The Narragansett Electric Company
d/b/a National Grid

Electric Infrastructure, Safety, and Reliability Plan FY 2022 Proposal

Responses to Division's Data Requests

Book 2 of 2

December 21, 2020

Docket No. 5098

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:
nationalgrid

Filing Letter

Andrew S. Marcaccio
Senior Counsel

December 21, 2020

VIA ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: National Grid's Proposed FY 2022 Electric Infrastructure, Safety, and Reliability Plan Docket No. 5098

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company"), enclosed[1], please see the Company's proposed Electric Infrastructure, Safety, and Reliability Plan (the "Electric ISR Plan" or "Plan") for fiscal year ("FY") 2022 for review by the Public Utilities Commission ("Commission"). This Electric ISR Plan is being filed in accordance with R.I. Gen. Laws § 39-1-27.7.1(d).

In accordance with R.I. Gen. Laws § 39-1-27.7.1(d), the enclosed Plan addresses (i) capital spending on electric infrastructure; (ii) operation and maintenance ("O&M") expenses on vegetation management; (iii) O&M expenses on system inspection; and (iv) other costs related to maintaining the safety and reliability of the electric distribution system ("Other O&M"). In accordance with R.I. Gen. Laws § 39-1-27.7.1(c)(2), the enclosed Plan also addresses revenue requirement, rate design and bill impacts.

On October 2, 2020, the Company submitted an earlier version of the enclosed Electric ISR Plan to the Division of Public Utilities and Carriers ("Division"). In accordance with R.I. Gen. Laws § 39-1-27.7.1(d), the Division worked in cooperation with the Company to reach an agreement on a proposed plan to be filed with the Commission. Specifically, the Company consulted with the Division's representatives and received and responded to discovery requests from the Division. As a result of this process, the earlier version of the Plan was refined resulting in the enclosed Electric ISR Plan. The Division has indicated general concurrence with the enclosed Electric ISR Plan.

In support of the Electric ISR Plan, the Company has included joint pre-filed direct testimony of Patricia C. Easterly, Ryan A. Moe, And Caitlin Broderick. As explained in their joint testimony, the Company is proposing spending of $103.7 million of capital investment (approved FY 2021 was $103.8 million); $10.8 million of vegetation management O&M spending (approved

[1] Per Commission counsel's update on October 2, 2020, concerning the COVID-19 emergency period, the Company is submitting an electronic version of this filing followed by an original and five hard copies filed with the Clerk within 24 hours of the electronic filing.

280 Melrose Street, Providence, RI 02907
T: 401-784-7263 ■ andrew.marcaccio@nationalgrid.com ■ www.nationalgrid.com

FY 2021 was $10.6 million); and $1.2 million of Other O&M spending (approved FY 2021 was $1.5 million). Their joint testimony also explains the Company's application of the Docket 4600 goals and framework.

The Company's FY 2022 Electric ISR Plan cumulative revenue requirement is $41,443,447 (approved FY 2021 was $32,941,518). The Company has included pre-filed direct testimony of Melissa A. Little which describes the calculation of the Company's revenue requirement for FY 2022.

For a residential customer receiving Standard Offer Service ("SOS")[2], and using 500 kWh per month, implementation of the proposed ISR factors will result in a monthly bill increase of $1.12, or 0.9%. The Company has included pre-filed direct testimony of Daniel E. Gallagher to describe the customer bill impacts of the proposed rate changes.

The Company respectfully requests that the Commission approve the enclosed Electric ISR Plan as filed.

Thank you for your attention to this transmittal. If you have any questions or concerns, please do not hesitate to contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket 5098 Service List
John Bell, Division
Greg Booth, Division
Christy Hetherington, Esq.
Al Contente, Division

---

[2] Effective January 1, 2021, SOS will be replaced by Last Resort Service ("LRS").

Division Set 1

nationalgrid

Andrew S. Marcaccio
Senior Counsel

November 25, 2020

VIA 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 2022 Electric Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – Set 1

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company"), enclosed, please find the electronic version of the Company's responses to the Division's First Set of Data Requests issued in the above-referenced matter.

Thank you for your attention to this transmittal. If you have any questions, please contact me at 401-784-7263

Sincerely,

Andrew S. Marcaccio

Enclosure

cc: Leo Wold, Esq.
Christy Hetherington, Esq.
John Bell, Division
Greg Booth, Division
Al Contente, Division

280 Melrose Street, Providence, RI 02907
T: 401.784.4263 ■ andrew.marcaccio@nationalgrid.com ■ www.nationalgrid.com

R-I-1

Request:

Provide an updated copy of the FY 2022-Elec ISR-Att 3, also referenced as the Excel "Mega-file", with the following:

a. Add Initial Estimate at time of First Sanction to applicable projects
b. For prior year FY2021, add FYTD Actual Capital Spend (6-MTD) and Capital Forecast (6+6 DRAFT)
c. Add detailed worksheet that includes Project # and Project Description for each ISR Grouping.

Response:

The Company is providing the updated Excel "Mega-file" as Attachment 1 to R-I-1 and detailed worksheet that includes Project # and Project Description for each ISR Grouping as Attachment 2 to R-I-1.

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

R-I-2

Request:

The Company indicates in Chart 6, *National Grid's Study Areas: Current Priority and Statistics*, that studies have been completed which have not been delivered. Please provide an updated table.

Response:

Please see the updated table below.

Rank	Study Area	Load (MVA)	% State Load	# Feeders	# Stations	Annual Planning Review % Status	Area Planning Study % Complete	Area Planning Study Stage	Estimated Planning Study Complete Date	Expected Commencement of next Area Study
1	Providence	358	19%	95	17	100%	100%	Stage 9	Complete 2017	2024
2	East Bay	147	8%	22	7	100%	100%	Stage 9	Complete 2015	2022
3	Central Rhode Island East	204	11%	37	9	100%	100%	Stage 9	Complete 2017	2024
4	South County East	159	9%	22	9	100%	100%	Stage 9	Complete 2018	2025
5A	Blackstone Valley North	139	8%	27	6	100%	85%	Stage 7	Mar-2021	2028
5B	North Central Rhode Island	269	15%	35	10	100%	85%	Stage 7	Mar-2021	2028
6	South County West	98	5%	14	5	100%	40%	Stage 4	Dec-2021	2028
7	Central Rhode Island West	167	9%	33	11	100%	60%	Stage 5	Sep-2021	2028
8	Tiverton	28	2%	4	1	100%	20%	Stage 3	Aug-2021	2028
9	Blackstone Valley South	171	9%	54	11	100%	20%	Stage 3	Oct-2021	2028
10	Newport	105	6%	42	12	100%	5%	Stage 1	Dec-2021	2028
	TOTALS*	**1845**	**100%**	**385**	**98**	**100%**	**76%**			

* Study Status Total = % State Load weighted total

Prepared by or under the supervision of: Caitlin Broderick

R-I-3

Request:

Provide the status of the NWRI (NCRI + Blackstone) Area Study, including anticipated completion date. Discuss scope changes that have occurred since the preliminary study and drivers for those changes.

Response:

The Northwest Rhode Island Area study is currently in the final steps of plan development with an anticipated completion date of February 2021. Following a plan development meeting with the Division of Public Utilities and Carriers ("Division") on April 28, 2020, Company representatives met for an internal plan development meeting, at which it was brought to the team's attention that a separate project related to a transmission system need at West Farnum substation did not move forward due to a change in a transmission customer request. Part of the previously identified separate transmission project scope now must be added to the alternatives proposed to address the Nasonville substation load at risk issues. This added scope prompted additional analysis on the West Farnum alternative. The details of the scope additions will be reviewed with the Division in the second plan development meeting that is anticipated within the next two months.

Prepared by or under the supervision of: Caitlin Broderick

R-I-4

Request:

Provide a table of forecasted and actual system peaks for the previous five years.

Response:

Please see Attachment R-I-4 for a table of forecasted and actual system peaks for the previous five years.

Prepared by or under the supervision of: Caitlin Broderick

Summer Peak (MW) (50/50)

Year	Actuals	Weather-Adjusted Actuals	2016 Forecast vintage: fall 2015	2017 Forecast vintage: fall 2016	2018 Forecast vintage: fall 2017	2019 Forecast vintage: fall 2018	2020 Forecast vintage: fall 2019
2016	1,803	1,810	1,814				
2017	1,688	1,756	1,815	1,793			
2018	1,847	1,805	1,815	1,783	1,706		
2019	1,750	1,775	1,813	1,780	1,691	1,764	
2020	1,855	1,749	1,813	1,780	1,679	1,755	1,730

R-I-5

Request:

What range of forecasted growth rates does the Company apply to individual feeders and sub-transmission lines, and how has the actual growth rate compared with previous forecasts?

Response:

There are four Power Supply Areas (PSA) in Rhode Island and each PSA has specific load growth factors and the same weather adjustment, see the table from the 2020 Electric Peak (MW) Forecast report below

Year One Weather – Adjustment and Multi-Year Annual Growth Percentages (Summary)

After Energy Efficiency, Solar Photovoltaics, and Electric Vehicles impacts

			2019 Weather Adjustments	Annual Growth Rates (percents)					5-yr avg	5-yr avg	5-yr avg
State	PSA	Zone (1)	for 95/5	2020	2021	2022	2023	2024	20 to '24	25 to '29	30 to '34
RI	Blackstone Valley	RI	115.1%	(4.2)	(1.1)	(0.2)	(0.2)	(0.2)	(1.2)	(0.3)	(0.5)
RI	Newport	RI	115.1%	(3.7)	(0.7)	0.1	0.1	0.1	(0.8)	(0.1)	(0.4)
RI	Providence	RI	115.1%	(4.1)	(1.0)	(0.2)	(0.2)	(0.2)	(1.1)	(0.3)	(0.5)
RI	Western Narraganset	RI	115.1%	(3.2)	(0.2)	0.6	0.5	0.4	(0.4)	0.2	(0.2)

Historically, the Company has done ad hoc comparisons of forecasted growth rates versus actual growth rates; however, there has been no formal comparison. Starting with the 2021 forecast cycle, the Company will perform a one-year back comparison each forecast cycle.

Prepared by or under the supervision of: Caitlin Broderick

R-I-6

Request:

At what point does the Company review previously completed Area Studies to compare forecasted load to actual load? Does the Company adjust the scheduled implementation of a system capacity project if actual loads deviate from forecasted load levels? Please discuss any Area Study review process and correlation to the annual Capacity Review.

Response:

The Company reviews completed Area Study projects at the initiation of Stage 4.3 in Complex Capital Delivery process to validate the need has not changed based on the most recent forecast. If the review indicates that the need or need date of the proposed project(s) has changed or no longer exists, the project(s) will be reanalyzed to align with the new need or need date or when applicable, removed from the plan.

As described in System Planning, Section 2 of the FY 2022 ISR Plan, when Annual Capacity Reviews highlight an area which has capacity constraints of a level where a detailed and comprehensive review is warranted, that area is identified as needing an Area Planning Study.

Other prompts for an Area Planning Study include the identification of asset condition issues, large new customer load request, or acute reliability issues. The annual capacity review, asset condition evaluations, large customer requests, and reliability reviews inform the prioritization of Area Planning Studies to be completed. This is re-assessed as new information (such as a new forecast) is made available, and adjustments to the area study prioritization are made accordingly.

Prepared by or under the supervision of: Caitlin Broderick

R-I-7

Request:

The Company indicates in Chart 9: Area Planning Study Process, that the planning process results in either infrastructure projects that advance through the ISR or NWAs that are proposed in SRP Plans. For clarification, if a NWA proposal does not advance in SRP and the Company must implement a traditional solution, does the project progress through the ISR? How does the Company intend to track and represent parallel solutions which may progress through separate proceedings (ISR vs. SRP)?

Response:

If a project passes the non-wires alternatives (NWA) screening, development of the traditional and NWA solutions are done in parallel, prior to advancing either solution through the ISR or SRP Plans. Once all alternatives have been evaluated and viable bids are received for any NWA option, the least cost, fit-for-purpose option will be selected. If the NWA option is selected as the recommended plan, it will advance through SRP and no wires alternative will be included in the ISR. If the traditional wires solution is selected as the recommended plan, it will advance through the ISR, with no NWA included in the SRP. Only one alternative will be selected and progressed, either through the SRP or the ISR.

R-I-8

Request:

Describe in more detail the COVID-19 related system analysis performed by the Company and current status. Provide findings, examples of system issues, and actions taken by Company to remedy system issues.

Response:

The analysis was divided into two efforts, an extreme light load analysis and a peak load analysis.

Extreme Light Load Analysis

Due to societal and economic adjustments made to combat the spread of the COVID-19 pandemic, the Company anticipated a change in electric energy usage. Many businesses were temporarily closed or operating at reduced capacity and certain portions of the workforce were furloughed. These reductions were occurring during the Spring light load period, resulting in the potential for extreme light load conditions. The Company monitored and gathered information from foreign countries that had experienced COVID-19 impacts to inform this emerging need.

While the information gathered by National Grid was limited, a 20% reduction from previous light load levels was determined a reasonable approximation based on international trends. This reduced load level coincided with peak or near-peak distributed generation output, creating new or increased reverse power flow conditions. This was the main concern of the extreme light load analysis.

For efficiency and speed, the analysis was divided in two steps. The first step was a system-wide load versus generation screening analysis to identify high-risk feeders. Once these feeders were ranked by reverse power flow levels, step two investigated these high-risk feeders in detail.

Step 1 identified 0 feeders from the total population of approximately 425 feeders across Rhode Island with greater than 7 MVA of reverse power flow during light load. Since there were no feeders identified for Rhode Island in Step 1, no additional analysis was performed.

Peak Load Analysis

Due to societal and economic adjustments made to combat the spread of the COVID-19 pandemic, the Company anticipated a change in electric energy usage. Many businesses were temporarily closed or operating at reduced capacity and certain portions of the work force were furloughed or requested to work from home. Consequently, loads associated with a remote workforce increased. The Company monitored and gathered information from foreign countries to inform this emerging need. These load shifts continued through the Summer resulting in the potential for portions of the distribution system to experience abnormal conditions.

The analysis was divided in three steps. The first step was adding incremental load and reviewing feeders serving critical facilities like hospitals medical facilities and nursing homes. The second step was a system-wide feeder review on the feeders reviewed in step one by adding incremental load to each feeder. The third step was a system-wide feeder review of the reduction of commercial and industrial (C&I) load and increase of residential load. The analysis was performed in CYME utilizing System Data Portal models.

Step 1 identified six feeders serving COVID-critical facilities in Rhode Island predicted to be loaded in excess of their summer normal (SN) capabilities after the incremental load. Of these circuits, four feeders had been predicted to be loaded in excess of the SN capabilities prior to the added load. In summary, two feeders which serve COVID-critical facilities were predicted to have loading concerns introduced as a result of the load shifts associated with the COVID-19 pandemic. These two feeders that are predicted to be overloaded had projected loads which are marginally greater than 100%, ranging from 100.1% to 101.9%. Because the identified risk associated with these load levels was so low, Engineering and the Control Center monitored these feeders' loading through the summer months and took appropriate actions, such as temporary switching reconfigurations, as needed.

Step 2 identified 37 feeders in Rhode Island predicted to be loaded in excess of their SN capabilities after the added incremental load. Of these, 19 feeders had been predicted to be loaded in excess of the SN capabilities prior to the added load. In summary, 18 feeders were predicted to have loading concerns introduced as a result of the load shifts associated with the COVID-19 pandemic. No action was recommended on the results of this analysis. Step 2 was intended to be informative should additional medical load occur.

Step 3 was a system-wide screening analysis using radial distribution software (CYME). While the information gathered by National Grid is still limited, a 20% reduction of the Commercial & Industrial load and a 10% increase of residential load from previous peak load levels was determined a reasonable approximation based on the information gathered from other utilities. Of the approximately 425 feeders in Rhode Island, 195 feeders were identified in Step 3 as having either overload, low voltage or load imbalance issues. These 195 circuits are being analyzed in detail using CYME to validate the issues identified in Step 3 and to develop any necessary solutions.

The detailed analysis on the 195 circuits identified in Step 3 is ongoing. The Company is more than 85% complete with the analysis and anticipates full completion by December 2020.

Prepared by or under the supervision of: Caitlin Broderick

R-I-8, page 3

Where device overloads, conductor overloads, load imbalance and/or voltage issues are confirmed in the detailed CYME analysis, appropriate solutions are being developed. Solutions include but are not limited to fuse replacements, switch replacements, device settings changes, reconductoring, load balancing, and phase extensions. Any data errors found during the analysis are being corrected as part of this effort.

The Company has progressed small scale work on approximately 34 feeders to date. An additional ten feeders have been identified with large scale recommendations (i.e. over $100,000 of reconductoring). These feeders are currently being analyzed in more detail to finalize the scope and will be prioritized based on the severity of the issues identified. The Company is recommending the least cost option to address each verified issue and is ensuring that all solutions align with long term planning.

R-I-9

Request:

What impact has COVID-19 had on the overall system load? What are observed impacts to individual feeder loads and changes in residential or commercial consumption?

Response:

At the retail system load level, the Company has seen higher residential and lower commercial & industrial energy since the start of the COVID-19 pandemic. As noted in the response to DIV 1-10, CYME is used to estimate feeder level impacts. The table below lists the system level variances in comparing to the same months of the prior year, after adjusting the differences in weather and number of billing days. A positive number means this year's weather-normalized energy is higher than the weather-normalized energy of last year. Over these months, the residential sector is about 4.5% higher than the same period of the prior year, while the C&I sector is about 7% lower.

	RESIDENTIAL	C&I	TOTAL
APR	7.2%	-8.5%	-2.3%
MAY	9.7%	-1.0%	3.3%
JUN	3.8%	-6.7%	-2.1%
JUL	11.7%	-12.1%	-1.8%
AUG	13.1%	-7.4%	2.7%
SEP	-3.6%	-11.8%	-7.4%
OCT	6.6%	-3.3%	1.1%

Prepared by or under the supervision of: Caitlin Broderick

R-I-10

Request:

The Company proposes a $2 million budget for COVID-WORK in FY2022. Please explain the proposed projects in this category and how the budget was derived.

Response:

The Company is still performing detailed CYME analysis on the 195 feeders identified in the Company's COVID Peak Load analysis as having projected loading, imbalance and/or voltage issues resulting from COVID load shifts (See response to R I-8). Of the approximately 170 feeders the Company has completed analysis on, approximately ten feeders have solutions with significant reconductoring or phase extensions to correct these issues. These feeders are currently being analyzed in more detail to further validate the issues found utilizing 2020 actual loads with the latest weather adjustment and load growth for the 2021 forecast. This additional analysis will also include determining the most cost-effective solutions to address the issues. The Company anticipates this analysis will be complete by December 2020. It is possible there will be additional feeders with large scale recommendations since the analysis is not complete.

Since the Company has not finished the detailed COVID analysis, the full scope of COVID related work has not been determined. The $2 million in FY 2022 for COVID work is an estimate based upon the scope of work identified to date. Estimated work to be done generally represents reconductoring the identified feeders.

The COVID work will be prioritized based on the severity of system issues identified. Due to this prioritization and the time required to implement large scale recommendations, all of the feeders with significant scope will not be complete in the field in FY21 and therefore are budgeted in FY 2022. The COVID related work is in the non-discretionary portfolio and as such, work will be associated with identified loading, imbalance and or/voltage issues that currently exist and not projected issues.

R-I-11

Request:

For the Strategic DER/Grid Mod investments 1) implemented in FY2021 and 2) proposed in FY2022, provide:

a. How the Company identified the system issues that would necessitate Strategic DER/Grid Mod investments (feeder monitors, advanced metering, SCADA, etc.)
b. The actual system anomalies identified by the Company as compared to expected tolerances (e.g. actual measured voltage or power factor compared to Company requirements).
c. How the Company determined that the system anomalies are attributed to existing DERs and the type of DER contributing to the issues.
d. The thresholds or other criteria used by the Company to prioritize work on specific feeders.
e. The targeted feeders, feeder voltage, feeder length, and substation.
f. The frequency, duration, and general time of day of the system anomalies on each targeted feeder.
g. The existing DERs on each targeted feeder by type and capacity.
h. Have the system issues caused outages, including momentary outages?
i. Have the system issues resulted in equipment or other damages to the distribution system?
j. Have the system issues resulted in equipment or other damages on the customer side of a meter?
k. Has the Company received power quality complaints from customers on the targeted feeders?
l. The proposed projects on targeted feeders and breakdown of costs.

Response:

a. The Company discovers system issues through a variety of methods including, but not limited to, annual capacity reviews, continuous consultation with control centers and operations personnel on operational issues, as well as different types of detailed studies. During recent Distributed Generation (DG) Interconnection studies, preexisting issues are being discovered that are not associated with the DG site under study. Grid Modernization analysis is showing these issues are emerging also.

b. System issues were identified at the Chopmist substation. See Attachment R-I-11 for details. The full analysis for the FY 2022 proposed work has not been completed, but the Company has identified Hopkins Hill substation as a potential location with similar voltage issues.

Prepared by or under the supervision of: Caitlin Broderick

R-I-11, page 2

c. See Attachment DIV R-I-11 for explanation of how accumulation of Distributed Energy Resources (DER) led to system issues at Chopmist substation.

d. As described in response to part a., above, the Company discovers emerging system issues through a variety of methods and studies. The work is prioritized based on the severity of the issues identified in the areas identified.

e. The targeted feeders for FY 2021 are listed in the table below.

Substation Name	Feeder Number	Voltage	Mainline length (miles)
CHOPMIST	34F1	12.47	43
CHOPMIST	34F2	12.47	23
CHOPMIST	34F3	12.47	15

The targeted feeders for FY 2022 are listed in the table below.

Substation Name	Feeder Number	Voltage	Mainline length (miles)
HOPKINS HILL	63F2	12.47	15
HOPKINS HILL	63F3	12.47	12
HOPKINS HILL	63F4	12.47	8
HOPKINS HILL	63F5	12.47	9
HOPKINS HILL	63F6	12.47	36

f. The Company has started to obtain analysis tools to perform daily cycle and yearly cycle analysis; however, the Company does not have these capabilities fully implemented. Based on engineering analysis, generally, the system anomalies due to the proliferation of DG occur in the springtime daytime hours and some fall daytime hours.

g. The existing DERs on the targeted feeders in FY 2021 are listed below.

Substation	Feeder	Interconnected DG Solar (kW)	Interconnected DG Wind(kW)	Interconnected DG Other(kW)	Total (kW)
Chopmist	34F1	3461	0	0	3461
Chopmist	34F2	778	0	0	778
Chopmist	34F3	2140	1	0	2141

Prepared by or under the supervision of: Caitlin Broderick

R-I-11, page 3

The existing DERs on the targeted feeders planned for FY 2022 are listed below.

Substation	Feeder	Interconnected DG Solar (kW)	Interconnected DG Wind(kW)	Interconnected DG Other(kW)	Total (kW)
Hopkins Hill	63F2	81	0	0	81
Hopkins Hill	63F3	192	0	0	192
Hopkins Hill	63F4	427	0	0	427
Hopkins Hill	63F5	257	0	0	257
Hopkins Hill	63F6	5238	0	0	5238

h. No, the system issues identified have not caused outages on the Rhode Island distribution system; however, in the Company's other affiliate jurisdictions, system issues have resulted in the need to curtail the DER until weather and system characteristics change, such that these resources can be reconnected. The Company is aiming to implement solutions to prevent an outage from occurring.

i. No, the system issues identified have not resulted in equipment or other damages to the Rhode Island distribution system; however, the Company is aware that system issues have resulted in equipment damage in the Company's other affiliate jurisdictions. Similar to the approach stated in the response to part h., above, the Company is aiming to implement solutions to prevent such damage from occurring to its Rhode Island distribution system.

j. No, the system issues identified have not resulted in equipment or other damages on the customer side of a meter.

k. No, the Company has not received power quality complaints from customers on the targeted feeders.

l. Estimated costs for DER Enablement investments planned in FY 2021 and FY 2022 are included in the table below. The Chopmist substation was identified for DER Enablement investments in FY 2021 (see Attachment R-I-11 for more detailed scope and cost estimates). The Company is still performing analysis to confirm the scope of work potentially recommended in FY 2022. Hopkins Hill substation has been identified as a potential substation with emerging issues resulting from the proliferation of DER. Though the analysis is still ongoing for Hopkins Hill, the Company has put together initial cost estimates for this work. Cost estimates for Hopkins Hill substation could change upon completion of the analysis. In addition, it is possible that some of the work on the Chopmist Substation may lag from FY21 into FY22.

Prepared by or under the supervision of: Caitlin Broderick

R-I-11, page 4

Substation	Feeder	Cost type	Projected spend ($K)	
			FY21	FY22
Chopmist	34F1	Capex	$1,235	
		Opex	$126	
		Removal	$62	
	34F2	Capex	$440	
		Opex	$46	
		Removal	$22	
	34F3	Capex	$325	$275
		Opex		$60
		Removal		$30
Hopkins Hill	63F2	Capex		$730
		Opex		$73
		Removal		$37
	63F3	Capex		$670
		Opex		$62
		Removal		$59
	63F4	Capex		$690
		Opex		$64
		Removal		$60
	63F5	Capex		$750
		Opex		$70
		Removal		$63
	63F6	Capex		$1,210
		Opex		$116
		Removal		$86
Total		Capex	$2,000	$4,325
		Opex	$172	$445
		Removal	$84	$335

Prepared by or under the supervision of: Caitlin Broderick

nationalgrid

Memorandum

To: Caitlin Broderick

From: Brandon Lopes

Date: 10/20/2020

Subject: DER Investment Chopmist Substation, 12.47kV Feeder

This memo documents the recommendations for advanced field devices which along with robust communications systems and centralized operations and processing capabilities, would facilitate protection and voltage compliance associated with DER interconnections.

The table below shows how much existing and proposed Distributed Generation is being interconnected to the 23kV supply lines and 12.47kV distribution at the Chopmist substation.

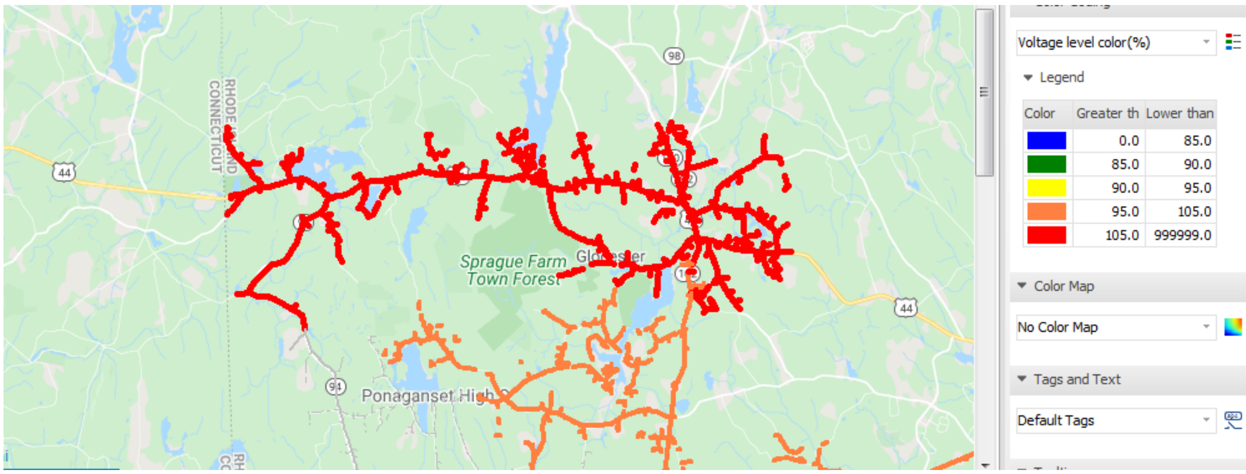
Feeder	Larger scale Generation installed and operation (kW)	Small Scale Generation installed and operation (kW)	Small scale (total) generation in process (kW)	Larger scale (total) generation in process (kW)	*TOTAL* (kW)
34F1	3,540.00	749.00	128.00	0.00	4,417
34F2	0.00	768.00	115.00	2,200.00	3,083
34F3	1,950.00	176.00	48.00	4,586.00	6,760
2221	1,800.00	0.00	0.00	0.00	1,800
2227	25,000.00	0.00	0.00	0.00	25,000
TOTAL	32,290.00	1,693.00	291.00	6,786.00	41,060.00

Chopmist is served by the SubT 23kV 2221 feeder from Wolf Hill and the SubT 23 kV 2227 Feeder from Johnston.

