51	499	631	358	72%	15.0%	357	72%	-0.2%	356	71%	-0.2%
Blackstone Valley North	RIVERSIDE 8	13.8	108W53	499	631	464	93%	15.0%	463	93%	-0.2%	462	93%	-0.2%
Blackstone Valley North	RIVERSIDE 8	13.8	108W55	474	474	472	100%	15.0%	116	24%	-0.2%	116	24%	-0.2%
Blackstone Valley North	RIVERSIDE 8	13.8	108W60	515	515	256	50%	15.0%	255	50%	-0.2%	255	49%	-0.2%
Blackstone Valley North	RIVERSIDE 8	13.8	108W61	500	500	204	41%	15.0%	204	41%	-0.2%	203	41%	-0.2%
Blackstone Valley North	RIVERSIDE 8	13.8	108W62	515	515	132	26%	15.0%	132	26%	-0.2%	131	26%	-0.2%
Blackstone Valley North	RIVERSIDE 8	13.8	108W63	515	515	575	112%	15.0%	254	49%	-0.2%	254	49%	-0.2%
Blackstone Valley North	RIVERSIDE 8	13.8	108W65	515	515	343	67%	15.0%	342	66%	-0.2%	342	66%	-0.2%
Blackstone Valley North	STAPLES 112	13.8	112W41	515	515	191	37%	15.0%	105	20%	-0.2%	104	20%	-0.2%
Blackstone Valley North	STAPLES 112	13.8	112W42	500	599	378	76%	15.0%	378	76%	-0.2%	377	75%	-0.2%
Blackstone Valley North	STAPLES 112	13.8	112W43	515	515	159	31%	15.0%	158	31%	-0.2%	158	31%	-0.2%
Blackstone Valley North	STAPLES 112	13.8	112W44	406	484	372	92%	15.0%	371	91%	-0.2%	370	91%	-0.2%
Blackstone Valley North	WEST FARNUM #17	13.8	17W42	0	0	0	0%	15.0%	0	0%	-0.2%	0	0%	-0.2%
Blackstone Valley North	WEST FARNUM #17	13.8	17W43	0	0	0	0%	15.0%	0	0%	-0.2%	0	0%	-0.2%
Blackstone Valley North	HIGHLAND PARK #200	13.8	200W1	465	570	94	20%	15.0%	93	20%	-0.2%	93	20%	-0.2%
Blackstone Valley North	HIGHLAND PARK #200	13.8	200W2	530	705	276	52%	15.0%	275	52%	-0.2%	275	52%	-0.2%
Blackstone Valley North	HIGHLAND PARK #200	13.8	200W3	530	705	252	48%	15.0%	251	47%	-0.2%	251	47%	-0.2%
Blackstone Valley North	HIGHLAND PARK #200	13.8	200W4	530	705	38	7%	15.0%	38	7%	-0.2%	38	7%	-0.2%
Blackstone Valley North	HIGHLAND PARK #200	13.8	200W5	530	650	0	0%	15.0%	355	67%	-0.2%	354	67%	-0.2%
Blackstone Valley North	HIGHLAND PARK #200	13.8	200W6	515	515	0	0%	15.0%	405	79%	-0.2%	404	78%	-0.2%
Blackstone Valley North	WOONSOCKET	13.8	26W1	505	515	233	46%	15.0%	233	46%	-0.2%	232	46%	-0.2%
Blackstone Valley North	WOONSOCKET	13.8	26W3	507	612	384	76%	15.0%	383	76%	-0.2%	382	75%	-0.2%
Blackstone Valley North	WOONSOCKET	13.8	26W5	513	612	317	62%	15.0%	317	62%	-0.2%	316	62%	-0.2%
Blackstone Valley North	WOONSOCKET	13.8	26W7	515	515	269	52%	15.0%	269	52%	-0.2%	268	52%	-0.2%
Blackstone Valley South	VALLEY SUB	23	102K22	9999	9999	76	1%	15.0%	76	1%	-0.2%	76	1%	-0.2%
Blackstone Valley South	PAWTUCKET #1	13.8	107W1	9999	9999	59	1%	15.0%	59	1%	-0.2%	58	1%	-0.2%
Blackstone Valley South	PAWTUCKET #1	13.8	107W2	9999	9999	36	0%	15.0%	36	0%	-0.2%	36	0%	-0.2%
Blackstone Valley South	PAWTUCKET #1	13.8	107W3	9999	9999	48	0%	15.0%	48	0%	-0.2%	48	0%	-0.2%
Blackstone Valley South	PAWTUCKET #1	13.8	107W43	365	365	331	91%	15.0%	331	91%	-0.2%	330	90%	-0.2%
Blackstone Valley South	PAWTUCKET #1	13.8	107W49	202	250	148	73%	15.0%	148	73%	-0.2%	148	73%	-0.2%
Blackstone Valley South	PAWTUCKET #1	13.8	107W50	356	365	329	93%	15.0%	329	92%	-0.2%	328	92%	-0.2%
Blackstone Valley South	PAWTUCKET #1	13.8	107W51	365	365	276	76%	15.0%	275	75%	-0.2%	275	75%	-0.2%
Blackstone Valley South	PAWTUCKET #1	13.8	107W53	407	540	212	52%	15.0%	249	61%	-0.2%	249	61%	-0.2%
Blackstone Valley South	PAWTUCKET #1	13.8	107W60	334	449	327	98%	15.0%	327	98%	-0.2%	326	98%	-0.2%
Blackstone Valley South	PAWTUCKET #1	13.8	107W61	343	411	379	111%	15.0%	379	110%	-0.2%	378	110%	-0.2%
Blackstone Valley South	PAWTUCKET #1	13.8	107W62	480	480	329	69%	15.0%	328	68%	-0.2%	328	68%	-0.2%
Blackstone Valley South	PAWTUCKET #1	13.8	107W63	515	515	290	56%	15.0%	290	56%	-0.2%	289	56%	-0.2%
Blackstone Valley South	PAWTUCKET #1	13.8	107W65	345	360	319	92%	15.0%	252	73%	-0.2%	251	73%	-0.2%
Blackstone Valley South	PAWTUCKET #1	13.8	107W66	360	360	179	50%	15.0%	179	50%	-0.2%	179	50%	-0.2%
Blackstone Valley South	PAWTUCKET #1	13.8	107W80	285	365	264	93%	15.0%	264	93%	-0.2%	263	92%	-0.2%
Blackstone Valley South	PAWTUCKET #1	13.8	107W81	368	540	399	108%	15.0%	398	108%	-0.2%	397	108%	-0.2%
Blackstone Valley South	PAWTUCKET #1	13.8	107W83	346	540	289	83%	15.0%	288	83%	-0.2%	287	83%	-0.2%
Blackstone Valley South	PAWTUCKET #1	13.8	107W84	332	365	204	61%	15.0%	231	70%	-0.2%	231	69%	-0.2%
Blackstone Valley South	PAWTUCKET #1	13.8	107W85	305	365	235	77%	15.0%	234	77%	-0.2%	234	77%	-0.2%
Blackstone Valley South	VALLEY	13.8	102W41	493	515	281	57%	15.0%	280	57%	-0.2%	280	57%	-0.2%
Blackstone Valley South	VALLEY	13.8	102W42	463	515	366	79%	15.0%	365	79%	-0.2%	364	79%	-0.2%
Blackstone Valley South	VALLEY	13.8	102W44	328	460	277	85%	15.0%	277	84%	-0.2%	276	84%	-0.2%
Blackstone Valley South	VALLEY	13.8	102W50	364	375	54	15%	15.0%	54	15%	-0.2%	54	15%	-0.2%
Blackstone Valley South	VALLEY	13.8	102W51	341	497	293	86%	15.0%	293	86%	-0.2%	292	86%	-0.2%
Blackstone Valley South	VALLEY	13.8	102W52	300	365	280	93%	15.0%	279	93%	-0.2%	279	93%	-0.2%

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Blackstone Valley South	VALLEY	13.8	102W54	292	413	240	82%	15.0%	240	82%	-0.2%	239	82%	-0.2%
Blackstone Valley South	WASHINGTON	13.8	126W40	515	645	253	49%	15.0%	252	49%	-0.2%	252	49%	-0.2%
Blackstone Valley South	WASHINGTON	13.8	126W41	520	535	443	85%	15.0%	442	85%	-0.2%	441	85%	-0.2%
Blackstone Valley South	WASHINGTON	13.8	126W42	525	600	437	83%	15.0%	436	83%	-0.2%	435	83%	-0.2%
Blackstone Valley South	WASHINGTON	13.8	126W50	528	645	515	97%	15.0%	514	97%	-0.2%	513	97%	-0.2%
Blackstone Valley South	WASHINGTON	13.8	126W51	515	515	509	99%	15.0%	508	99%	-0.2%	507	99%	-0.2%
Blackstone Valley South	WASHINGTON	13.8	126W53	583	750	33	6%	15.0%	33	6%	-0.2%	33	6%	-0.2%
Blackstone Valley South	WASHINGTON	13.8	126W54	530	645	419	79%	15.0%	418	79%	-0.2%	418	79%	-0.2%
Blackstone Valley South	CENTRAL FALLS	4.16	104J1	350	350	288	82%	15.0%	287	82%	-0.2%	287	82%	-0.2%
Blackstone Valley South	CENTRAL FALLS	4.16	104J3	350	350	0	0%	15.0%	0	0%	-0.2%	0	0%	-0.2%
Blackstone Valley South	CENTRAL FALLS	4.16	104J5	350	350	0	0%	15.0%	0	0%	-0.2%	0	0%	-0.2%
Blackstone Valley South	CENTRAL FALLS	4.16	104J7	350	350	206	59%	15.0%	205	59%	-0.2%	205	59%	-0.2%
Blackstone Valley South	CENTRE ST	4.16	106J1	350	350	115	33%	15.0%	114	33%	-0.2%	114	33%	-0.2%
Blackstone Valley South	CENTRE ST	4.16	106J3	350	350	182	52%	15.0%	181	52%	-0.2%	181	52%	-0.2%
Blackstone Valley South	CENTRE ST	4.16	106J7	350	350	32	9%	15.0%	32	9%	-0.2%	32	9%	-0.2%
Blackstone Valley South	COTTAGE STREET	4.16	109J1	408	408	376	92%	15.0%	375	92%	-0.2%	375	92%	-0.2%
Blackstone Valley South	COTTAGE STREET	4.16	109J3	408	408	274	67%	15.0%	274	67%	-0.2%	273	67%	-0.2%
Blackstone Valley South	COTTAGE STREET	4.16	109J5	408	408	375	92%	15.0%	374	92%	-0.2%	374	92%	-0.2%
Blackstone Valley South	CROSSMAN STREET	4.16	111J1	340	340	284	84%	15.0%	284	83%	-0.2%	283	83%	-0.2%
Blackstone Valley South	CROSSMAN STREET	4.16	111J3	340	340	230	68%	15.0%	230	68%	-0.2%	229	67%	-0.2%
Blackstone Valley South	DAGGETT	4.16	113J1	390	390	277	71%	15.0%	0	0%	-0.2%	0	0%	-0.2%
Blackstone Valley South	DAGGETT	4.16	113J2	390	390	278	71%	15.0%	0	0%	-0.2%	0	0%	-0.2%
Blackstone Valley South	FRONT ST	4.16	24J1	400	400	219	55%	15.0%	218	55%	-0.2%	218	54%	-0.2%
Blackstone Valley South	HYDE	4.16	28J1	400	400	185	46%	15.0%	0	0%	-0.2%	0	0%	-0.2%
Blackstone Valley South	HYDE	4.16	28J2	400	400	287	72%	15.0%	0	0%	-0.2%	0	0%	-0.2%
Blackstone Valley South	LEE STREET	4.16	30J1	380	380	263	69%	15.0%	263	69%	-0.2%	262	69%	-0.2%
Blackstone Valley South	LEE STREET	4.16	30J3	380	380	299	79%	15.0%	298	78%	-0.2%	297	78%	-0.2%
Blackstone Valley South	LEE STREET	4.16	30J5	380	380	312	82%	15.0%	312	82%	-0.2%	311	82%	-0.2%
Blackstone Valley South	PAWTUCKET #2	4.16	148J1	370	370	281	76%	15.0%	280	76%	-0.2%	280	76%	-0.2%
Blackstone Valley South	PAWTUCKET #2	4.16	148J3	290	290	195	67%	15.0%	195	67%	-0.2%	194	67%	-0.2%
Blackstone Valley South	PAWTUCKET #2	4.16	148J5	370	370	264	71%	15.0%	264	71%	-0.2%	263	71%	-0.2%
Blackstone Valley South	PAWTUCKET #2	4.16	148J7	370	370	242	65%	15.0%	241	65%	-0.2%	241	65%	-0.2%
Blackstone Valley South	SOUTHEAST	4.16	60J1	408	408	128	31%	15.0%	0	0%	-0.2%	0	0%	-0.2%
Blackstone Valley South	SOUTHEAST	4.16	60J3	408	408	143	35%	15.0%	0	0%	-0.2%	0	0%	-0.2%
Blackstone Valley South	SOUTHEAST	4.16	60J5	380	380	92	24%	15.0%	0	0%	-0.2%	0	0%	-0.2%
Central RI East	APPONAUG 3	12.47	3F1	526	612	374	71%	15.5%	375	71%	0.3%	376	71%	0.2%
Central RI East	APPONAUG 3	12.47	3F2	515	515	318	62%	15.5%	379	74%	0.3%	380	74%	0.2%
Central RI East	DRUMROCK 14	12.47	14F1	530	612	420	79%	15.5%	312	59%	0.3%	312	59%	0.2%
Central RI East	DRUMROCK 14	12.47	14F2	530	595	513	97%	15.5%	385	73%	0.3%	386	73%	0.2%
Central RI East	DRUMROCK 14	12.47	14F3	515	515	423	82%	15.5%	319	62%	0.3%	319	62%	0.2%
Central RI East	DRUMROCK 14	12.47	14F4	515	515	418	81%	15.5%	266	52%	0.3%	267	52%	0.2%
Central RI East	KILVERT STREET 87	12.47	87F1	574	645	410	71%	15.5%	411	72%	0.3%	412	72%	0.2%
Central RI East	KILVERT STREET 87	12.47	87F2	570	662	389	68%	15.5%	350	61%	0.3%	351	62%	0.2%
Central RI East	KILVERT STREET 87	12.47	87F3	530	645	302	57%	15.5%	328	62%	0.3%	328	62%	0.2%
Central RI East	KILVERT STREET 87	12.47	87F4	530	650	313	59%	15.5%	314	59%	0.3%	315	59%	0.2%
Central RI East	KILVERT STREET 87	12.47	87F5	530	650	0	0%	0.0%	335	63%	0.3%	336	63%	0.2%
Central RI East	KILVERT STREET 87	12.47	87F6	530	650	0	0%	0.0%	310	58%	0.3%	310	59%	0.2%
Central RI East	LINCOLN AVENUE 72	12.47	72F1	530	650	401	76%	15.5%	273	51%	0.3%	273	52%	0.2%
Central RI East	LINCOLN AVENUE 72	12.47	72F2	530	650	362	68%	15.5%	363	69%	0.3%	364	69%	0.2%
Central RI East	LINCOLN AVENUE 72	12.47	72F3	530	650	465	88%	15.5%	467	88%	0.3%	468	88%	0.2%
Central RI East	LINCOLN AVENUE 72	12.47	72F4	530	650	433	82%	15.5%	374	71%	0.3%	375	71%	0.2%
Central RI East	LINCOLN AVENUE 72	12.47	72F5	515	515	448	87%	15.5%	400	78%	0.3%	400	78%	0.2%
Central RI East	LINCOLN AVENUE 72	12.47	72F6	567	645	458	81%	15.5%	460	81%	0.3%	461	81%	0.2%
Central RI East	PONTIAC 27	12.47	27F1	530	650	376	71%	15.5%	378	71%	0.3%	378	71%	0.2%
Central RI East	PONTIAC 27	12.47	27F2	530	650	529	100%	15.5%	430	81%	0.3%	431	81%	0.2%

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Central RI East	PONTIAC 27	12.47	27F3	460	515	168	37%	15.5%	169	37%	0.3%	169	37%	0.2%
Central RI East	PONTIAC 27	12.47	27F4	460	515	413	90%	15.5%	414	90%	0.3%	415	90%	0.2%
Central RI East	PONTIAC 27	12.47	27F5	530	650	474	89%	15.5%	475	90%	0.3%	476	90%	0.2%
Central RI East	PONTIAC 27	12.47	27F6	530	645	246	46%	15.5%	247	47%	0.3%	247	47%	0.2%
Central RI East	WARWICK 52	12.47	52F1	485	490	248	51%	15.5%	239	49%	0.3%	239	49%	0.2%
Central RI East	WARWICK 52	12.47	52F2	485	490	211	43%	15.5%	111	23%	0.3%	111	23%	0.2%
Central RI East	WARWICK 52	12.47	52F3	526	560	375	71%	15.5%	376	72%	0.3%	377	72%	0.2%
Central RI East	AUBURN 73	4.16	73J1	369	408	144	39%	15.5%	145	39%	0.3%	145	39%	0.2%
Central RI East	AUBURN 73	4.16	73J2	385	385	139	36%	15.5%	139	36%	0.3%	139	36%	0.2%
Central RI East	AUBURN 73	4.16	73J3	385	385	314	82%	15.5%	315	82%	0.3%	316	82%	0.2%
Central RI East	AUBURN 73	4.16	73J4	385	385	175	46%	15.5%	176	46%	0.3%	176	46%	0.2%
Central RI East	AUBURN 73	4.16	73J5	408	408	314	77%	15.5%	315	77%	0.3%	316	77%	0.2%
Central RI East	AUBURN 73	4.16	73J6	381	408	208	55%	15.5%	208	55%	0.3%	209	55%	0.2%
Central RI East	LAKEWOOD 57	4.16	57J1	369	441	157	43%	15.5%	157	43%	0.3%	158	43%	0.2%
Central RI East	LAKEWOOD 57	4.16	57J2	452	556	289	64%	15.5%	289	64%	0.3%	290	64%	0.2%
Central RI East	LAKEWOOD 57	4.16	57J3	408	408	349	85%	15.5%	350	86%	0.3%	350	86%	0.2%
Central RI East	LAKEWOOD 57	4.16	57J5	492	510	323	66%	15.5%	324	66%	0.3%	325	66%	0.2%
Central RI West	ANTHONY	12.47	64F1	361	374	226	62%	15.5%	226	63%	0.3%	227	63%	0.2%
Central RI West	ANTHONY	12.47	64F2	361	374	333	92%	15.5%	184	51%	0.3%	184	51%	0.2%
Central RI West	COVENTRY	12.47	54F1	526	560	419	80%	15.5%	420	80%	0.3%	421	80%	0.2%
Central RI West	DIVISION ST	12.47	61F1	450	515	361	80%	15.5%	362	80%	0.3%	362	81%	0.2%
Central RI West	DIVISION ST	12.47	61F2	450	667	282	63%	15.5%	283	63%	0.3%	283	63%	0.2%
Central RI West	DIVISION ST	12.47	61F3	450	476	368	82%	15.5%	369	82%	0.3%	370	82%	0.2%
Central RI West	DIVISION ST	12.47	61F4	450	645	374	83%	15.5%	244	54%	0.3%	245	54%	0.2%
Central RI West	HOPE	12.47	15F1	348	394	317	91%	15.5%	193	56%	0.3%	194	56%	0.2%
Central RI West	HOPE	12.47	15F2	476	476	429	90%	15.5%	355	75%	0.3%	356	75%	0.2%
Central RI West	HOPKINS HILL	12.47	63F1	538	650	249	46%	15.5%	250	46%	0.3%	251	47%	0.2%
Central RI West	HOPKINS HILL	12.47	63F2	530	650	376	71%	15.5%	302	57%	0.3%	302	57%	0.2%
Central RI West	HOPKINS HILL	12.47	63F3	530	650	292	55%	15.5%	293	55%	0.3%	294	55%	0.2%
Central RI West	HOPKINS HILL	12.47	63F4	530	650	388	73%	15.5%	389	73%	0.3%	390	74%	0.2%
Central RI West	HOPKINS HILL	12.47	63F5	530	650	448	85%	15.5%	379	71%	0.3%	379	72%	0.2%
Central RI West	HOPKINS HILL	12.47	63F6	530	650	436	82%	15.5%	437	83%	0.3%	438	83%	0.2%
Central RI West	HUNT RIVER	12.47	40F1	274	327	0	0%	0.0%	0	0%	0.0%	0	0%	0.0%
Central RI West	KENT COUNTY	12.47	22F1	530	650	392	74%	15.5%	393	74%	0.3%	394	74%	0.2%
Central RI West	KENT COUNTY	12.47	22F2	530	650	386	73%	15.5%	387	73%	0.3%	388	73%	0.2%
Central RI West	KENT COUNTY	12.47	22F3	530	650	443	84%	15.5%	311	59%	0.3%	312	59%	0.2%
Central RI West	KENT COUNTY	12.47	22F4	586	662	327	56%	15.5%	328	56%	0.3%	329	56%	0.2%
Central RI West	KENT COUNTY	12.47	22F6	530	650	402	76%	empty:	403	76%	0.3%	404	76%	0.2%
Central RI West	NATICK	12.47	29F1	385	385	373	97%	15.5%	292	76%	0.3%	292	76%	0.2%
Central RI West	NATICK	12.47	29F2	409	489	282	69%	15.5%	313	77%	0.3%	314	77%	0.2%
Central RI West	WARWICK MALL	12.47	28F1	390	412	145	37%	15.5%	146	37%	0.3%	146	37%	0.2%
Central RI West	WARWICK MALL	12.47	28F2	390	422	94	24%	15.5%	95	24%	0.3%	95	24%	0.2%
Central RI West	ARCTIC	4.16	49J1	295	352	252	85%	15.5%	0	0%	0.3%	0	0%	0.2%
Central RI West	ARCTIC	4.16	49J2	295	352	162	55%	15.5%	0	0%	0.3%	0	0%	0.2%
Central RI West	ARCTIC	4.16	49J3	295	315	214	73%	15.5%	0	0%	0.3%	0	0%	0.2%
Central RI West	ARCTIC	4.16	49J4	295	352	262	89%	15.5%	0	0%	0.3%	0	0%	0.2%
Central RI West	TIOGUE AVE	12.47	100F1	570	612	495	87%	15.5%	497	87%	0.3%	498	87%	0.2%
Central RI West	NEW LONDON AVE	12.47	150F1	0	0	0	0%	0.0%	342	53%	0.3%	342	53%	0.2%
Central RI West	NEW LONDON AVE	12.47	150F3	0	0	0	0%	0.0%	301	57%	0.3%	301	57%	0.2%
Central RI West	NEW LONDON AVE	12.47	150F5	0	0	0	0%	0.0%	342	64%	0.3%	342	65%	0.2%
Central RI West	NEW LONDON AVE	12.47	150F7	0	0	0	0%	0.0%	383	59%	0.3%	383	59%	0.2%
East Bay	BARRINGTON 4	12.47	4F1	515	515	301	58%	15.6%	302	59%	0.3%	303	59%	0.2%
East Bay	BARRINGTON 4	12.47	4F2	510	510	416	82%	15.6%	417	82%	0.3%	418	82%	0.2%
East Bay	BRISTOL 51A	12.47	51F1	645	645	482	75%	15.6%	483	75%	0.3%	484	75%	0.2%
East Bay	BRISTOL 51A	12.47	51F2	530	612	482	91%	15.6%	484	91%	0.3%	485	91%	0.2%

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East Bay	BRISTOL 51A	12.47	51F3	502	567	406	81%	15.6%	407	81%	0.3%	408	81%	0.2%
East Bay	PHILLIPSDALE 20	12.47	20F1	425	450	349	82%	15.6%	350	82%	0.3%	351	83%	0.2%
East Bay	PHILLIPSDALE 20	12.47	20F2	425	450	322	76%	15.6%	323	76%	0.3%	323	76%	0.2%
East Bay	WAMPANOAG 48	12.47	48F1	502	507	428	85%	15.6%	429	85%	0.3%	430	86%	0.2%
East Bay	WAMPANOAG 48	12.47	48F2	515	515	430	83%	15.6%	431	84%	0.3%	432	84%	0.2%
East Bay	WAMPANOAG 48	12.47	48F3	510	515	476	**93%**	15.6%	478	**94%**	0.3%	479	**94%**	0.2%
East Bay	WAMPANOAG 48	12.47	48F4	530	612	520	**98%**	15.6%	522	**98%**	0.3%	523	**99%**	0.2%
East Bay	WAMPANOAG 48	12.47	48F5	485	490	442	**91%**	15.6%	443	**91%**	0.3%	444	**92%**	0.2%
East Bay	WAMPANOAG 48	12.47	48F6	530	612	425	80%	15.6%	427	80%	0.3%	427	81%	0.2%
East Bay	WARREN 5	12.47	5F1	425	520	354	83%	15.6%	355	84%	0.3%	356	84%	0.2%
East Bay	WARREN 5	12.47	5F2	434	434	387	89%	15.6%	388	89%	0.3%	389	90%	0.2%
East Bay	WARREN 5	12.47	5F3	515	515	384	75%	15.6%	385	75%	0.3%	386	75%	0.2%
East Bay	WARREN 5	12.47	5F4	510	510	394	77%	15.6%	396	78%	0.3%	396	78%	0.2%
East Bay	WATERMAN AVENUE 78	12.47	78F3	409	489	241	59%	15.6%	241	59%	0.3%	242	59%	0.2%
East Bay	WATERMAN AVENUE 78	12.47	78F4	409	489	232	57%	15.6%	232	57%	0.3%	233	57%	0.2%
East Bay	KENT CORNERS 47	4.16	47J1	408	408	0	0%	15.6%	0	0%	0.3%	0	0%	0.2%
East Bay	KENT CORNERS 47	4.16	47J2	408	408	282	69%	15.6%	283	69%	0.3%	283	69%	0.2%
East Bay	KENT CORNERS 47	4.16	47J3	408	408	268	66%	15.6%	269	66%	0.3%	269	66%	0.2%
East Bay	KENT CORNERS 47	4.16	47J4	408	408	374	**92%**	15.6%	376	**92%**	0.3%	376	**92%**	0.2%
East Bay	EAST PROVIDENCE SUB	12.47	F1	0	0	0	0%	0.0%	0	0%	0.0%	0	0%	0.0%
East Bay	EAST PROVIDENCE SUB	12.47	F2	0	0	0	0%	0.0%	0	0%	0.0%	0	0%	0.0%
East Bay	EAST PROVIDENCE SUB	12.47	F3	0	0	0	0%	0.0%	0	0%	0.0%	0	0%	0.0%
East Bay	EAST PROVIDENCE SUB	12.47	F4	0	0	0	0%	0.0%	0	0%	0.0%	0	0%	0.0%
East Bay	WARREN 5	12.47	5F5	0	0	0	0%	0.0%	0	0%	0.0%	0	0%	0.0%
East Bay	WARREN 5	12.47	5F6	0	0	0	0%	0.0%	0	0%	0.0%	0	0%	0.0%
East Bay	PHILLIPSDALE 20	12.47	F1	0	0	0	0%	0.0%	0	0%	0.0%	0	0%	0.0%
East Bay	PHILLIPSDALE 20	12.47	F2	0	0	0	0%	0.0%	0	0%	0.0%	0	0%	0.0%
East Bay	PHILLIPSDALE 20	12.47	F3	0	0	0	0%	0.0%	0	0%	0.0%	0	0%	0.0%
East Bay	PHILLIPSDALE 20	12.47	F4	0	0	0	0%	0.0%	0	0%	0.0%	0	0%	0.0%
East Bay	BRISTOL 51A	12.47	51F4	0	0	0	0%	0.0%	0	0%	0.0%	0	0%	0.0%
Newport	DEXTER	13.8	36W41	464	566	315	68%	14.6%	313	67%	-0.7%	311	67%	-0.8%
Newport	DEXTER	13.8	36W42	464	515	226	49%	14.6%	224	48%	-0.7%	222	48%	-0.8%
Newport	DEXTER	13.8	36W43	464	566	154	33%	14.6%	153	33%	-0.7%	151	33%	-0.8%
Newport	DEXTER	13.8	36W44	464	566	313	67%	14.6%	311	67%	-0.7%	308	66%	-0.8%
Newport	JEPSON	13.8	37W41	560	560	340	61%	14.6%	338	60%	-0.7%	335	60%	-0.8%
Newport	JEPSON	13.8	37W42	560	560	385	69%	14.6%	382	68%	-0.7%	379	68%	-0.8%
Newport	JEPSON	13.8	37W43	560	560	295	53%	14.6%	293	52%	-0.7%	290	52%	-0.8%
Newport	BAILEY BROOK	4.16	19J2	447	476	220	49%	14.6%	219	49%	-0.7%	217	49%	-0.8%
Newport	BAILEY BROOK	4.16	19J14	476	476	265	56%	14.6%	263	55%	-0.7%	261	55%	-0.8%
Newport	BAILEY BROOK	4.16	19J16	476	476	0	0%	14.6%	0	0%	-0.7%	0	0%	-0.8%
Newport	CLARKE STREET	4.16	65J2	570	595	415	73%	14.6%	413	72%	-0.7%	409	72%	-0.8%
Newport	CLARKE STREET	4.16	65J12	575	575	382	67%	14.6%	380	66%	-0.7%	377	66%	-0.8%
Newport	ELDRED	4.16	45J3	560	668	483	86%	14.6%	480	86%	-0.7%	476	85%	-0.8%
Newport	ELDRED	4.16	45J4	560	668	328	59%	14.6%	326	58%	-0.7%	323	58%	-0.8%
Newport	ELDRED	4.16	45J6	448	476	0	0%	0.0%	0	0%	0.0%	0	0%	0.0%
Newport	GATE 2	4.16	38J2	440	476	289	66%	14.6%	287	65%	-0.7%	285	65%	-0.8%
Newport	GATE 2	4.16	38J4	440	476	202	46%	14.6%	200	46%	-0.7%	199	45%	-0.8%
Newport	HARRISON	4.16	32J2	350	420	284	81%	14.6%	282	81%	-0.7%	280	80%	-0.8%
Newport	HARRISON	4.16	32J4	300	380	149	50%	14.6%	148	49%	-0.7%	146	49%	-0.8%
Newport	HARRISON	4.16	32J12	372	380	325	87%	14.6%	323	87%	-0.7%	320	86%	-0.8%
Newport	HARRISON	4.16	32J14	366	500	327	89%	14.6%	325	89%	-0.7%	322	88%	-0.8%
Newport	HOSPITAL	4.16	146J2	300	357	71	24%	14.6%	71	24%	-0.7%	70	23%	-0.8%
Newport	HOSPITAL	4.16	146J4	434	434	201	46%	14.6%	199	46%	-0.7%	198	46%	-0.8%
Newport	HOSPITAL	4.16	146J12	434	434	149	34%	14.6%	148	34%	-0.7%	147	34%	-0.8%
Newport	HOSPITAL	4.16	146J14	307	365	149	49%	14.6%	148	48%	-0.7%	147	48%	-0.8%