Analysis:

This analysis was conducted using National Grid's radial distribution analysis tool (CYME). The tool was used to model loading, voltage and protection characteristics across the Chopmist feeders. Engineering analysis has shown the Chopmist 34F2 feeder has the most severe pre-existing voltage issues of the Chopmist feeders; therefore, the 34F2 feeder was the main focus of this analysis.

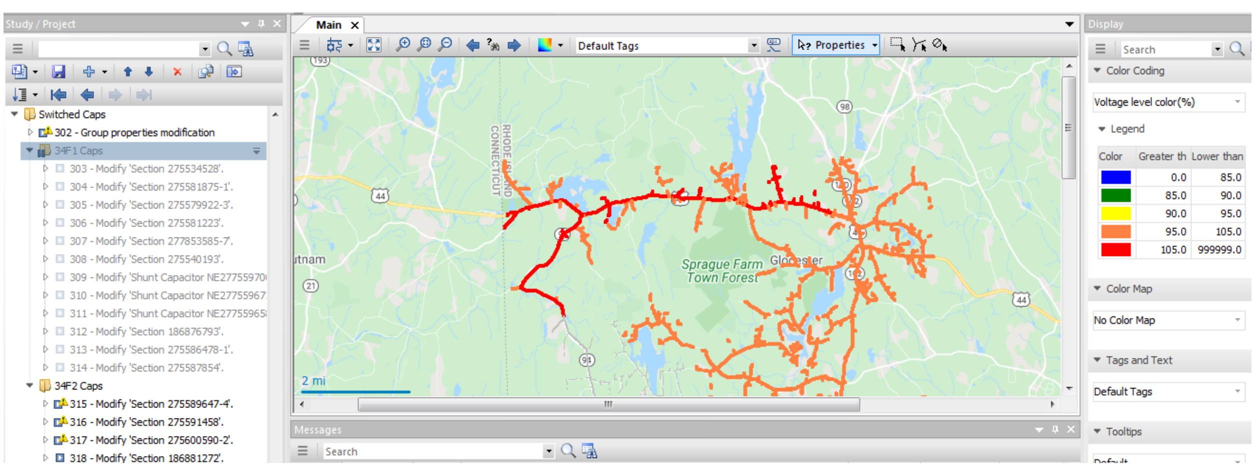
<u>CASE 1:</u> Low load day (Winter) during expected high solar DER production hours. 34F2 feeder in current configuration with currently connected and proposed DER (large and small scale).



The voltage profile above depicts the 34F2 feeder in its current state, including existing and proposed large and small scale DER facilities. The voltage stability worsens the further away from the substation due to the increased levels of DER interconnected to the Chopmist Substation.

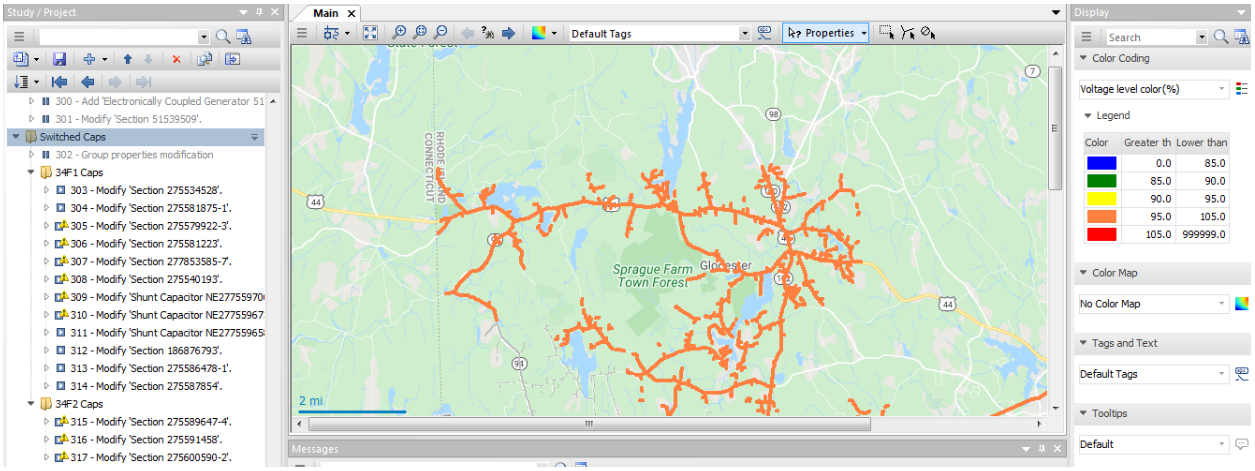
The substation was also modeled using only existing connected DER (large and small scale), and analysis showed voltage issues are already emerging today.

<u>CASE 2</u>: Low load day (Winter) during expected high solar DER production. 34F2 feeder in current configuration with currently connected and proposed DER (large and small scale) with only installing advanced capacitor controls on the 34F2 Feeder.



Replacing existing capacitors with advanced switched capacitors on the 34F2 slightly improves the voltage profile but does not solve all issues.

<u>CASE 3</u>: Low load day (Winter) during expected high solar DER production. 34F2 feeder in current configuration with currently connected and proposed DER (large and small scale) with installing advanced capacitor controls on both the 34F1 and 34F2 Feeder.



Replacing all existing capacitors with advanced switched capacitors on both the 34F1 and 34F2 improves the voltage profile and brings voltages within an acceptable range.

Sensitivity analysis

As described in the analysis above, voltage issues exist on the Chopmist 34F2 feeder in its current configuration due to the accumulation of existing small DER. Further analysis demonstrated voltage issues increase with low levels of additional small scale DG. The severity of these voltage issues varies depending upon where the small scale DER is interconnected. Since detailed interconnection studies are not feasible for small scale DER interconnections, it is difficult to determine their individual impacts on voltage stability. This makes it increasingly difficult to assign infrastructure improvement costs to any one DER customer and demonstrates the need for the Company to install advanced devices in areas experiencing these issues.

All voltage issues can be mitigated by installing advanced devices at Chopmist substation. These advanced devices will also allow the company to monitor and adjust when load shift peak changes occur throughout the upcoming years as more DER facilities interconnect.

Recommendations

The recommendation is to install advanced devices on all the Chopmist feeders. As can be seen in Case 2, installing advanced devices on only one feeder at the substation would not solve all the issues. Case 3 shows upgrading all devices at a substation solves all voltage issues. This demonstrates how DER can impact voltage across multiple feeders at a substation and a more comprehensive solution is necessary.

All devices should be replaced with advanced devices with radios (Feeder monitors, Reclosers, Regulators, and Capacitors)

The following chart shows the number of new and replacement distribution line devices recommended from the study of Chopmist substation:

	Feeder Monitors			Reclosers			Regulators			Capacitors		
Feeder	Existing	New	Replacing	Existing	New	Replacing	Existing	New	Replacing	Existing	New	Replacing
34F1	0	3	0	4	12	1	0	0	0	5	0	4
34F2	0	2	0	5	3	0	0	0	0	5	0	5
34F3	0	1	0	6	4	1	1	0	1	2	0	2
Total	0	6	0	15	19	2	1	0	1	12	0	11

All three feeders at the Chopmist substation have substation feeder regulators that require small upgrades to allow for cogeneration functionality. The substation scope of work includes:

- 34F1 and 34F2 – No control upgrades are necessary but minor setting changes are required.
- 34F3 – Controller must be upgraded.

Alignment with Company Strategies/Programs

The recommendation above is aligned with current company programs such as VVO. VVO is an optimization program to manage voltage to reduce customer bills. While these capacitors are being installed for voltage compliance, they can be incorporated into VVO systems in the future as an added benefit to all customers.

The recommendation above is also aligned with the long-term Grid Modernization Plan (GMP). The GMP proposes similar feeder technologies for increased visibility and control of the distribution system. Additional benefits could be obtained after certain back office features are enabled such as an Advanced Distribution Management System (ADMS).

Cost Estimates

Distribution Line estimates:

CATEGORY	DEVICE	Cost Type	34F1 ($K)	34F2 ($K)	34F3 ($K)	Total ($K)
Distribution Grid Control-Voltage Compliance	**Smart Capacitors**	**# Devices**	**4**	**5**	**2**	**11**
		Capex	$120	$150	$60	$330
		Opex	$12	$15	$6	$33
		Rem	$6	$8	$3	$17
Distribution Grid Control-Voltage Compliance	**Advanced Regulators**	**# Devices**	**0**	**0**	**1**	**1**
		Capex	$0	$0	$100	$100
		Opex	$0	$0	$10	$10
		Rem	$0	$0	$5	$5
Distribution Grid Control-Voltage Compliance	**Feeder Monitors**	**# Devices**	**3**	**2**	**1**	**6**
		Capex	$75	$50	$25	$150
		Opex	$8	$5	$3	$15
		Rem	$4	$3	$1	$8
ibution Grid Control-Load/Protection Manager	**Advanced Reclosers**	**# Devices**	**13**	**3**	**5**	**21**
		Capex	$1,040	$240	$400	$1,680
		Opex	$104	$24	$40	$168
		Rem	$52	$12	$20	$84
Total	**Total**	**# Devices**	**20**	**10**	**9**	**39**
		Capex	$1,235	$440	$585	$2,260
		Opex	$124	$44	$59	$226
		Rem	$62	$22	$29	$113
		Total	$1,420	$506	$673	$2,599

Substation estimates:

DEVICE	Cost Type	34F1 ($K)	34F2 ($K)	34F3 ($K)	Total ($K)
Substation Regulators	Capex	$0	$0	$15	$15
	Opex	$2	$2	$1	$5
	Rem	$0	$0	$1	$1
Total	Total	$2	$2	$17	$21

Appendix – Detailed scope recommendations

Existing devices along with the recommended replacements are listed below. All recommendations should be replaced with advanced devices with radios (Feeder monitors, Reclosers, Regulators, and Capacitors)

- 34F1
  - Capacitor Banks
    - 300 kVAR P178 Danielson Pike, Foster
      - Replace with Advanced Cap Bank
    - 600 kVAR P89 Danielson Pike, Foster
      - Replace with Advanced Cap Bank
    - 600 kVAR P85 Chopmist Hill Road, Scituate
      - Replace with Advanced Cap Bank
    - 600 kVAR P89 Danielson Pike, Scituate
      - Replace with Advanced Cap Bank
    - 600 kVAR P64-50 Plainfield Pike, Foster
      - Replace with Advanced Cap Bank
    - Remove 900 kVAR P140 Chopmist Hill Road, Scituate
  - Reclosers
    - P111 Danielson Pike, Foster (No Change)
    - P96 Chopmist Hill Road, Scituate (No Change)
    - P202 Danielson Pike, Scituate (No Change)
    - P188-50-3 Danielson Pike, Foster (Solar DG PCC, No Change)
    - Replace P206 Danielson Pike, Scituate Recloser with Recloser with 6IVS
    - Remove load Break Pole 12 Mount Hygea Rd, Foster Install Recloser with 6IVS
    - Remove load Break Pole 47 Danielson Pike, Scituate Install Recloser with 6IVS.
    - Remove fusing at Pole 27 Cucumber Hill Rd, Foster Install Recloser with 6IVS, with bypass.
    - Remove fusing at Pole 161 Foster Ctr Rd, Foster Install Recloser with 6IVS, with bypass.
    - Remove fusing at Pole 2 Moosup Valley Rd, Foster Install Recloser with 6IVS, with bypass.
    - Remove fusing at Pole 3 Foster Ctr Rd, Foster Install Recloser with 6IVS, with bypass.
    - Remove fusing at Pole 37 Plainfield Pike, Foster Install Recloser with 6IVS, with bypass.
    - Remove fusing at Pole 3 Rockland Rd, Scituate Install Recloser with 6IVS, with bypass.
    - Remove load break at Pole 267 Tunk Hill Rd, Foster Install Recloser with 6IVS, with bypass.
    - Remove load break at Pole 162 Rockland Rd, Scituate Install Recloser with 6IVS, with bypass.
    - Remove Air Break Pole 148 Victory Hwy, Foster Install Recloser with 6IVS, with bypass
    - Remove Air Break Pole 216 Plainfiled Rd, Coventry Install Recloser with 6IVS, with bypass.
  - 1 station regulator (No Change)
  - Feeder Monitors
    - Install FM on Pole 149 Victory Hwy, Foster
    - Install FM on Pole 48 Danielson Pike, Scituate

        - Install FM on Pole 215-50 Plainfield Pike, Coventry
    - Miscellaneous
        - Remove fusing at Pole 83 Danielson Pike, Scituate.
- 34F2
    - 5 Capacitor banks
        - 900 kVAR P576 Putnam Pike, Glocester
            - Replace with Advanced Cap Bank
        - 600 kVAR P452 Putnam Pike, Glocester
            - Replace with Advanced Cap Bank
        - 600 kVAR P393 Putnam Pike, Glocester
            - Replace with Advanced Cap Bank
        - 600 kVAR p14-50 Snake Hill Road, Glocester
            - Replace with Advanced Cap Bank
        - 900 kVAR P11 Chopmist Hill Road, Glocester
            - Replace with Advanced Cap Bank
    - 5 Reclosers
        - P396 Putnam Pike, Glocester (No Change)
        - P46 Chopmist Hill Road, Glocester (No Change)
        - P229 Snake Hill Rd, Glocester (No Change)
        - P78 Reynolds Road, Glocester (No Change)
        - P2 Anan Wade Road, Foster (No Change)
        - Remove load Break Pole 152 Putnam Pike, Glocester Install Recloser with 6IVS, with bypass.
        - Remove load Break Pole 183-50 Snake Hill Rd, Glocester Install Recloser with 6IVS, with bypass.
        - Remove load Break Pole 166-25 Chopmist Hill Rd, Scituate Install Recloser with 6IVS, with bypass.
    - 1 station regulator
    - Feeder Monitors
        - Install FM on Pole 588 Putnam Pike, Glocester
        - Install FM on Pole 3-50 Anan Wade Rd, Foster
- 34F3
    - 2 Capacitor banks
        - 900 kVAR P24 Reynolds Road, Gloucester
            - Replace with Advanced Cap Bank
        - 900 kVAR P74-50 Reynolds Road, Gloucester
            - Replace with Advanced Cap Bank
    - 7 Reclosers
        - P78 Reynolds Road, Gloucester (No Change)
        - P107 Reynolds Road, Foster (No Change)
        - P2 Anan Wade Road, Foster (No Change)
        - P1-50 Theodore Foster Road, Foster (No Change)
        - P22-9 Theodore Foster Road, Foster (Solar DG PCC, No Change)
        - P18-7 Theodore Foster Road, Foster (Solar DG PCC, No Change)
        - Remove Form 3A Recloser P76-51 Reynolds Rd Gloucester Install Recloser with 6IVS, with bypass.
        - Remove fuses Pole 103 Mt. Hygea Rd, Foster Install Recloser with 6IVS, with bypass.
        - Remove load Break Pole 2 Mount Hygea Rd, Foster Install Recloser with 6IVS, with bypass.
        - Remove load Break Pole 168 Chopmist Hill Rd, Scituate Install Recloser with 6IVS, with bypass.
        - Remove load Break Pole 230 Hartford Pike, Scituate Install Recloser with 6IVS, with bypass.

- 3-1ph Distribution regulator
  - Replace 167kVA P185, P186, P187 Hartford Pike, Foster with 333kVA Advanced Regulators.
- 1 station regulator
- Feeder Monitors
  - Install FM on Pole 77-50 Reynolds Rd, Glocester

R-I-12

Request:

Is the Company planning to implement VVO/CVR on the circuits receiving non-discretionary Strategic DER/Grid Mod investments in advance of a Grid Mod filing? Why or why not?

Response:

No, not at this time. The Company is not planning to implement VVO/CVR on the circuits receiving non-discretionary Strategic DER investments in advance of the Company's filing of its Grid Modernization Plan with the PUC. The primary focus of the Strategic DER investments being installed in FY 2022 is to address system issues (*e.g*, voltage performance concerns resulting from an aggregation of DER), not optimize the system (*e.g.*, through VVO/CVR implementation). However, the Strategic DER investments are being designed with the consideration of future implementation of a VVO/CVR application once the Company implements a centralized VVO system.

Prepared by or under the supervision of: Caitlin Broderick

R-I-13

Request:

Provide a list of all substation retirements in the past three years or proposed in the following five years. Provide a general description/location of the land and the Company's plans for future land utilization or disposition. Explain how any revenues from potential land sales or leases are reported.

Response:

The Property Strategy Team performs reviews of available property generally after the retirement work completes to determine whether a potential market option might exist for such property and prioritizes locations if the preliminary review indicates some degree of marketability. In addition, a review for marketability could occur on an as request basis for a site that is not yet retired but has received some external interest.

Further detail review occurs to confirm ownership, value, parcel and neighborhood characteristics, company ongoing usage and field verification. If after that detail review the site meets standards for marketability it is added to lists to be marketed by our third-party vendor or internally thru various sources or if the site indicates low market value or other redevelopment challenges, it would be considered for our donation program.

See the list below for the status of reviewed substation sites.

R-I-13, page 2

Substation	Status	Calendar Year	Street	Town	Status
Arctic 49	Retired	2019	56 Gough Ave	WEST WARWICK	Retaining due to easement requirement
Hope Valley 41	Retired	2018	1152 Main St.	HOPKINTON	Retaining due to easement requirement
Hunt River 40	Retired	2017	5890 Post Rd.	WARWICK	Internal review underway
Pawtuxet 31	Retired	2015	70 Bellows St.	WARWICK	Retaining due to not meeting marketability standard
Dagget Ave 113	Retired	2017	918 Central Ave.	PAWTUCKET	Sold effective March 7, 2019
Hyde Ave 28	Retired	2017	36 Hyde Ave.	PAWTUCKET	Sold effective December 12, 2019
Southeast Sub 60	Retired	2017	206 York Ave.	PAWTUCKET	Internal review underway
Ashaway 43	Retired	2018	31 Oak St.	HOPKINTON	Retaining due to easement requirement
Lee St	Retired	2018	44 Lee St.	PAWTUCKET	Retaining due to potential future company use
Dyer St. 2		2023*	144 Dyer St	PROVIDENCE	Consider future use alternatives due to third party request
*Estimated Retirement date					

The following substations are expected to be retired in the next five years. A review of the marketability for these sites will occur as the site is retired.

Front Street
Cottage Street
Bailey Brook,
Vernon,
N Aquidneck
S Aquidneck
Jepson
Kent Corners (East Providence)
Waterman (East Providence)
Harris Ave (Providence)
Olneyville
Rochambeau
Geneva

Prepared by or under the supervision of: Patricia Easterly and Melissa Little

R-I-13, page 3

The Company records proceeds from land sales in Cost of Removal. Revenue from leases would be recorded in Other Operating Income.

Pursuant to Paragraph 13(A) of the Distribution Rate Plan Second Amended Stipulation and Settlement Agreement in Docket No. 3617, the Company files an annual report listing all properties that were sold during the calendar year.

R-I-14

Request:

The Company states that it is in year one of the third five-year inspection cycle (page 87). Has the Company considered increasing the inspection cycle to ten years based on the Division's recommendations in prior years and enumerated in its recommendation list in the FY 2021 ISR Plan filing? Why or why not? Compare the estimated annual budget for a five year cycle to a ten year cycle.

Response:

Yes, the Company has considered increasing the inspection cycle to ten years. The Company believes it is still beneficial to perform a five-year inspection cycle to ensure equipment condition is assessed for reliability purposes, but it will reduce the equipment evaluation to only high priority items. The estimated annual budget for a ten-year inspection cycle would be half of the five-year inspection cycle budget.

Prepared by or under the supervision of: Caitlin Broderick

R-I-15

Request:

What is the current I&M repair cycle? Describe the repairs targeted each year and how the Company addresses or prioritizes the backlog of work identified in previous inspection cycles.

Response:

The Company recently streamlined the I&M program to only address priority items including Level 1s, Level 9s, potted porcelain cutouts and some guying issues. Level 1 maintenance items are repaired or replaced within 30 days. Level 9 priority conditions are targeted for completion within 90 days. For any Level 9 priority conditions not completed within 90 days, the company periodically performs site visits to monitor the condition of the temporary repair. Potted porcelain cutouts and guying issues depend on site specific detail and severity of the condition. This streamlined I&M program allows the Company to address the backlog of work identified in previous years to progress. Though Level 2s and 3s are no longer captured in the I&M program, Level 2 and Level 3 issues identified in past years will be progressed as needed and as the budget allows.

Prepared by or under the supervision of: Caitlin Broderick

R-I-16

Request:

For FY2020 and FY2021 YTD, provide a 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:

	Number of Individual Repairs Completed	Total Spend	Labor Cost	Material Cost	Total Man Hours
FY20	2,047	$ 1,894,490	$ 479,635	$ 159,603	5,230
FY21*	583	$ 1,369,490	$ 817,312	$ 63,985	8,710

* FY21 data through September 30, 2020

Prepared by or under the supervision of: Patricia Easterly

R-I-17

Request:

Provide a current copy of the Company's Inspection & Maintenance Program guidelines.

Response:

Please see attachment R-I-17 for a current copy of the Company's Inspection & Maintenance Program guidelines.

Prepared by or under the supervision of: Caitlin Broderick

nationalgrid	ELECTRIC OPERATING PROCEDURE DISTRIBUION OVERHEAD	Doc. # NG-EOP D004 Page 1 of 11
	DISTRIBUTION LINE PATROL AND MAINTENANCE	Version 4.0 – 10/01/20

INTRODUCTION

The purpose of this procedure is to outline the requirements for the patrol and maintenance activities associated with National Grid Distribution feeders.

The inspection procedures shall be dictated by the individual state's regulatory agency. If the regulatory agency in a specific state (MA & RI) does not require inspection procedures the inspections can still be performed in those states per this EOP but are not required.

The Distribution Maintenance Program was designed to provide for a patrol and inspection of each distribution feeder once every five (5) years. The patrols are conducted by a Distribution Inspector identifying all required maintenance on a *Windows*® based hand-held computer. The maintenance items identified through this patrol are separated into five priority levels 1, 2, 3, 4 and 9. The maintenance codes identified default to the appropriate priority level. The default priority level can be adjusted by the individual performing the inspection based on actual field conditions. These priority levels are defined as follows:

Level 1 - An identified facility/component or tree condition that shall be repaired/replaced within 30 days for (NE) and 7 days for (NY).

Level 2 - Identified facility/component condition that shall be repaired/replaced within 1 year or as scheduled by Program Management for NE.

Level 3 – Identified facility/component condition that shall be repaired/replaced within 3 years or as scheduled by Program Management for NE.

Level 4 – This priority category is to collect inventory information on actual field conditions to be used by Investment Strategy and Work Planning.

Level 9 – This priority category is to collect inventory information for temporary repairs made by operations to restore service or maintain public safety until permanent repairs can be made.

All Level 1 priority conditions identified in the field shall be called in by the Distribution Inspector as follows:

1. Notification by location:
   New York: System Operations Dispatch 1-877-716-4996
   NE North: Bay State West & Central: Northborough Control Center 1-508-421-7879
   NE North: North & Granite: Northborough Control Center 1-508-421-7879
   NE South: Bay State South & Ocean State (RI): Northborough Control Center 1-508-421-7885

2. Detailed information provided to the regional notification location:
   a. Identify yourself as a Company Distribution Inspector and your work reporting area.
   b. Details of the Level 1 Priority Condition:
      i. Problem found.
      ii. District, Feeder No., Line No., Tax District and Pole No.

iii. Street address and any additional information that would assist in finding the location of the problem.

iv. If you are standing by or have secured the location.

3. Notify area Inspections Supervisor for follow-up.

PURPOSE

This procedure applies to all personnel involved with or responsible for the inspection and repair of Overhead (OH) Distribution and Sub Transmission facilities, Underground Residential Developments (URDs) and Underground Commercial Developments (UCDs).

ACCOUNTABILITY

1. Electric Work Methods
   A. Update procedure as necessary
2. Electric Operations
   A. Ensure the work generated by the Distribution Maintenance Program and assigned by Asset Strategy and Investment Planning is completed in the appropriate time frame.
   B. Request assistance from Distribution Line Contracting when necessary to complete work assigned in the appropriate time frame.
3. Distribution Line Contracting
   A. At the request of Operations obtain, schedule and manage contractors to perform inspections and required maintenance.
   B. Provide input into program revisions.
4. Distribution Inspector
   A. Demonstrate the ability to identify maintenance concerns and the aptitude to become proficient in the use of a hand-held computer and desktop computer.
   B. Demonstrate the understanding and requirements of this NG EOP D004.
   C. Possess the ability to do walking patrols, collect information on a hand held, download to a desk top computer, edit data, provide requested information/reports/work tickets to supervision, and track/close out work completed in the database system.
5. Distribution Network Strategy
   A. Select program codes/circuits to be scheduled for maintenance repair work using data collected through Distribution Maintenance Program.
   B. Approve changes to the maintenance code table.
   C. Select circuits to be patrolled for a running five-year cycle.
   D. Provide input into program revisions.

6. Inspections and Maintenance
   A. Ensure circuits scheduled for patrol are completed each year.
   B. Provide qualified personnel as inspectors to provide consistent and accurate identified maintenance concerns/problems.
   C. Provide program management.
   D. Report System Maintenance progress monthly by Division.
7. Process and Systems.
   A. Provide and support database.

REFERENCES

National Grid Safety Procedures
National Grid Employee Safety Handbook
NY PSC Order 04-M-0159
NY PSC Order Adopting Changes to Electric Safety Standard, December 2008
Elevated Equipment Voltage Testing NG-EOP G016
Underground Inspection NG-EOP UG006
Work Methods Bulletin 11-14 Voltage Regulation Limits
Massachusetts DTE Directive 12/9/05

TRAINING

Provided by appropriate National Grid training program.

DOCUMENT CONTENTS

Table of Contents

1.0 SAFETY REQUIREMENTS

1.1 All work shall be performed in accordance with:

- 1.1.1. National Grid Employee Safety Handbook
- 1.1.2. Applicable National Grid Electric Operating Procedures (EOP)
- 1.1.3. Applicable National Grid Safety and Health Procedures (SHP)

1.2. All applicable and appropriate Personal Protective Equipment (PPE) shall be worn.

1.3. The employee in charge of the work shall conduct a written pre-job brief with the employees involved prior to the start of each job. Using the Job Brief Form as an aide, discussions for performing the work should include:

- 1.3.1. Traffic control devices – Work Area Protection (WAP)
- 1.3.2. Emergency Events: communication methods (code blue), first responders, and closest hospital.

1.4. Minimum Approach Distances (MAD) to energized lines or exposed live parts shall be maintained (refer to Employee Safety Handbook Tables 2A, 2B and Appendix A for distances).

- 1.4.1. Use of DI Foot wear if MAD will be broken, according to NG-EOP G026 "Mechanized Equipment Grounding"

1.5 Identify if a Process Hazard Assessment (PHA) is required. Refer to NG-EOP G037 "Process Hazard Analysis"

1.6 Identify if an ARC flash assessment is required. Refer to NG-EOP G035 "ARC Flash Awareness and Mitigation" and Work Methods Infonet site for Arc Flash Table to determine working distance and energy levels – see link below:

Arc Flash Mitigation Tables

2.0 DISTRIBUTION PATROL

2.1 New York

2.1.1 Distribution Patrols are conducted by a Distribution Inspector that has been trained to identify deficiencies or non-standard construction conditions on National Grid facilities.

2.1.2 Distribution patrols are scheduled in such a manner that each distribution feeder is examined in the field once every five (5) years. In NY, the patrols shall be completed by December 31 due to regulatory reporting.

2.1.3 New Distribution Feeders added to the system will be incorporated through our Geographic Information System (GIS) system and added to the appropriate inspection cycle.

2.1.4 If the Distribution Inspector finds unmapped facilities from the information supplied from GIS, the inspector shall add the information into the *Windows®* based hand-held computer for maintenance tracking purposes. NG-EOP G011, Preparation and Distribution of Electric Facilities Records, identifies the correct procedure for updating GIS records, if needed.