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Newport	JEPSON	4.16	37J2	380	380	77	20%	14.6%	77	20%	-0.7%	76	20%	-0.8%
Newport	JEPSON	4.16	37J4	380	380	227	60%	14.6%	226	59%	-0.7%	224	59%	-0.8%
Newport	KINGSTON	4.16	131J2	397	510	320	81%	14.6%	318	80%	-0.7%	315	79%	-0.8%
Newport	KINGSTON	4.16	131J4	510	510	329	65%	14.6%	327	64%	-0.7%	324	64%	-0.8%
Newport	KINGSTON	4.16	131J6	380	380	160	42%	14.6%	159	42%	-0.7%	158	42%	-0.8%
Newport	KINGSTON	4.16	131J12	380	380	367	97%	14.6%	364	96%	-0.7%	361	95%	-0.8%
Newport	KINGSTON	4.16	131J14	307	365	253	82%	14.6%	251	82%	-0.7%	249	81%	-0.8%
Newport	MERTON	4.16	51J2	310	333	294	95%	14.6%	292	94%	-0.7%	290	94%	-0.8%
Newport	MERTON	4.16	51J12	356	408	202	57%	14.6%	200	56%	-0.7%	199	56%	-0.8%
Newport	MERTON	4.16	51J14	310	368	151	49%	14.6%	150	48%	-0.7%	149	48%	-0.8%
Newport	MERTON	4.16	51J16	380	380	358	94%	14.6%	355	93%	-0.7%	352	93%	-0.8%
Newport	NO. AQUIDNECK	4.16	21J2	480	480	207	43%	14.6%	206	43%	-0.7%	204	43%	-0.8%
Newport	NO. AQUIDNECK	4.16	21J4	480	480	222	46%	14.6%	220	46%	-0.7%	218	45%	-0.8%
Newport	NO. AQUIDNECK	4.16	21J6	480	480	266	55%	14.6%	264	55%	-0.7%	262	55%	-0.8%
Newport	SO. AQUIDNECK	4.16	122J2	481	510	478	99%	14.6%	474	99%	-0.7%	471	98%	-0.8%
Newport	SO. AQUIDNECK	4.16	122J4	480	510	436	91%	14.6%	433	90%	-0.7%	429	89%	-0.8%
Newport	SO. AQUIDNECK	4.16	122J6	480	480	257	53%	14.6%	255	53%	-0.7%	253	53%	-0.8%
Newport	VERNON	4.16	23J2	384	408	78	20%	14.6%	77	20%	-0.7%	76	20%	-0.8%
Newport	VERNON	4.16	23J4	384	408	250	65%	14.6%	248	65%	-0.7%	246	64%	-0.8%
Newport	VERNON	4.16	23J6	384	408	124	32%	14.6%	123	32%	-0.7%	122	32%	-0.8%
Newport	VERNON	4.16	23J12	384	408	148	39%	14.6%	147	38%	-0.7%	146	38%	-0.8%
Newport	VERNON	4.16	23J14	384	408	0	0%	14.6%	0	0%	-0.7%	0	0%	-0.8%
Newport	WEST HOWARD	4.16	154J2	480	688	303	63%	14.6%	301	63%	-0.7%	299	62%	-0.8%
Newport	WEST HOWARD	4.16	154J4	290	350	160	55%	14.6%	159	55%	-0.7%	158	54%	-0.8%
Newport	WEST HOWARD	4.16	154J6	268	346	75	28%	14.6%	75	28%	-0.7%	74	28%	-0.8%
Newport	WEST HOWARD	4.16	154J8	380	380	369	97%	14.6%	367	96%	-0.7%	364	96%	-0.8%
Newport	WEST HOWARD	4.16	154J14	290	350	24	8%	14.6%	24	8%	-0.7%	24	8%	-0.8%
Newport	WEST HOWARD	4.16	154J16	270	340	236	88%	14.6%	235	87%	-0.7%	233	86%	-0.8%
Newport	WEST HOWARD	4.16	154J18	380	380	260	68%	14.6%	258	68%	-0.7%	256	67%	-0.8%
Newport	GATE 2	13.8	38W2	515	515	331	64%	empty:	332	65%	0.4%	333	65%	0.1%
North Central RI	CENTREDALE 50	12.47	50F2	367	386	274	75%	15.6%	274	75%	0.3%	275	75%	0.2%
North Central RI	CHOPMIST 34	12.47	34F1	530	544	437	83%	15.6%	439	83%	0.3%	440	83%	0.2%
North Central RI	CHOPMIST 34	12.47	34F2	415	415	324	78%	15.6%	325	78%	0.3%	326	78%	0.2%
North Central RI	CHOPMIST 34	12.47	34F3	385	385	324	84%	15.6%	325	84%	0.3%	325	84%	0.2%
North Central RI	FARNUM PIKE 23	12.47	23F1	530	650	335	63%	15.6%	336	63%	0.3%	337	64%	0.2%
North Central RI	FARNUM PIKE 23	12.47	23F2	515	515	427	83%	15.6%	428	83%	0.3%	429	83%	0.2%
North Central RI	FARNUM PIKE 23	12.47	23F3	530	640	504	95%	15.6%	506	95%	0.3%	507	96%	0.2%
North Central RI	FARNUM PIKE 23	12.47	23F4	530	612	296	56%	15.6%	297	56%	0.3%	298	56%	0.2%
North Central RI	FARNUM PIKE 23	12.47	23F5	515	515	127	25%	15.6%	127	25%	0.3%	127	25%	0.2%
North Central RI	FARNUM PIKE 23	12.47	23F6	515	515	366	71%	15.6%	368	71%	0.3%	368	72%	0.2%
North Central RI	JOHNSTON 18	12.47	18F1	526	626	0	0%	15.6%	0	0%	0.3%	0	0%	0.2%
North Central RI	JOHNSTON 18	12.47	18F2	452	515	0	0%	15.6%	0	0%	0.3%	0	0%	0.2%
North Central RI	JOHNSTON 18	12.47	18F3	515	515	0	0%	15.6%	0	0%	0.3%	0	0%	0.2%
North Central RI	JOHNSTON 18	12.47	18F4	530	560	0	0%	15.6%	0	0%	0.3%	0	0%	0.2%
North Central RI	JOHNSTON 18	12.47	18F5	530	612	493	93%	15.6%	494	93%	0.3%	495	93%	0.2%
North Central RI	JOHNSTON 18	12.47	18F6	515	515	464	90%	15.6%	465	90%	0.3%	429	83%	0.2%
North Central RI	JOHNSTON 18	12.47	18F7	530	612	300	57%	15.6%	300	57%	0.3%	301	57%	0.2%
North Central RI	JOHNSTON 18	12.47	18F8	530	612	283	53%	15.6%	284	54%	0.3%	284	54%	0.2%
North Central RI	JOHNSTON 18	12.47	18F9	530	612	400	75%	15.6%	401	76%	0.3%	402	76%	0.2%
North Central RI	JOHNSTON 18	12.47	18F10	531	612	414	78%	15.6%	415	78%	0.3%	416	78%	0.2%
North Central RI	JOHNSTON 18	12.47	18F11	526	612	434	83%	15.6%	436	83%	0.3%	436	83%	0.2%
North Central RI	JOHNSTON 18	12.47	18F12	507	612	163	32%	15.6%	164	32%	0.3%	164	32%	0.2%
North Central RI	JOHNSTON 18	12.47	18F13	460	515	315	68%	15.6%	316	69%	0.3%	317	69%	0.2%
North Central RI	JOHNSTON 18	12.47	18F14	515	612	237	46%	15.6%	238	46%	0.3%	238	46%	0.2%
North Central RI	MANTON 69	12.47	69F1	515	515	462	90%	15.6%	464	90%	0.3%	465	90%	0.2%

Study Area	Substation	Voltage (kV)	Feeder ID	Rating (Amps)		2016			2017			2018		
				Normal Rating	Emergency Rating	Projected Load (Amps)	%SN	Growth Rate	Projected Load (Amps)	%SN	Growth Rate	Projected Load (Amps)	%SN	Growth Rate
North Central RI	MANTON 69	12.47	69F3	502	515	378	75%	15.6%	380	76%	0.3%	380	76%	0.2%
North Central RI	PUTNAM PIKE 38	12.47	38F1	530	650	516	97%	15.6%	517	98%	0.3%	518	98%	0.2%
North Central RI	PUTNAM PIKE 38	12.47	38F2	530	650	211	40%	15.6%	212	40%	0.3%	212	40%	0.2%
North Central RI	PUTNAM PIKE 38	12.47	38F3	530	650	423	80%	15.6%	424	80%	0.3%	526	99%	0.2%
North Central RI	PUTNAM PIKE 38	12.47	38F4	515	515	252	49%	15.6%	253	49%	0.3%	310	60%	0.2%
North Central RI	PUTNAM PIKE 38	12.47	38F5	530	395	393	74%	15.6%	394	74%	0.3%	482	91%	0.2%
North Central RI	PUTNAM PIKE 38	12.47	38F6	530	612	415	78%	15.6%	416	78%	0.3%	417	79%	0.2%
North Central RI	WEST CRANSTON 21	12.47	21F1	515	515	510	99%	15.6%	511	99%	0.3%	512	99%	0.2%
North Central RI	WEST CRANSTON 21	12.47	21F2	515	515	410	80%	15.6%	411	80%	0.3%	412	80%	0.2%
North Central RI	WEST CRANSTON 21	12.47	21F4	515	515	495	96%	15.6%	496	96%	0.3%	497	97%	0.2%
North Central RI	WEST GREENVILLE 45	12.47	45F2	425	520	92	22%	15.6%	93	22%	0.3%	93	22%	0.2%
North Central RI	CENTREDALE 50	4.16	50J1	285	313	153	54%	15.6%	153	54%	0.3%	153	54%	0.2%
North Central RI	CENTREDALE 50	4.16	50J2	295	352	0	0%	15.6%	0	0%	0.3%	0	0%	0.2%
North Central RI	CENTREDALE 50	4.16	50J3	408	408	208	51%	15.6%	209	51%	0.3%	209	51%	0.2%
Providence	CLARKSON STREET 13	12.47	13F1	400	533	182	45%	15.6%	182	46%	0.3%	183	46%	0.2%
Providence	CLARKSON STREET 13	12.47	13F2	540	612	246	46%	15.6%	247	46%	0.3%	247	46%	0.2%
Providence	CLARKSON STREET 13	12.47	13F3	425	612	383	90%	15.6%	384	90%	0.3%	385	91%	0.2%
Providence	CLARKSON STREET 13	12.47	13F4	520	612	459	88%	15.6%	460	88%	0.3%	461	89%	0.2%
Providence	CLARKSON STREET 13	12.47	13F5	455	612	430	95%	15.6%	432	95%	0.3%	432	95%	0.2%
Providence	CLARKSON STREET 13	12.47	13F6	415	542	196	47%	15.6%	197	47%	0.3%	197	48%	0.2%
Providence	CLARKSON STREET 13	12.47	13F7	436	571	439	101%	15.6%	440	101%	0.3%	441	101%	0.2%
Providence	CLARKSON STREET 13	12.47	13F8	437	563	460	105%	15.6%	461	105%	0.3%	462	106%	0.2%
Providence	CLARKSON STREET 13	12.47	13F9	530	612	414	78%	15.6%	415	78%	0.3%	416	78%	0.2%
Providence	CLARKSON STREET 13	12.47	13F10	400	533	281	70%	15.6%	282	70%	0.3%	282	71%	0.2%
Providence	ELMWOOD 7 - OUTDOOR	12.47	7F1	530	612	350	66%	15.6%	351	66%	0.3%	352	66%	0.2%
Providence	ELMWOOD 7 - OUTDOOR	12.47	7F2	530	612	435	82%	15.6%	436	82%	0.3%	437	82%	0.2%
Providence	ELMWOOD 7 - OUTDOOR	12.47	7F4	530	612	455	86%	15.6%	456	86%	0.3%	457	86%	0.2%
Providence	LIPPITT HILL 79	12.47	79F1	459	579	438	95%	15.6%	439	96%	0.3%	440	96%	0.2%
Providence	LIPPITT HILL 79	12.47	79F2	459	579	421	92%	15.6%	423	92%	0.3%	424	92%	0.2%
Providence	POINT STREET 76	12.47	76F1	484	490	448	93%	15.6%	450	93%	0.3%	451	93%	0.2%
Providence	POINT STREET 76	12.47	76F2	500	612	494	99%	15.6%	496	99%	0.3%	497	99%	0.2%
Providence	POINT STREET 76	12.47	76F3	546	653	250	46%	15.6%	251	46%	0.3%	251	46%	0.2%
Providence	POINT STREET 76	12.47	76F4	530	612	500	94%	15.6%	501	95%	0.3%	502	95%	0.2%
Providence	POINT STREET 76	12.47	76F5	448	570	419	93%	15.6%	420	94%	0.3%	421	94%	0.2%
Providence	POINT STREET 76	12.47	76F6	518	612	487	94%	15.6%	495	96%	0.3%	496	96%	0.2%
Providence	POINT STREET 76	12.47	76F7	525	612	470	90%	15.6%	499	95%	0.3%	500	95%	0.2%
Providence	POINT STREET 76	12.47	76F8	530	612	353	67%	15.6%	354	67%	0.3%	355	67%	0.2%
Providence	ADMIRAL STREET 9	11.5	1115	9999	0	135	1%	15.6%	135	1%	0.3%	136	1%	0.2%
Providence	ADMIRAL STREET 9	11.5	1117	9999	0	69	1%	15.6%	70	1%	0.3%	70	1%	0.2%
Providence	ADMIRAL STREET 9	11.5	1119	9999	0	139	1%	15.6%	139	1%	0.3%	139	1%	0.2%
Providence	DYER STREET 2	11.5	1103	9999	0	210	2%	15.6%	211	2%	0.3%	211	2%	0.2%
Providence	FRANKLIN SQUARE 11	11.5	1112	280	280	78	28%	15.6%	78	28%	0.3%	79	28%	0.2%
Providence	FRANKLIN SQUARE 11	11.5	1121	363	455	109	30%	15.6%	109	30%	0.3%	110	30%	0.2%
Providence	FRANKLIN SQUARE 11	11.5	1123	404	404	0	0%	15.6%	0	0%	0.3%	0	0%	0.2%
Providence	FRANKLIN SQUARE 11	11.5	1125	696	834	171	25%	15.6%	172	25%	0.3%	172	25%	0.2%
Providence	FRANKLIN SQUARE 11	11.5	1126	327	450	276	84%	15.6%	277	85%	0.3%	278	85%	0.2%
Providence	FRANKLIN SQUARE 11	11.5	1149	249	0	61	24%	15.6%	61	25%	0.3%	61	25%	0.2%
Providence	FRANKLIN SQUARE 11	11.5	1153	313	350	170	54%	15.6%	170	54%	0.3%	170	54%	0.2%
Providence	HARRIS AVENUE 12	11.5	1129	290	290	129	45%	15.6%	130	45%	0.3%	130	45%	0.2%
Providence	HARRIS AVENUE 12	11.5	1131	290	290	79	27%	15.6%	79	27%	0.3%	79	27%	0.2%
Providence	HARRIS AVENUE 12	11.5	1133	290	290	102	35%	15.6%	144	50%	0.3%	144	50%	0.2%
Providence	HARRIS AVENUE 12	11.5	1137	290	290	228	79%	15.6%	229	79%	0.3%	229	79%	0.2%
Providence	HARRIS AVENUE 12	11.5	1145	9999	0	100	1%	15.6%	100	1%	0.3%	101	1%	0.2%
Providence	HARRIS AVENUE 12	11.5	1147	290	290	74	26%	15.6%	74	26%	0.3%	74	26%	0.2%
Providence	SOUTH STREET 1	11.5	1101	9999	0	248	2%	15.6%	249	2%	0.3%	249	2%	0.2%

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				Normal Rating	Emergency Rating	Projected Load (Amps)	%SN	Growth Rate	Projected Load (Amps)	%SN	Growth Rate	Projected Load (Amps)	%SN	Growth Rate
Providence	SOUTH STREET 1	11.5	1151	322	375	277	86%	15.6%	277	86%	0.3%	278	86%	0.2%
Providence	SOUTH STREET 1	11.5	1152	326	389	201	62%	15.6%	202	62%	0.3%	202	62%	0.2%
Providence	SOUTH STREET 1	11.5	1169	9999	0	198	2%	15.6%	198	2%	0.3%	199	2%	0.2%
Providence	SOUTH STREET 1	11.5	1171	9999	0	51	1%	15.6%	51	1%	0.3%	51	1%	0.2%
Providence	ADMIRAL STREET 9	4.16	9J1	408	472	349	85%	15.6%	350	86%	0.3%	350	86%	0.2%
Providence	ADMIRAL STREET 9	4.16	9J2	408	408	220	54%	15.6%	248	61%	0.3%	249	61%	0.2%
Providence	ADMIRAL STREET 9	4.16	9J3	255	255	235	92%	15.6%	236	92%	0.3%	236	93%	0.2%
Providence	ADMIRAL STREET 9	4.16	9J5	408	408	38	9%	15.6%	38	9%	0.3%	38	9%	0.2%
Providence	DYER STREET 2	4.16	2J1	408	408	339	83%	15.6%	340	83%	0.3%	341	84%	0.2%
Providence	DYER STREET 2	4.16	2J2	354	354	177	50%	15.6%	178	50%	0.3%	178	50%	0.2%
Providence	DYER STREET 2	4.16	2J3	285	313	69	24%	15.6%	70	24%	0.3%	70	24%	0.2%
Providence	DYER STREET 2	4.16	2J4	297	326	166	56%	15.6%	166	56%	0.3%	166	56%	0.2%
Providence	DYER STREET 2	4.16	2J5	340	340	181	53%	15.6%	182	53%	0.3%	182	54%	0.2%
Providence	DYER STREET 2	4.16	2J7	354	354	227	64%	15.6%	228	64%	0.3%	228	65%	0.2%
Providence	DYER STREET 2	4.16	2J8	354	354	223	63%	15.6%	224	63%	0.3%	225	63%	0.2%
Providence	DYER STREET 2	4.16	2J9	354	354	266	75%	15.6%	267	75%	0.3%	267	75%	0.2%
Providence	DYER STREET 2	4.16	2J10	340	340	189	56%	15.6%	189	56%	0.3%	190	56%	0.2%
Providence	EAST GEORGE ST 77	4.16	77J1	371	408	266	72%	15.6%	267	72%	0.3%	267	72%	0.2%
Providence	EAST GEORGE ST 77	4.16	77J2	364	495	331	91%	15.6%	332	91%	0.3%	333	91%	0.2%
Providence	EAST GEORGE ST 77	4.16	77J3	371	385	335	90%	15.6%	336	91%	0.3%	337	91%	0.2%
Providence	EAST GEORGE ST 77	4.16	77J4	364	495	316	87%	15.6%	317	87%	0.3%	317	87%	0.2%
Providence	GENEVA 71	4.16	71J1	274	274	240	88%	15.6%	241	88%	0.3%	242	88%	0.2%
Providence	GENEVA 71	4.16	71J2	274	274	116	42%	15.6%	116	42%	0.3%	116	42%	0.2%
Providence	GENEVA 71	4.16	71J3	274	274	208	76%	15.6%	209	76%	0.3%	209	76%	0.2%
Providence	GENEVA 71	4.16	71J4	274	274	210	77%	15.6%	211	77%	0.3%	211	77%	0.2%
Providence	GENEVA 71	4.16	71J5	408	408	316	77%	15.6%	317	78%	0.3%	317	78%	0.2%
Providence	HARRIS AVENUE 12	4.16	12J1	425	425	108	25%	15.6%	108	25%	0.3%	108	26%	0.2%
Providence	HARRIS AVENUE 12	4.16	12J2	425	425	258	61%	15.6%	259	61%	0.3%	259	61%	0.2%
Providence	HARRIS AVENUE 12	4.16	12J3	425	425	0	0%	15.6%	0	0%	0.3%	0	0%	0.2%
Providence	HARRIS AVENUE 12	4.16	12J4	425	425	277	65%	15.6%	278	65%	0.3%	279	66%	0.2%
Providence	HARRIS AVENUE 12	4.16	12J5	340	340	116	34%	15.6%	116	34%	0.3%	116	34%	0.2%
Providence	HARRIS AVENUE 12	4.16	12J6	408	408	173	42%	15.6%	174	43%	0.3%	174	43%	0.2%
Providence	HUNTINGTON PARK 67	4.16	67J1	274	274	256	93%	15.6%	256	94%	0.3%	257	94%	0.2%
Providence	KNIGHTSVILLE 66	4.16	66J1	248	353	209	84%	15.6%	210	85%	0.3%	210	85%	0.2%
Providence	KNIGHTSVILLE 66	4.16	66J2	379	408	320	84%	15.6%	321	85%	0.3%	321	85%	0.2%
Providence	KNIGHTSVILLE 66	4.16	66J3	379	408	312	82%	15.6%	313	83%	0.3%	314	83%	0.2%
Providence	KNIGHTSVILLE 66	4.16	66J4	379	408	333	88%	15.6%	334	88%	0.3%	335	88%	0.2%
Providence	KNIGHTSVILLE 66	4.16	66J5	379	408	216	57%	15.6%	216	57%	0.3%	217	57%	0.2%
Providence	OLNEYVILLE 6	4.16	6J1	306	354	215	70%	15.6%	216	70%	0.3%	216	71%	0.2%
Providence	OLNEYVILLE 6	4.16	6J2	306	354	240	79%	15.6%	241	79%	0.3%	242	79%	0.2%
Providence	OLNEYVILLE 6	4.16	6J3	306	354	100	33%	15.6%	100	33%	0.3%	101	33%	0.2%
Providence	OLNEYVILLE 6	4.16	6J5	306	354	1	0%	15.6%	1	0%	0.3%	1	0%	0.2%
Providence	OLNEYVILLE 6	4.16	6J6	306	354	116	38%	15.6%	116	38%	0.3%	116	38%	0.2%
Providence	OLNEYVILLE 6	4.16	6J7	306	354	238	78%	15.6%	239	78%	0.3%	239	78%	0.2%
Providence	OLNEYVILLE 6	4.16	6J8	306	354	145	47%	15.6%	145	47%	0.3%	146	48%	0.2%
Providence	ROCHAMBEAU AVENUE 37	4.16	37J1	329	408	238	72%	15.6%	239	73%	0.3%	239	73%	0.2%
Providence	ROCHAMBEAU AVENUE 37	4.16	37J2	291	349	311	107%	15.6%	312	107%	0.3%	313	107%	0.2%
Providence	ROCHAMBEAU AVENUE 37	4.16	37J3	303	408	260	86%	15.6%	261	86%	0.3%	261	86%	0.2%
Providence	ROCHAMBEAU AVENUE 37	4.16	37J4	278	371	237	85%	15.6%	238	85%	0.3%	238	86%	0.2%
Providence	ROCHAMBEAU AVENUE 37	4.16	37J5	347	408	296	85%	15.6%	297	86%	0.3%	297	86%	0.2%
Providence	SPRAGUE STREET 36	4.16	36J1	236	283	191	81%	15.6%	191	81%	0.3%	192	81%	0.2%
Providence	SPRAGUE STREET 36	4.16	36J2	252	299	216	86%	15.6%	216	86%	0.3%	217	86%	0.2%
Providence	SPRAGUE STREET 36	4.16	36J4	344	405	223	65%	15.6%	224	65%	0.3%	225	65%	0.2%
Providence	SPRAGUE STREET 36	4.16	36J5	315	315	262	83%	15.6%	263	84%	0.3%	264	84%	0.2%
South County East	BONNET 42	12.47	42F1	525	566	411	78%	15.5%	412	79%	0.3%	413	79%	0.2%

Study Area	Substation	Voltage (kV)	Feeder ID	Rating (Amps)		2016			2017			2018		
				Normal Rating	Emergency Rating	Projected Load (Amps)	%SN	Growth Rate	Projected Load (Amps)	%SN	Growth Rate	Projected Load (Amps)	%SN	Growth Rate
South County East	LAFAYETTE 30	12.47	30F1	350	398	261	74%	15.5%	261	75%	0.3%	262	75%	0.2%
South County East	LAFAYETTE 30	12.47	30F2	530	612	418	79%	15.5%	419	79%	0.3%	420	79%	0.2%
South County East	OLD BAPTIST ROAD 46	12.47	46F1	530	612	399	75%	15.5%	400	76%	0.3%	401	76%	0.2%
South County East	OLD BAPTIST ROAD 46	12.47	46F2	530	612	296	56%	15.5%	297	56%	0.3%	298	56%	0.2%
South County East	OLD BAPTIST ROAD 46	12.47	46F3	565	612	339	60%	15.5%	340	60%	0.3%	340	60%	0.2%
South County East	OLD BAPTIST ROAD 46	12.47	46F4	594	612	544	92%	15.5%	546	92%	0.3%	547	92%	0.2%
South County East	PEACEDALE 59	12.47	59F1	409	489	151	37%	15.5%	151	37%	0.3%	152	37%	0.2%
South County East	PEACEDALE 59	12.47	59F2	492	515	307	62%	15.5%	308	63%	0.3%	309	63%	0.2%
South County East	PEACEDALE 59	12.47	59F3	492	650	394	80%	15.5%	395	80%	0.3%	396	80%	0.2%
South County East	PEACEDALE 59	12.47	59F4	425	515	195	46%	15.5%	196	46%	0.3%	196	46%	0.2%
South County East	QUONSET 83	12.47	83F1	645	645	241	37%	15.5%	242	38%	0.3%	170	26%	0.2%
South County East	QUONSET 83	12.47	83F2	490	650	387	79%	15.5%	428	87%	0.3%	172	35%	0.2%
South County East	QUONSET 83	12.47	83F3	645	645	283	44%	15.5%	284	44%	0.3%	285	44%	0.2%
South County East	WAKEFIELD 17	12.47	17F1	602	612	424	70%	15.5%	425	71%	0.3%	426	71%	0.2%
South County East	WAKEFIELD 17	12.47	17F2	510	510	469	92%	15.5%	471	92%	0.3%	471	92%	0.2%
South County East	WAKEFIELD 17	12.47	17F3	597	626	468	78%	15.5%	469	79%	0.3%	470	79%	0.2%
South County East	TOWER HILL 88	12.47	88F1	530	650	404	76%	15.5%	406	77%	0.3%	406	77%	0.2%
South County East	TOWER HILL 88	12.47	88F3	550	645	408	74%	15.5%	410	74%	0.3%	410	75%	0.2%
South County East	TOWER HILL 88	12.47	88F5	530	650	392	74%	15.5%	393	74%	0.3%	394	74%	0.2%
South County East	TOWER HILL 88	12.47	88F7	530	650	346	65%	15.5%	347	66%	0.3%	348	66%	0.2%
South County East	QUONSET 83	12.47	83F4	0	0	0	0%	0.0%	0	0%	0.0%	329	55%	0.2%
South County West	ASHAWAY 43	12.47	43F1	388	423	347	89%	15.5%	348	90%	0.3%	0	0%	0.2%
South County West	HOPE VALLEY 41	12.47	41F1	347	430	300	86%	15.5%	301	87%	0.3%	0	0%	0.2%
South County West	KENYON 68	12.47	68F1	512	612	340	66%	15.5%	341	67%	0.3%	342	67%	0.2%
South County West	KENYON 68	12.47	68F2	511	612	415	81%	15.5%	416	82%	0.3%	417	82%	0.2%
South County West	KENYON 68	12.47	68F3	512	515	346	67%	15.5%	347	68%	0.3%	347	68%	0.2%
South County West	KENYON 68	12.47	68F4	514	612	331	64%	15.5%	332	65%	0.3%	332	65%	0.2%
South County West	KENYON 68	12.47	68F5	612	612	222	36%	15.5%	223	36%	0.3%	223	36%	0.2%
South County West	LANGWORTHY 86	12.47	86F1	600	612	508	85%	15.5%	509	85%	0.3%	408	68%	0.2%
South County West	WESTERLY 16	12.47	16F1	515	515	459	89%	15.5%	460	89%	0.3%	433	84%	0.2%
South County West	WESTERLY 16	12.47	16F2	515	515	461	90%	15.5%	463	90%	0.3%	279	54%	0.2%
South County West	WESTERLY 16	12.47	16F3	515	515	447	87%	15.5%	448	87%	0.3%	382	74%	0.2%
South County West	WESTERLY 16	12.47	16F4	645	645	279	43%	15.5%	280	43%	0.3%	365	57%	0.2%
South County West	CHASE HILL	12.47	155F2	0	0	0	0%	0.0%	0	0%	0.0%	190	36%	0.2%
South County West	CHASE HILL	12.47	155F4	0	0	0	0%	0.0%	0	0%	0.0%	246	46%	0.2%
South County West	CHASE HILL	12.47	155F6	0	0	0	0%	0.0%	0	0%	0.0%	275	52%	0.2%
South County West	CHASE HILL	12.47	155F8	0	0	0	0%	0.0%	0	0%	0.0%	237	47%	0.2%
TIVERTON	TIVERTON	12.47	33F1	478	515	287	60%	15.6%	287	60%	0.3%	288	60%	0.2%
TIVERTON	TIVERTON	12.47	33F2	456	515	426	93%	15.6%	427	94%	0.3%	428	94%	0.2%
TIVERTON	TIVERTON	12.47	33F3	478	600	366	77%	15.6%	367	77%	0.3%	368	77%	0.2%
TIVERTON	TIVERTON	12.47	33F4	456	576	440	97%	15.6%	442	97%	0.3%	443	97%	0.2%

Study Area	Substation	Transformer ID	System Voltage (kV)		Rating (MVA)		2016		2017			2018		
			From Voltage (kV)	To Voltage (kV)	Normal Rating	Emergency Rating	Load (MVA)	% SN	Load (MVA)	% SN	% Load Growth	Load (MVA)	% SN	% Load Growth
Blackstone Valley North	Highland Park #200	T1	115	13.8	73	82	6.1	8%	14.2	20%	135%	14.3	20%	0%
Blackstone Valley North	Highland Park #200	T2	115	13.8	70	79	4.8	7%	9.4	13%	94%	10.1	14%	8%
Blackstone Valley North	Farnum #105	T1	115	23	37.3	37.3	1.6	4%	1.8	5%	11%	1.9	5%	5%
Blackstone Valley North	Nasonville #127	T271	115	13.8	47.8	47.8	29.3	61%	28.0	59%	-5%	30.5	64%	9%
Blackstone Valley North	Riverside #108	T81	115	13.8	41.83	45.23	20.9	50%	20.7	49%	-1%	19.3	46%	-7%
Blackstone Valley North	Riverside #108	T82	115	13.8	49.62	58.74	28.8	58%	22.7	46%	-21%	24.8	50%	9%
Blackstone Valley North	Staples #112	T124	115	13.8	47.8	47.8	26.3	55%	23.7	50%	-10%	26.4	55%	11%
Blackstone Valley North	West Farnum	T1	115	13.8	20	20	0.0	0%	0.0	0%	0%	0.0	0%	0%
Blackstone Valley North	Woonsocket	T1	115	13.8	47.8	50	25.4	53%	22.4	47%	-11%	23.7	50%	6%
Blackstone Valley South	Valley #102	T23	115	24	42.01	51.51	2.6	6%	2.5	6%	-3%	2.5	6%	-2%
Blackstone Valley South	Pawtucket No.1 #107	T71	115	13.8	47.8	47.8	31.6	66%	33.1	69%	5%	37.6	79%	14%
Blackstone Valley South	Pawtucket No.1 #107	T73A	115	13.8	47.8	47.8	43.4	91%	32.2	67%	-26%	31.7	66%	-1%
Blackstone Valley South	Pawtucket No.1 #107	T74	115	13.8	47.8	47.8	31.4	66%	26.0	54%	-17%	27.5	58%	6%
Blackstone Valley South	Valley #102	T21	115	13.8	38.36	45.95	16.2	42%	14.6	38%	-10%	14.6	38%	0%
Blackstone Valley South	Valley #102	T22	115	13.8	52	59	18.2	35%	16.3	31%	-10%	19.5	38%	20%
Blackstone Valley South	Washington #126	T261	115	13.8	47.8	47.8	23.3	49%	22.0	46%	-6%	22.8	48%	4%
Blackstone Valley South	Washington #126	T262	115	13.8	59.27	59.27	32.1	54%	28.4	48%	-12%	30.5	51%	7%
Blackstone Valley South	Central Falls #104	South Bank	13.8	4.16	3.12	3.12	1.6	52%	1.3	42%	-19%	0.9	28%	-33%
Blackstone Valley South	Central Falls #104	North Bank	13.8	4.16	3	3	1.1	36%	0.7	23%	-35%	1.0	33%	42%
Blackstone Valley South	Centre Street #106	empty:u	13.8	4.16	3.1	3.1	2.8	90%	2.4	76%	-15%	2.0	65%	-15%
Blackstone Valley South	Cottage St #109	empty:u	13.8	4.16	8.25	9.43	5.5	67%	4.7	57%	-15%	5.3	64%	13%
Blackstone Valley South	Crossman St #111	empty:u	13.8	4.16	8.26	9.44	3.3	40%	3.3	41%	2%	3.9	48%	18%
Blackstone Valley South	Daggett Ave #113	empty:u	13.8	4.16	4.23	5.02	3.2	75%	0.0	0%	-100%	0.0	0%	0%
Blackstone Valley South	Front #24	empty:u	13.8	4.16	3.1	3.1	1.3	42%	1.2	39%	-6%	1.1	35%	-11%
Blackstone Valley South	Hyde Avenue #28	empty:u	13.8	4.16	5.25	5.25	1.6	30%	0.0	0%	-100%	0.0	0%	0%
Blackstone Valley South	Lee St. #30	empty:u	13.8	4.16	7	7	4.9	70%	3.9	56%	-20%	2.7	39%	-31%
Blackstone Valley South	Pawtucket No.2 #148	T1	13.8	4.16	7.6	9.36	1.7	22%	3.3	44%	97%	3.7	49%	12%
Blackstone Valley South	Pawtucket No.2 #148	T2	13.8	4.16	7.6	9.36	2.2	29%	3.4	45%	54%	4.3	56%	26%
Blackstone Valley South	Southeast #60	T1	115	13.8	70	80	0.0	0%	0.0	0%	0%	0.0	0%	0%
Blackstone Valley South	Southeast #60	T2	115	13.8	70	80	0.0	0%	0.0	0%	0%	0.0	0%	0%
Central RI East	APPONAUG 3	3	23	12.47	15.5	19.6	7.1	46%	5.6	36%	-21%	6.1	40%	9%
Central RI East	APPONAUG 3	4	23	12.47	11.9	12.6	6.0	50%	6.2	52%	4%	6.1	51%	-2%
Central RI East	KILVERT STREET 87	1	115	12.47	72	82	21.4	30%	20.0	28%	-6%	21.5	30%	7%
Central RI East	KILVERT STREET 87	2	115	12.47	70	78	16.7	24%	18.1	26%	8%	16.9	24%	-6%
Central RI East	LINCOLN AVENUE 72	1	115	12.47	52.07	54.92	23.8	46%	21.5	41%	-10%	24.6	47%	14%
Central RI East	LINCOLN AVENUE 72	2	115	12.47	52.07	54.92	25.2	48%	25.8	49%	2%	26.9	52%	4%
Central RI East	PONTIAC 27	1	115	12.47	50.67	53.32	20.2	40%	19.5	39%	-3%	20.3	40%	4%
Central RI East	PONTIAC 27	2	115	12.47	46.49	51.88	22.7	49%	19.3	42%	-15%	18.3	39%	-5%
Central RI East	WARWICK 52	1	23	12.47	11.6	12.7	7.5	64%	7.9	68%	6%	7.8	67%	-1%
Central RI East	WARWICK 52	4	23	12.47	12	12	8.9	74%	7.6	63%	-14%	8.4	70%	10%
Central RI East	AUBURN 73	1	23	4.16	10.56	11.81	4.8	45%	4.3	40%	-10%	4.8	46%	13%
Central RI East	AUBURN 73	2	23	4.16	9.66	10.64	3.2	33%	3.0	31%	-5%	3.0	31%	-1%
Central RI East	LAKEWOOD 57	1	23	4.16	10.09	10.63	4.3	43%	1.9	19%	-57%	2.2	22%	16%
Central RI East	LAKEWOOD 57	2	23	4.16	10.15	11.46	2.6	25%	3.0	30%	18%	1.4	14%	-53%
Central RI East	DRUMROCK 14	3	115	23/12.47	53	76.04	24.8	47%	24.8	47%	0%	27.0	51%	9%
Central RI East	DRUMROCK 14	4	115	23	89	107.4	33.6	38%	33.6	38%	0%	36.5	41%	9%
Central RI East	DRUMROCK 14	5	115	23/12.47	107	107	45.6	43%	45.6	43%	0%	45.7	43%	0%
Central RI East	SOCKANOSSET 24	1	115	23	50.29	56.81	17.5	35%	17.5	35%	0%	17.4	35%	-1%
Central RI East	SOCKANOSSET 24	2	115	23	50.37	57.03	20.8	41%	20.8	41%	0%	26.6	53%	28%
Central RI East	AUBURN 73	T1	115	12.47	0	0	0.0	0%	0.0	0%	0%	0.0	0%	0%