2.2 Rhode Island

2.2.1 Distribution Patrols are conducted by a Distribution Inspector that has been trained to identify deficiencies or non-standard construction conditions on National Grid facilities.

2.2.2 Distribution patrols are scheduled in such a manner that each distribution feeder is examined in the field once every five (5) years. In RI the patrols shall be completed by March 31. The most current Distribution Patrol schedule can be found in the Distribution Maintenance Program data base (RPT 1310 Feeder Patrol Status).

2.2.3 New Distribution Feeders added to the system will be incorporated through our Geographic Information System (GIS) system and added to the appropriate inspection cycle.

2.2.4 If the Distribution Inspector finds unmapped facilities from the information supplied from GIS, the inspector shall add the information into the *Windows*® based hand-held computer for maintenance tracking purposes. NG-EOP G011, Preparation and Distribution of Electric Facilities Records, identifies the correct procedure for updating GIS records, if needed.

2.3 Massachusetts

2.3.1 Distribution Patrols are conducted by a Distribution Inspector that has been trained to identify deficiencies or non-standard construction conditions on National Grid facilities.

2.3.2 Distribution patrols are scheduled in such a manner that each distribution feeder is examined in the field once every five (5) years. In MA, the patrols shall be completed by December 31 due to regulatory reporting. The most current Distribution Patrol schedule can be found in the Distribution Maintenance Program data base (RPT 1310 Feeder Patrol Status).

2.3.3 New Distribution Feeders added to the system will be incorporated through our Geographic Information System (GIS) system and added to the appropriate inspection cycle.

2.3.4 If the Distribution Inspector finds unmapped facilities from the information supplied from GIS, the inspector shall add the information into the *Windows*® based hand-held computer for maintenance tracking purposes. NG-EOP G011, Preparation and Distribution of Electric Facilities Records, identifies the correct procedure for updating GIS records, if needed.

2.4 Records

2.4.1 Distribution Patrol data is recorded by the Distribution Inspector on a *Windows*® based hand-held computer and downloaded to the Distribution Maintenance Program.

2.4.2 The Distribution Inspector should also complete maintenance code 118 - stencil installed and maintenance code 220 - guy wire marker, maintenance code 660 - switchgear missing nomenclature, maintenance code 681- transformer missing nomenclature, and maintenance code 745 - enclosure missing nomenclature if found deficient upon inspection while at the site or enter the appropriate code as a Level 4 maintenance item including a comment.

2.4.3 Maintenance Codes are shown on the Distribution Field Survey Worksheet #NG0236 (Page 8). The Distribution Field Survey Worksheet can be used by the field to record maintenance items and is used for informational purposes only.

2.4.4 The latest distribution maintenance codes are downloaded to the hand-held computer each time there is a change that affects the maintenance code table contained in the Distribution Maintenance Database. Printed copies of the latest maintenance code tables may be obtained by running a report on the look up tables from the Distribution Maintenance Database.

2.5 The *Windows*® based hand-held computer is to be used as the primary vehicle for recording maintenance problems in the field. There may be times where it is not practicable to use the hand-held computer. In these cases, the person performing the inspection should record the information on the Distribution Field Survey Worksheet (#NG0236).

https://teams.nationalgrid.com/sites/Syracuse/SitePages/Home.aspx

Once complete, the Distribution Field Survey Worksheet information shall be input into the Distribution Maintenance Database by the inspector, clerk, or supervisor or their designee.

3.0 EQUIPMENT TO BE INSPECTED AND MAINTENANCE CODES

3.1 This EOP requires the visual inspection of the following facilities as designated above for New York, Rhode Island or Massachusetts:

a. Wood Pole Mounted Street Light
b. Poles
c. Crossarms
d. Insulators
e. Primary
f. Transformers
g. Capacitor
h. Regulator
i. Sectionalizer
j. Recloser
k. Switches
l. Ground
m. Guy
n. Anchor
o. Secondary
p. Service
q. ROW
r. GIS
s. Spacer Cable
t. Cutout
u. Risers
v. Switchgear
w. Padmount Transformers
x. Enclosures

4.0 DISTRIBUTION MAINTENANCE DATABASE

4.1 The Distribution Maintenance Database consists of information collected in the field downloaded from the *Windows*® based hand-held computer and data gathered from other sources entered from the desktop computer. The *Windows*® based hand-held computer can be downloaded to any National Grid desk top computer that is connected to the network by an employee that has been authorized to perform this function. The Distribution Maintenance Database is used by various departments throughout National Grid to generate maintenance reports and cost estimates.

4.2 The Distribution Maintenance Database contains information to be used by Asset Strategy and Investment Planning to track maintenance codes that may affect reliability (R), affect reliability that have a specific program in place to address (RP), or may not directly affect reliability (NR):

5.0 MAINTENANCE SCHEDULE

5.1 Maintenance activities are scheduled by maintenance codes. Maintenance codes are given a priority level to aide in the scheduling of work assuring a safe and reliable distribution system.

5.2 All “Level 1 Priority” conditions identified shall be repaired/corrected within:

5.2.1 New England – 30 days

5.2.2 New York – 7 days.

5.3 NY Only - all “Level 2 Priority” conditions identified shall be repaired/corrected within 1 year. In NE, work will be reviewed, prioritized and scheduled according to the Annual Work Plan

5.4 NY Only - All “Level 3 Priority” conditions shall be repaired within 3 years. In NE, work will be reviewed, prioritized and scheduled according to the Annual Work Plan

5.5 All Level 4 Priority is for inventory purposes only.

5.6 All Level 9 priority conditions should be completed within 90 days. Level 9 priority conditions not completed within 90 days, the company shall periodically perform site visits to monitor the condition of the temporary repair. Refer to NG-EOP G029 – Tracking Temporary Repairs to Electric System for details on Level 9 priority conditions.

5.7 NY Only - Once the Distribution Feeder is completed in the Distribution Maintenance Database or 21 days have elapsed since the inspection, the Level 2 and Level 3 Priority maintenance codes are downloaded into STORMS. Expense maintenance work goes straight to scheduling while the capital work goes to Distribution Design. Level 1 Priority maintenance codes are communicated by the Distribution Inspector directly to the field operations group for the area where the feeder is located.

6.0 COMPLETION OF MAINTENANCE CODES

6.1 Level 1 priority maintenance codes completion process:

6.1.1 Distribution Inspector contacts System Operations Dispatch (SOD) providing information on the Level 1 maintenance item and fills out a Level 1 Priority Report Form (page 11).

6.1.2 SOD generates an ABB OMS order for Regional Control

6.1.3 Inspections Supervisor captures ABB OMS ID # and details for Level 1 maintenance item status. Inspections Supervisor tracks Level 1 maintenance status with operations ensuring that the Level 1 item is completed within 30 days (NE) and 7 days (NY). Inspection Supervisor closes out the Level 1 maintenance item in the Distribution Maintenance Database by adding the ABB OMS ID # number to maintenance record.

6.2 NY Only - Level 2 and Level 3 priority maintenance codes are completed in the Distribution Maintenance database once the 699 requirement is completed in STORMS for the work request associated with the maintenance code.

ALL MAINTENANCE WORK IS TO BE COMPLETED PER NATIONAL GRID DISTRIBUTION STANDARDS.

ALL MAINTENANCE WORK PERFORMED THAT WAS IDENTIFIED ON THE WORK ORDER OR DISCOVERED DURING THE REPLACEMENT/REPAIR/CORRECTION OF THE ORIGINAL MAINTENANCE PROBLEM SHALL BE LISTED ON THE DATABASE AND THEN CLOSED OUT WHEN COMPLETE.

Reference Only

DISTRIBUTION FIELD SURVEY WORKSHEET

nationalgrid

REGION	DISTRICT	EMPLOYEE ID	DATE
FEEDER	TAX DISTRICT/TOWN	MAP #	
LINE # / ROUTE #	POLE #/SUFFIX #		
LOCATION			
# MAIN LINE CATV ATTACHMENT 1 2 3 4 5	# MAIN LINE TELEPHONE ATTACHMENT 1 2 3 4 5	STREET LIGHT ATTACHED ☐ Yes ☐ No	

WOOD POLE MOUNTED STREET LIGHT	P/Q
098 1,2 (NR) ☐ Street Light Hazard Cond.	/
099 2 (NR) ☐ Not Bonded	/
POLE	
106 3,9 (NR) ☐ Dbl Wood-NG Trnsf Req'd	/
107 4 (NR) ☐ Dbl Wood-Tel Trnsf Req'd	/
108 4 (NR) ☐ Dbl Wood-CATV Trnsf Req'd	/
110 1,2,9 (R) ☐ Broken/severely damaged	/
111 1,2,3,4 (RP) ☐ Visual Rotting Grd Line	/
112 1,2,3 (RP) ☐ Woodpecker Holes - Replace	/
113 3 (NR) ☐ CuNap Treated Bthmark Yr	/
114 2 (R) ☐ Woodpecker Holes	/
115 1,2,3,9 (NR) ☐ Riser Guard Req'd	/
116 1,2,3,9 (RP) ☐ Visual Rotting Pole Top	/
117 1,2 (NR) ☐ Leaning Pole	/
118 4 P (NR) ☐ Stencil / Correction Req'd	/
119 4 (NR) ☐ Bird's Nest	/
CROSSARM	
120 1,2,4,9 (R) ☐ Damage Arm	/
121 1,2,4,9 (NR) ☐ Loose/Defective Pins	/
122 3 (NR) ☐ Wooden Pine 13.2kv	/
123 1,2,4,9 (R) ☐ Loose Brace, Hrdwr	/
124 1,2,4,9 (R) ☐ Damage Dbl Crossarm	/
125 1,2,4,9 (R) ☐ Damage Alley Arm	/
127 1,2 (R) ☐ Primary On Arm	/
128 3,9 (R) ☐ Loose Ridge Pin	/
INSULATOR	
130 1,2 (R) ☐ Broken/Cracked/Flashed	/
131 1,2,9 (R) ☐ Floating	/
132 4 (NR) ☐ I7 Aluminum Capped	/
133 3 (R) ☐ Non-Standard Voltage	/
134 4 (NR) ☐ AL Cap Assoc w/Switch/Fuse	/
PRIMARY	
140 1,2,9 (R) ☐ Insuff. Grnd Clearance	/
141 1,2,3 ☐ Damaged Cond/Brkn Strands	/
142 1 (NR) ☐ Limbs on Primary	/
145 1,2,3 (R) ☐ Dmg'd Stirups/Connector	/
146 1,2,3 (R) ☐ Improper Sag	/
147 3 (R) ☐ LA Missing Transition	/
148 3 (R) ☐ LA Missing End of Line	/
149 3 (R) ☐ LA Blown	/
TRANSFORMER	
150 1,2 (NR) ☐ Oil Weeping	/
151 1,2 (R) ☐ Bushings Broken/Cracked	/
152 2 (R) ☐ Missing Ground Wire	/
153 2,3,4 (R) ☐ LA Blown/Missing/Improper	/
154 3,4 (NR) ☐ Not in Use	/
155 3,4 (R) ☐ Animal guards required	/
156 3 (NR) ☐ Non Std Install of Gap	/
157 2 (R) ☐ Improper/Missing Bond	/
CAPACITOR	
160 1,2 (NR) ☐ Oil Weeping	/
161 1,2 (R) ☐ Bulging	/
162 1,2 (R) ☐ Bushings Broken/Cracked	/
163 2 (R) ☐ Missing Ground Wire	/
164 2 (NR) ☐ Blown Fuse	/
165 3 (NR) ☐ Improper/Missing Bond	/
166 3 (R) ☐ Animal Guard Missing	/
167 3 (R) ☐ LA Blown/Missing/Improper	/
168 4 (NR) ☐ Control Cab Heigh/Ground	/
169 4 (NR) ☐ Capacitor Out of Service	/

REGULATOR	P/Q
170 1,2 (NR) ☐ Oil Weeping	/
171 1,2 (R) ☐ Bushings Broken/Cracked	/
172 2 (R) ☐ Missing Ground Wire	/
174 4 (NR) ☐ Control Cab Height/Ground	/
175 3 (R) ☐ Improper/Missing Bond	/
176 3 (R) ☐ Animal Guard Missing	/
177 3 (R) ☐ LA Blown/Missing/Improper	/
SECTIONALIZER	
180 1,2 (NR) ☐ Oil Weeping	/
181 2 (R) ☐ Bushings Broken/Cracked	/
182 2 (R) ☐ Missing Ground Wire	/
183 4 (NR) ☐ Control Cab Height/Ground	/
184 3 (R) ☐ Improper/Missing Bond	/
185 3 (R) ☐ Animal Guard Missing	/
186 3 (R) ☐ LA Blown/Missing/Improper	/
RECLOSER	
190 1,2 (R) ☐ Oil Weeping	/
191 1,2 (R) ☐ Bushings Broken/Cracked	/
192 2(R) ☐ Missing Ground Wire	/
193 4 (NR) ☐ Control Cab Height/Ground	/
194 3(R) ☐ Improper/Missing Bond	/
195 3 (R) ☐ Animal Guard Missing	/
196 2,3 (R) ☐ LA Blown/Missing/Improper	/
197 2 (R) ☐ TripSaver - Light On	/
SWITCH	
203 1,2 (R) ☐ Gang Oper'd Defective	/
204 1,2,3 (R) ☐ Single Phase Defective	/
205 3 (R) ☐ Improper/Missing Bond	/
207 3,4 (R) ☐ LA Blown/Missing/Improper	/
208 2 (NR) ☐ Handle Not Bonded	/
GROUND	
210 1,2,9 (R) Wire Broken/Loose	/
211 1,2 (R) ☐ Hazard Condition	/
212 3 (NR) ☐ Guard Req'd	/
213 3,4 (NR) ☐ Non Standard	/
214 3,9 (NR) ☐ Not Bonded to Neutral	/
GUY	
215 3(NR) ☐ Guy-Span Not In Compliance w/Code	/
220 4,P (NR) ☐ Guy Wire Marker	/
221 3 (NR) ☐ Not in Compliance w/Code	/
222 3,9 (NR) ☐ Excessive Slack	/
223 1,2,3,9 (R) ☐ Broken Wire	/
ANCHOR	
226 1,2,3,9 (NR) ☐ Req'd - Jt. Owned	/
227 1,2,3,9 (NR) ☐ Req'd - Sole NG	/
SECONDARY	
231 1 (NR) ☐ Limb on Secondary	/
232 1,2,9 (NR) ☐ Improper Sag	/
234 1,2,3,9 (NR) ☐ Floating	/
SERVICE	
240 1 (NR) ☐ Ins. Loose from House	/
241 1 (NR) ☐ Limb on Service	/
243 1,9 (NR) ☐ Non Std/Unsecured	/
ROW	
250 4 (NR) ☐ Brush/Tree/Washout	/
GIS	
260 4(NR) ☐ Map Doesn't Match Field	/
261 4(NR) ☐ Pole/Line Numbering Error	/
262 4(NR) ☐ Equip/Hardware/Missing	/
263 4(NR) ☐ Equip Removed in Field, Remove From GIS	/
264 4(NR) ☐ Misc.-Transmission Overbuilt	/
269 4 (NR) ☐ Other GPS/GIS Errors	/

SPACER CABLE	P/Q
270 1,2,3,9 (R) ☐ Damaged/Missing Spacer	/
271 1,2,3,9 (R) ☐ Bracket Damage	/
272 3 (R) ☐ Bracket Not Bonded	/
273 3 (R) ☐ Messenger Not Bonded	/
274 3 (R) ☐ Messenger Guard Missing	/
276 3 (R) ☐ Uncovered Splice	/
CUTOUT	
280 2 (R) ☐ Defective Cutout	/
281 2 (R) ☐ Potted Porcelain	/
287 4 (NR) ☐ 3 Phase Equip Mount	/
288 3 (NR) ☐ S&C SMD - 20 Power Fuse	/
RISER	
290 1,2,3,9 (NR) ☐ Improp Cable Supp/Term	/
291 2 (R) ☐ Improper/Missing Bond	/
292 3 (R) ☐ Animal Guard Missing	/
293 2,3 (R) ☐ LA Blown/Missing/Improper	/
CONDUCTOR	
300 4 (NR) ☐ Pool Clearance	/
HANDHOLES	
600 1,2,9 (NR) ☐ Broken/Damaged/Unsecured	/
601 4 (NR) ☐ Improper Grade	/
602 P (NR) ☐ Missing Nomenclature	/
603 1 (R) ☐ Secondary Needs Repair	/
604 4 (NR) ☐ Other (use comments)	/
605 4 (NR) ☐ Excessive Vegetation	/
SWITCHGEAR	
651 1,2,3 (R) ☐ Barrier Brkn/Dmgd/Unsec	/
652 1,2 (NR) ☐ Base Broken/Damaged	/
656 1,2,9 (R) ☐ Door Broken/Damaged	/
657 1 (NR) ☐ Excessive Vegetation	/
660 P (NR) ☐ Missing Nomenclature	/
661 4 (NR) ☐ Other	/
662 4 (NR) ☐ Rusted/Paint Peeling	/
PAD TRANSFORMER	
673 1,2 (R) ☐ Door Broken/Damaged	/
676 4 (NR) ☐ Excessive Vegetation	/
681 4,P (NR) ☐ Missing Nomenclature	/
684 1,2 (NR) ☐ Oil Weeping	/
685 1,2,3,4,9 (NR) ☐ Pad Broken/Damaged	/
686 4 (NR) ☐ Protection (Ballards)	/
687 4 (NR) ☐ Rusted/Paint Peeling	/
688 1,2,9 (NR) ☐ Pushed Off Base	/
ENCLOSURES	
740 1,2,3,4 (R) ☐ Base Broken/Cracked	/
741 1,2,3,9 P (R) ☐ Door Brkn/Dmgd/Unsec	/
743 4 (NR) ☐ Excessive Vegetation	/
745 4 P (R) ☐ Missing Nomenclature	/
746 4 (NR) ☐ Rusted/Paint Peeling	/
POLE INSPECTION	
801 1,2,3,4 (R) ☐ Identified Priority Pole	/
802 1,2,3,4 (R) ☐ Identified Reject Pole	/
803 4 (NR) ☐ Excessive Checking	/
804 4 (NR) ☐ Climbing Inspection	/

Comments:

KEY

P/Q = Priority / Quantity
NR = Maint. Code May Not Direct Affect Reliability
R = Maint. Code May Affect Reliability
RP = Maint. Code May Affect Reilability and Has Speci?c Program to Place to Address

NG0236 (02.15)

Level "1" & Elevated Voltage Priority Report Form

Any Level "1" Priority or Elevated Voltage condition found must be called into Dispatch.

Feeder:______________________________

Line #:______________________________

Pole #:______________________________

Closest Meter #:_____________________________

Street Address: _______________________

City/Town: __________________________

Level "1" Priority/Elevated Voltage condition found.

____

____

Call Dispatch to inform that this is either an Elevated Voltage call or an Inspection issue.

Dispatcher notified: ____________________

Date/Time: ___________________________

Inspector: ____________________________

7.0 REVISION HISTORY

Version	Date	Description of Revision
1.0	04/01/11	This document supersedes document dated 08/17/09.
2.0	04/27/15	This document supersedes document dated 12/03/14
3.0	04/25/17	Four-year revision, separated by state and removed priority levels 2 & 3 for MA & RI, NY Remains the same, Aligned with UG 006 for uniformity.
4.0	10/01/20	Updated Accountability section to reflect department name changes, Section 1: Added Safety Section, Introduction, Section 5.2, 6.1.3: Updated Repair time for New England.

R-I-18

Request:

Provide a detailed scope, design and budget estimate for the revised Dyer Street project. Compare/contrast any expected changes in reliability between the previous and revised design.

Response:

1.0 DETAILED SCOPE DISTRIBUTION SUBSTATION

1.1 Property/Site Work

a. High Level Scope:
   1. This is an existing site and the work will be within the confines of the existing fenced yard.

1.2 Foundations:

Based on recent geotechnical report, the underlying soil at this site is not suitable for shallow type foundations. Specialized foundations like driven piles, pressure injected footing, helical piles, etc., will need to be utilized.

a. Install:
   1. One (1)- Foundation for the MCSPC.
   2. Two (2)- Foundations at the future 115/12.47 kV substation location. This is for interim use to store the relocated 115/11.5 kV and 23/11.5 kV spare transformers at South Street Substation to make room for the 11.5/4.16 kV Substation.
   3. Two (2)- 11.5 kV cable terminating structure support foundations at the 11.5/4.16 kV transformers.
   4. Two (2)- 4.16 kV cable terminating structure foundations at the 11.5/4.16 kV transformers.
   5. One (1)- two- hour rated fire wall between the two 11.5/4.16 kV power transformers.
   6. Two (2)- 34.5 kV airbreak switch structure foundations at the 11.5/4.16 kV transformers

b. Modify:
   1. Existing 115/11.5 kV and 23/11.5 kV spare transformer foundations to accommodate the new 11.5/4.16 kV, 10/12.5 MVA power transformers and the firewall.

R-I-18, page 2

1.3 Structures:

a. High Level Scope:

1. Four (4) transformer cable terminating structures, two each for 11.5 kV and 4.16 kV.

1.4 Control /Equipment Enclosure

a. High Level Scope:

1. One factory fabricated metal-clad switchgear power center (MCSPC), approximate dimensions 44 x 24 ft.

1.5 Raceways and Conductors

a. High Level Scope:

1. Existing cable trench in the yard will be used, with short trench / conduit runs to interface with the power transformers, MCSPC, and South Street Switchgear building.
2. Non-shielded 600V power and control cables interconnecting power transformers, MCSPC, South Street Switchgear building AC/DC cabinets, 1102 and 1104 control switchboards.
3. Fiber optic cable run from MCSPC to the Telecom rack in South Street switchgear building.
4. Total twelve 15 kV, 1/c, 1000 kcmil, Cu conductor, EPR power cable runs (six for each of the circuits, two/1c per phase) for interconnection between 1102-3 & 1104-3 disconnects in the switchgear building first floor and 11.5 kV cable terminating structures at the transformers. 1102 will require new cable all the way from the -3 disconnect and 1104 will require a new cable from the switchgear building basement, as the existing 1104 cable can be intercepted and spliced to the new cable toward the 11.5 kV cable terminating structure at the transformer.
5. Total twelve, 35 kV, 2000 kcmil, 1/c, Cu conductor, EPR power cable runs (six for each of the circuits, two/1c per phase) between MCSPC and 4.16 kV cable terminating structures at the transformer.

R-I-18, page 3

1.6 Primary Equipment:

a. Install:

1. Two (2) new 10/12.5MVA, 11.5 kV-4.16GRD Y/2.4 kV LTC power transformers.
2. One (1) metal-clad switchgear power center (MCSPC). This will include metal-clad switchgear, control & protection equipment. Metal-clad switchgear will be rated 15 kV, 3000A, 25 kA in breaker and a half bus configuration (BAAH). The switchgear will be operated at 4.16 kV. It will include four BAAH bays with twelve, 1200 A, 25 kA circuit breakers and eight outgoing feeder positions. Metal-clad switchgear will come equipped with arc flash protection and fiber optic arc flash sensing with very fast arc flash tripping.
3. Two (2) 34.5 kV, 2000A group operated airbreak switches for 4.16 kV side of 11.5/4.16 kV transformers.
4. Primary conductor interconnects between the cable terminators and 11.5/4.16 kV power transformers (1x795 kcmil per phase at 11.5 kV and 2x1113 kcmil AAC/phase at 4.16 kV)

1.7 Station Service:

a. High Level Scope:

1. 208 V, 3 Phase, 4 wire AC panelboards in the MCSPC will be served from a feeder coming from main AC Distribution Panel in the South Street Switchgear building.
2. 125 V DC panelboard in the MCSPC will be served from branch feeders coming from DC Cabinets in the South Street Switchgear building.

1.8 Protection/Control/Metering:

a. Install:

1. For the two 11.5/4.16 kV power transformers and 4.16 kV bus, primary system of protection will consist of overall transformer/bus differential relay SEL-387 and SEL-751 relay for arc flash and backup protection. Power transformers will have fault pressure relay and low oil tripping.
2. Arc Flash protection (SEL-751) for the 4.16 kV switchgear.
3. Each 4.16kV feeder will have a primary protection (SEL-351) and secondary protection (SEL-551). SEL-351 will also serve as the under-frequency protection to trip and block closing / reclosing of the 4.16kV feeders.

Prepared by or under the supervision of: David Arthur

R-I-18, page 4

b. Control/Metering System:

   Install:

   1. Eight (8) simple control switchboards, one each for (a) two transformers (b) four 4 kV BAAH bays (c) RTU and (d) annunciator. Due to space restrictions, two control switchboards associated with the transformers will not be in the same lineup as the 4 kV control switchboards, but directly opposite.
   2. Metering: N/A.

1.9 Telecommunications:

a. High Level Scope:
   1. RTU will be connected to the fiber racks in the South Street Control Room for interface with the private NGRID network.
   2. Extending phone line service from 11 kV switchgear building to the MCSPC.
b. Non-National Grid Circuit OPEX Cost:
   1. Use of existing South Street Telecom circuit is foreseen.

1.10 Dyer Street Substation: Demolition of the existing AC building originally constructed during the 1920's. The scope includes the following:

a. Removal of all 11.5 kV and 4.16 kV equipment bus work, cables, lighting, heating, cabinets/panels, and miscellaneous substation equipment inside the AC building (see Section 7.0).
b. Removal of two 11.5/4.16 kV, 10/12.5 MVA outdoor transformers No. 1 and No.2
c. Removal of 11.5 and 4.16 kV cables interconnecting Transformers No. 1 and 2 and the switchgear inside the AC building.
d. Removal of 11.5 kV, 5.4 Mvar metal-enclosed capacitor bank.
e. Temporary sedimentation, storm water and dust control measures.
f. Cut and cap water and sewer lines at main.
g. Demolish four story AC building consisting of brick and reinforced concrete elements with supplemental steel framing.
h. Chip down foundation walls to 2 ft., below grade.
i. Breakup basement/subgrade floor and abandon below grade.
j. Remove transformer pad with associated oil containment system.
k. Remove capacitor bank foundation pad.

R-I-18, page 5

l. Removal of 1 foot of existing contaminated soil, install barrier and backfill with imported soil to RI specifications.
m. Removal of all debris and site cleanup.
n. Backfill and site grading with a 6" layer of ¾" crushed stone surfacing.

2.0 DETAILED SCOPE DISTRIBUTION LINE

See Attachment R-I-18 for the scope details for the line portion of this project

3.0 BUDGET ESTIMATE

Cost Breakdown	D-Sub
Contractor	$ 4,646
Material	$ 3,279
Payroll/Benefits	$ 1,878
Overheads	$ 1,322
Contingency	$ 3,873
Total	**$ 14,998**

Cost Breakdown	D-Line
Contractor	$ 1,569
Material	$ 506
Payroll/Benefits	$ 1,997
Overheads	$ 1,117
Contingency	$ 1,805
Total	**$ 6,994**

4.0 RELIABILITY COMPARISON

There are no expected reliability differences between the original scope at Dyer Street and the revised design at South Street. There are minor differences in underground mainline lengths between the two designs but with negligible impact on reliability.

nationalgrid

Memorandum

To: Distribution Design

From: James Wise

Date: 5/28/2020

Subject: Dyer St Substation Rebuild-South St Alternative- Distribution Line Work Phase I

The following is recommended as the Distribution Line portion of the Dyer St Substation Rebuild project. A new 11.5/4.16kV substation will be constructed at the South St Substation.

General:
- A manhole survey was performed to ensure constructability
- The Distribution Line work within the South St substation yard is based on conceptual drawings dated 5/20/2020

2J8 Feeder:
- Remove the 3-1/c #2 CU EPR cable in the following sections:
  - MH629 Pine St to MH123 Richmond St
  - MH123 Richmond St to MH2743 Richmond St
- Install 1 set of 3-1/c 500 CU EPR Compact cable, Standard Item UC16G, in the following sections:
  - MH629 Pine St to MH123 Richmond St, approximately 147'
  - MH123 Richmond St to 122 Richmond St
- Install 2 sets of 3-1/c 500 CU EPR Compact cable, Standard Item UC16G, in the following sections:
  - MH123 Richmond St to MH2743 Richmond St, approximately 89'
- In MH629 Pine St, splice into 2J8 cable using existing premolded H joint
- In MH122 Richmond St, splice into existing 2J2 cable toward Clifford St Switchgear
- In MH2743 Richmond St:
  - Install six (6) 600A deadbreak switch terminations with 200A reducing tap wells
  - Reconfigure existing submersible switch, 2J8 to loop through switch

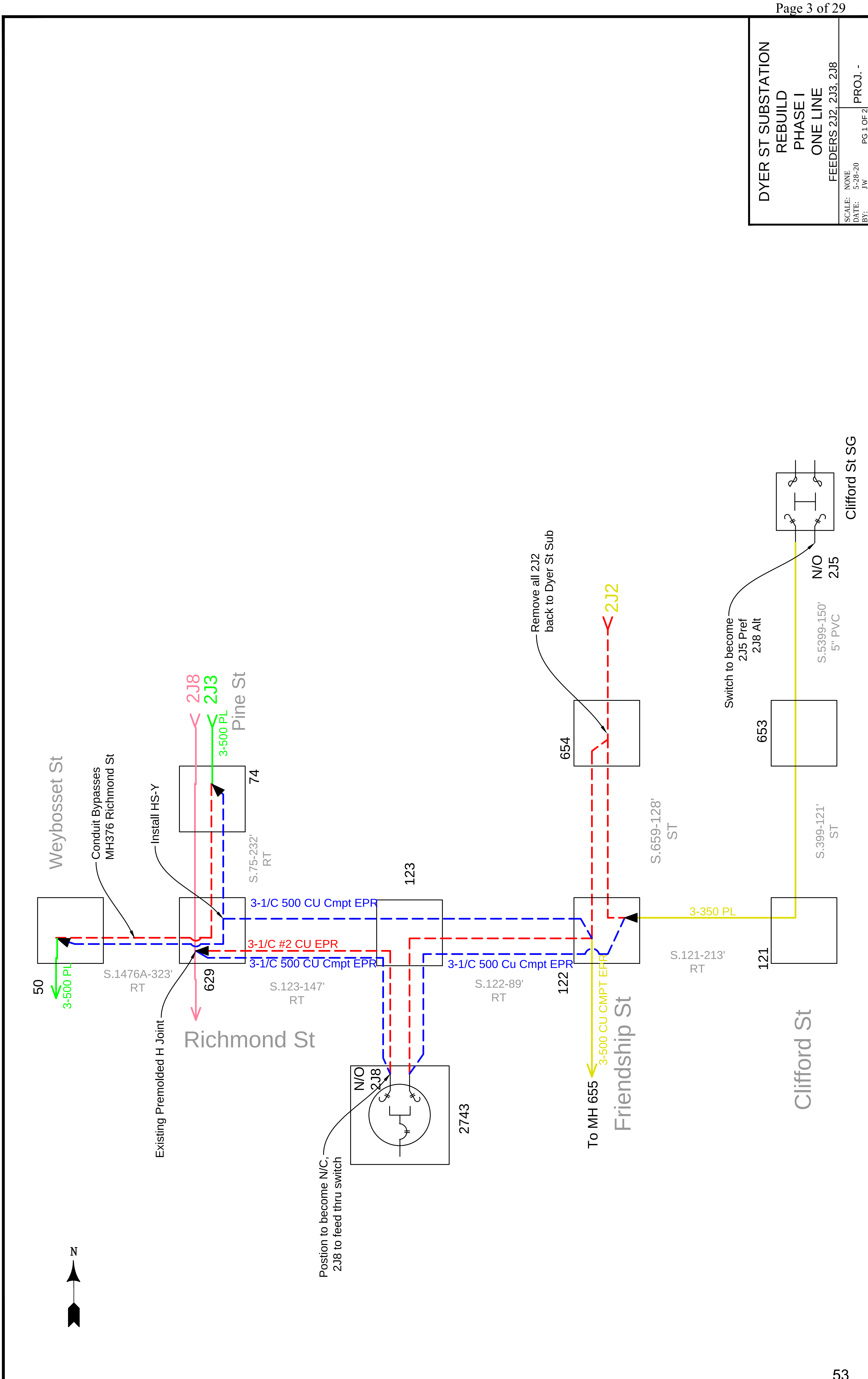
2J3 Feeder:
- Remove the 3-500 PL cable in the following sections:
  - MH74 Pine St to MH629 Pine St
  - MH629 Pine St to MH50 Weybosset St
- Install 1 set of 3-1/c 500 CU EPR Compact cable, Standard Item UC16G, in the following sections:
  - MH74 Pine St to MH629 Pine St, approximately 232'
  - MH629 Pine St to MH50 Weybosset St, approximately 323'
  - MH629 Pine St to MH123 Richmond St, approximately 147'

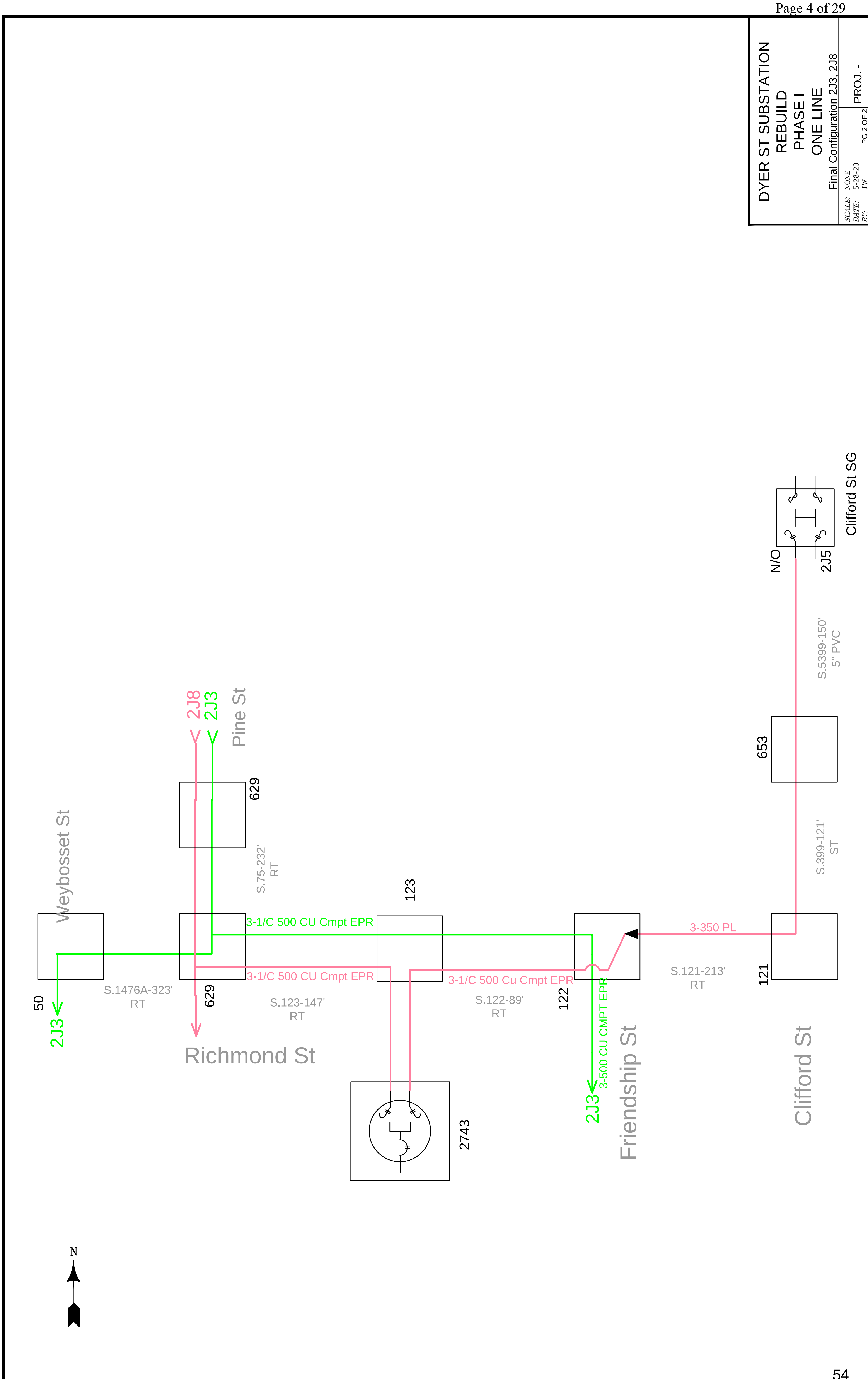
    - MH123 Richmond St to MH122 Richmond St, approximately 89'
- In MH629 Pine St, install heat shrink Y splice
- In MH122 Richmond St, splice into existing 2J2 cable toward MH655 Friendship St

2J2 Feeder:
- Remove all 2J2 mainline cable from Dyer St Substation to MH122 Richmond St
    - Dyer St 2J2-3 Disconnects to MH85D Dyer St Substation
    - MH85D Dyer St Substation to MH9D Dyer St
    - MH9D Dyer St to MH9A Dyer St
    - MH9A Dyer St to MH351 Peck St
    - MH351 Peck St to MH427 Friendship St
    - MH427 Friendship St to MH428 Friendship St
    - MH428 Friendship St to MH429 Friendship St
    - MH429 Friendship St to MH430 Friendship St
    - MH430 Friendship St to MH431 Friendship St
    - MH431 Friendship St to MH432 Friendship St
    - MH432 Friendship St to MH654 Friendship St
    - MH654 Friendship St to MH122 Richmond St, both sets
    - MH122 Richmond St to MH123 Richmond St
    - MH123 Richmond St to MH2743 Richmond St

Switches to be Reconfigured:
- Submersible Switch in MH2743 Richmond St
    - Current Configuration:
        - 2J2 Preferred,2J8 Alternate
        - LB 6011667 Normally Closed to 2J2
        - LB 601668 Normally Open to 2J8
    - Configuration after Phase I Work:
        - 2J8 Loop Through,
        - LB 601668 Normally Closed to 2J8
        - LB 6011667 Normally Closed to 2J8
- Clifford St Switchgear, off MH653 Clifford St
    - Current Configuration:
        - 2J2 Preferred, 2J5 Alternate
        - LB 2J2 Normally Closed
        - LB 2J5 Normally Open
    - Configuration after Phase I Work:
        - 2J5 Preferred, 2J8 Alternate
        - LB 2J2 Normally Open, will require new switch number
        - LB 2J5 Normally Closed, will require new switch number
- Remaining 2J2 submersible switches in Vault 47 Chestnut St, MH1575 Chestnut St, and MH853 Elbow St will be supplied from the 2J3 feeder

Attachments:
- One Line- Phase I, Feeders 2J2, 2J3, 2J8
- One Line- Phase I, Final Configuration 2J3, 2J8


DYER ST SUBSTATION
REBUILD
PHASE I
ONE LINE
FEEDERS 2J2, 2J3, 2J8
SCALE: NONE
DATE: 5-28-20
BY: JW
PG 1 OF 2
PROJ. -
Clifford St SG
N/O
2J5
Switch to become
2J5 Pref
2J8 Alt
S.5399-150'
5" PVC
653
S.399-121'
ST
121
3-350 PL
S.121-213'
RT
Clifford St
Remove all 2J2
back to Dyer St Sub
2J2
654
S.659-128'
ST
122
3-500 CU CMPT EPR
To MH 655
Friendship St
3-1/C 500 Cu Cmpt EPR
S.122-89'
RT
123
3-1/C 500 CU Cmpt EPR
3-1/C #2 CU EPR
3-1/C 500 CU Cmpt EPR
S.123-147'
RT
N/O
2J8
2743
Postion to become N/C,
2J8 to feed thru switch
2J8
2J3
3-500 PL
Pine St
74
S.75-232'
RT
Install HS-Y
629
Richmond St
Existing Premolded H Joint
Weybosset St
Conduit Bypasses
MH376 Richmond St
50
3-500 PL
S.1476A-323'
RT
N
53


DYER ST SUBSTATION
REBUILD
PHASE I
ONE LINE
Final Configuration 2J3, 2J8
SCALE: NONE
DATE: 5-28-20
BY: JW
PG 2 OF 2
PROJ. -
Clifford St SG
N/O
2J5
S.5399-150'
5" PVC
653
S.399-121'
ST
121
3-350 PL
S.121-213'
RT
Clifford St
122
3-1/C 500 Cu Cmpt EPR
3-500 CU CMPT EPR
2J3
Friendship St
S.122-89'
RT
123
3-1/C 500 CU Cmpt EPR
3-1/C 500 CU Cmpt EPR
S.123-147'
RT
2743
2J8
2J3
Pine St
629
S.75-232'
RT
629
Richmond St
Weybosset St
50
2J3
S.1476A-323'
RT
N
54

nationalgrid

Memorandum

To: Distribution Design

From: James Wise

Date: 5/28/2020

Subject: Dyer St Substation Rebuild-South St Alternative- Distribution Line Work Phase II

The following is recommended as the Distribution Line portion of the Dyer St Substation Rebuild project. A new 11.5/4.16kV substation will be constructed at the South St Substation.

General:
- A manhole survey was performed to ensure constructability
- The Distribution Line work within the South St substation yard is based on conceptual drawings dated 5/20/2020

1102A and 1102B Cables:
- Remove 1102A and 1102B 3-1/c 500 CU EPR cable in the following sections:
  - MH3330 South St Substation to MH3331 South St Substation
  - MH3331 South St Substation to MH3332 South St Substation
- Remove 1102A cable in the following sections:
  - MH8 Dyer St to MH9B Dyer St
  - MH9B Dyer St to MH84B Dyer St Substation
  - MH84B Dyer St Substation to 1102-3 Disconnects
- Remove 1102B cable in the following sections:
  - MH8 Dyer St to MH9B Dyer St
  - MH9B Dyer St to MH83B Dyer St Substation
  - MH83B Dyer St Substation to 1102-3 Disconnects
- Install 2 sets of 3-1/c 1000 CU EPR cable, Standard Item UC12TC, in the following sections:
  - MH3330 South St Substation to MH3331 South St Substation, approximately 34'
  - MH3331 South St Substation to MH"C" South St Substation, estimated 105'
  - MH"C" South St Substation to riser structure at 11.5:4.16kV substation transformer, estimated 250'

2J1 Feeder:
- Remove 2J1 Mainline cable in the following sections:
  - Dyer St Substation 2J1-3 Disconnects to MH88C Dyer St Substation
  - MH88C Dyer St Substation to MH9C Dyer St
  - MH9C Dyer St to MH1826 Dyer St

  - MH1826 Dyer St to MH2126 Dyer St
  - MH2126 Dyer St to MH1868 Dyer St
  - MH1868 Dyer St to MH1867 Dyer St
  - MH1867 Dyer St to MH1866 Dyer St
  - MH1866 Dyer St to MH1563 Dyer St
- Install 1 set of 3-1/c 1000 CU EPR cable, Standard Item UC12TC, in the following sections:
  - New Dyer St 2J1-3 Disconnects to MH"B" South St Substation, estimated 75'
  - MH"B" South St Substation to MH"C" South St Substation, estimated 205'
  - MH"C" South St Substation to MH3331 South St Substation, estimated 105'
  - MH3331 South St Substation to MH3332 South St Substation, approximately 105'
- Install 1 set of 3-1/c 500 CU EPR cable, Standard Item UC17, in the following sections:
  - MH8 Dyer St to MH2993 Peck St, approximately 120'
  - MH2993 Peck St to MH2990 Peck St, approximately 95'
  - MH2990 Peck St to MH2991 Peck St, approximately 5'
  - MH2991 Peck St to MH2992 Peck St, approximately 227'
  - MH2992 Peck St to MH2994 behind Dyer St substation, approximately 300'
  - MH2994 behind Dyer St substation to MH2995 north of Dyer St substation, approximately 300'
  - MH 2995 north of Dyer St substation to MH180 Dyer St, approximately 277'
- Install 1 set of 3-1/c 500 CU EPR Compact cable, Standard Item UC16G, in the following sections:
  - MH180 Dyer St to MH2688 Dyer St, approximately 25'
  - MH2688 Dyer St to MH1563 Dyer St, approximately 64'
- In MH3332 South St Substation, Splice new 2J1 cable to former 1102B cable toward MH3 Dyer St
- In MH8 Dyer St, Splice new 2J1 cable to former 1102B cable toward MH7 Dyer St

2J4 Feeder:
- Remove 2J4 Mainline cable in the following sections:
  - MH2 Eddy St to MH1 Eddy St
  - MH1 Eddy St to MH251 Eddy St
- Install 1 set of 3-1/c 1000 CU EPR cable, Standard Item UC12TC, in the following sections:
  - New Dyer St 2J4-3 Disconnects to MH"B" South St Substation, estimated 75'
  - MH"B" South St Substation to MH"A" South St Substation, estimated 75'
- Install 1 set of 3-1/c 500 CU EPR cable, Standard Item UC17, in the following sections:
  - MH"A" South St Substation to MH1883 South St Substation, estimated 67'
- Install 1 set of 3-1/c 500 CU EPR Compact cable, Standard Item UC16G, in the following sections
  - MH1883 South St Substation to MH1 Eddy St, approximately 195'
  - MH1 Eddy St to MH251 Eddy St, approximately 237'
- In MH251 Eddy St, Install three (3) 600A deadbreak switch terminations with 200A reducing tap wells

2J5 Feeder:
- Remove 2J5 Mainline cable in the following sections:
  - Dyer St Substation 2J7-3 Disconnects to MH85D Dyer St Substation
  - MH85D Dyer St Substation to MH2991 Peck St
  - MH2991 Peck St to MH2990 Peck St
  - MH2990 Peck St to MH2993 Peck St

  - MH2993 Peck St to MH8 Dyer St
  - MH8 Dyer St to MH201 Clifford St
  - MH201 Clifford St to MH420 Clifford St
  - MH420 Clifford St to MH134 Clifford St
  - MH134 Clifford St to MH109 Clifford St
  - MH109 Clifford St to MH418 Clifford St
  - MH418Clifford St to MH653 Clifford St
- Install 1 set of 3-1/c 1000 CU EPR cable, Standard Item UC12TC, in the following sections:
  - New Dyer St 2J5-3 Disconnects to MH"A" South St Substation, estimated 75'
- Install 1 set of 3-1/c 500 CU EPR cable, Standard Item UC17, in the following sections:
  - MH"A" South St Substation to MH1883 South St Substation, estimated 67'
- Install 1 set of 3-1/c 500 CU EPR Compact cable, Standard Item UC16G, in the following sections
  - MH1883 South St Substation to MH1 Eddy St, approximately 195'
  - MH1 Eddy St to MH116 Richmond St, approximately 231'
  - MH116 Richmond St to MH2115 Elm St, approximately 118'
  - MH116 Richmond St to MH967 Richmond St, approximately 94'
- In MH2115 Elm St, Install three (3) 600A deadbreak switch terminations with 200A reducing tap wells
- In MH116 Elm St, install Heat Shrink Y splices
- In MH653 Clifford St, make new straight splices with existing cable

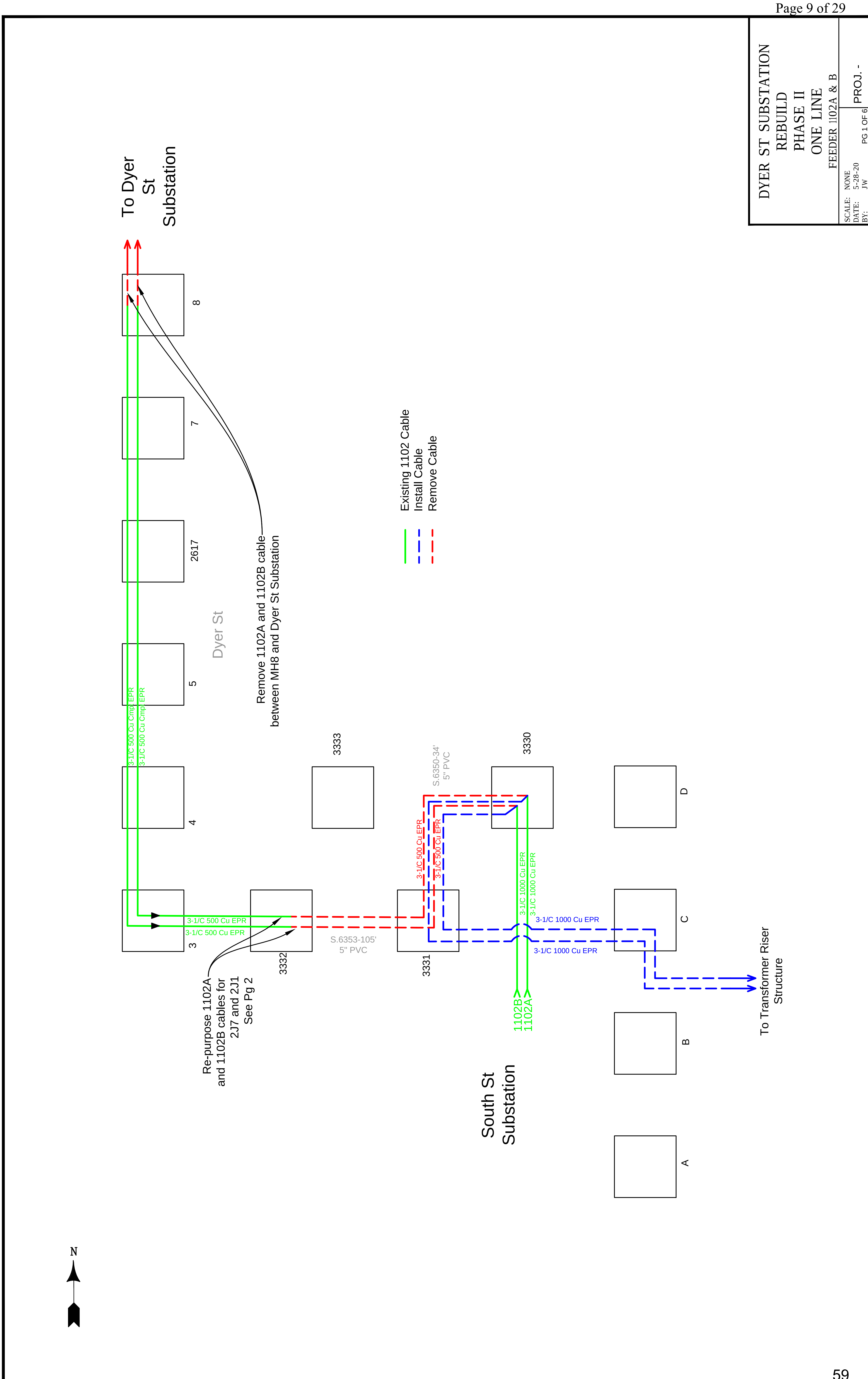
2J7 Feeder:

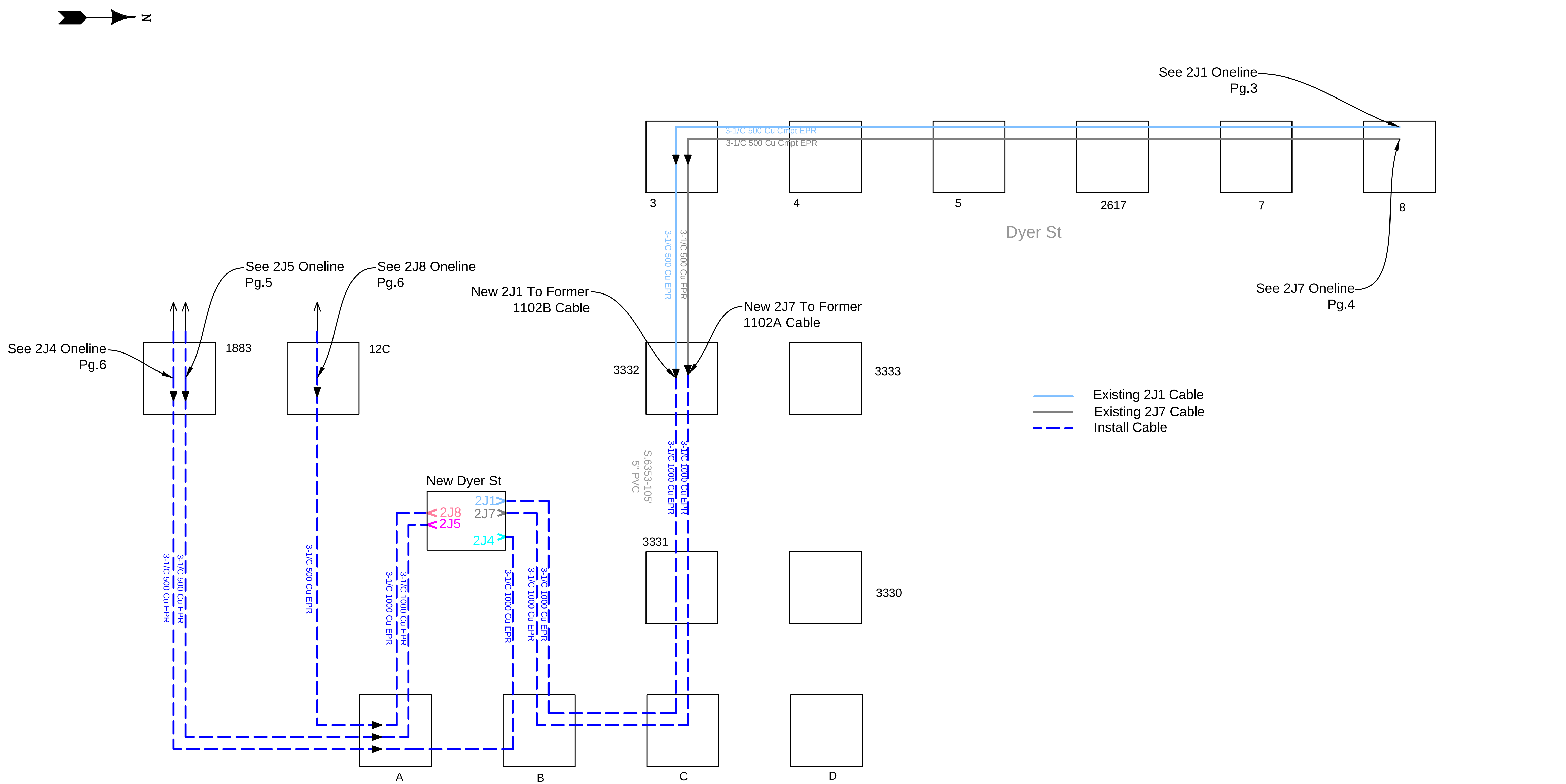
- Remove 2J7 Mainline cable in the following sections:
  - Dyer St Substation 2J7-3 Disconnects to MH85D Dyer St Substation
  - MH85D Dyer St Substation to MH9D Dyer St
  - MH9D Dyer St Substation to MH9C Dyer St
  - MH9C Dyer St to MH1826 Dyer St
  - MH1826 Dyer St to MH2126 Dyer St
  - MH2126 Dyer St to MH1868 Dyer St
  - MH1868 Dyer St to MH1867 Dyer St
  - MH1867 Dyer St to MH1866 Dyer St
  - MH1866 Dyer St to MH1563 Dyer St
- Install 1 set of 3-1/c 1000 CU EPR cable, Standard Item UC12TC, in the following sections:
  - New Dyer St 2J1-3 Disconnects to MH"B" South St Substation, estimated 75'
  - MH"B" South St Substation to MH"C" South St Substation, estimated 205'
  - MH"C" South St Substation to MH3331 South St Substation, estimated 105'
  - MH3331 South St Substation to MH3332 South St Substation, approximately 105'
- Install 1 set of 3-1/c 500 CU EPR cable, Standard Item UC17, in the following sections:
  - MH8 Dyer St to MH2993 Peck St, approximately 120'
  - MH2993 Peck St to MH2124 Dyer St, approximately 136'
  - MH2124 Dyer St to MH2125 Dyer St, approximately 137'
  - MH2125 Dyer St to MH2126 Dyer St, approximately 98'
  - MH2126 Dyer St to MH1868 Dyer St, approximately 139'
  - MH1868 Dyer St to MH1867 Dyer St, approximately 186'
  - MH1867 Dyer St to MH1866 Dyer St, approximately 131'
  - MH1866 Dyer St to MH1563 Dyer St, approximately 40'

- In MH3332 South St Substation, Splice new 2J7 cable to former 1102A cable toward MH3 Dyer St
- In MH8 Dyer St, Splice new 2J7 cable to former 1102A cable toward MH7 Dyer St

2J8 Feeder:
- Install 1 set of 3-1/c 1000 CU EPR cable, Standard Item UC12TC, in the following sections:
    - New Dyer St 2J1-3 Disconnects to MH"A" South St Substation, estimated 75'
- Install 1 set of 3-1/c 500 CU EPR cable, Standard Item UC17, in the following sections:
    - MH"A" South St Substation to MH12C South St Substation, estimated 56'
- Install 1 set of 3-1/c 500 CU EPR Compact cable, Standard Item UC16G, in the following sections
    - MH12C South St Substation to MH15 Eddy St, approximately 213'
    - MH15 Eddy St to MH2 Eddy St, approximately 220'
- In MH2 Eddy St, Install three (3) 600A deadbreak switch terminations with 200A reducing tap wells
    - Note: Submersible switch in MH2 will be Normally Open to 2J8 From New Dyer St Substation and 2J4 from Old Dyer Substation until Phase IV.