Study Area	Substation	Transformer ID	System Voltage (kV)		Rating (MVA)		2016		2017			2018		
			From Voltage (kV)	To Voltage (kV)	Normal Rating	Emergency Rating	Load (MVA)	% SN	Load (MVA)	% SN	% Load Growth	Load (MVA)	% SN	% Load Growth
Central RI East	AUBURN 73	T2	115	12.47	0	0	0.0	0%	0.0	0%	0%	0.0	0%	0%
Central RI West	ANTHONY	1	23	12.47	7.8	8.1	5.4	70%	4.2	54%	-23%	4.6	58%	9%
Central RI West	ANTHONY	2	23	12.47	7.8	8.1	7.0	89%	6.0	77%	-13%	4.8	61%	-21%
Central RI West	COVENTRY	1	23	12.47	11.4	13.5	9.2	81%	7.6	67%	-18%	9.5	83%	25%
Central RI West	DIVISION ST	1	34.5	12.47	23.7	27.6	13.4	56%	13.5	57%	1%	14.3	60%	6%
Central RI West	DIVISION ST	2	34.5	12.47	23.7	27.6	14.5	61%	13.2	56%	-9%	14.4	61%	9%
Central RI West	HOPE	1	23	12.47	7.53	8.51	6.8	90%	6.1	81%	-10%	7.1	94%	16%
Central RI West	HOPE	2	23	12.47	13.65	16.46	9.1	67%	7.8	57%	-15%	9.5	70%	22%
Central RI West	HOPKINS HILL	1	34.5	12.47	48.8	51	20.3	42%	20.1	41%	-1%	18.8	39%	-6%
Central RI West	HOPKINS HILL	2	34.5	12.47	49.2	52	21.6	44%	22.8	46%	6%	23.3	47%	2%
Central RI West	HUNT RIVER	2	34.5	12.47	11.22	12.67	4.4	39%	0.0	0%	0%	0.0	0%	0%
Central RI West	KENT COUNTY	1	115	34.5	57.25	67.64	29.4	51%	27.9	49%	-5%	29.4	51%	5%
Central RI West	KENT COUNTY	2	115	34.5	66.33	69.9	33.1	50%	31.6	48%	-5%	33.0	50%	4%
Central RI West	KENT COUNTY	6	115	12.47	50.69	58.89	33.0	65%	15.5	31%	-53%	22.4	44%	44%
Central RI West	KENT COUNTY	7	115	34.5	57.25	68.78	32.4	57%	30.9	54%	-5%	32.1	56%	4%
Central RI West	KENT COUNTY	5	115	12.47	50	58	0.0	0%	21.0	42%	0%	17.1	34%	-19%
Central RI West	NATICK	1	23	12.47	13.2	14.3	7.6	58%	6.9	52%	-10%	7.3	55%	6%
Central RI West	NATICK	2	23	12.47	13.5	14.5	5.4	40%	5.1	37%	-6%	5.4	40%	7%
Central RI West	WARWICK MALL	1	23	12.47	8.8	8.9	2.8	32%	2.5	28%	-11%	2.5	29%	2%
Central RI West	WARWICK MALL	2	23	12.47	8.7	9.1	1.8	21%	1.7	19%	-7%	1.6	18%	-5%
Central RI West	ARCTIC	1	23	4.16	5	5	3.2	63%	2.9	58%	-8%	3.1	62%	7%
Central RI West	ARCTIC	2	23	4.16	6.7	7.4	3.4	51%	2.8	42%	-17%	2.4	36%	-14%
Central RI West	TIOGUE AVE	1	34.5	12.47	13	14	9.6	74%	8.7	67%	-10%	8.7	67%	0%
Central RI West	NEW LONDON AVE	1	115	12.47	52.3	55	0.0	0%	0.0	0%	0%	0.0	0%	0%
East Bay	BARRINGTON 4	1	23	12.47	35.19	35.19	17.4	49%	12.7	36%	-27%	17.0	48%	34%
East Bay	BRISTOL 51	1	115	12.47	56.9	63.4	17.7	31%	15.9	28%	-10%	18.1	32%	14%
East Bay	BRISTOL 51	2	23	12.47	25.1	29.8	10.1	40%	8.6	34%	-14%	10.1	40%	16%
East Bay	PHILLIPSDALE 20	T1	115	23	56	56	17.6	31%	17.0	30%	-4%	17.3	31%	2%
East Bay	PHILLIPSDALE 20	T2	115	23	45.32	56.75	8.9	20%	7.3	16%	-18%	7.4	16%	1%
East Bay	PHILLIPSDALE 20	T3	23	12.47	25.16	28.87	13.0	52%	12.3	49%	-6%	12.9	51%	5%
East Bay	WAMPANOAG 48	T1	115	12.47	42.83	52.72	30.8	72%	24.3	57%	-21%	25.9	60%	6%
East Bay	WAMPANOAG 48	T2	115	12.47	52.36	55.33	27.0	52%	23.2	44%	-14%	25.3	48%	9%
East Bay	WARREN 5	T1	115	12.47	48.28	53.43	15.8	33%	14.6	30%	-8%	15.8	33%	8%
East Bay	WARREN 5	T2	115	12.47	50.62	59.57	16.5	33%	15.0	30%	-9%	16.8	33%	12%
East Bay	WARREN 5	5	115	23	60.96	65.05	10.2	17%	10.0	16%	-2%	11.4	19%	15%
East Bay	WARREN 5	6	115	23	59.6	64.17	23.8	40%	22.3	37%	-6%	26.0	44%	16%
East Bay	WATERMAN AVENUE 78	T1	23	12.47	16.36	18.26	5.7	35%	4.2	26%	-26%	4.7	29%	10%
East Bay	WATERMAN AVENUE 78	T2	23	12.47	16.36	18.26	5.3	32%	4.3	26%	-19%	4.5	28%	6%
East Bay	KENT CORNERS 47	T1	23	4.16	7.14	7.53	2.4	34%	1.8	25%	-24%	2.1	30%	17%
East Bay	KENT CORNERS 47	T2	23	4.16	6.82	8.07	4.1	60%	3.4	50%	-17%	4.6	67%	34%
East Bay	EAST PROVIDENCE SUB	T1	115	12.47	50	60	0.0	0%	0.0	0%	0%	0.0	0%	0%
East Bay	PHILLIPSDALE 20	T4	115	12.47	50	60	0.0	0%	0.0	0%	0%	0.0	0%	0%
Newport	Bailey Brook	191	23	4.16	8.32	8.68	1.6	19%	1.5	18%	-8%	1.4	17%	-2%
Newport	Bailey Brook	192	23	4.16	8.57	10.43	1.7	19%	1.3	15%	-23%	1.5	18%	18%
Newport	Clarke St	651	23	4.16	4.06	4.34	2.7	67%	2.4	60%	-9%	3.0	74%	22%
Newport	Clarke St	652	23	4.16	6	7	2.4	40%	2.1	35%	-14%	2.2	36%	4%
Newport	Dexter	361	115	69	121	130	59.0	49%	56.9	47%	-4%	61.4	51%	8%
Newport	Dexter	362	115	69	61	65	25.3	41%	24.2	40%	-4%	26.2	43%	8%
Newport	Dexter	363	115	69	61	65	25.3	41%	24.3	40%	-4%	26.3	43%	8%
Newport	Dexter	364	115	13.8	44.64	47.44	22.4	50%	20.8	47%	-7%	21.4	48%	3%

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Newport	Eldred	T1	23	4.16	6.54	7.4	3.6	55%	3.0	46%	-16%	3.4	53%	14%
Newport	Gate 2	381	69	23	54.24	63.7	18.8	35%	17.9	33%	-5%	20.7	38%	16%
Newport	Gate 2	T2	69	13.8	11	12	5.3	48%	4.8	44%	-8%	5.3	48%	9%
Newport	Gate 2	731	23	4.16	8.11	8.7	2.7	34%	2.6	31%	-7%	3.1	39%	23%
Newport	Harrison	321	23	4.16	8.33	9.73	3.3	40%	2.6	31%	-22%	3.0	36%	17%
Newport	Harrison	322	23	4.16	8.07	10.12	4.8	59%	4.0	49%	-17%	4.9	60%	23%
Newport	Hospital	461	23	4.16	4.06	4.34	1.9	46%	2.1	52%	12%	2.9	70%	36%
Newport	Hospital	462	23	4.16	4.06	4.34	2.1	53%	1.9	46%	-13%	1.9	47%	2%
Newport	Jepson	371	69	23	16.52	18.47	1.8	11%	1.8	11%	0%	3.4	21%	89%
Newport	Jepson	372	69	23	23.2	24.8	9.0	39%	9.0	39%	0%	9.9	43%	10%
Newport	Jepson	373	69	23	48.88	57.87	27.3	56%	27.3	56%	0%	30.3	62%	11%
Newport	Jepson	374	69	13.8	42.86	48.58	25.6	60%	24.7	58%	-4%	25.5	59%	3%
Newport	Jepson	341	23	4.16	9.74	10.42	1.9	20%	1.7	18%	-10%	2.1	21%	19%
Newport	Jepson	376	69	23	15.44	16.35	5.5	36%	5.5	36%	0%	5.8	38%	5%
Newport	Kingston	311	23	4.16	7.9	9.56	5.1	65%	4.6	59%	-10%	4.6	59%	0%
Newport	Kingston	312	23	4.16	7.9	9.56	3.9	50%	4.0	50%	1%	4.0	51%	0%
Newport	Merton	511	23	4.16	2.24	2.4	2.1	94%	1.7	76%	-19%	1.4	62%	-18%
Newport	Merton	512	23	4.16	8.38	10	4.8	57%	4.3	51%	-10%	4.2	50%	-1%
Newport	No. Aquidneck	211	23	4.16	7.98	10.2	4.3	54%	3.4	42%	-23%	3.3	41%	-2%
Newport	So. Aquidneck	221	23	4.16	7.9	9.56	4.4	56%	5.3	68%	21%	5.7	72%	6%
Newport	Vernon Ave	231	23	4.16	3.63	3.88	2.9	80%	2.6	73%	-8%	2.3	63%	-13%
Newport	Vernon Ave	232	23	4.16	3.63	3.88	1.0	29%	1.3	36%	24%	1.1	30%	-15%
Newport	West Howard	541	23	4.16	12.57	14.76	6.3	50%	5.4	43%	-14%	5.7	46%	6%
Newport	West Howard	542	23	4.16	13.09	13.58	3.4	26%	4.5	34%	33%	4.4	34%	-2%
Newport	Newport Sub	T1	69	13.8	0	0	0.0	0%	0.0	0%	0%	0.0	0%	0%
Newport	Jepson	T2	69	13.8	0	0	0.0	0%	0.0	0%	0%	0.0	0%	0%
Newport	Eldred	T2	23	4.16	6.49	7.35	1.8	28%	1.5	24%	-16%	1.7	26%	10%
North Central RI	Johnston #18	T1	115	23	63.4	77	28.2	44%	27.7	44%	-2%	31.1	49%	12%
North Central RI	Johnston #18	T2	115	23	80	90	25.1	31%	24.8	31%	-1%	27.8	35%	12%
North Central RI	Wolf Hill #19	T1	115	23	65.01	69.83	26.8	41%	29.2	45%	9%	26.6	41%	-9%
North Central RI	Centerdale #50	T3	23	12.47	7.93	8.34	6.5	82%	5.6	71%	-13%	6.2	78%	11%
North Central RI	Chopmist #34	T1	23	12.47	15.96	16.42	10.1	63%	7.6	48%	-25%	9.1	57%	20%
North Central RI	Chopmist #34	T2	23	12.47	13.84	13.57	7.2	52%	5.4	39%	-24%	6.6	47%	21%
North Central RI	Chopmist #34	T3	23	12.47	12.81	13.94	4.3	33%	4.6	36%	8%	4.8	37%	3%
North Central RI	Farnum Pike #23 (New)	T1	115	12.47	77	86	18.4	24%	17.4	23%	-6%	18.1	24%	4%
North Central RI	Farnum Pike #23 (New)	T2	115	12.47	77	86	21.4	28%	20.2	26%	-5%	21.0	27%	4%
North Central RI	Johnston #18	T1	115	12.47	25	35	0.0	0%	0.0	0%	0%	0.0	0%	0%
North Central RI	Johnston #18	T3	115	12.47	80	94	37.8	47%	36.4	46%	-4%	39.4	49%	8%
North Central RI	Johnston #18	T4	115	12.47	68.6	74	29.8	43%	28.5	42%	-4%	29.0	42%	2%
North Central RI	Manton #69	T2	23	12.47	25.46	26.66	19.2	75%	17.3	68%	-10%	19.2	75%	11%
North Central RI	Putnam Pike #38	T1	115	12.47	64.94	68.79	26.6	41%	24.1	37%	-9%	22.7	35%	-6%
North Central RI	Putnam Pike #38	T2	115	12.47	64.94	68.79	16.2	25%	18.0	28%	11%	20.9	32%	16%
North Central RI	West Cranston #21	T1	115	12.47	27.78	29.91	11.0	39%	8.9	32%	-19%	9.9	36%	11%
North Central RI	West Cranston #21	T2	115	12.47	27.76	29.86	17.7	64%	13.5	49%	-24%	14.8	53%	9%
North Central RI	West Greenville # 45	T3	23	12.47	11.91	13.56	2.0	17%	1.6	14%	-18%	7.4	62%	350%
North Central RI	Centerdale #50	T1	23	4.16	7.1	7.54	2.4	34%	2.5	36%	4%	2.9	41%	15%
North Central RI	Shun Pike #128	T1	115	13.2	26	30	14.7	57%	11.5	44%	-22%	16.8	65%	47%
Providence	Admiral Street #9	T1	23	11/4.16	15	15	9.7	65%	10.6	70%	8%	11.4	76%	8%
Providence	Admiral Street #9	T2	23	11/4.16	15	15	0.0	0%	0.0	0%	0%	0.0	0%	0%
Providence	Franklin Square #11	3320	11.5	34.5	25.87	29.66	5.2	20%	5.3	20%	2%	5.2	20%	-1%