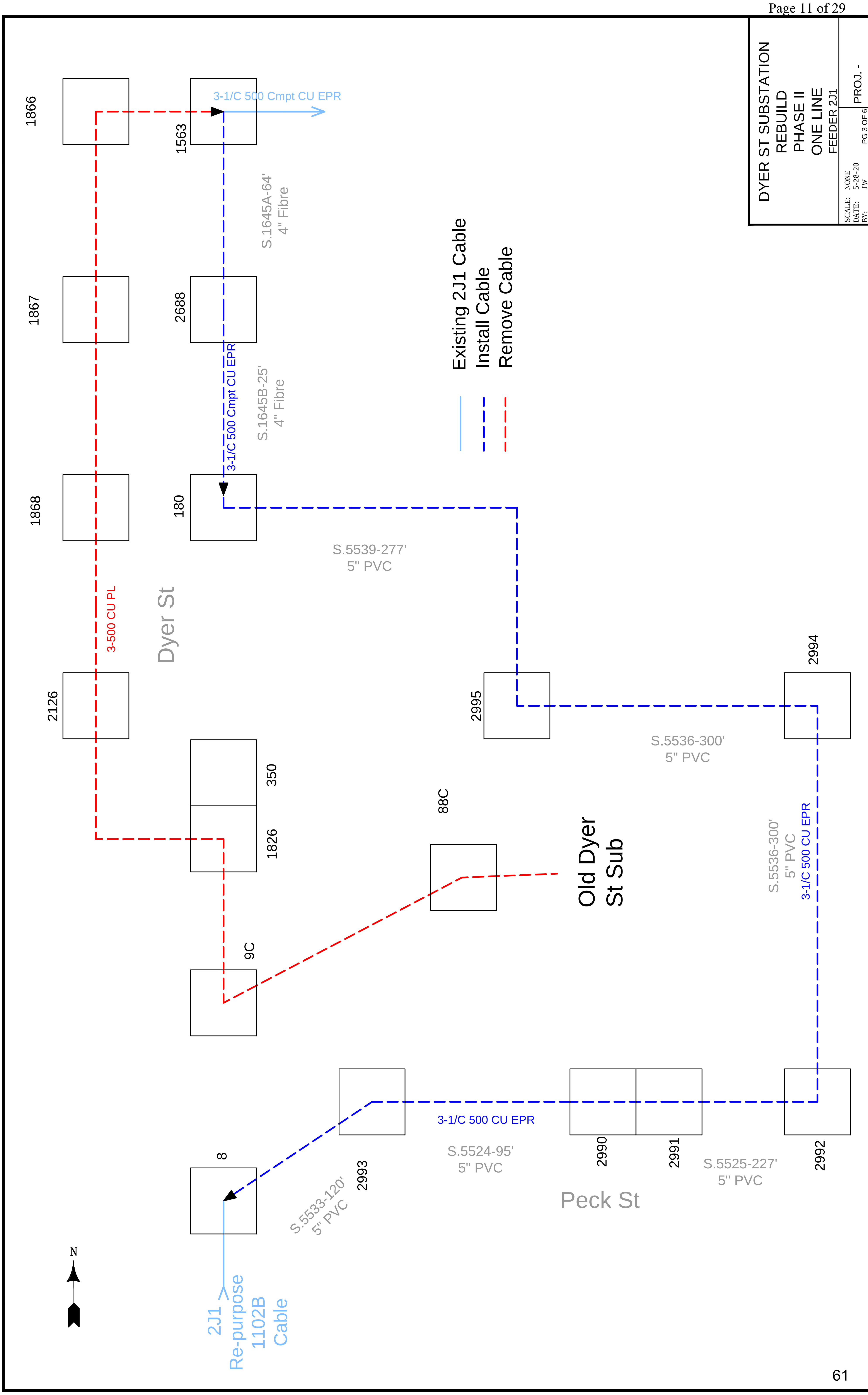
Attachments:
- One Line- Phase II, Feeders 1102A &B
- One Line- Phase II, Feeders 2J1, 2J4, 2J5, 2J7, 2J8
- One Line- Phase II, Feeder 2J1
- One Line- Phase II, Feeder 2J7
- One Line- Phase II, Feeder 2J5
- One Line- Phase II, Feeders 2J4, 2J8

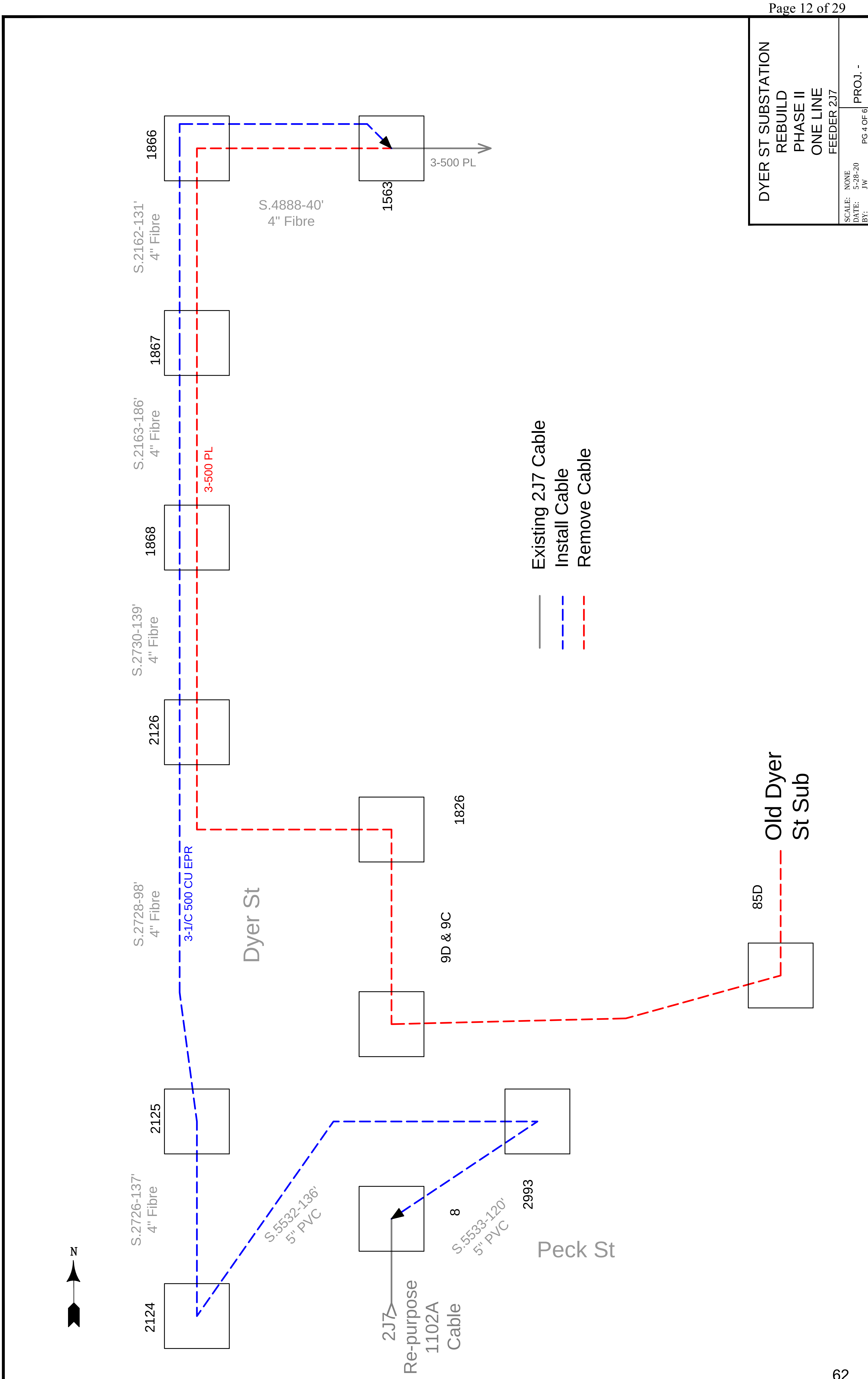

DYER ST SUBSTATION
REBUILD
PHASE II
ONE LINE
FEEDER 1102A & B
SCALE: NONE
DATE: 5-28-20
BY: JW
PG 1 OF 6
PROJ. -
To Dyer St Substation
8
7
2617
5
4
3
3332
3331
3333
3330
A
B
C
D
Dyer St
3-1/C 500 Cu Cmp EPR
3-1/C 500 Cu Cmp EPR
3-1/C 500 Cu EPR
3-1/C 500 Cu EPR
S.6353-105'
5" PVC
S.6350-34'
5" PVC
3-1/C 500 Cu EPR
3-1/C 500 Cu EPR
3-1/C 1000 Cu EPR
3-1/C 1000 Cu EPR
3-1/C 1000 Cu EPR
3-1/C 1000 Cu EPR
1102B
1102A
Remove 1102A and 1102B cable
between MH8 and Dyer St Substation
Re-purpose 1102A
and 1102B cables for
2J7 and 2J1
See Pg 2
Existing 1102 Cable
Install Cable
Remove Cable
South St
Substation
To Transformer Riser
Structure
N

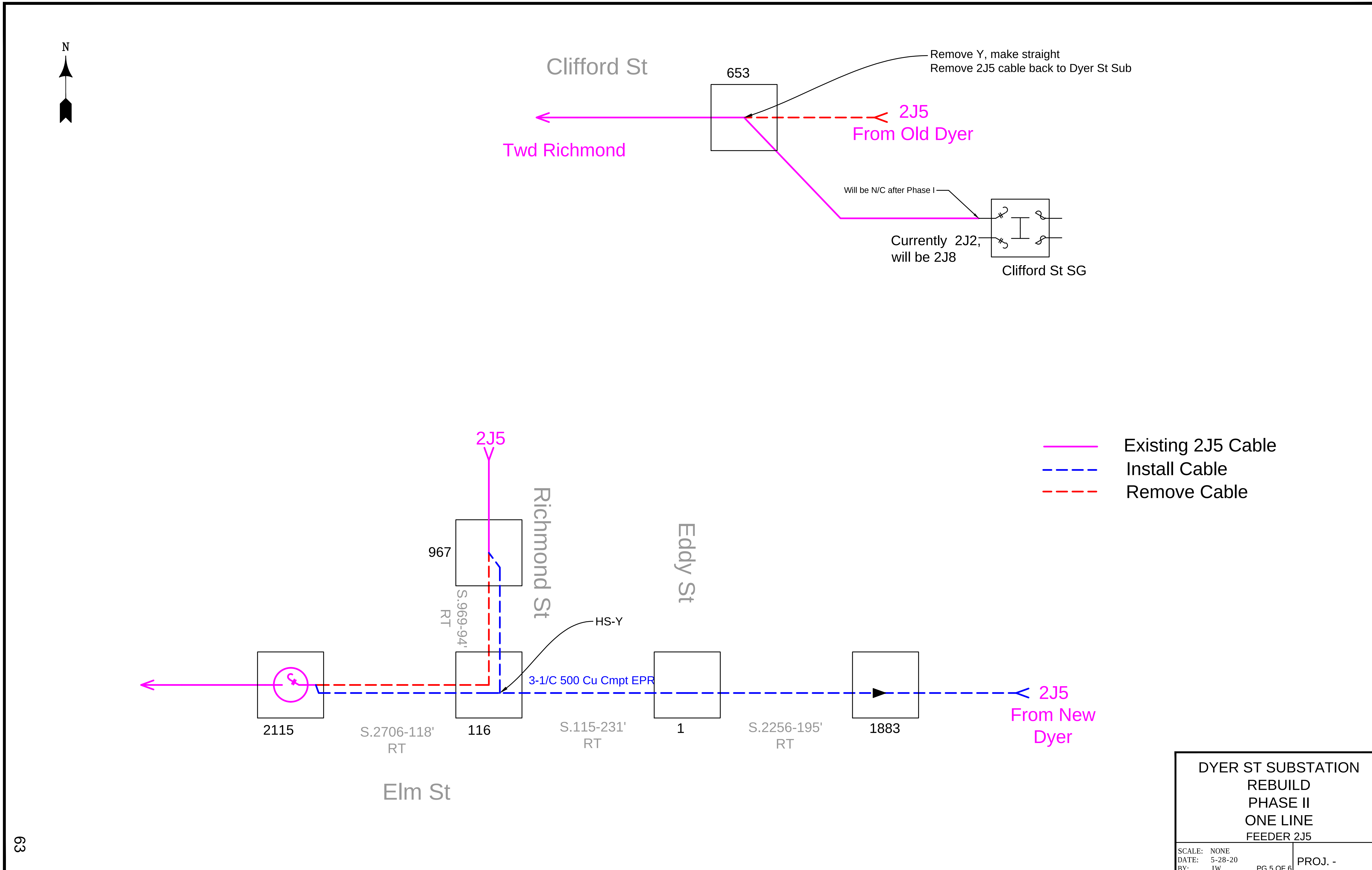


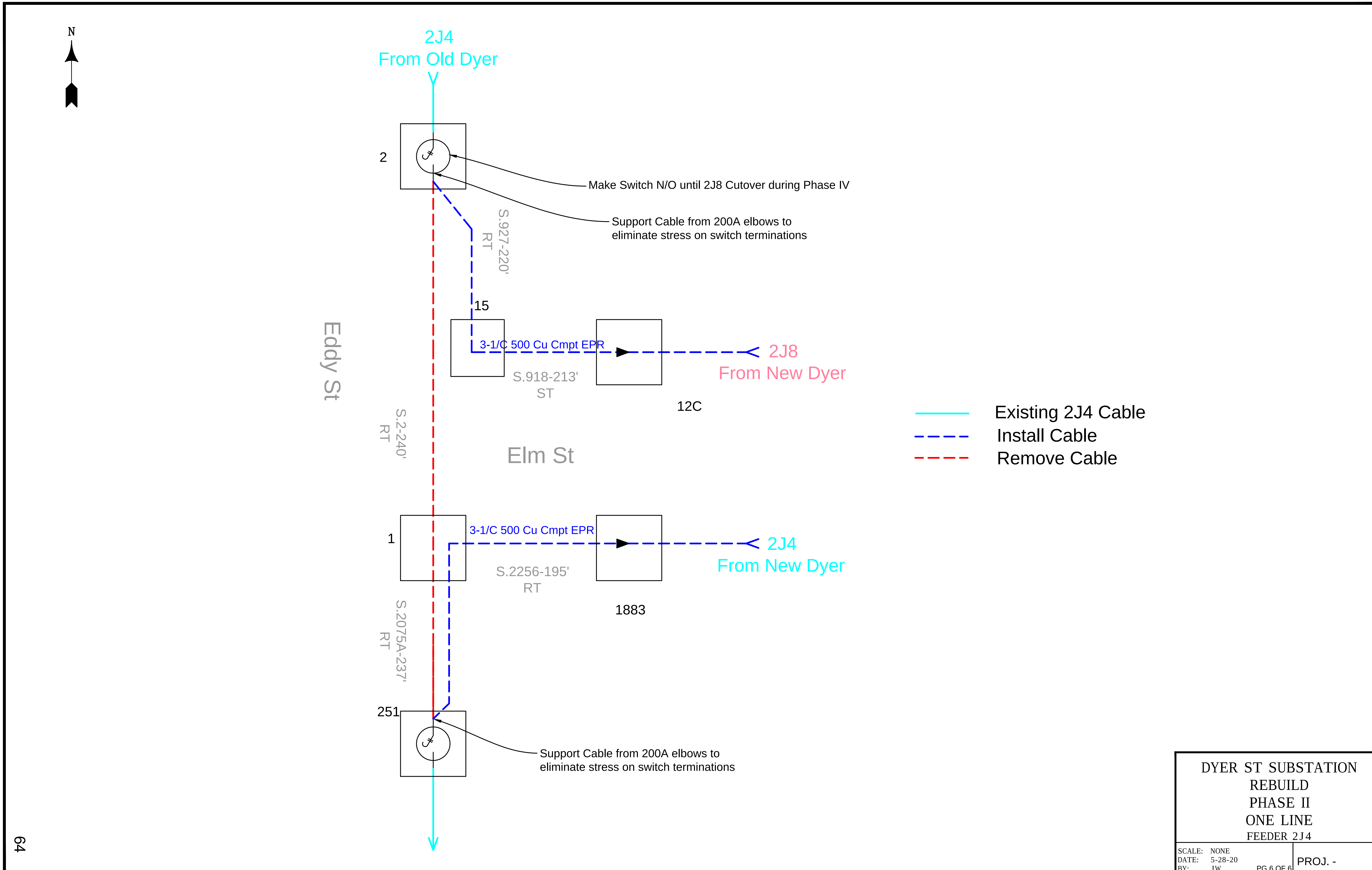
DYER ST SUBSTATION
REBUILD
PHASE II
ONE LINE
FEEDER 2J1, 2J4, 2J5, 2J7, 2J8

SCALE: NONE
DATE: 5-28-20
BY: JW
PG 2 OF 6
PROJ. -


DYER ST SUBSTATION
REBUILD
PHASE II
ONE LINE
FEEDER 2J1
PROJ. -
SCALE: NONE
DATE: 5-28-20
BY: JW
PG 3 OF 6
Existing 2J1 Cable
Install Cable
Remove Cable
1866
1867
1868
2126
1563
2688
180
350
1826
9C
88C
8
2993
2990
2991
2992
2994
2995
3-1/C 500 Cmpt CU EPR
3-1/C 500 Cmpt CU EPR
3-500 CU PL
3-1/C 500 CU EPR
3-1/C 500 CU EPR
S.1645A-64'
4" Fibre
S.1645B-25'
4" Fibre
S.5539-277'
5" PVC
S.5536-300'
5" PVC
S.5536-300'
5" PVC
S.5524-95'
5" PVC
S.5525-227'
5" PVC
S.5533-120'
5" PVC
Dyer St
Peck St
Old Dyer
St Sub
2J1
Re-purpose
1102B
Cable
N


DYER ST SUBSTATION
REBUILD
PHASE II
ONE LINE
FEEDER 2J7
PROJ. -
SCALE: NONE
DATE: 5-28-20
BY: JW
PG 4 OF 6
1866
1867
1868
2126
2125
2124
1563
1826
9D & 9C
2993
8
85D
3-500 PL
S.4888-40'
4" Fibre
S.2162-131'
4" Fibre
S.2163-186'
4" Fibre
S.2730-139'
4" Fibre
S.2728-98'
4" Fibre
S.2726-137'
4" Fibre
3-500 PL
3-1/C 500 CU EPR
Dyer St
Peck St
S.5532-136'
5" PVC
S.5533-120'
5" PVC
2J7
Re-purpose
1102A
Cable
Existing 2J7 Cable
Install Cable
Remove Cable
Old Dyer
St Sub
N
62


Clifford St
653
Remove Y, make straight
Remove 2J5 cable back to Dyer St Sub
2J5
From Old Dyer
Twd Richmond
Will be N/C after Phase I
Currently 2J2,
will be 2J8
Clifford St SG
2J5
967
Richmond St
Eddy St
HS-Y
S.969-94'
RT
3-1/C 500 Cu Cmpt EPR
2115
S.2706-118'
RT
116
S.115-231'
RT
1
S.2256-195'
RT
1883
2J5
From New
Dyer
Elm St
Existing 2J5 Cable
Install Cable
Remove Cable
N
DYER ST SUBSTATION
REBUILD
PHASE II
ONE LINE
FEEDER 2J5
SCALE: NONE
DATE: 5-28-20
BY: JW
PG 5 OF 6
PROJ. -


N
2J4
From Old Dyer
2
Make Switch N/O until 2J8 Cutover during Phase IV
Support Cable from 200A elbows to eliminate stress on switch terminations
S.927-220'
RT
15
3-1/C 500 Cu Cmpt EPR
2J8
From New Dyer
S.918-213'
ST
12C
Eddy St
S.2-240'
RT
Elm St
Existing 2J4 Cable
Install Cable
Remove Cable
1
3-1/C 500 Cu Cmpt EPR
2J4
From New Dyer
S.2256-195'
RT
1883
S.2075A-237'
RT
251
Support Cable from 200A elbows to eliminate stress on switch terminations
DYER ST SUBSTATION
REBUILD
PHASE II
ONE LINE
FEEDER 2J4
SCALE: NONE
DATE: 5-28-20
BY: JW
PG 6 OF 6
PROJ. -

nationalgrid

Memorandum

To: Distribution Design

From: James Wise

Date: 6/1/2020

Subject: Dyer St Substation Rebuild-South St Alternative- Distribution Line Work Phase III

The following is recommended as the Distribution Line portion of the Dyer St Substation Rebuild project. A new 11.5/4.16kV substation will be constructed at the South St Substation.

General:
- A manhole survey was performed to ensure constructability
- The Distribution Line work within the South St substation yard is based on conceptual drawings dated 5/20/2020

1104A and 1104B Cables:
- Remove 1104A and 1104B 3-1/c 500 CU EPR cable in the following sections:
  - MH3330 South St Substation to MH3333 South St Substation
- Remove 1104A cable in the following sections:
  - MH8 Dyer St to MH9B Dyer St
  - MH9B Dyer St to MH83B Dyer St Substation
  - MH83B Dyer St Substation to 1104-3 Disconnects
- Remove 1104B cable in the following sections:
  - MH8 Dyer St to MH9B Dyer St
  - MH9B Dyer St to MH84B Dyer St Substation
  - MH84B Dyer St Substation to 1104-3 Disconnects
- Install 2 sets of 3-1/c 1000 CU EPR cable, Standard Item UC12TC, in the following sections:
  - MH3330 South St Substation to MH"D" South St Substation, estimated 57'
  - MH"D" South St Substation to MH"C" South St Substation, estimated 10'
  - MH"C" South St Substation to riser structure at 11.5:4.16kV substation transformer, estimated 250'

2J3 Feeder:
- Remove 2J3 Mainline cable in the following sections:
  - Dyer St Substation 2J3-3 Disconnects to MH85D Dyer St Substation
  - MH85D Dyer St Substation to MH9D Dyer St

- MH9D Dyer St to MH351Peck St

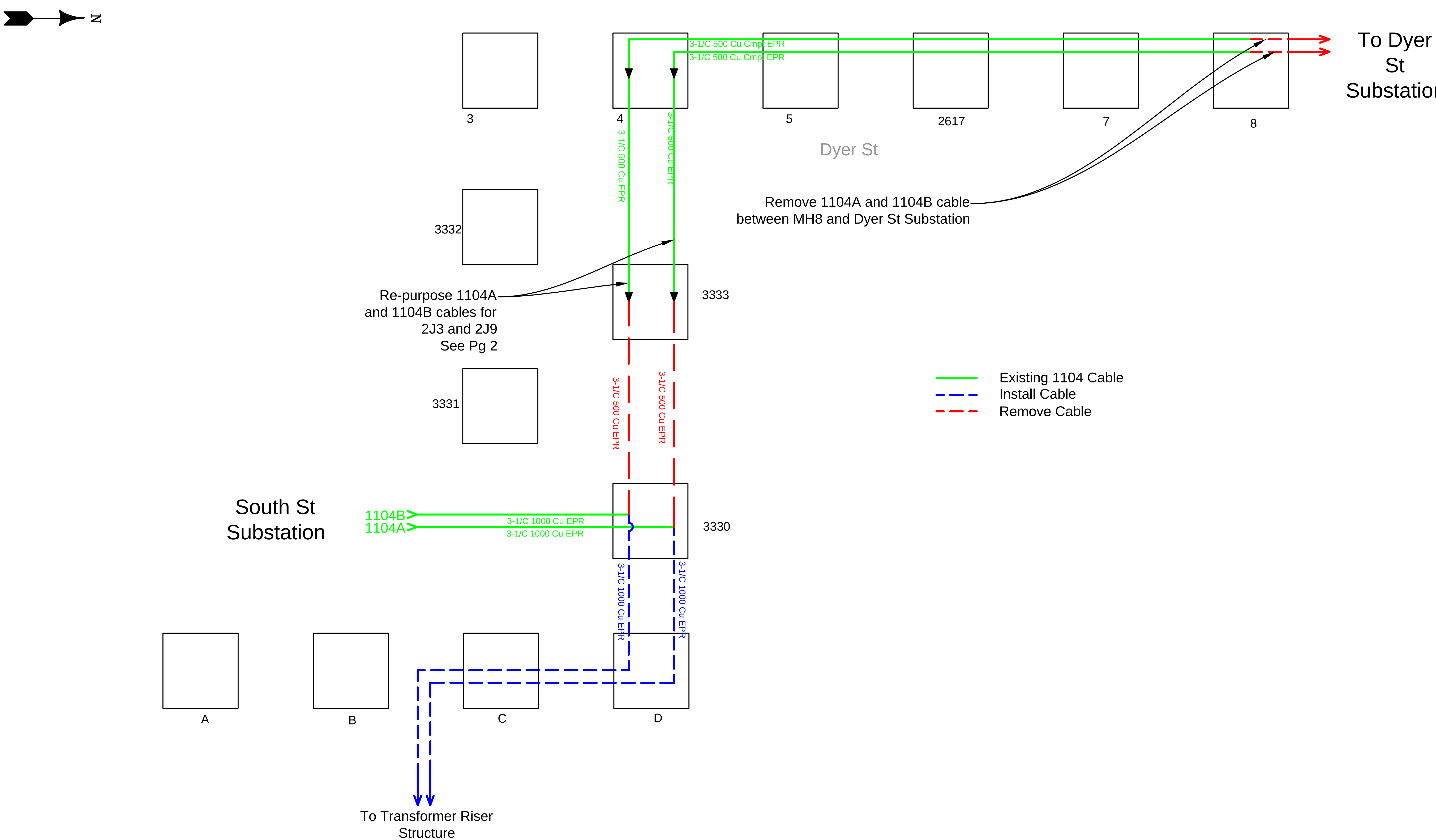
- Install 1 set of 3-1/c 1000 CU EPR cable, Standard Item UC12TC, in the following sections:
  - New Dyer St 2J3-3 Disconnects to MH“B” South St Substation, estimated 75’
  - MH“B” South St Substation to MH“C” South St Substation, estimated 205’
  - MH“C” South St Substation to MH“D” South St Substation, estimated 10’
  - MH“D” South St Substation to MH3330 South St Substation, estimated 57’
  - MH3330 South St Substation to MH3333 South St Substation, approximately 142’
- Install 1 set of 3-1/c 500 CU EPR cable, Standard Item UC17, in the following sections:
  - MH8 Dyer St to MH2993 Peck St, approximately 120’
  - MH2993 Peck St to MH351 Peck St, approximately 120’
- In MH3333 South St Substation, Splice new 2J3 cable to former 1104A cable toward MH4 Dyer St
- In MH8 Dyer St, Splice new 2J3 cable to former 1104A cable toward MH7 Dyer St

2J9 Feeder:

- Remove 2J1 Mainline cable in the following sections:
  - Dyer St Substation 2J9-3 Disconnects to MH85D Dyer St Substation
  - MH85D Dyer St Substation to MH9D Dyer St
  - MH9D Dyer St to MH9C Dyer St
  - MH9C Dyer St to MH1826 Dyer St
  - MH1826 Dyer St to MH350 Dyer St
  - MH350 Dyer St to MH644 Dyer St
  - MH644 Dyer St to MH180 Dyer St
  - MH180 Dyer St to MH2688 Dyer St
- Install 1 set of 3-1/c 1000 CU EPR cable, Standard Item UC12TC, in the following sections:
  - New Dyer St 2J9-3 Disconnects to MH“A” South St Substation, estimated 75’
  - MH“A” South St Substation to MH“B” South St Substation, estimated 105’
  - MH“B” South St Substation to MH“C” South St Substation, estimated 205’
  - MH“C” South St Substation to MH“D” South St Substation, estimated 10’
  - MH“D” South St Substation to MH3330 South St Substation, estimated 57’
  - MH3330 South St Substation to MH3333 South St Substation, approximately 142’
- Install 1 set of 3-1/c 500 CU EPR cable, Standard Item UC17, in the following sections:
  - MH8 Dyer St to MH2993 Peck St, approximately 120’
  - MH2993 Peck St to MH2990 Peck St, approximately 95’
  - MH2990 Peck St to MH2991 Peck St, approximately 5’
  - MH2991 Peck St to MH2992 Peck St, approximately 227’
  - MH2992 Peck St to MH2994 behind Dyer St substation, approximately 300’
  - MH2994 behind Dyer St substation to MH2995 north of Dyer St substation, approximately 300’
  - MH 2995 north of Dyer St substation to MH180 Dyer St, approximately 277’
- Install 1 set of 3-1/c 500 CU EPR Compact cable, Standard Item UC16G, in the following sections:
  - MH180 Dyer St to MH2688 Dyer St, approximately 25’
- In MH3333 South St Substation, Splice new 2J9 cable to former 1104B cable toward MH4 Dyer St
- In MH8 Dyer St, Splice new 2J9 cable to former 1104B cable toward MH7 Dyer St

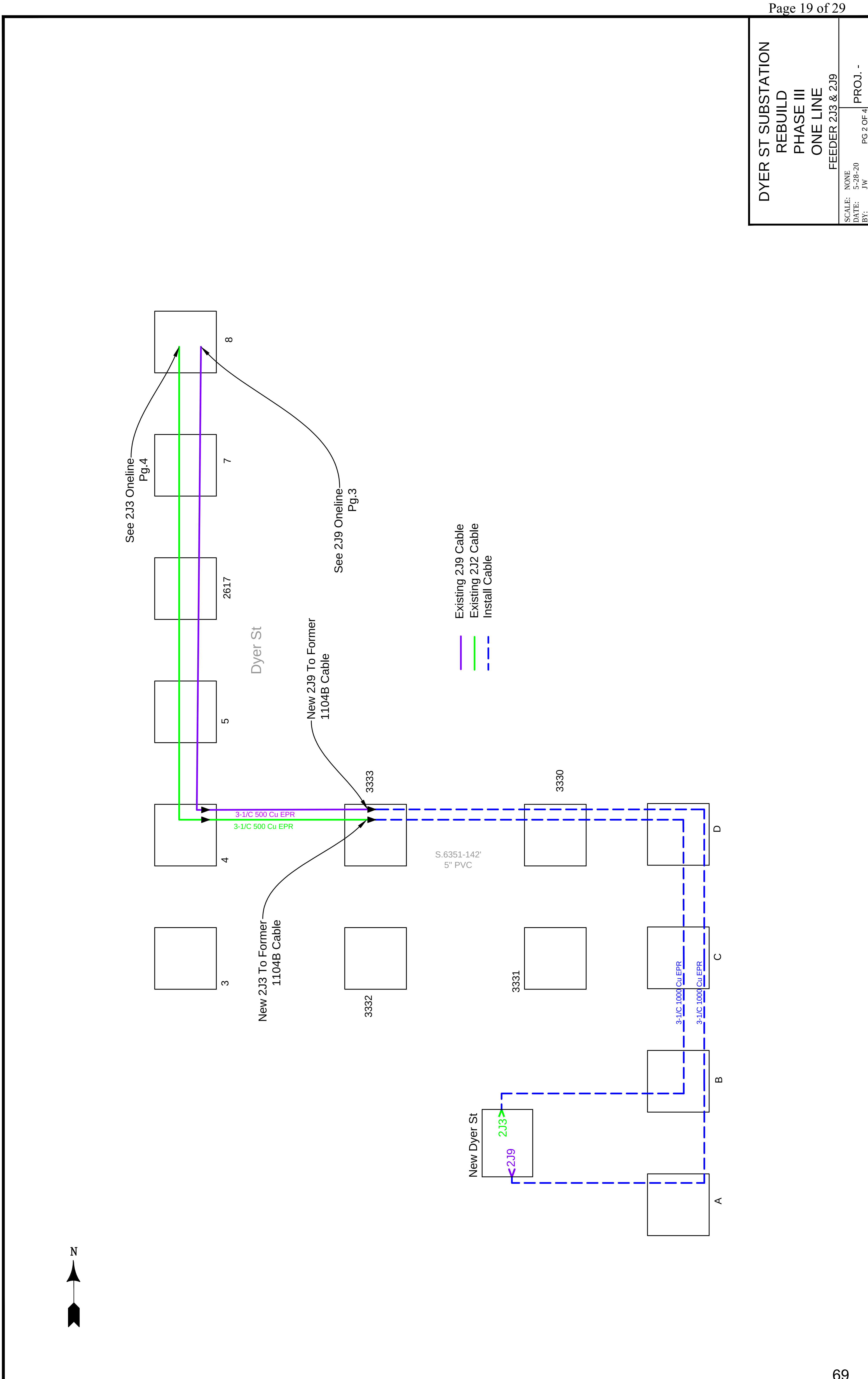
Attachments:

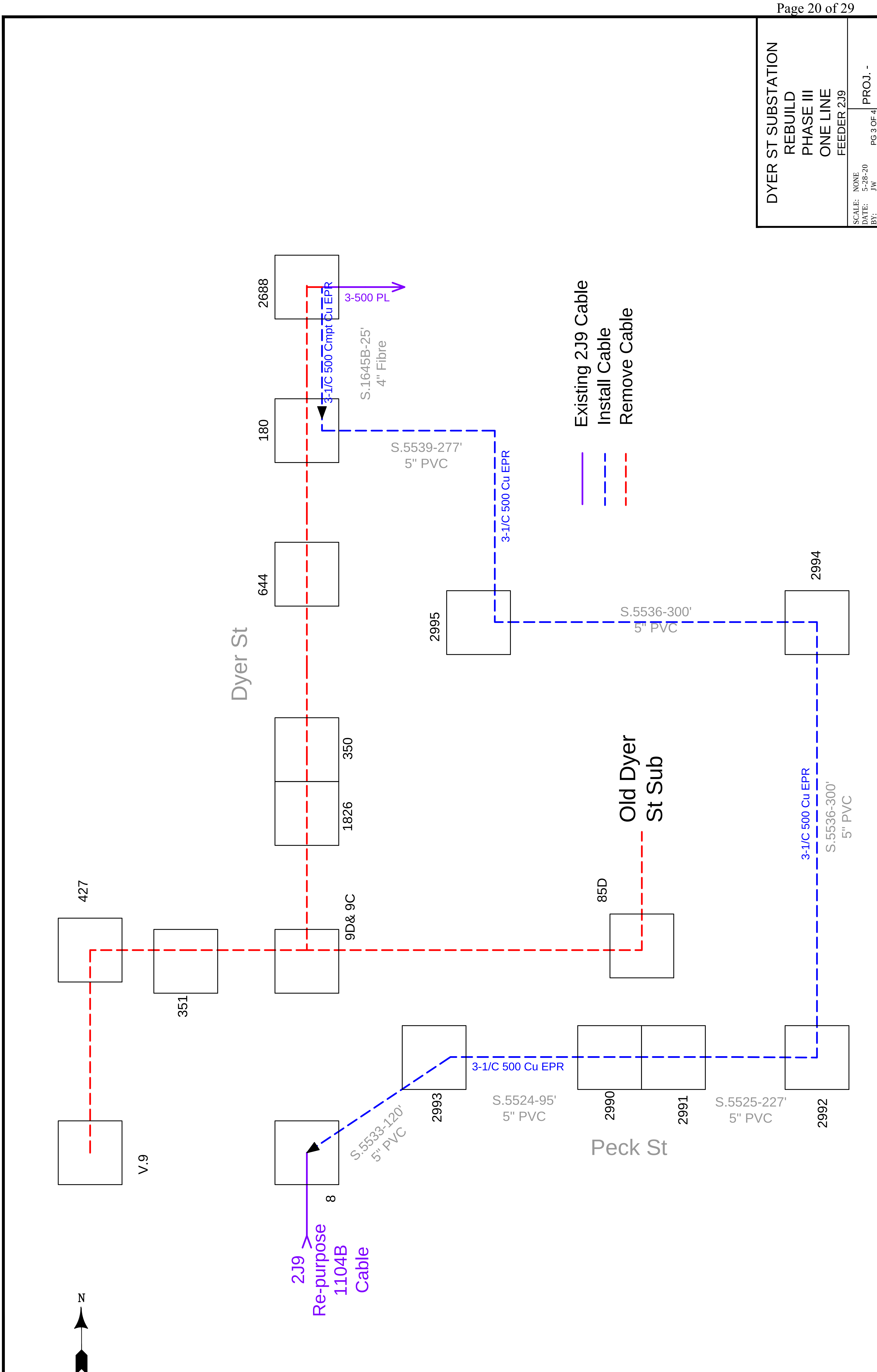
- One Line- Phase III, Feeders 1104A &B
- One Line- Phase III, Feeders 2J3, 2J9
- One Line- Phase II, Feeder 2J9
- One Line- Phase II, Feeder 2J3

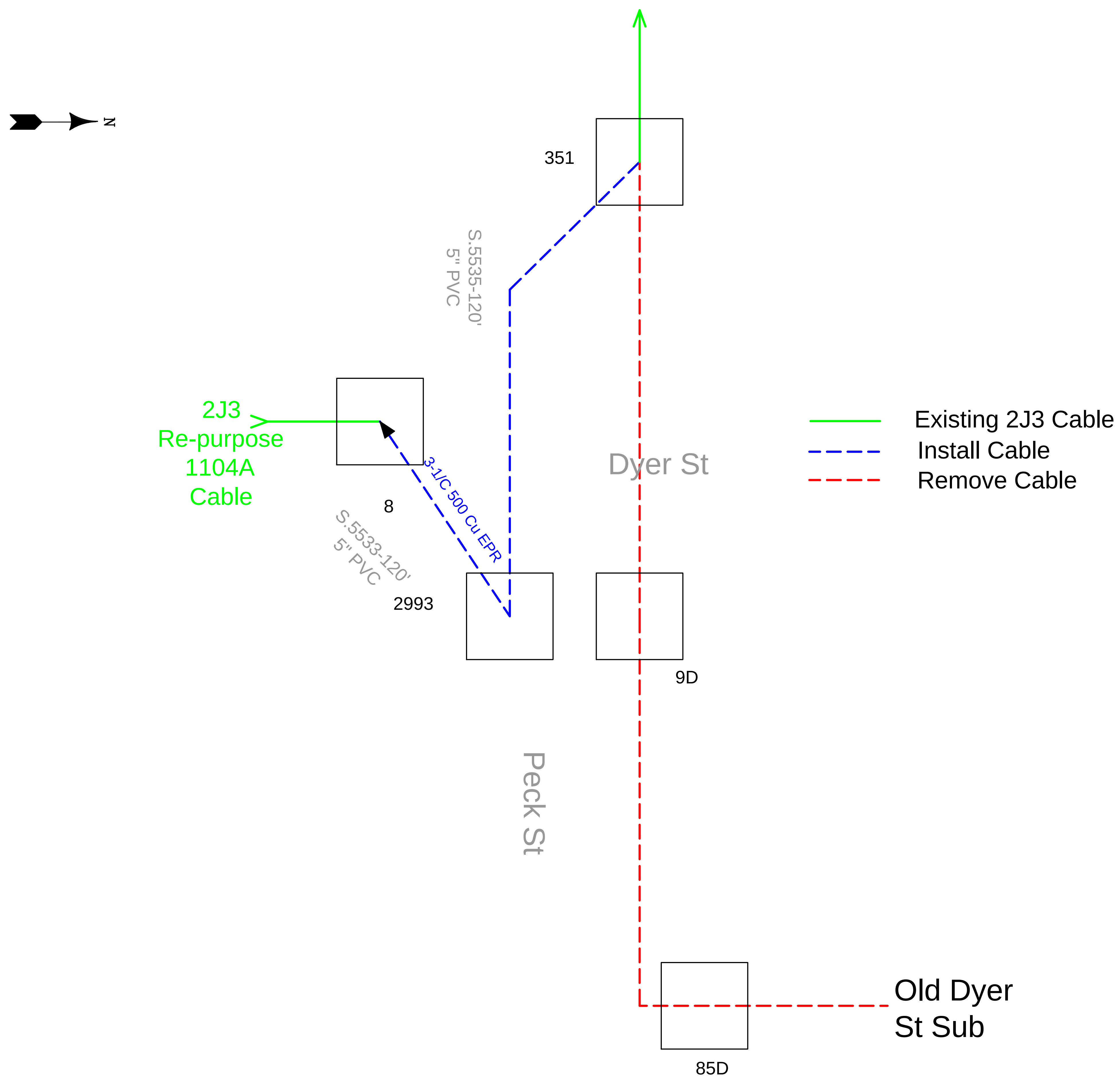


DYER ST SUBSTATION
REBUILD
PHASE III
ONE LINE
FEEDER 1104A&B

SCALE: NONE
DATE: 5-28-20
BY: JW
PG 1 OF 4
PROJ. -


DYER ST SUBSTATION
REBUILD
PHASE III
ONE LINE
FEEDER 2J3 & 2J9
SCALE: NONE
DATE: 5-28-20
BY: JW
PG 2 OF 4
PROJ. -
See 2J3 Oneline
Pg.4
See 2J9 Oneline
Pg.3
8
7
2617
5
4
3
Dyer St
New 2J9 To Former
1104B Cable
New 2J3 To Former
1104B Cable
3-1/C 500 Cu EPR
3-1/C 500 Cu EPR
3333
3332
3330
3331
S.6351-142'
5" PVC
Existing 2J9 Cable
Existing 2J2 Cable
Install Cable
D
C
B
A
3-1/C 1000 Cu EPR
3-1/C 1000 Cu EPR
New Dyer St
2J3
2J9
N


DYER ST SUBSTATION
REBUILD
PHASE III
ONE LINE
FEEDER 2J9
PROJ. -
PG 3 OF 4
SCALE: NONE
DATE: 5-28-20
BY: JW
Existing 2J9 Cable
Install Cable
Remove Cable
2688
180
644
350
1826
9D& 9C
427
351
V.9
8
2995
2994
2993
2990
2991
2992
85D
3-500 PL
3-1/C 500 Cmpt Cu EPR
S.1645B-25'
4" Fibre
S.5539-277'
5" PVC
3-1/C 500 Cu EPR
S.5536-300'
5" PVC
Dyer St
Old Dyer
St Sub
3-1/C 500 Cu EPR
S.5536-300'
5" PVC
3-1/C 500 Cu EPR
S.5524-95'
5" PVC
S.5525-227'
5" PVC
S.5533-120'
5" PVC
Peck St
2J9
Re-purpose
1104B
Cable
N



DYER ST SUBSTATION
REBUILD
PHASE III
ONE LINE
FEEDER 2J3

SCALE: NONE
DATE: 5-28-20
BY: JW
PG 4 OF 4
PROJ. -

nationalgrid

Memorandum

To: Distribution Design

From: James Wise

Date: 5/28/2020

Subject: Dyer St Substation Rebuild-South St Alternative- Distribution Line Work Phase IV

The following is recommended as the Distribution Line portion of the Dyer St Substation Rebuild project. A new 11.5/4.16kV substation will be constructed at the South St Substation.

General:

- A manhole survey was performed to ensure constructability
- The Distribution Line work within the South St substation yard is based on conceptual drawings dated 5/20/2020

1106A and 1106B Cables:

- Remove 1106 3-1/c 500 CU EPR cable in the following sections:
    - MH3330 South St Substation to MH3333 South St Substation
- Remove 1106A cable in the following sections:
    - MH3333 South St Substation to MH4 Dyer St
    - MH8 Dyer St to MH9B Dyer St
    - MH9B Dyer St to MH83B Dyer St Substation
    - MH83B Dyer St Substation to 1106-3 Disconnects
- Remove 1106B cable in the following sections:
    - MH3333 South St Substation to MH4 Dyer St
    - MH8 Dyer St to MH9B Dyer St
    - MH9B Dyer St to MH83B Dyer St Substation
    - MH83B Dyer St Substation to 1106-3 Disconnects
- In MH3330 South St Substation, cut and cap 1106 Cable toward MH3333 South St Substation

2J10 Feeder:

- Remove 2J10 Mainline cable in the following sections:
    - Dyer St Substation 2J10-3 Disconnects to MH85D Dyer St Substation
    - MH85D Dyer St Substation to MH9D Dyer St
    - MH9D Dyer St to MH9C Dyer St
    - MH9C Dyer St to MH1826 Dyer St
    - MH1826 Dyer St to MH350 Dyer St
    - MH350 Dyer St to MH644 Dyer St

  - MH644 Dyer St to MH180 Dyer St
  - MH180 Dyer St to MH2688 Dyer St
- Install 1 set of 3-1/c 1000 CU EPR cable, Standard Item UC12TC, in the following sections:
  - New Dyer St 2J10-3 Disconnects to MH"A" South St Substation, estimated 75'
- Install 1 set of 3-1/c 500 CU EPR cable, Standard Item UC17, in the following sections:
  - MH"A" South St Substation to MH12C South St Substation, estimated 56'
  - MH8 Dyer St to MH2993 Peck St, approximately 120'
  - MH2993 Peck St to MH2990 Peck St, approximately 95'
  - MH2990 Peck St to MH2991 Peck St, approximately 5'
  - MH2991 Peck St to MH2992 Peck St, approximately 227'
  - MH2992 Peck St to MH2994 behind Dyer St substation, approximately 300'
  - MH2994 behind Dyer St substation to MH2995 north of Dyer St substation, approximately 300'
  - MH 2995 north of Dyer St substation to MH180 Dyer St, approximately 277'
- Install 1 set of 3-1/c 500 CU EPR Compact cable, Standard Item UC16G, in the following sections:
  - MH12C South St Substation to MH15 Eddy St, approximately 213'
  - MH15 Eddy St to MH2 Eddy St, approximately 220'
  - MH2 Eddy St to MH3 Dyer St, approximately 182'
  - MH3 Dyer St to MH4 Dyer St, approximately 38'
  - MH180 Dyer St to MH2688 Dyer St, approximately 25'
- In MH4 Dyer St, Splice new 2J10 cable to former 1106B cable toward MH5 Dyer St
- In MH8 Dyer St, Splice new 2J10 cable to former 1106B cable toward MH7 Dyer St

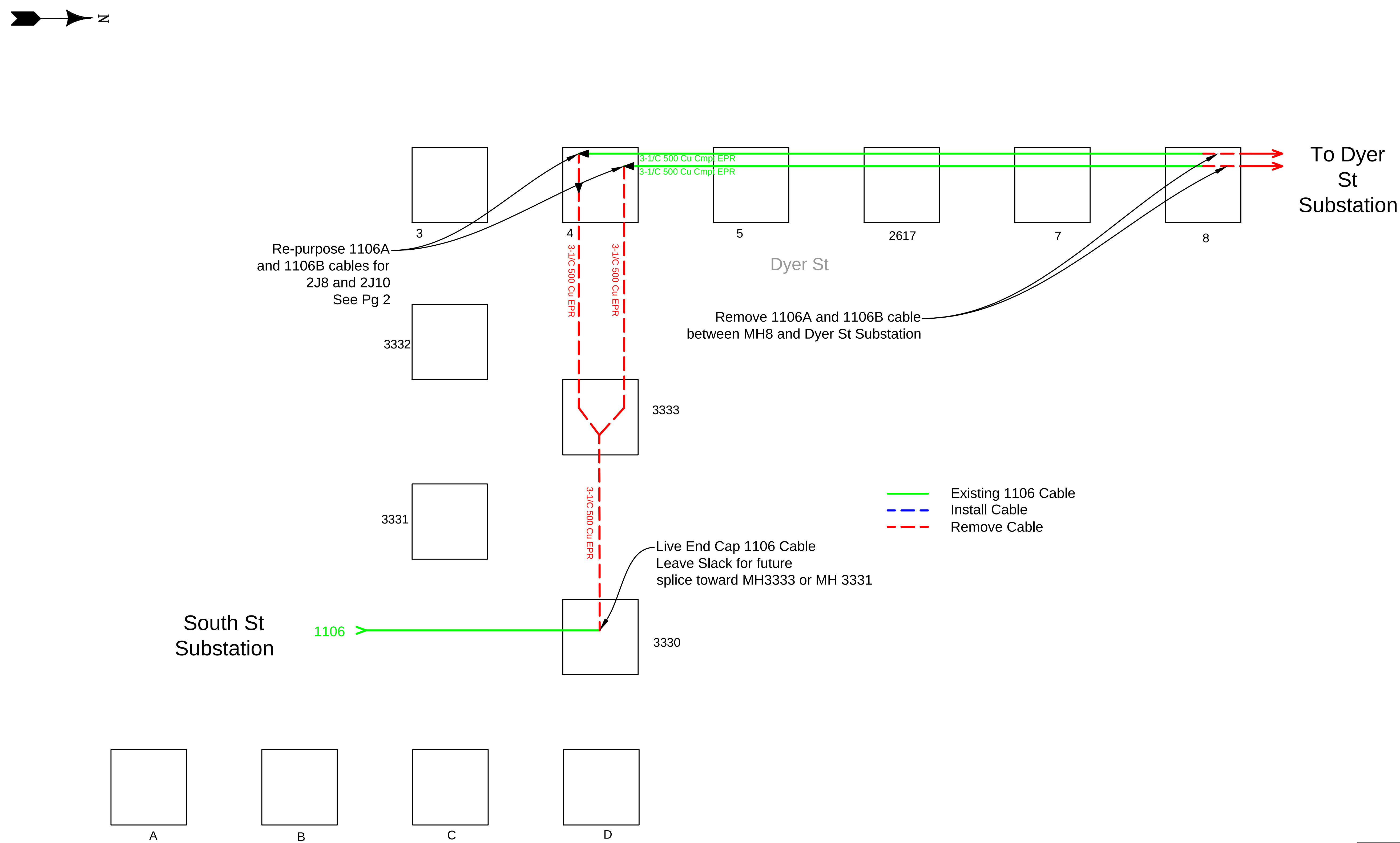
2J8 Feeder:
- Remove 2J8 Mainline cable in the following sections:
  - Dyer St Substation 2J8-3 Disconnects to MH85D Dyer St Substation
  - MH85D Dyer St Substation to MH2991 Peck St
  - MH2991 Peck St to MH2990 Peck St
  - MH2990 Peck St to MH2993 Peck St
- Install 1 set of 3-1/c 500 CU EPR Compact cable, Standard Item UC16G, in the following sections:
  - MH2 Eddy St to MH3 Dyer St, approximately 182'
  - MH3 Dyer St to MH4 Dyer St, approximately 38'
- Install 1 set of 3-1/c 500 CU EPR cable, Standard Item UC17, in the following sections:
  - MH8 Dyer St to MH2993 Peck St, approximately 120'
- In MH4 Dyer St, Splice new 2J8 cable to former 1106A cable toward MH5 Dyer St
- In MH8 Dyer St, Splice new 2J8 cable to former 1106A cable toward MH7 Dyer St
- In MH2 Eddy St, Install three (3) 600A deadbreak switch terminations with 200A reducing tap wells
  - Note: Submersible switch in MH2 will be Normally Closed

2J4 Feeder:
- Remove 2J4 Mainline cable in the following sections:
  - Dyer St Substation 2J4-3 Disconnects to MH85D Dyer St Substation
  - MH85D Dyer St Substation to MH9D Dyer St
  - MH9D Dyer St to MH8 Dyer St
  - MH8 Dyer St to MH7 Dyer St
  - MH7 Dyer St to MH2617 Dyer St

- MH2617 Dyer St to MH5 Dyer St
- MH5 Dyer St to MH4 Dyer St
- MH4 Dyer St to MH3 Dyer St
- MH3 Dyer St to MH2 Dyer St

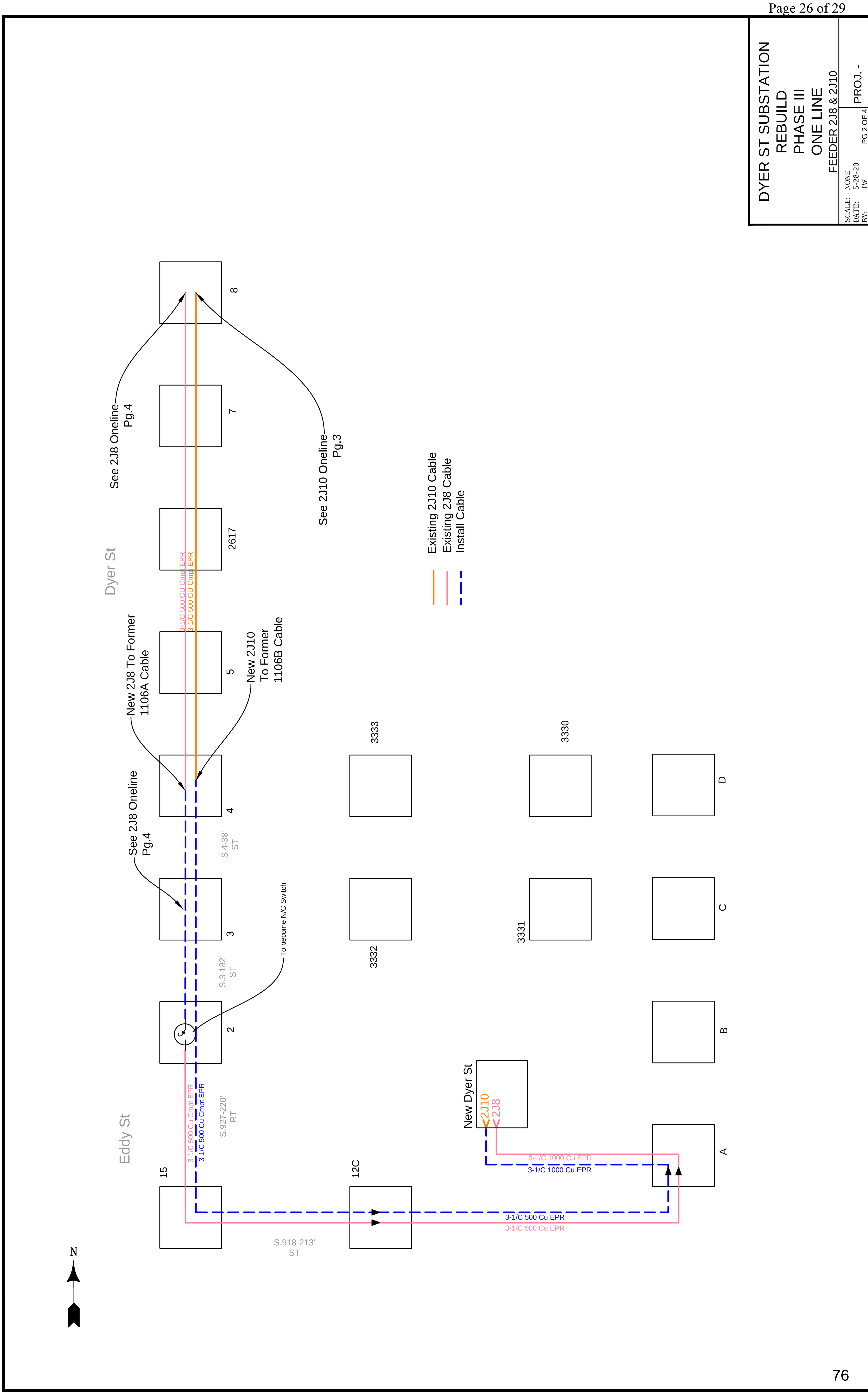
Attachments:

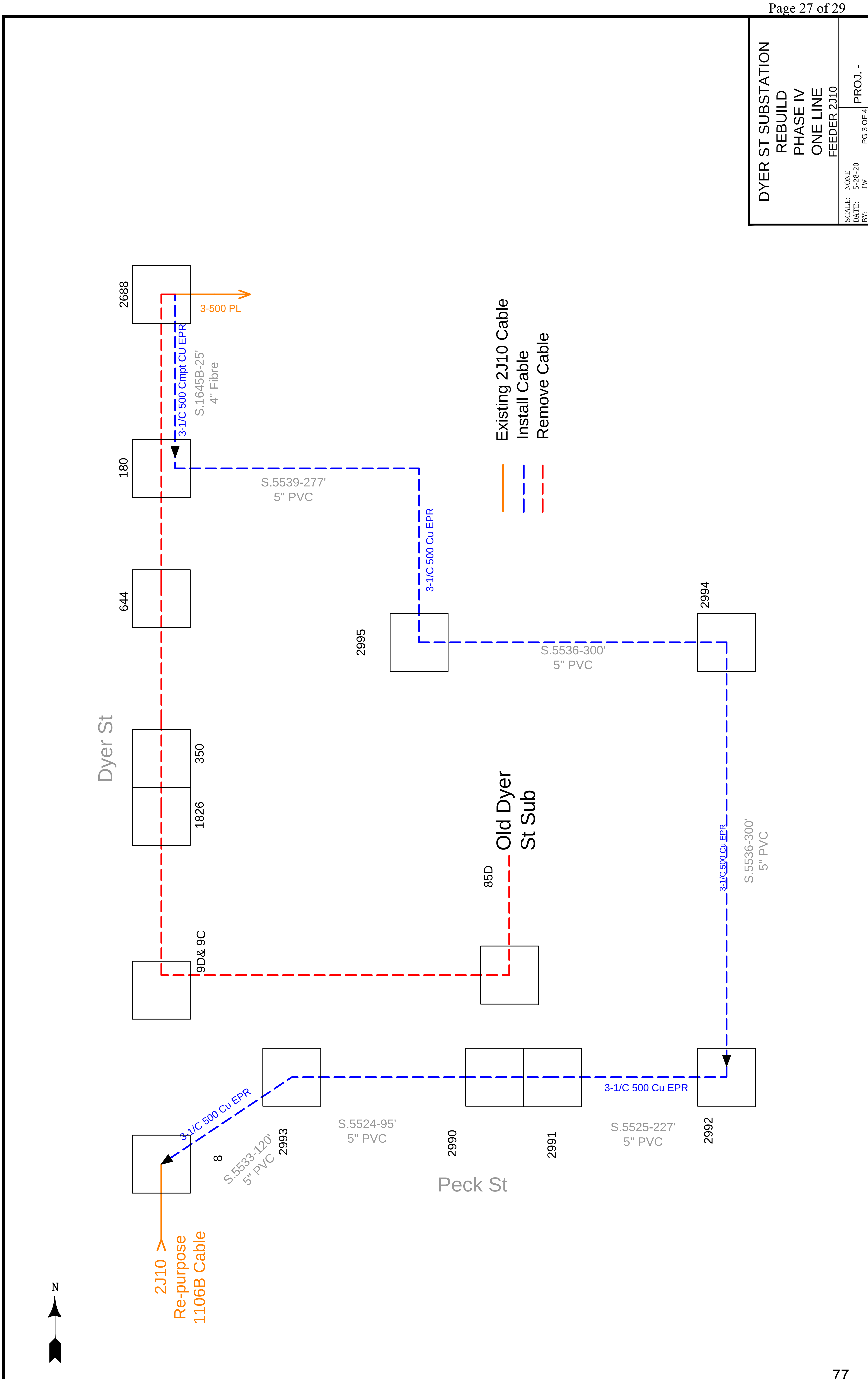
- One Line- Phase IV, Feeders 1106A &B
- One Line- Phase IV, Feeders 2J8, 2J10
- One Line- Phase IV, Feeder 2J8
- One Line- Phase IV, Feeder 2J10

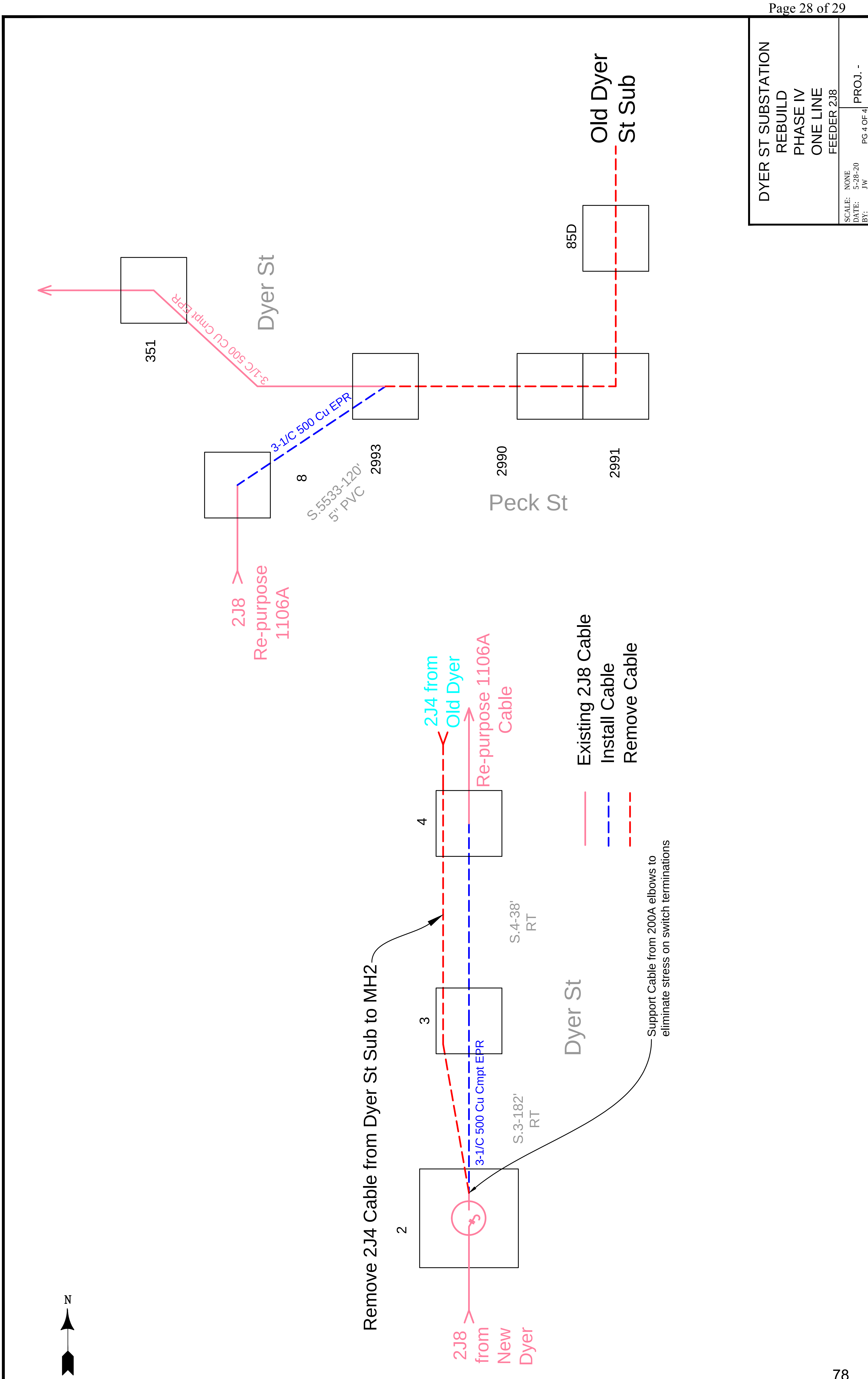


DYER ST SUBSTATION
REBUILD
PHASE III
ONE LINE
FEEDER 1106

SCALE: NONE
DATE: 5-28-20
BY: JW
PG 1 OF 4
PROJ. -


DYER ST SUBSTATION
REBUILD
PHASE III
ONE LINE
FEEDER 2J8 & 2J10
SCALE: NONE
DATE: 5-28-20
BY: JW
PG 2 OF 4
PROJ. -
Dyer St
Eddy St
New Dyer St
See 2J8 Oneline Pg.4
See 2J10 Oneline Pg.3
New 2J8 To Former 1106A Cable
New 2J10 To Former 1106B Cable
To become N/C Switch
Existing 2J10 Cable
Existing 2J8 Cable
Install Cable
3-1/C 500 CU Cmpt EPR
3-1/C 500 Cu Cmpt EPR
3-1/C 500 Cu EPR
3-1/C 1000 Cu EPR
S.4-38' ST
S.3-182' ST
S.927-220' RT
S.918-213' ST
2J10
2J8
15
2
3
4
5
2617
7
8
12C
3332
3333
3331
3330
A
B
C
D
N
76


DYER ST SUBSTATION
REBUILD
PHASE IV
ONE LINE
FEEDER 2J10
SCALE: NONE
DATE: 5-28-20
BY: JW
PG 3 OF 4
PROJ. -
Existing 2J10 Cable
Install Cable
Remove Cable
2688
180
644
350
1826
9D& 9C
2995
2994
2993
2990
2991
2992
85D
8
3-500 PL
3-1/C 500 Cmpt CU EPR
S.1645B-25'
4" Fibre
S.5539-277'
5" PVC
3-1/C 500 Cu EPR
S.5536-300'
5" PVC
3-1/C 500 Cu EPR
S.5536-300'
5" PVC
3-1/C 500 Cu EPR
S.5525-227'
5" PVC
S.5524-95'
5" PVC
3-1/C 500 Cu EPR
S.5533-120'
5" PVC
Dyer St
Old Dyer
St Sub
Peck St
2J10
Re-purpose
1106B Cable
N
77


DYER ST SUBSTATION
REBUILD
PHASE IV
ONE LINE
FEEDER 2J8
PROJ. -
PG 4 OF 4
SCALE: NONE
DATE: 5-28-20
BY: JW
Old Dyer St Sub
85D
351
Dyer St
3-1/C 500 Cu Cmpt EPR
3-1/C 500 Cu EPR
2993
2990
2991
8
S.5533-120'
5" PVC
Peck St
2J8 Re-purpose 1106A
2J4 from Old Dyer
Re-purpose 1106A Cable
Existing 2J8 Cable
Install Cable
Remove Cable
4
3
2
S.4-38' RT
S.3-182' RT
Dyer St
3-1/C 500 Cu Cmpt EPR
Remove 2J4 Cable from Dyer St Sub to MH2
Support Cable from 200A elbows to eliminate stress on switch terminations
2J8 from New Dyer
N


nationalgrid
DYER ST SUBSTATION REBUILD
ALTERNATIVES
SOUTH ST SUBSTATION ALTERNATIVE
PROVIDENCE, RI
CONCEPTUAL ONE LINES
KEY PLAN
SCALE: N.T.S.
ABBREVIATED ONE LINE
SCALE: NONE
SIDE PROFILE
1"=30'
CONCEPTUAL ONLY
NOT FOR CONSTRUCTION
REVISIONS

R-I-19

Request:

Provide the most recent project sanctioning paper for Dyer Street. Since the capacity and new substation facilities are now proposed for the South Street substation site, will the substation project name be changed?

Response:

The most recent sanction paper is attached as Attachment R-I-19. Re-Sanction on updated scope is expected to be completed in Q4 of FY21 prior to any construction activities.

The Substation Project name will not be changed.

Prepared by or under the supervision of: David Arthur

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.

nationalgrid

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
O Mandatory ⊙ Policy- Driven O Justified NPV O Other	National Grid Indoor Substation Strategy, December 21, 2011.

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

		Current Planning Horizon						
		Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6 +	
$M	Prior Yrs	2016/17	2017/18	2018/19	2019/20	2020/21	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

nationalgrid

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

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....2/14/17........

Christopher Kelly
Senior Vice President
Electric Process and Engineering

US Sanction Paper

nationalgrid

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.

nationalgrid

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.

nationalgrid

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.

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.

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

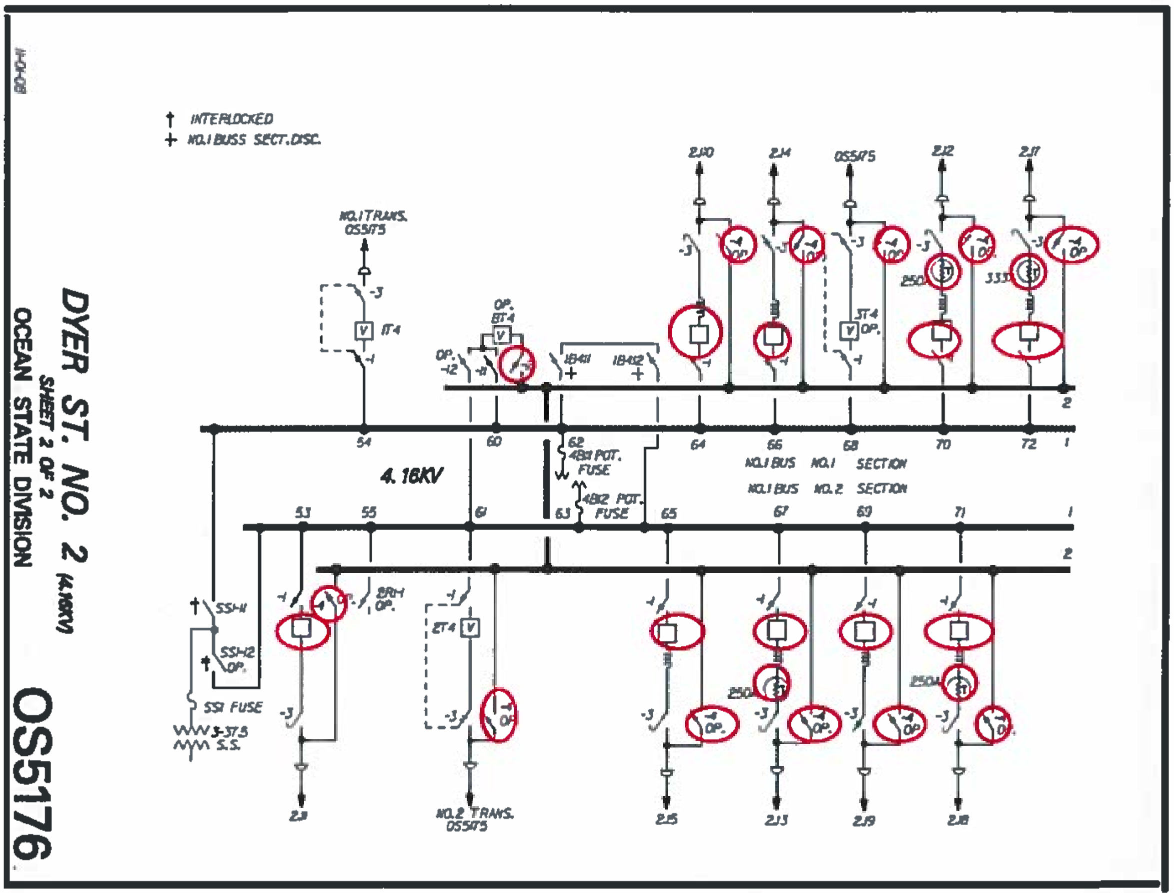
4.1 Sanction Request Breakdown by Project

$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

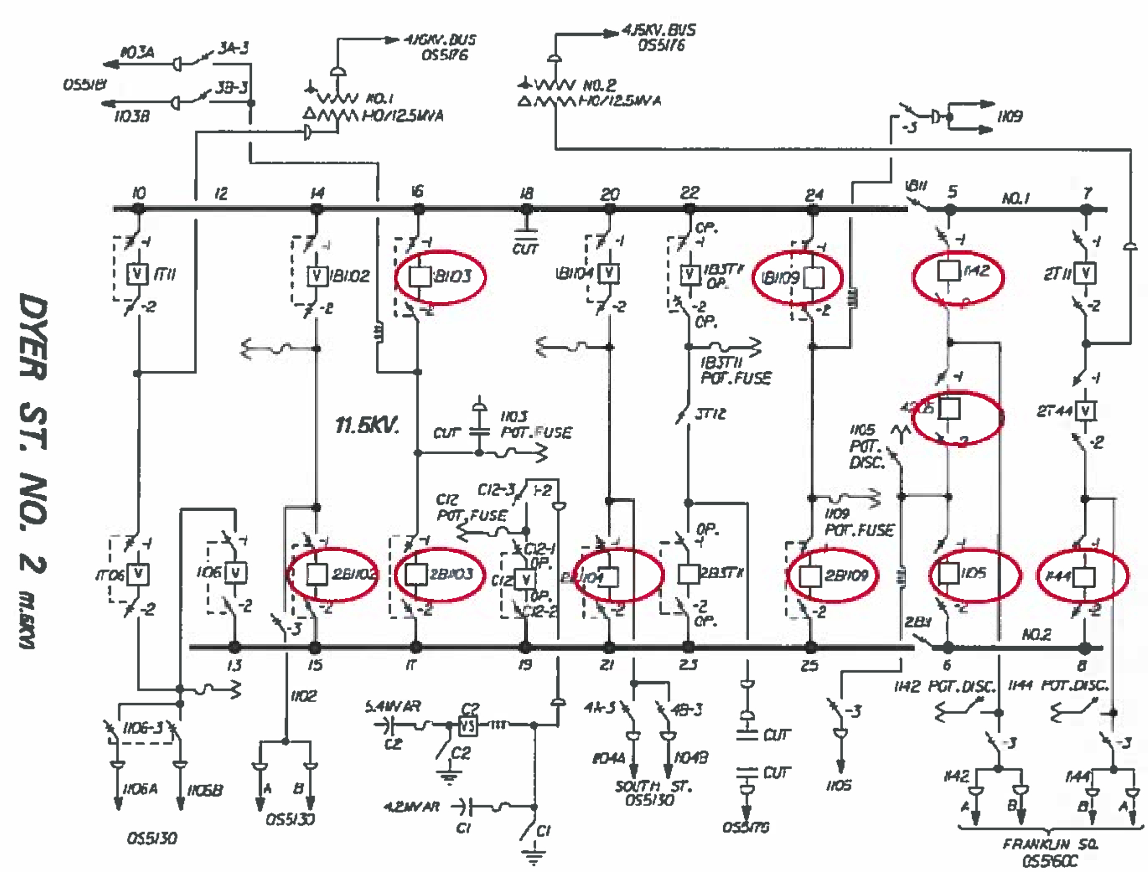


Equipment with red circle was identified for replacement in the O&M Services Asset Condition Report

US Sanction Paper

Asset Condition Report – Dyer Street Station

Substation O&M Services



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

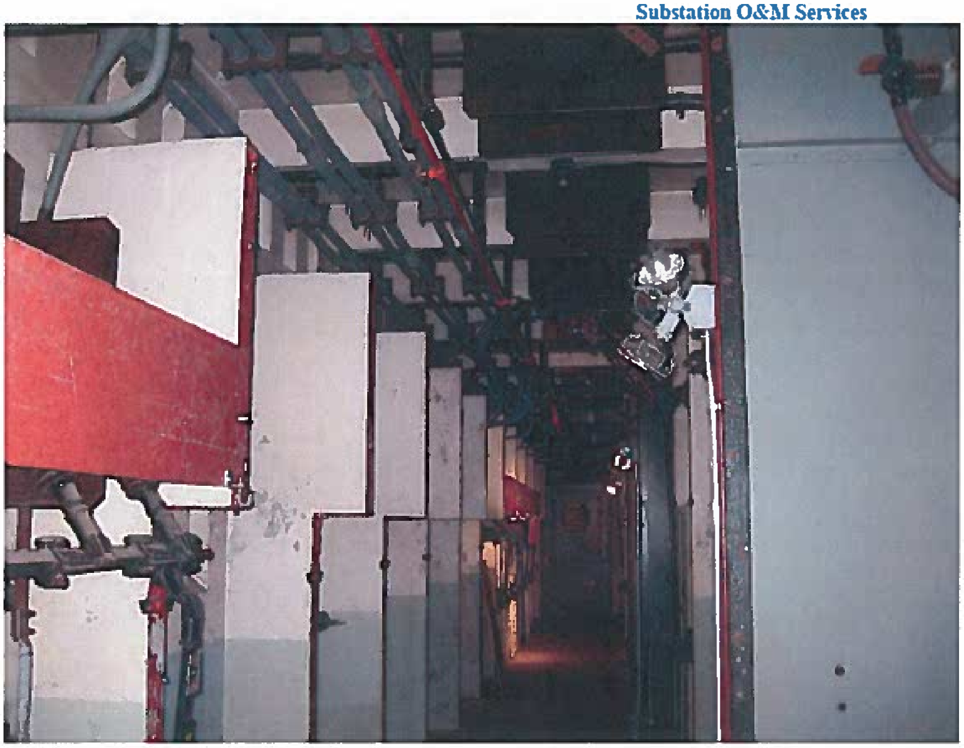
US Sanction Paper

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

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

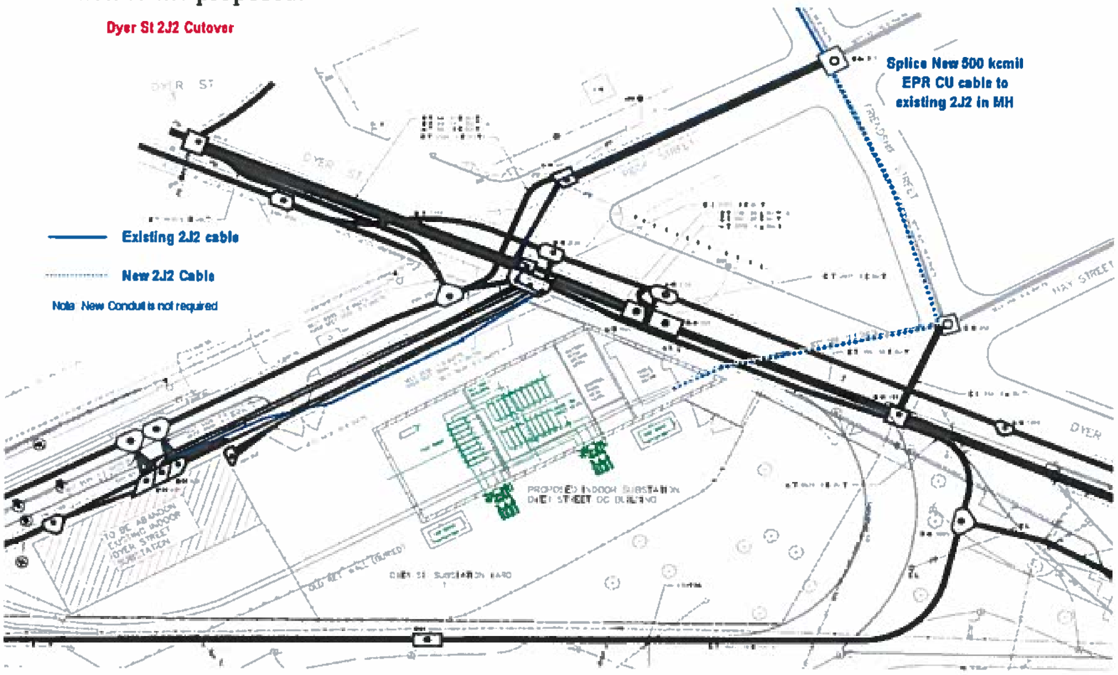
Substation O&M Services

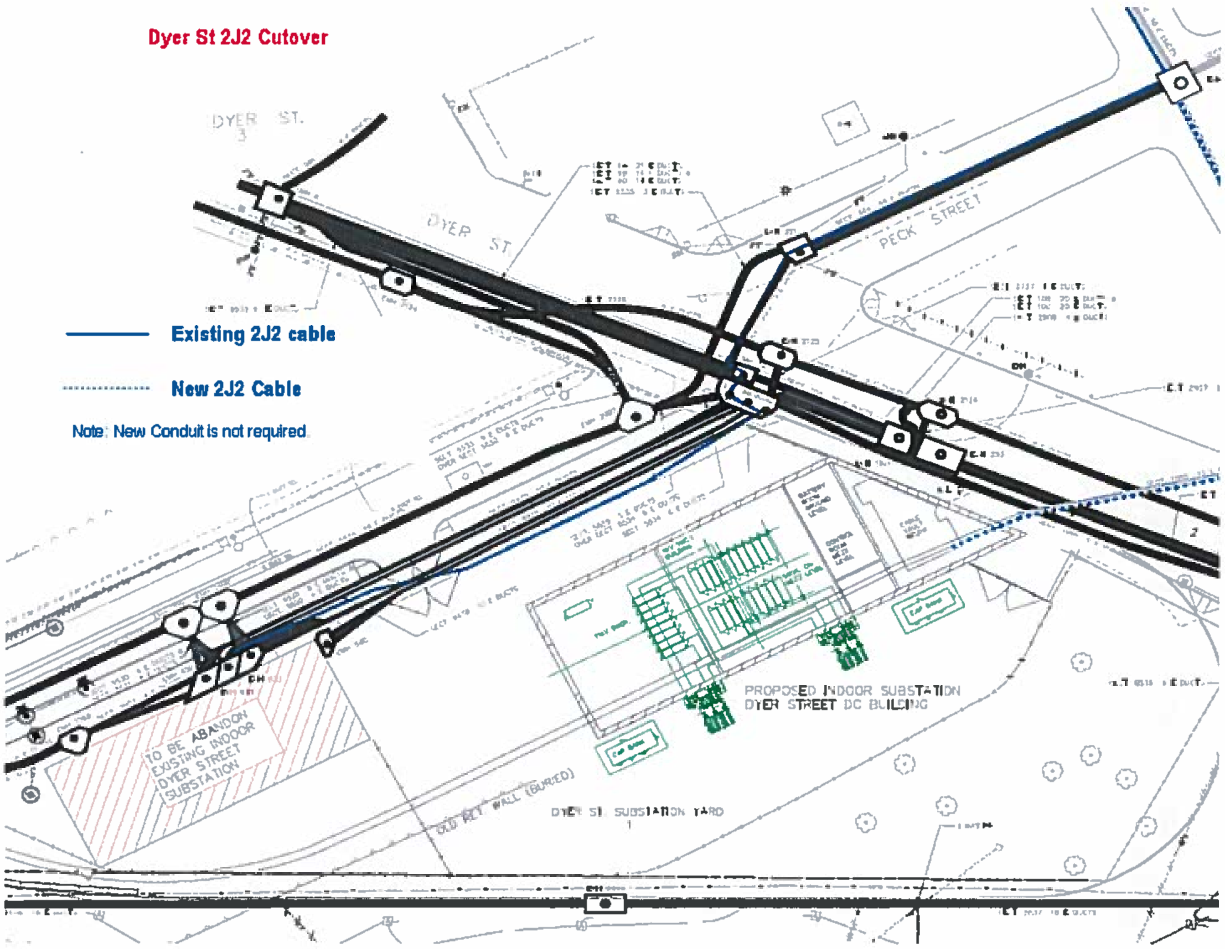


Room with 4.16kV -4 switches (left), -3 disconnects (ceiling)

US Sanction Paper nationalgrid

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




Dyer St 2J2 Cutover
Existing 2J2 cable
New 2J2 Cable
Note: New Conduit is not required
DYER ST.
DYER ST.
PECK STREET
PROPOSED INDOOR SUBSTATION
DYER STREET DC BUILDING
TO BE ABANDON
EXISTING INDOOR
DYER STREET
SUBSTATION
OLD RET. WALL (BURIED)
DYER ST. SUBSTATION YARD

R-I-20

Request:

Regarding the Complex Capital Delivery Stage-Gate Process (page 28); what determines when a project is a complex project? Assuming Area study projects are considered complex, what stage is assigned to a project resulting from an Area Study once the study is completed?