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Providence	Franklin Square #11	3324	11.5	34.5	25.75	29.5	5.2	20%	5.3	20%	2%	5.2	20%	-1%
Providence	Admiral Street #9	T3	115	23	62.1	63.7	24.3	39%	23.7	38%	-3%	25.3	41%	7%
Providence	Admiral Street #9	T4	115	23	63	64.9	23.7	38%	23.1	37%	-3%	24.7	39%	7%
Providence	Franklin Square #11	2207	11.5	23	16.06	18.75	1.4	9%	1.3	8%	-7%	1.5	10%	19%
Providence	Franklin Square #11	2210	11.5	23	17.14	15.85	6.0	35%	8.0	47%	33%	8.5	50%	6%
Providence	Franklin Square #11	2220	11.5	23	17.7	19.3	8.0	45%	7.8	44%	-2%	9.1	51%	16%
Providence	Franklin Square #11	2260	11.5	23	16.06	18.75	0.0	0%	0.0	0%	0%	0.0	0%	0%
Providence	South Street #1	2201	11.5	23	7.5	7.5	2.9	38%	2.9	38%	0%	2.9	39%	1%
Providence	South Street #1	2216	11.5	23	10	10	3.1	31%	3.0	30%	-4%	2.8	28%	-5%
Providence	South Street #1	2248	11.5	23	12.81	14.33	7.2	56%	6.4	50%	-11%	7.5	59%	17%
Providence	South Street #1	24	11.5	23	9.1	10.23	4.1	45%	4.2	46%	2%	4.5	49%	8%
Providence	Clarkson Street #13	T1	115	12.47	65.46	81.01	38.7	59%	29.8	45%	-23%	31.0	47%	4%
Providence	Clarkson Street #13	T2	115	12.47	65.16	80.24	32.0	49%	24.0	37%	-25%	27.0	42%	13%
Providence	Elmwood #7 (12.47 kV)	T2	23	12.47	40.58	45.78	22.4	55%	21.4	53%	-4%	24.0	59%	12%
Providence	Lippitt Hill #79	T1	22.9	12.47	25.11	27.54	8.1	32%	7.5	30%	-7%	7.6	30%	0%
Providence	Lippitt Hill #79	T2	22.9	12.47	25.11	27.54	8.3	33%	8.4	33%	2%	9.2	36%	9%
Providence	Point Street #76	T1	115	12.47	77	89.8	30.9	40%	29.5	38%	-5%	32.0	42%	8%
Providence	Point Street #76	T2	115	12.47	76.7	86.5	35.3	46%	33.2	43%	-6%	36.0	47%	8%
Providence	Franklin Square #11	T1	115	11.5	50.65	61.04	21.8	43%	22.5	44%	3%	22.4	44%	0%
Providence	Franklin Square #11	T2	115	11.5	51.24	56.69	23.0	45%	21.7	42%	-6%	21.0	41%	-3%
Providence	Franklin Square #11	T3	115	11.5	51.24	56.69	25.7	50%	25.1	49%	-2%	30.5	60%	22%
Providence	South Street #1	T1	115	11.5	66.34	78.75	23.6	36%	27.7	42%	17%	21.9	33%	-21%
Providence	South Street #1	T2	115	11.5	66.78	77.14	24.3	36%	29.0	43%	19%	21.3	32%	-27%
Providence	South Street #1	T3	115	11.5	72.69	91.22	21.0	29%	26.2	36%	25%	26.2	36%	0%
Providence	Admiral Street #9	T5	23	4.16	15.13	15.36	5.3	35%	5.2	34%	-2%	6.0	40%	16%
Providence	Dyer St #2	T1	11.5	4.16	18.27	19.78	5.6	30%	5.2	29%	-6%	5.5	30%	5%
Providence	Dyer St #2	T2	11.5	4.16	18.25	19.74	5.6	30%	5.2	29%	-6%	5.5	30%	5%
Providence	East George St. #77	T1	23	4.16	12.59	15.27	3.9	31%	3.7	29%	-6%	4.3	34%	17%
Providence	East George St. #77	T2	23	4.16	12.59	15.27	4.1	32%	4.2	33%	2%	4.5	35%	8%
Providence	Geneva #71	T1	23	4.16	11.54	14.19	3.7	32%	3.4	30%	-9%	3.3	29%	-2%
Providence	Geneva #71	T2	23	4.16	7	8	3.7	54%	3.4	49%	-9%	3.3	48%	-2%
Providence	Harris Avenue #12	T1	23	4.16	11.48	12.72	4.3	38%	4.1	36%	-6%	4.8	42%	18%
Providence	Harris Avenue #12	T2	23	4.16	9.06	11.52	1.4	15%	1.3	14%	-7%	1.5	17%	19%
Providence	Huntington Park #67	T1	23	4.16	3	3	1.7	55%	1.7	55%	-1%	1.8	61%	10%
Providence	Knightsville #66	T1	22.9	4.16	10.48	11.02	4.9	47%	4.5	42%	-9%	4.6	44%	4%
Providence	Knightsville #66	T2	22.9	4.16	10.48	11.02	4.9	47%	4.5	42%	-9%	4.6	44%	4%
Providence	Olneyville #6	T1	11.5	4.16	11.8	13.02	3.3	28%	3.1	26%	-8%	3.3	28%	8%
Providence	Olneyville #6	T3	11.5	4.16	11.8	13.02	3.3	28%	3.1	26%	-8%	3.3	28%	8%
Providence	Rochambeau Ave #37	T1	22.9	4.16	11.96	13.12	3.2	27%	2.7	23%	-17%	3.2	27%	18%
Providence	Rochambeau Ave #37	T2	11.45	4.16	11.02	13.04	5.2	47%	5.1	46%	-2%	4.8	44%	-5%
Providence	Sprague St. #36	T1	23	4.16	10.58	11.85	2.5	24%	2.5	24%	0%	2.5	24%	1%
Providence	Sprague St. #36	T2	23	4.16	10.79	12	3.2	30%	3.2	30%	0%	3.2	30%	1%
South County East	BONNET 42	2	34.5	12.47	11.3	12.2	10.1	89%	8.5	75%	-16%	9.2	81%	9%
South County East	DAVISVILLE 84	1	115	34.5	45.3	52.1	16.5	36%	16.6	37%	0%	19.0	42%	14%
South County East	DAVISVILLE 84	2A	115	34.5	45.1	51.8	21.2	47%	22.8	51%	7%	26.1	58%	14%
South County East	LAFAYETTE 30	1	34.5	12.47	7.6	8.6	5.1	67%	4.4	58%	-14%	4.9	64%	11%
South County East	LAFAYETTE 30	2	34.5	12.47	12.3	13.2	9.0	73%	7.5	61%	-17%	8.2	67%	10%
South County East	OLD BAPTIST ROAD 46	1	115	12.47	48.7	54.4	15.4	32%	14.1	29%	-8%	15.7	32%	11%
South County East	OLD BAPTIST ROAD 46	2	115	12.47	48.9	51.9	18.0	37%	15.8	32%	-12%	17.6	36%	11%
South County East	PEACEDALE 59	1	34.5	12.47	24.2	27.2	12.6	52%	10.9	45%	-13%	12.1	50%	11%

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South County East	PEACEDALE 59	2	34.5	12.47	24.2	27.2	10.1	42%	9.1	38%	-10%	10.6	44%	16%
South County East	QUONSET 83	1	34.5	12.47	25.6	26.7	14.5	57%	15.3	60%	6%	8.4	33%	-45%
South County East	WAKEFIELD 17	3	34.5	12.47	12.9	13.5	9.2	72%	8.4	65%	-10%	9.1	71%	9%
South County East	WAKEFIELD 17	4	34.5	12.47	12.9	13.5	10.0	77%	9.2	71%	-8%	10.1	78%	10%
South County East	WAKEFIELD 17	5	34.5	12.47	12.9	13.5	9.6	74%	9.0	70%	-6%	9.7	75%	8%
South County East	WEST KINGSTON 62	1	115	34.5	43.9	55.7	27.6	63%	23.6	54%	-15%	28.6	65%	21%
South County East	WEST KINGSTON 62	2	115	34.5	75.8	93.5	43.4	57%	38.0	50%	-12%	46.2	61%	22%
South County East	TOWER HILL 88	1	115	12.47	51	60	32.7	64%	29.7	58%	-9%	32.3	63%	9%
South County East	QUONSET 83	2	34.5	12.47	50	50	0.0	0%	0.0	0%	0%	11.0	22%	0%
South County East	BIPCO	1	34.5	2.4	10	11.5	0.0	0%	4.7	47%	0%	5.3	53%	14%
South County West	ASHAWAY 43	1	34.5	12.47	8.39	9.13	7.3	87%	6.7	80%	-8%	0.0	0%	-100%
South County West	HOPE VALLEY 41	1	34.5	12.47	7.25	9.29	6.4	89%	5.9	81%	-9%	0.0	0%	-100%
South County West	KENYON 68	1	115	12.47	49.68	53.71	16.8	34%	14.9	30%	-11%	15.8	32%	6%
South County West	KENYON 68	2	115	12.47	49.69	53.74	14.9	30%	13.1	26%	-12%	14.5	29%	11%
South County West	LANGWORTHY 86	1	34.5	12.47	13	14	11.3	87%	10.8	83%	-5%	10.7	82%	-1%
South County West	WESTERLY 16	2	34.5	12.47	25.6	26.65	18.3	72%	16.8	65%	-8%	18.7	73%	11%
South County West	WESTERLY 16	4	34.5	12.47	25.6	26.65	15.0	59%	16.0	63%	7%	15.3	60%	-4%
South County West	WOOD RIVER 85	10	115	34.5	48.18	52.44	46.3	96%	46.1	96%	0%	37.9	79%	-18%
South County West	WOOD RIVER 85	20	115	34.5	91.24	106.56	25.6	28%	23.5	26%	-8%	18.0	20%	-23%
South County West	CHASE HILL	2	115	12.47	54.3	63.5	0.0	0%	0.0	0%	0%	23.2	43%	0%
TIVERTON	TIVERTON	1	115	12.47	33.39	33.39	13.7	45%	12.6	38%	-8%	14.8	44%	18%
TIVERTON	TIVERTON	2	115	12.47	49.35	53.71	17.4	36%	15.5	31%	-11%	17.0	34%	10%

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Blackstone Valley North	Highland Park #200	T1	115	13.8	73	82	8.3	11%	15.0%	16.7	23%	-0.2%	16.7	23%	-0.2%
Blackstone Valley North	Highland Park #200	T2	115	13.8	70	79	7.5	11%	15.0%	17.2	25%	-0.2%	17.1	24%	-0.2%
Blackstone Valley North	Farnum #105	T1	115	23	37.3	37.3	1.8	5%	15.0%	1.8	5%	-0.2%	1.8	5%	-0.2%
Blackstone Valley North	Nasonville #127	T271	115	13.8	47.8	47.8	32.9	69%	15.0%	32.2	67%	-0.2%	32.4	68%	-0.2%
Blackstone Valley North	Riverside #108	T81	115	13.8	41.83	45.23	30.9	74%	15.0%	22.4	53%	-0.2%	22.3	53%	-0.2%
Blackstone Valley North	Riverside #108	T82	115	13.8	49.62	58.74	36.1	73%	15.0%	28.4	57%	-0.2%	28.3	57%	-0.2%
Blackstone Valley North	Staples #112	T124	115	13.8	47.8	47.8	26.3	55%	15.0%	24.2	51%	-0.2%	24.1	50%	-0.2%
Blackstone Valley North	West Farnum	T1	115	13.8	20	20	0.0	0%	15.0%	0.0	0%	-0.2%	0.0	0%	-0.2%
Blackstone Valley North	Woonsocket	T1	115	13.8	47.8	50	27.3	57%	15.0%	27.3	57%	-0.2%	27.2	57%	-0.2%
Blackstone Valley South	Valley #102	T23	115	24	42.01	51.51	3.0	7%	15.0%	3.0	7%	-0.2%	3.0	7%	-0.2%
Blackstone Valley South	Pawtucket No.1 #107	T71	115	13.8	47.8	47.8	33.0	69%	15.0%	33.8	71%	-0.2%	35.2	74%	-0.2%
Blackstone Valley South	Pawtucket No.1 #107	T73A	115	13.8	47.8	47.8	48.8	102%	15.0%	47.0	98%	-0.2%	46.9	98%	-0.2%
Blackstone Valley South	Pawtucket No.1 #107	T74	115	13.8	47.8	47.8	35.2	74%	15.0%	35.9	75%	-0.2%	35.8	75%	-0.2%
Blackstone Valley South	Valley #102	T21	115	13.8	38.36	45.95	22.1	58%	15.0%	22.0	57%	-0.2%	22.0	57%	-0.2%
Blackstone Valley South	Valley #102	T22	115	13.8	31.6	40.29	22.8	72%	15.0%	22.8	72%	-0.2%	22.7	72%	-0.2%
Blackstone Valley South	Washington #126	T261	115	13.8	47.8	47.8	27.1	57%	15.0%	27.0	57%	-0.2%	27.0	56%	-0.2%
Blackstone Valley South	Washington #126	T262	115	13.8	59.27	59.27	35.3	60%	15.0%	35.2	59%	-0.2%	35.1	59%	-0.2%
Blackstone Valley South	Central Falls #104	South Bank	13.8	4.16	3.12	3.12	2.1	66%	15.0%	2.1	66%	-0.2%	2.1	66%	-0.2%
Blackstone Valley South	Central Falls #104	North Bank	13.8	4.16	3	3	1.5	50%	15.0%	1.5	49%	-0.2%	1.5	49%	-0.2%
Blackstone Valley South	Centre Street #106	empty:u	13.8	4.16	3.1	3.1	2.4	76%	15.0%	2.4	76%	-0.2%	2.4	76%	-0.2%
Blackstone Valley South	Cottage St #109	empty:u	13.8	4.16	8.25	9.43	7.4	90%	15.0%	7.4	89%	-0.2%	7.4	89%	-0.2%
Blackstone Valley South	Crossman St #111	empty:u	13.8	4.16	8.26	9.44	3.7	45%	15.0%	3.7	45%	-0.2%	3.7	45%	-0.2%
Blackstone Valley South	Daggett Ave #113	empty:u	13.8	4.16	4.23	5.02	4.0	95%	15.0%	0.0	0%	-0.2%	0.0	0%	-0.2%
Blackstone Valley South	Front #24	empty:u	13.8	4.16	3.1	3.1	1.6	51%	15.0%	1.6	51%	-0.2%	1.6	51%	-0.2%
Blackstone Valley South	Hyde Avenue #28	empty:u	13.8	4.16	5.25	5.25	3.4	65%	15.0%	0.0	0%	0.0%	0.0	0%	0.0%
Blackstone Valley South	Lee St. #30	empty:u	13.8	4.16	7	7	6.3	90%	15.0%	6.3	90%	-0.2%	6.3	90%	-0.2%
Blackstone Valley South	Pawtucket No.2 #148	T1	13.8	4.16	7.6	9.36	3.4	45%	15.0%	3.4	45%	-0.2%	3.4	45%	-0.2%
Blackstone Valley South	Pawtucket No.2 #148	T2	13.8	4.16	7.6	9.36	3.6	48%	15.0%	3.6	48%	-0.2%	3.6	48%	-0.2%
Blackstone Valley South	Southeast #60	T1	115	13.8	70	80	0.0	0%	0.0%	0.0	0%	0.0%	0.0	0%	0.0%
Blackstone Valley South	Southeast #60	T2	115	13.8	70	80	0.0	0%	0.0%	0.0	0%	0.0%	0.0	0%	0.0%
Central RI East	APPONAUG 3	3	23	12.47	15.5	19.6	8.1	52%	15.5%	8.1	52%	0.3%	8.1	52%	0.2%
Central RI East	APPONAUG 3	4	23	12.47	11.9	12.6	6.9	58%	15.5%	8.2	69%	0.3%	8.2	69%	0.2%
Central RI East	KILVERT STREET 87	1	115	12.47	72	82	15.4	21%	15.5%	23.2	32%	0.3%	23.3	32%	0.2%
Central RI East	KILVERT STREET 87	2	115	12.47	70	79	15.2	22%	15.5%	21.0	30%	0.3%	21.1	30%	0.2%
Central RI East	LINCOLN AVENUE 72	1	115	12.47	52.07	54.92	28.4	55%	15.5%	24.6	47%	0.3%	24.6	47%	0.2%
Central RI East	LINCOLN AVENUE 72	2	115	12.47	52.07	54.92	26.5	51%	15.5%	25.3	49%	0.3%	25.4	49%	0.2%
Central RI East	PONTIAC 27	1	115	12.47	50.67	53.32	21.6	43%	15.5%	21.6	43%	0.3%	21.7	43%	0.2%
Central RI East	PONTIAC 27	2	115	12.47	46.49	51.88	24.6	53%	15.5%	22.6	49%	0.3%	22.7	49%	0.2%
Central RI East	WARWICK 52	1	23	12.47	11.6	12.7	9.9	85%	15.5%	7.6	65%	0.3%	7.6	65%	0.2%
Central RI East	WARWICK 52	4	23	12.47	12	12	8.1	68%	15.5%	8.1	68%	0.3%	8.1	68%	0.2%
Central RI East	AUBURN 73	1	23	4.16	10.56	11.81	5.6	53%	15.5%	5.6	53%	0.3%	5.6	53%	0.2%
Central RI East	AUBURN 73	2	23	4.16	9.66	10.64	3.8	39%	15.5%	3.8	39%	0.3%	3.8	39%	0.2%
Central RI East	LAKEWOOD 57	1	23	4.16	10.09	10.63	4.7	47%	15.5%	4.7	47%	0.3%	4.7	47%	0.2%
Central RI East	LAKEWOOD 57	2	23	4.16	10.15	11.46	3.1	31%	15.5%	3.1	31%	0.3%	3.1	31%	0.2%
Central RI East	DRUMROCK 14	3	115	23/12.47	53	76.04	28.7	54%	15.5%	28.8	54%	0.3%	28.9	55%	0.2%
Central RI East	DRUMROCK 14	4	115	23	89	107.4	38.4	43%	15.5%	38.6	43%	0.3%	38.6	43%	0.2%
Central RI East	DRUMROCK 14	5	115	23/12.47	107	107	53.0	50%	15.5%	53.2	50%	0.3%	53.3	50%	0.2%
Central RI East	SOCKANOSSET 24	1	115	23	50.29	56.81	19.2	38%	15.5%	19.3	38%	0.3%	19.3	38%	0.2%
Central RI East	SOCKANOSSET 24	2	115	23	50.37	57.03	20.6	41%	15.5%	20.7	41%	0.3%	20.7	41%	0.2%
Central RI West	ANTHONY	1	23	12.47	7.8	8.1	4.9	62%	15.5%	4.9	63%	0.3%	4.9	63%	0.2%
Central RI West	ANTHONY	2	23	12.47	7.8	8.1	7.2	92%	15.5%	4.0	51%	0.3%	4.0	51%	0.2%
Central RI West	COVENTRY	1	23	12.47	11.4	13.5	9.1	79%	15.5%	9.1	80%	0.3%	9.1	80%	0.2%
Central RI West	DIVISION ST	1	34.5	12.47	23.7	27.6	15.7	66%	15.5%	15.8	67%	0.3%	15.8	67%	0.2%
Central RI West	DIVISION ST	2	34.5	12.47	23.7	27.6	14.2	60%	15.5%	11.4	48%	0.3%	11.4	48%	0.2%
Central RI West	HOPE	1	23	12.47	7.53	8.51	6.9	91%	15.5%	4.2	55%	0.3%	4.2	56%	0.2%
Central RI West	HOPE	2	23	12.47	13.65	16.46	9.3	68%	15.5%	7.7	56%	0.3%	7.7	56%	0.2%
Central RI West	HOPKINS HILL	1	34.5	12.47	48.8	51	21.4	44%	15.5%	19.9	41%	0.3%	20.0	41%	0.2%
Central RI West	HOPKINS HILL	2	34.5	12.47	49.2	52	25.9	53%	15.5%	24.4	50%	0.3%	24.4	50%	0.2%
Central RI West	HUNT RIVER	2	34.5	12.47	11.22	12.67	0.0	0%	15.5%	0.0	0%	0.3%	0.0	0%	0.2%
Central RI West	KENT COUNTY	1	115	34.5	57.25	67.64	30.7	54%	15.5%	29.3	51%	0.3%	29.3	51%	0.2%
Central RI West	KENT COUNTY	2	115	34.5	66.33	69.9	36.1	54%	15.5%	34.8	52%	0.3%	34.8	52%	0.2%
Central RI West	KENT COUNTY	6	115	12.47	50.69	58.89	18.0	36%	15.5%	15.2	30%	0.3%	15.3	30%	0.2%

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			From Voltage (kV)	To Voltage (kV)	Normal Rating	Emergency Rating	Projected Load	%SN	Growth Rate	Projected Load	%SN	Growth Rate	Projected Load	%SN	Growth Rate
Central RI West	KENT COUNTY	7	115	34.5	57.25	68.78	37.3	65%	15.5%	35.9	63%	0.3%	36.0	63%	0.2%
Central RI West	KENT COUNTY	5	115	12.47	50	58	24.1	48%	empty:	24.2	48%	0.3%	24.2	48%	0.2%
Central RI West	NATICK	1	23	12.47	13.2	14.3	8.0	61%	15.5%	6.3	48%	0.3%	6.3	48%	0.2%
Central RI West	NATICK	2	23	12.47	13.5	14.5	6.1	45%	15.5%	6.8	50%	0.3%	6.8	50%	0.2%
Central RI West	WARWICK MALL	1	23	12.47	8.8	8.9	3.1	36%	15.5%	3.2	36%	0.3%	3.2	36%	0.2%
Central RI West	WARWICK MALL	2	23	12.47	8.7	9.1	2.0	23%	15.5%	2.0	23%	0.3%	2.0	24%	0.2%
Central RI West	ARCTIC	1	23	4.16	5	5	3.4	67%	15.5%	0.0	0%	0.3%	0.0	0%	0.2%
Central RI West	ARCTIC	2	23	4.16	6.7	7.4	3.1	46%	15.5%	0.0	0%	0.3%	0.0	0%	0.2%
Central RI West	TIOGUE AVE	1	34.5	12.47	13	14	10.7	82%	15.5%	10.7	83%	0.3%	10.8	83%	0.2%
Central RI West	NEW LONDON AVE	1	115	12.47	55	60	empty:	empty:	empty:	29.5	54%	0.3%	29.6	54%	0.2%
East Bay	BARRINGTON 4	1	23	12.47	35.19	35.19	15.5	44%	15.6%	15.5	44%	0.3%	15.6	44%	0.2%
East Bay	BRISTOL 51	1	115	12.47	56.9	63.4	19.2	34%	15.6%	19.2	34%	0.3%	19.3	34%	0.2%
East Bay	BRISTOL 51	2	23	12.47	25.1	29.8	10.4	42%	15.6%	10.4	42%	0.3%	10.5	42%	0.2%
East Bay	PHILLIPSDALE 20	T1	115	23	56	56	19.8	35%	15.6%	19.9	35%	0.3%	19.9	36%	0.2%
East Bay	PHILLIPSDALE 20	T2	115	23	45.32	56.75	8.9	20%	15.6%	8.9	20%	0.3%	8.9	20%	0.2%
East Bay	PHILLIPSDALE 20	T3	23	12.47	25.16	28.87	14.5	58%	15.6%	14.5	58%	0.3%	14.6	58%	0.2%
East Bay	WAMPANOAG 48	T1	115	12.47	42.83	52.72	29.1	68%	15.6%	29.1	68%	0.3%	29.2	68%	0.2%
East Bay	WAMPANOAG 48	T2	115	12.47	52.36	55.33	29.7	57%	15.6%	29.8	57%	0.3%	29.9	57%	0.2%
East Bay	WARREN 5	T1	115	12.47	48.28	53.43	15.9	33%	15.6%	16.0	33%	0.3%	16.0	33%	0.2%
East Bay	WARREN 5	T2	115	12.47	50.62	59.57	16.9	33%	15.6%	16.9	33%	0.3%	17.0	34%	0.2%
East Bay	WARREN 5	5	115	23	60.96	65.05	9.8	16%	15.6%	9.8	16%	0.3%	9.8	16%	0.2%
East Bay	WARREN 5	6	115	23	59.6	64.17	22.8	38%	15.6%	22.9	38%	0.3%	22.9	38%	0.2%
East Bay	WATERMAN AVENUE 78	T1	23	12.47	16.36	18.26	5.2	32%	15.6%	5.2	32%	0.3%	5.2	32%	0.2%
East Bay	WATERMAN AVENUE 78	T2	23	12.47	16.36	18.26	5.0	31%	15.6%	5.0	31%	0.3%	5.0	31%	0.2%
East Bay	KENT CORNERS 47	T1	23	4.16	7.14	7.53	2.7	38%	15.6%	2.7	38%	0.3%	2.7	38%	0.2%
East Bay	KENT CORNERS 47	T2	23	4.16	6.82	8.07	4.0	58%	15.6%	4.0	58%	0.3%	4.0	58%	0.2%
East Bay	EAST PROVIDENCE SUB	T1	115	12.47	50	60	0.0	0%	0.0%	0.0	0%	0.0%	0.0	0%	0.0%
East Bay	PHILLIPSDALE 20	T4	115	12.47	50	60	0.0	0%	0.0%	0.0	0%	0.0%	0.0	0%	0.0%
Newport	Bailey Brook	191	23	4.16	8.32	8.68	1.6	19%	14.6%	1.6	19%	-0.7%	1.6	19%	-0.8%
Newport	Bailey Brook	192	23	4.16	8.57	10.43	1.9	22%	14.6%	1.9	22%	-0.7%	1.9	22%	-0.8%
Newport	Clarke St	651	23	4.16	4.06	4.34	3.0	74%	14.6%	3.0	73%	-0.7%	2.9	73%	-0.8%
Newport	Clarke St	652	23	4.16	6	7	2.8	46%	14.6%	2.7	46%	-0.7%	2.7	45%	-0.8%
Newport	Dexter	361	115	69	121	130	67.2	56%	14.6%	66.7	55%	-0.7%	66.2	55%	-0.8%
Newport	Dexter	362	115	69	61	65	29.0	48%	14.6%	28.8	47%	-0.7%	28.6	47%	-0.8%
Newport	Dexter	363	115	69	61	65	29.0	48%	14.6%	28.8	47%	-0.7%	28.6	47%	-0.8%
Newport	Dexter	364	115	13.8	44.64	47.44	24.1	54%	14.6%	23.9	54%	-0.7%	23.7	53%	-0.8%
Newport	Eldred	T1	23	4.16	6.54	7.4	3.5	53%	14.6%	3.5	53%	-0.7%	3.4	52%	-0.8%
Newport	Gate 2	381	69	23	54.24	63.7	20.7	38%	14.6%	20.6	38%	-0.7%	20.4	38%	-0.8%
Newport	Gate 2	T2	69	13.8	11	12	7.9	72%	14.6%	7.9	71%	-0.7%	7.8	71%	-0.8%
Newport	Gate 2	731	23	4.16	8.11	8.7	3.5	44%	14.6%	3.5	43%	-0.7%	3.5	43%	-0.8%
Newport	Harrison	321	23	4.16	8.33	9.73	3.1	37%	14.6%	3.1	37%	-0.7%	3.1	37%	-0.8%
Newport	Harrison	322	23	4.16	8.07	10.12	4.7	58%	14.6%	4.6	58%	-0.7%	4.6	57%	-0.8%
Newport	Hospital	461	23	4.16	4.06	4.34	2.0	48%	14.6%	1.9	48%	-0.7%	1.9	48%	-0.8%
Newport	Hospital	462	23	4.16	4.06	4.34	2.1	51%	14.6%	2.1	51%	-0.7%	2.1	51%	-0.8%
Newport	Jepson	371	69	23	16.52	18.47	2.4	15%	14.6%	2.4	14%	-0.7%	2.4	14%	-0.8%
Newport	Jepson	372	69	23	23.2	24.8	10.8	46%	14.6%	10.7	46%	-0.7%	10.6	46%	-0.8%
Newport	Jepson	373	69	23	48.88	57.87	31.1	64%	14.6%	30.9	63%	-0.7%	30.6	63%	-0.8%
Newport	Jepson	374	69	13.8	42.86	48.58	24.4	57%	14.6%	24.2	56%	-0.7%	24.0	56%	-0.8%
Newport	Jepson	341	23	4.16	9.74	10.42	2.2	23%	14.6%	2.2	22%	-0.7%	2.2	22%	-0.8%
Newport	Jepson	376	69	23	15.44	16.35	6.6	43%	14.6%	6.6	43%	-0.7%	6.5	42%	-0.8%
Newport	Kingston	311	23	4.16	7.9	9.56	5.8	74%	14.6%	5.8	73%	-0.7%	5.7	73%	-0.8%
Newport	Kingston	312	23	4.16	7.9	9.56	4.5	57%	14.6%	4.4	56%	-0.7%	4.4	56%	-0.8%
Newport	Merton	511	23	4.16	2.24	2.4	2.1	92%	14.6%	2.0	91%	-0.7%	2.0	90%	-0.8%
Newport	Merton	512	23	4.16	8.38	10	5.6	67%	14.6%	5.6	67%	-0.7%	5.5	66%	-0.8%
Newport	No. Aquidneck	211	23	4.16	7.98	10.2	4.9	61%	14.6%	4.8	60%	-0.7%	4.8	60%	-0.8%
Newport	So. Aquidneck	221	23	4.16	7.9	9.56	7.9	100%	14.6%	7.9	100%	-0.7%	7.8	99%	-0.8%
Newport	Vernon Ave	231	23	4.16	3.63	3.88	3.3	90%	14.6%	3.2	89%	-0.7%	3.2	88%	-0.8%
Newport	Vernon Ave	232	23	4.16	3.63	3.88	1.1	29%	14.6%	1.1	29%	-0.7%	1.0	29%	-0.8%
Newport	West Howard	541	23	4.16	12.57	14.76	6.5	52%	14.6%	6.5	52%	-0.7%	6.4	51%	-0.8%
Newport	West Howard	542	23	4.16	13.09	13.58	3.8	29%	14.6%	3.7	28%	-0.7%	3.7	28%	-0.8%
Newport	Newport Sub	T1	69	13.8	0	0	0.0	0%	0.0%	0.0	0%	0.0%	0.0	0%	0.0%
Newport	Jepson	T2	69	13.8	0	0	0.0	0%	0.0%	0.0	0%	0.0%	0.0	0%	0.0%

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Newport	Eldred	T2	23	4.16	6.49	7.35	2.4	36%	14.6%	2.3	36%	-0.7%	2.3	36%	-0.8%
North Central RI	Johnston #18	T1	115	23	63.4	77	32.9	52%	15.6%	33.0	52%	0.3%	33.1	52%	0.2%
North Central RI	Johnston #18	T2	115	23	80	90	28.7	36%	15.6%	28.8	36%	0.3%	28.9	36%	0.2%
North Central RI	Wolf Hill #19	T1	115	23	65.01	69.83	27.8	43%	15.6%	27.9	43%	0.3%	28.0	43%	0.2%
North Central RI	Centerdale #50	T3	23	12.47	7.93	8.34	5.9	74%	15.6%	5.9	75%	0.3%	5.9	75%	0.2%
North Central RI	Chopmist #34	T1	23	12.47	15.96	16.42	9.4	59%	15.6%	9.5	59%	0.3%	9.5	59%	0.2%
North Central RI	Chopmist #34	T2	23	12.47	13.84	13.57	7.0	51%	15.6%	7.0	51%	0.3%	7.0	51%	0.2%
North Central RI	Chopmist #34	T3	23	12.47	12.81	13.94	7.0	55%	15.6%	7.0	55%	0.3%	7.0	55%	0.2%
North Central RI	Farnum Pike #23 (New)	T1	115	12.47	77	86	20.9	27%	15.6%	20.9	27%	0.3%	21.0	27%	0.2%
North Central RI	Farnum Pike #23 (New)	T2	115	12.47	77	86	22.8	30%	15.6%	22.9	30%	0.3%	22.9	30%	0.2%
North Central RI	Johnston #18	T1	115	12.47	25	35	0.0	0%	15.6%	0.0	0%	0.3%	0.0	0%	0.2%
North Central RI	Johnston #18	T3	115	12.47	80	94	41.9	52%	15.6%	42.1	53%	0.3%	42.1	53%	0.2%
North Central RI	Johnston #18	T4	115	12.47	68.6	74	31.8	46%	15.6%	31.9	47%	0.3%	31.3	46%	0.2%
North Central RI	Manton #69	T2	23	12.47	25.46	26.66	18.2	71%	15.6%	18.2	72%	0.3%	18.2	72%	0.2%
North Central RI	Putnam Pike #38	T1	115	12.47	64.94	68.79	28.8	44%	15.6%	28.8	44%	0.3%	33.0	51%	0.2%
North Central RI	Putnam Pike #38	T2	115	12.47	64.94	68.79	19.0	29%	15.6%	19.0	29%	0.3%	20.3	31%	0.2%
North Central RI	West Cranston #21	T1	115	12.47	27.78	29.91	11.0	40%	15.6%	11.0	40%	0.3%	11.1	40%	0.2%
North Central RI	West Cranston #21	T2	115	12.47	27.76	29.86	19.5	70%	15.6%	19.6	71%	0.3%	19.6	71%	0.2%
North Central RI	West Greenville # 45	T3	23	12.47	11.91	13.56	2.0	17%	15.6%	2.0	17%	0.3%	2.0	17%	0.2%
North Central RI	Centerdale #50	T1	23	4.16	7.1	7.54	2.6	37%	15.6%	2.6	37%	0.3%	2.6	37%	0.2%
Providence	Admiral Street #9	T1	23	11/4.16	15	15	12.5	84%	15.6%	12.6	84%	0.3%	12.6	84%	0.2%
Providence	Admiral Street #9	T2	23	11/4.16	15	15	0.0	0%	15.6%	0.0	0%	0.3%	0.0	0%	0.2%
Providence	Franklin Square #11	3320	11.5	34.5	25.87	29.66	6.2	24%	15.6%	6.2	24%	0.3%	6.2	24%	0.2%
Providence	Franklin Square #11	3324	11.5	34.5	25.75	29.5	6.2	24%	15.6%	6.2	24%	0.3%	6.2	24%	0.2%
Providence	Admiral Street #9	T3	115	23	62.1	63.7	25.4	41%	15.6%	25.5	41%	0.3%	25.5	41%	0.2%
Providence	Admiral Street #9	T4	115	23	63	64.9	24.8	39%	15.6%	24.9	39%	0.3%	24.9	40%	0.2%
Providence	Franklin Square #11	2207	11.5	23	16.06	18.75	1.6	10%	15.6%	1.6	10%	0.3%	1.6	10%	0.2%
Providence	Franklin Square #11	2210	11.5	23	17.14	15.85	11.4	66%	15.6%	11.4	66%	0.3%	11.4	67%	0.2%
Providence	Franklin Square #11	2220	11.5	23	17.7	19.3	9.5	54%	15.6%	9.6	54%	0.3%	9.6	54%	0.2%
Providence	Franklin Square #11	2260	11.5	23	16.06	18.75	8.0	50%	15.6%	8.0	50%	0.3%	8.0	50%	0.2%
Providence	South Street #1	2201	11.5	23	7.5	7.5	3.2	43%	15.6%	3.2	43%	0.3%	3.2	43%	0.2%
Providence	South Street #1	2216	11.5	23	10	10	5.8	58%	15.6%	5.8	58%	0.3%	5.8	58%	0.2%
Providence	South Street #1	2248	11.5	23	12.81	14.33	8.3	65%	15.6%	8.3	65%	0.3%	8.3	65%	0.2%
Providence	South Street #1	24	11.5	23	9.1	10.23	4.7	51%	15.6%	4.7	51%	0.3%	4.7	51%	0.2%
Providence	Clarkson Street #13	T1	115	12.47	65.46	81.01	36.7	56%	15.6%	36.8	56%	0.3%	36.9	56%	0.2%
Providence	Clarkson Street #13	T2	115	12.47	65.16	80.24	36.2	56%	15.6%	36.3	56%	0.3%	36.4	56%	0.2%
Providence	Elmwood #7 (12.47 kV)	T2	23	12.47	40.58	45.78	26.2	65%	15.6%	26.3	65%	0.3%	26.4	65%	0.2%
Providence	Lippitt Hill #79	T1	22.9	12.47	25.11	27.54	9.5	38%	15.6%	9.5	38%	0.3%	9.5	38%	0.2%
Providence	Lippitt Hill #79	T2	22.9	12.47	25.11	27.54	9.1	36%	15.6%	9.1	36%	0.3%	9.1	36%	0.2%
Providence	Point Street #76	T1	115	12.47	77	89.8	34.3	45%	15.6%	35.0	45%	0.3%	35.1	46%	0.2%
Providence	Point Street #76	T2	115	12.47	76.7	86.5	36.7	48%	15.6%	37.0	48%	0.3%	37.0	48%	0.2%
Providence	Franklin Square #11	T1	115	11.5	50.65	61.04	28.9	57%	15.6%	29.0	57%	0.3%	29.0	57%	0.2%
Providence	Franklin Square #11	T2	115	11.5	51.24	56.69	25.2	49%	15.6%	25.3	49%	0.3%	25.3	49%	0.2%
Providence	Franklin Square #11	T3	115	11.5	51.24	56.69	30.3	59%	15.6%	30.4	59%	0.3%	30.4	59%	0.2%
Providence	South Street #1	T1	115	11.5	66.34	78.75	38.7	58%	15.6%	38.8	59%	0.3%	38.9	59%	0.2%
Providence	South Street #1	T2	115	11.5	66.78	77.14	27.2	41%	15.6%	27.3	41%	0.3%	27.4	41%	0.2%
Providence	South Street #1	T3	115	11.5	72.69	91.22	31.2	43%	15.6%	31.3	43%	0.3%	31.4	43%	0.2%
Providence	Admiral Street #9	T5	23	4.16	15.13	15.36	6.1	40%	15.6%	6.3	41%	0.3%	6.3	42%	0.2%
Providence	Dyer St #2	T1	11.5	4.16	18.27	19.78	6.6	36%	15.6%	6.6	36%	0.3%	6.7	36%	0.2%
Providence	Dyer St #2	T2	11.5	4.16	18.25	19.74	6.6	36%	15.6%	6.6	36%	0.3%	6.7	36%	0.2%
Providence	East George St. #77	T1	23	4.16	12.59	15.27	4.3	34%	15.6%	4.3	34%	0.3%	4.4	35%	0.2%
Providence	East George St. #77	T2	23	4.16	12.59	15.27	4.7	37%	15.6%	4.7	37%	0.3%	4.7	37%	0.2%
Providence	Geneva #71	T1	23	4.16	11.54	14.19	3.9	34%	15.6%	3.9	34%	0.3%	3.9	34%	0.2%
Providence	Geneva #71	T2	23	4.16	7	8	3.9	56%	15.6%	3.9	56%	0.3%	3.9	56%	0.2%
Providence	Harris Avenue #12	T1	23	4.16	11.48	12.72	5.1	44%	15.6%	5.1	45%	0.3%	5.1	45%	0.2%
Providence	Harris Avenue #12	T2	23	4.16	9.06	11.52	1.6	18%	15.6%	1.6	18%	0.3%	1.6	18%	0.2%
Providence	Huntington Park #67	T1	23	4.16	3	3	1.8	61%	15.6%	1.8	62%	0.3%	1.9	62%	0.2%
Providence	Knightsville #66	T1	22.9	4.16	10.48	11.02	5.0	48%	15.6%	5.0	48%	0.3%	5.0	48%	0.2%
Providence	Knightsville #66	T2	22.9	4.16	10.48	11.02	5.0	48%	15.6%	5.0	48%	0.3%	5.0	48%	0.2%
Providence	Olneyville #6	T1	11.5	4.16	11.8	13.02	3.8	32%	15.6%	3.8	32%	0.3%	3.8	32%	0.2%
Providence	Olneyville #6	T3	11.5	4.16	11.8	13.02	3.8	32%	15.6%	3.8	32%	0.3%	3.8	32%	0.2%
Providence	Rochambeau Ave #37	T1	22.9	4.16	11.96	13.12	3.9	33%	15.6%	4.0	33%	0.3%	4.0	33%	0.2%

Study Area	Substation	Transformer ID	System Voltage (kV)		Rating (MVA)		2016			2017			2018		
			From Voltage (kV)	To Voltage (kV)	Normal Rating	Emergency Rating	Projected Load	%SN	Growth Rate	Projected Load	%SN	Growth Rate	Projected Load	%SN	Growth Rate
Providence	Rochambeau Ave #37	T2	11.45	4.16	11.02	13.04	5.7	52%	15.6%	5.7	52%	0.3%	5.7	52%	0.2%
Providence	Sprague St. #36	T1	23	4.16	10.58	11.85	2.8	27%	15.6%	2.8	27%	0.3%	2.8	27%	0.2%
Providence	Sprague St. #36	T2	23	4.16	10.79	12	3.6	33%	15.6%	3.6	33%	0.3%	3.6	34%	0.2%
South County East	BONNET 42	2	34.5	12.47	11.3	12.2	8.9	79%	15.5%	8.9	79%	0.3%	8.9	79%	0.2%
South County East	DAVISVILLE 84	1	115	34.5	45.3	52.1	15.4	34%	15.5%	15.5	34%	0.3%	21.6	48%	0.2%
South County East	DAVISVILLE 84	2A	115	34.5	45.1	51.8	30.2	67%	15.5%	31.0	69%	0.3%	24.2	54%	0.2%
South County East	LAFAYETTE 30	1	34.5	12.47	7.6	8.6	5.6	74%	15.5%	5.6	74%	0.3%	5.7	74%	0.2%
South County East	LAFAYETTE 30	2	34.5	12.47	12.3	13.2	9.0	73%	15.5%	9.0	74%	0.3%	9.1	74%	0.2%
South County East	OLD BAPTIST ROAD 46	1	115	12.47	48.7	54.4	15.9	33%	15.5%	16.0	33%	0.3%	16.0	33%	0.2%
South County East	OLD BAPTIST ROAD 46	2	115	12.47	48.9	51.9	18.1	37%	15.5%	18.2	37%	0.3%	18.2	37%	0.2%
South County East	PEACEDALE 59	1	34.5	12.47	24.2	27.2	11.8	49%	15.5%	11.8	49%	0.3%	11.8	49%	0.2%
South County East	PEACEDALE 59	2	34.5	12.47	24.2	27.2	10.8	45%	15.5%	10.9	45%	0.3%	10.9	45%	0.2%
South County East	QUONSET 83	1	34.5	12.47	25.6	26.7	19.7	77%	15.5%	20.6	80%	0.3%	9.8	38%	0.2%
South County East	WAKEFIELD 17	3	34.5	12.47	12.9	13.5	9.2	71%	15.5%	9.2	71%	0.3%	9.2	71%	0.2%
South County East	WAKEFIELD 17	4	34.5	12.47	12.9	13.5	10.1	79%	15.5%	10.2	79%	0.3%	10.2	79%	0.2%
South County East	WAKEFIELD 17	5	34.5	12.47	12.9	13.5	10.1	78%	15.5%	10.1	79%	0.3%	10.2	79%	0.2%
South County East	WEST KINGSTON 62	1	115	34.5	43.9	55.7	28.4	65%	15.5%	28.5	65%	0.3%	28.5	65%	0.2%
South County East	WEST KINGSTON 62	2	115	34.5	75.8	93.5	44.5	59%	15.5%	44.6	59%	0.3%	44.6	59%	0.2%
South County East	TOWER HILL 88	1	115	12.47	51	60	33.5	66%	15.5%	33.6	66%	0.3%	33.7	66%	0.2%
South County East	QUONSET 83	2	34.5	12.47	50	50	0.0	0%	0.0%	0.0	0%	0.0%	10.8	22%	0.2%
South County West	ASHAWAY 43	1	34.5	12.47	8.39	9.13	7.5	89%	15.5%	7.5	90%	0.3%	0.0	0%	0.2%
South County West	HOPE VALLEY 41	1	34.5	12.47	7.25	9.29	6.5	89%	15.5%	6.5	90%	0.3%	0.0	0%	0.2%
South County West	KENYON 68	1	115	12.47	49.68	53.71	17.6	36%	15.5%	17.7	36%	0.3%	17.7	36%	0.2%
South County West	KENYON 68	2	115	12.47	49.69	53.74	15.6	31%	15.5%	15.7	32%	0.3%	15.7	32%	0.2%
South County West	LANGWORTHY 86	1	34.5	12.47	13	14	11.0	84%	15.5%	11.0	85%	0.3%	8.8	68%	0.2%
South County West	WESTERLY 16	2	34.5	12.47	25.6	26.65	19.6	76%	15.5%	19.6	77%	0.3%	17.6	69%	0.2%
South County West	WESTERLY 16	4	34.5	12.47	25.6	26.65	16.0	63%	15.5%	16.0	63%	0.3%	13.9	54%	0.2%
South County West	WOOD RIVER 85	10	115	34.5	48.18	52.44	43.7	**91%**	15.5%	43.8	**91%**	0.3%	33.2	69%	0.2%
South County West	WOOD RIVER 85	20	115	34.5	91.24	106.56	27.1	30%	15.5%	27.1	30%	0.3%	18.2	20%	0.2%
South County West	CHASE HILL	2	115	12.47	0	0	0.0	0%	0.0%	0.0	0%	0.0%	19.4	39%	0.2%
TIVERTON	TIVERTON	1	115	12.47	33.39	33.39	14.1	42%	15.6%	14.1	42%	0.3%	14.2	42%	0.2%
TIVERTON	TIVERTON	2	115	12.47	49.35	53.71	18.7	38%	15.6%	18.8	38%	0.3%	18.8	38%	0.2%

nationalgrid

Jennifer Brooks Hutchinson
Acting Assistant General Counsel and Director

November 22, 2019

VIA HAND DELIVERY & ELECTRONIC MAIL

Rhode Island Division of Public Utilities and Carriers
c/o Luly E. Massaro
89 Jefferson Boulevard
Warwick, RI 02888

RE: National Grid's Proposed FY 2021 Electric Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – R-II-5

Dear Ms. Massaro:

I have enclosed National Grid's[1] response to Division R-II-5.

This transmittal completes the Company's responses to the Division's Second Set of Data Requests in the above-referenced matter.

Thank you for your attention to this transmittal. If you have any questions, please contact me at 401-784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosure

cc: Leo Wold, Esq.
John Bell, Division
Greg Booth, Division
Linda Kushner, Division
Al Contente, Division

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

280 Melrose Street, Providence, RI 02907
T: 401-784-7288 ■ jennifer.hutchinson@nationalgrid.com ■ www.nationalgrid.com

R-II-5

Request:

In Section 2, pages 25 and 26 of 38, the Company discusses the Underground Cable Strategy. How many feet of cable was replaced through the damage and failure category in 2018 and 2019, including the dollars associated with each year's replacements, and what was the age of the failed cables?

Response:

Please see the table below for the requested information.

Year	Feet Installed	Feet Removed	Cost	Average Age
2018	22,602	22,108	$2,339,184	27 years
2019	15,479	18,724	$1,955,048	26 years

Prepared by or under the supervision of: Patricia C. Easterly