Response:

All Company projects are assigned a complexity score upon identification of likely alternatives to address a system need; for Area studies, this occurs during the study phase. Complexity scores are calculated using a scoring matrix that weighs nine different factors: Cost, Project Components, Outages, Duration / Customer Driven Timeline, Stakeholder Management, Asset Complexity, Land / Rights, Permits and Procurement. The project complexity score is determined by the sum of the nine weighted factors. If the total score is greater than or equal to 19 then the project is considered Complex and will follow the Complex Capital Delivery Process. If the total score is 18 or lower, then the project is considered Non-Complex. The complexity scoring matrix is calculated based on data available during the study phase of a project but may be updated once final scope has been identified.

All area study projects will be assigned a complexity score using the complexity scoring matrix to determine if they will be considered a complex or a non-complex project. Complexity scores are identified during 4.1 (Needs Case) of the Complex Capital Delivery Process, and projects identified as complex are brought through Gate A of the Capital Delivery Process during the Area study.

Note that each project or discrete effort identified within an area study receives its own complexity score; it is possible for multiple projects (both complex and non-complex) to result from the same Area study.

The Area study process encompasses steps 4.1 (Needs Case) and 4.2 (Option Selection) of the Complex Capital Delivery Process. Upon completion of an Area study, projects recommended by the study are progressed through Gate B of the Capital Delivery Process into step 4.3 (Project Development and Sanction).

R-I-21

Request:

Please elaborate on how a cost contingency is applied to a project estimate (page 30). What are typical percentage contingencies applied in the early stages of project development and later stages? Can the Company elaborate on the probabilistic calculation used to assign a contingency in later stages? Stakeholders are accustomed to a +/-% variance in project estimates. Is there any correlation between the applied contingency and expected variance?

Response:

Early estimates are typically created by Engineering using a Cost Book tool developed by the Estimating Department. There is also an option to request an estimate from the Estimating Department when the Cost Book is not fit for purpose. Estimates generated using the Cost Book typically include 30% (default value) contingency. The user has the option to select None, Low (10%), Medium (20%), or High (30%). Since much is still unknown in the early phases, a 30% contingency is typically applied.

Sanction level estimates are typically created by the Estimating Department and include risk based contingency values generated using a Monte Carlo simulation. Range estimating, along with expert judgement, is used to identify and quantify complex project risks. A risk register is developed with input from the project team members, stakeholder groups, and subject matter experts. The risk register inputs along with the base cost estimate are used to perform a Monte Carlo simulation (utilizing @RISK software) to generate a P50 estimate and contingency value. This P50 estimate is typically used to sanction the project.

P50 refers to a confidence level regarding the probability of the cost not being exceeded. P50 is the value at which there is a 50% chance of the project coming in above this cost and a 50% chance of it coming in below this cost. P50 is known as the best all-purpose estimate, especially when managing a large portfolio of projects. It makes cost efficient sense to control the project to the 50/50 point. However, controlling projects to the P50 value requires a certain tolerance for overruns since, statistically speaking, the project will overrun 50% of the time.
National Grid Delegations of Authority (DOA) governance rules allow a 10% tolerance to the sanction value and the project manager is responsible to re-sanction the project if additional funds are required. This 10% tolerance is not to be confused as an estimate accuracy range.

Prepared by or under the supervision of: Darrin Hunt

R-I-22

Request:

The Company states on page 30 that a pilot project is underway increasing the project sanctioning paper (PSP) requirement limit from $1.0 to $2.0 million. Why is the Company considering this increase? If implemented, how many projects would be impacted annually?

Response:

The purpose of setting the lower threshold is to create a balance between the time and effort needed to perform the USSC document preparation and review processes and the benefit received from that process.

As per the terms of reference for both the US Sanction Committee (USSC) and the Senior Executive Sanction Committee (SESC), the purpose of the capital sanction process is to ensure that all investments receive appropriate Delegation of Authority (DOA) approval and to provide executive direction and priority for major capital spend. All projects utilize a Business Review Process (BRP). The BRP takes place in the early stages of project development. Representatives from Investment Planning, Resource Planning, Engineering and Asset Management review the project for resourcing, scheduling, budget compliance, classification, and scope. After that review is completed, Asset Management approves the project.

The USSC provides executive management review and decision for proposed major capital projects and other proposed commitments having contemplated expenditures above $1 million and not exceeding $25 million on an individual basis that are deemed appropriate candidates for such review and decision, and administers a consistent and comprehensive sanctioning process for such projects and commitments. Projects under the current $1 million threshold receive electronic review and approval of the BRP within the Company's Powerplant system and require approval by either the Director of Transmission Planning and Asset Management or the Director of Distribution Planning and Asset Management. Projects over the current $1 million threshold require compliance with the USSC processes, which includes creating a formal sanction paper with specified content that documents the BRP in more detail and undergoing the USSC review process, which expands the approval to the USSC Committee. Major capital projects and other proposed commitments having contemplated expenditures of more than $25 million up to $203 million will be referred to the SESC.

As part of implementing its review and decision process, the USSC further delineates its review and decision processes by having all projects between $1 million and $8 million formally presented, reviewed and approved at a weekly USSC meeting and all projects between $8 million and $25 million at a similar monthly USSC meeting.

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

R-I-22, page 2

A pilot project is currently underway increasing the project USSC sanctioning paper requirement threshold from $1 million to $2 million for electric projects. It is estimated that implementation of this change would reduce the number of electric projects receiving the more detailed review at the $8M weekly meeting by approximately 20%.
The Company has considered this modification for the following reasons:

- The electronic DOA limit has remained at $1 million for a significant period, over 10 years.
- The complexity of projects within the $1 million to $2 million range are similar and are generally non-complex.
- Considering the volume of projects between $1 million and $2 million and the less complex nature of work being performed, and potential risk involved, the Company considers that $1 million may no longer be a relevant limit.
- The number of projects greater than $1 million has increased since Fiscal Year 2016. Looking at all utility services, the total volume of sanction papers being submitted to the weekly sanction meeting (projects under $8 million) for projects between $1M and $2M were:

    - Fiscal Year 2016 - 197
    - Fiscal Year 2017 - 312
    - Fiscal Year 2018 - 368
    - Fiscal Year 2019 - 280

- The projects reviewed associated with the up to $8 million threshold accounts for approximately 20% of total capital spending and 66% of the papers prepared and reviewed. To derive that percent, the period from Fiscal Years 2018 and 2019 were reviewed.

- There were over 1,360 sanction papers prepared and presented at the $8 million weekly meeting. Of those, 605 or 44% of these were electric papers and off these, 265 fell between $1 million and $2 million. If implemented, approximately 130-150 electric projects could be impacted annually.

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

R-I-23

Request:

The UG Replacement FY2021 budget is $3.8M and the proposed budget for FY2022 is $5.5M. Explain the rationale for the increase and failure rates that support the additional required work.

Response:

The forecasted spend of $5.5 million in FY 2022 on the underground cable replacement program is a return to previous spend levels recommended in the underground cable replacement program. This program targets known problematic cable types such as paper and lead insulated cables and certain cross-linked polyethylene (XLPE) insulated cables. The underground cable replacement program prioritizes the cables using a risk matrix focused on cable characteristics. The forecasted spend for FY 2022 includes cable replacements on the circuits in the table below.

Circuit	Circuit feet planned for replacement
79F1	3300
13F6	3000
1139	5500
1142	3300
1144	4500
1160	4900
Total	24500

In addition to the underground cable replacement projects in the table, the Company plans to install new ducts along the existing Charles/Orms Street UG duct bank. This work installs 1,600 feet of 6-5" ducts. Installation of these new ducts will allow proactive replacement of 79F1 and 13F6 as listed in the table above. The FY 2022 planned underground cable program work also includes replacing approximately 31,600 feet of secondary cable.

Prepared by or under the supervision of: Caitlin Broderick

R-I-24

Request:

For the UG cable on the Company system, provide:

a. the age of the cable by mile (or feet) in operation
b. an estimate of remaining life
c. the feet of UG cable replacement associated with the FY 2022 proposed substation projects or other capacity projects and the age of that cable being replaced

Response:

a. The Company categorizes age of underground cable into three different age groups. Based on Company records at the date of this data request, the underground cable currently in operation and the age of that cable is listed in the chart below.

Cable age	Miles of cable
25 or less Years	758
26 to 49 Years	356
50+ Years	20

b. The Company has applied a 40 year underground cable asset life to be responsive; however, the Company prioritizes cable replacement based on a variety of other factors including, but not limited to, type of cable, reliability history, and safety considerations. The Company does an evaluation of cable type and recent performance to determine the propensity for future failures but does not replace cable based on age alone. Therefore, typical asset life is not representative of remaining asset life.

c. The Company plans to replace 24,500 feet of primary underground cable and 31,600 feet of secondary underground cable in FY 2022. There is additional underground cable replacement work associated with other projects in the FY 2022 plan including Admiral Street projects; however, the Company does not have separate data readily available on how much cable will be replaced by year and the age of that cable for each of these multi-year projects.

Prepared by or under the supervision of: Caitlin Broderick

R-I-25

Request:

The IRURD FY2021 budget is $4.7M and the proposed budget for FY2022 is $6M. Explain the rationale for the increase and failure rates that support the additional required work. Additionally, provide a breakdown of cost between URD replacement versus injection projects.

Response:

The URD program is based on the type of cable, the cable fault history and the condition of the concentric neutral. All URDs identified for replacement or injection in FY 2022 have met the criteria for inclusion in the URD program. Of the $6 million planned for the URD program in FY 2022, approximately $500,000 is allocated for injections and $5,500,000 is for replacements.

Prepared by or under the supervision of: Caitlin Broderick

Division Set 2

nationalgrid

Andrew S. Marcaccio
Senior Counsel

December 3, 2020

VIA 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 2022 Electric Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – Set 2

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company"), enclosed, please find the electronic version of the Company's responses to the Division's Second Set of Data Requests issued in the above-referenced matter.

Consistent with discussions between the Company and the Division, which occurred on November 25 and December 2, 2020, the Company is not submitting a response to 2-2 and 2-3 at this time. Rather, the Company will submit the information requested by the Division through 2-2 and 2-3 as part of the filing materials it submits with the Public Utilities Commission ("PUC").

Thank you for your attention to this transmittal. If you have any questions, please contact me at 401-784-7263

Sincerely,

Andrew S. Marcaccio

Enclosure

cc: Leo Wold, Esq.
Christy Hetherington, Esq.
John Bell, Division
Greg Booth, Division
Al Contente, Division

280 Melrose Street, Providence, RI 02907
T: 401.784.4263 ■ andrew.marcaccio@nationalgrid.com ■ www.nationalgrid.com

nationalgrid

Andrew S. Marcaccio
Senior Counsel

December 21, 2020

VIA 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 2022 Electric Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – Set 2

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company"), enclosed, please find the electronic version of the Company's responses to 2-2 and 2-3, which completes the Company's responses issued in the Division's Second Set of Data Requests issued in the above-referenced matter.

Consistent with discussions between the Company and the Division, which occurred on November 25 and December 2, 2020, the Company is also submitting a copy of these responses to 2-2 and 2-3 as well as copies of entire sets of the Company's responses to Division Sets 1, 2, and 3 as part of the Company's proposed Electric ISR FY2022 Annual Plan filing with the Public Utilities Commission ("PUC").

Thank you for your attention to this transmittal. If you have any questions, please contact me at 401-784-7263

Sincerely,

Andrew S. Marcaccio

Enclosure

cc: Leo Wold, Esq.
Christy Hetherington, Esq.
John Bell, Division
Greg Booth, Division
Al Contente, Division

280 Melrose Street, Providence, RI 02907
T: 401.784.4263 ■ andrew.marcaccio@nationalgrid.com ■ www.nationalgrid.com

R-II-1

Request:

Provide the estimated annual power loss savings associated with the proposed VVO/CVR additions in FY 2022 ISR Plan. This should include kW, kWh and power cost. Include all inputs, assumptions, and calculations.

Response:

The substations planned for VVO/CVR in FY22 are Farnum, Pontiac and Putnam. The power loss savings associated with these projects are included in the tables below.

Substation	Summer Peak Estimate (kW)	GWh/year	% VVO savings	kW savings	kWh savings/year
Farnum	41900	163	2.80%	1173	4564000
Pontiac	42500	166	2.64%	1122	4382400
Putnam Pike	46700	182	2.65%	1238	4823000

R-II-1, page 2

Year	Load Spot Price Metric ($/MWh)*	Farnum Savings ($)	Pontiac Savings ($)	Putnam Pike Savings ($)
MWh savings/yr		4564	4382	4823
FY 21	$69.13	$315,509.32	$302,955.31	$333,413.99
FY 22	$70.23	$320,529.72	$307,775.95	$338,719.29
FY 23	$63.75	$290,955.00	$279,378.00	$307,466.25
FY 24	$68.74	$313,729.36	$301,246.18	$331,533.02
FY 25	$72.05	$328,836.20	$315,751.92	$347,497.15
FY 26	$73.43	$335,134.52	$321,799.63	$354,152.89
FY 27	$72.60	$331,346.40	$318,162.24	$350,149.80
FY 28	$72.01	$328,653.64	$315,576.62	$347,304.23
FY 29	$80.71	$368,360.44	$353,703.50	$389,264.33
FY 30	$76.09	$347,274.76	$333,456.82	$366,982.07
FY 31	$78.84	$359,825.76	$345,508.42	$380,245.32
FY 32	$83.35	$380,409.40	$365,273.04	$401,997.05
FY 33	$87.56	$399,623.84	$383,722.94	$422,301.88
FY 34	$86.68	$395,607.52	$379,866.43	$418,057.64
FY 35	$90.73	$414,091.72	$397,615.15	$437,590.79
FY 36	$94.15	$429,700.60	$412,602.96	$454,085.45
FY 37	$97.69	$445,857.16	$428,116.66	$471,158.87
FY 38	$101.39	$462,743.96	$444,331.54	$489,003.97
FY 39	$105.23	$480,269.72	$461,159.95	$507,524.29
FY 40	$109.23	$498,525.72	$478,689.55	$526,816.29
FY 41	$113.39	$517,511.96	$496,920.34	$546,879.97

*"Avoided Energy Supply Components in New England: 2018 Report", Appendix B, Synapse Energy Economics, Inc., 2018 (www.synapse-energy.com/project/aesc-2018-materials)

Prepared by or under the supervision of: Caitlin Broderick

R-II-1, page 3

Year	Critical Peak Pricing (CPP) Capacity Payment ($/kW)*	Farnum Savings ($)	Pontiac Savings ($)	Putnam Pike Savings ($)
kW savings		1173	1122	1238
FY 21	$83.13	$ 97,511.49	$ 93,271.86	$ 102,914.94
FY 22	$79.19	$ 92,889.87	$ 88,851.18	$ 98,037.22
FY 23	$80.82	$ 94,801.86	$ 90,680.04	$ 100,055.16
FY 24	$84.46	$ 99,071.58	$ 94,764.12	$ 104,561.48
FY 25	$87.71	$ 102,883.83	$ 98,410.62	$ 108,584.98
FY 26	$89.86	$ 105,405.78	$ 100,822.92	$ 111,246.68
FY 27	$92.13	$ 108,068.49	$ 103,369.86	$ 114,056.94
FY 28	$93.48	$ 109,652.04	$ 104,884.56	$ 115,728.24
FY 29	$95.79	$ 112,361.67	$ 107,476.38	$ 118,588.02
FY 30	$100.08	$ 117,393.84	$ 112,289.76	$ 123,899.04
FY 31	$101.41	$ 118,953.93	$ 113,782.02	$ 125,545.58
FY 32	$103.93	$ 121,909.89	$ 116,609.46	$ 128,665.34
FY 33	$108.53	$ 127,305.69	$ 121,770.66	$ 134,360.14
FY 34	$109.99	$ 129,018.27	$ 123,408.78	$ 136,167.62
FY 35	$112.67	$ 132,161.91	$ 126,415.74	$ 139,485.46
FY 36	$115.68	$ 135,692.64	$ 129,792.96	$ 143,211.84
FY 37	$118.77	$ 139,317.21	$ 133,259.94	$ 147,037.26
FY 38	$121.94	$ 143,035.62	$ 136,816.68	$ 150,961.72
FY 39	$125.20	$ 146,859.60	$ 140,474.40	$ 154,997.60
FY 40	$128.54	$ 150,777.42	$ 144,221.88	$ 159,132.52
FY 41	$131.97	$ 154,800.81	$ 148,070.34	$ 163,378.86

*"Avoided Energy Supply Components in New England: 2018 Report", Appendix B, Synapse Energy Economics, Inc., 2018 (www.synapse-energy.com/project/aesc-2018-materials)

R-II-2

Request:

Provide the estimated annual power loss savings associated with the proposed Providence Area Planning Study Phase 1A 4 kV and 11 kV rebuild and conversion project. This should include kW, kWh and power cost. Include all inputs, assumptions, and calculations.

Response:

As discussed with the Division in the meeting on December 2, 2020, the Company and the Division agreed that the Company would provide loss savings associated with the entire Providence Area Planning Study proposal instead of separating the values out into different phases of the projects resulting from the Area Study. Therefore, rather than provide separate responses for R-II-2 and R-II-3, the Company is providing one response for the entire set of projects from the Providence Area Study in this response. The annual power loss savings associated with the Providence Area Study is shown in the tables below. In addition, an Excel file is separately submitted with further detail on line losses and power transformer losses.

Providence Area Study Power Loss Savings		
Loss	**Saved kW**	**Saved kWH**
Distribution Losses	627	1142626
SubT Line Losses & Substation Transformer Losses	1470	2678458
Distribution Transformer Losses	1	3991
TOTAL	2098	3825075

R-II-2, page 2

Year	Critical Peak Pricing (CPP) Capacity Payment ($/kW)*	Providence Area Study Power Loss Savings
kW savings		2098
FY 21	$83.13	$174,421.73
FY 22	$79.19	$166,154.90
FY 23	$80.82	$169,574.93
FY 24	$84.46	$177,212.31
FY 25	$87.71	$184,031.39
FY 26	$89.86	$188,542.48
FY 27	$92.13	$193,305.35
FY 28	$93.48	$196,137.89
FY 29	$95.79	$200,984.69
FY 30	$100.08	$209,985.88
FY 31	$101.41	$212,776.46
FY 32	$103.93	$218,063.88
FY 33	$108.53	$227,715.51
FY 34	$109.99	$230,778.85
FY 35	$112.67	$236,401.97
FY 36	$115.68	$242,717.50
FY 37	$118.77	$249,200.87
FY 38	$121.94	$255,852.11
FY 39	$125.20	$262,692.17
FY 40	$128.54	$269,700.10
FY 41	$131.97	$276,896.85

*"Avoided Energy Supply Components in New England: 2018 Report", Appendix B, Synapse Energy Economics, Inc., 2018 (www.synapse-energy.com/project/aesc-2018-materials;)

Prepared by or under the supervision of: Caitlin Broderick

R-II-2, page 3

Year	Load Spot Price Metric ($/MWh)*	Providence Area Study Power Loss Savings
MWh savings/yr		**3825**
FY 21	$58.59	$224,103.88
FY 22	$59.49	$227,560.18
FY 23	$53.89	$206,121.84
FY 24	$58.10	$222,236.86
FY 25	$60.88	$232,852.14
FY 26	$61.99	$237,131.54
FY 27	$61.22	$234,157.92
FY 28	$60.65	$231,988.21
FY 29	$68.04	$260,272.03
FY 30	$63.98	$244,737.69
FY 31	$66.24	$253,389.05
FY 32	$70.01	$267,783.49
FY 33	$73.59	$281,484.10
FY 34	$72.80	$278,453.77
FY 35	$76.24	$291,622.17
FY 36	$79.13	$302,674.09
FY 37	$82.14	$314,176.10
FY 38	$85.27	$326,147.08
FY 39	$88.52	$338,606.72
FY 40	$91.91	$351,575.60
FY 41	$95.44	$365,075.20

*"Avoided Energy Supply Components in New England: 2018 Report", Appendix B, Synapse Energy Economics, Inc., 2018 (www.synapse-energy.com/project/aesc-2018-materials;).

Attachment R-II-2

The Company is also providing the Excel version of Attachment R-II-2.

	Base Case - YR 2030			Plan 1 - YR 2030	
Category	Total Losses (MW)	Total Losses (MVAR)		Total Losses (MW)	Total Losses (MVAR)
Transmission	2.32	14.7		2.27	14.58
Sub-transmission & Substation	5.25	75.74		3.83	66.35
Distribution Feeder	6.60	13.82		5.97	14.00
TOTAL	14.17	104.26		12.07	94.93
Savings				2.10	9.33

Base Case - YR 2030		
Network Id	Total Losses (kW)	Total Losses (kVAR)
TOTAL	*6598.03*	*13817.72*
1101	24.13	21.24
1103	29.68	24.13
1112	0.78	0.99
1115	4.46	4.16
1117	0.57	0.64
1119	2.58	2.97
1121	5.48	6.58
1123	0	0
1125	15.67	49.43
1126	32.9	59.52
1129	15.1	9.98
1131	7.38	8.82
1133	7.61	8.68
1137	21.36	21.58
1145	0.59	0.29
1147	1.13	1.35
1149	10.01	6.48
1151	61.5	65.25
1152	25.15	32.09
1153	26.71	34.07
1169	6.12	4.57
1171	1.14	1.07
12J1	6.79	5.2
12J2	10	13.95
12J3	0	0
12J4	26.06	44.91
12J5	8.17	11.61
12J6	9.85	11.55
13F1	9.89	21.26
13F10	94.52	195.9
13F2	16.9	44.67
13F3	63.86	173.27
13F4	191.78	442.13
13F5	77.73	182.3
13F6	44.71	71.05
13F7	89.94	175.19
13F8	53.5	107.36
13F9	161.74	464.96
18F10	175.17	406.29
18F5	264.28	668.94
18F7	93.95	221.19
18F9	111.65	281.16
23F6	259.3	570.77
27F1	189.26	450.96
27F2	289.34	675.59
27F3	7.13	14.41
27F4	198.34	447.42
27F5	173.8	402.05
27F6	33.92	79.97
2J1	87.39	81.97
2J10	7.58	7.49
2J3	12.71	7.41
2J4	14.37	11.8
2J5	5.97	4.9
2J7	44.59	65.72
2J8	29.2	28.41
2J9	27.8	26.69
36J1	4.28	7.88
36J2	13.21	16.76
36J4	58.6	76.12
36J5	29.56	45.74
37J1	39.07	45.76
37J2	42.72	53.15
37J3	35.04	50.7
37J4	19.19	23.95
37J5	45.69	56.77
66J1	10.54	21.67
66J2	81.73	103.9
66J3	51.26	75.81
66J4	23.62	37.19
66J5	19.75	26.34
67J1	21.41	28.12
69F1	60.86	128.95
69F3	149.25	353.08
6J1	33.1	42.5
6J2	49.8	77.94
6J3	3.75	6.54
6J5	0	0

Plan 1 - YR 2030		
Network Id	Total Losses (kW)	Total Losses (kVAR)
TOTAL	*5970.91*	*13997.48*
1101	24.64	22.01
1103	28.84	23.43
1112	0.78	0.99
1121	5.31	6.37
1125	15.63	49.21
1126	32.8	59.3
1149	9.1	5.9
1151	61.21	64.93
1152	24.86	31.7
1153	26.42	33.69
1169	6.16	4.74
1171	1.1	1.02
13F1	34.65	82.49
13F10	161.51	384.02
13F2	34.36	96.01
13F3	29.9	88.03
13F4	176.86	406.28
13F5	71.01	167.46
13F6	45.46	72.91
13F7	30.94	60.02
13F8	50.73	99.78
13F9	78.85	248.7
18F10	192.05	445.28
18F5	259.59	655.84
18F7	204.78	482
18F9	87.57	215.03
23F6	239.86	531.39
27F1	209.06	498.64
27F2	109.06	242.53
27F3	7.14	14.43
27F4	117.24	262.87
27F5	173.77	402
27F6	33.91	79.96
2J1	81.53	75.58
2J10	7.53	7.45
2J4	14.32	11.76
2J5	20.92	16.41
2J7	39.33	65.75
2J8	29.09	28.31
2J9	26.93	25.85
66F1	39.49	124.15
69F1	60.22	127.37
69F3	148.08	350.33
73F2	106.73	294.54
73F3	80.38	198.2
73F4	211.52	589.03
73F5	154.79	461.94
73F6	240.96	735.3
73F7	84.01	185.72
73F8	47.51	107.22
76F1	206.65	468.42
76F2	118.09	277.62
76F3	29.27	52.35
76F4	116.22	292.07
76F5	100.84	192.87
76F6	87.86	231.02
76F7	101.91	280.97
76F8	144.87	435.95
77J1	13.38	25.05
77J2	64.81	62.55
77J3	28.37	62.49
77J4	35.62	36.21
79F1	87.48	184.67
79F2	70.4	158.8
9F1	128.67	365.16
9F2	78.08	225.67
9F3	21.31	36.01
9F4	90.46	247.65
9F5	93.98	233.74
9F6	25.96	60.55
72F1	58.58	130.42
72F3	189.9	446.11
72F6	99.71	247.26

Total Losses (MW) for Existing system configuration =	**6.5980**
Total Losses (MW) for Plan 1 system configuration =	**5.9709**
Net reduction in losses (MW) after Plan 1 implementation =	**0.6271**

Base Case - YR 2030		
Network Id	Total Losses (kW)	Total Losses (kVAR)
TOTAL	*6598.03*	*13817.72*
6J6	4.41	3.83
6J7	51.2	49.26
6J8	14.1	14.68
71J1	48.59	96.5
71J2	7.09	12.12
71J3	11.2	22.86
71J4	9.64	21.3
71J5	66.08	93.05
73J1	8.75	12.02
73J2	0.63	1.19
73J3	32.58	49.74
73J4	10.03	15.71
73J5	56.81	111.55
73J6	24.66	38.7
76F1	214.11	484
76F2	143.81	334.03
76F3	22.53	36.02
76F4	163.57	396.51
76F5	76.12	159.23
76F6	79.16	207.47
76F7	200.37	558.63
76F8	184.4	442.99
77J1	13.39	25.08
77J2	56.06	72.47
77J3	30.64	64.82
77J4	36.81	37.01
79F1	51.16	77.06
79F2	85.23	189.54
7F1	103.46	244.92
7F2	160.85	447.42
7F4	89.31	198.06
9J1	58.21	116.05
9J2	8.21	13.51
9J3	48.63	60.36
9J5	0.91	1.83
72F1	55.34	122.24
72F3	216.67	519.18
72F6	169.64	405.57

Plan 1 - YR 2030		
Network Id	Total Losses (kW)	Total Losses (kVAR)
TOTAL	*5970.91*	*13997.48*

Base Case - YR 2030			
		X----- LOSSES -----X	
VOLTAGE			
LEVEL	BRANCHES	MW	MVAR
115	19	2.32	14.7
34.5	6	0.21	1.51
23	62	2.57	15.89
13.8	3	0	0.01
12.5	36	1.25	37.93
11.5	46	0.94	17.23
4.2	58	0.28	3.17
TOTAL		***7.57***	***90.44***

Plan 1 - YR 2030			
		X----- LOSSES -----X	
VOLTAGE			
LEVEL	BRANCHES	MW	MVAR
115	19	2.27	14.58
34.5	6	0.24	1.66
23	62	2.05	16.08
13.8	3	0	0.01
12.5	38	0.97	36.37
11.5	39	0.46	10.81
4.2	10	0.11	1.42
TOTAL		***6.1***	***80.93***

Total Losses (MW) for Existing system	**7.57**
Total Losses (MW) for Plan 1 system	**6.10**
Net reduction in losses (MW) after Plan 1	**1.47**

R-II-3

Request:

Provide the estimated annual power loss savings associated with the proposed Providence Area Planning Study Phase 1B 4 kV line replacement with 12.47 kV lines from Admiral Street substation. This should include kW, kWh and power cost. Include all inputs, assumptions, and calculations.

Response:

See response to R-II-2.

R-II-4

Request:

What footage (feeder feet) and percentage of total feeder length of UG Cable is being replaced or upgraded as a result of major asset or capacity projects such as Dyer Street substation, Admiral Street substation and Providence area feeders and all other projects excluding the asset condition category Underground Cable Projects in the FY 2022 ISR Plan? For projects that span multiple years, provide the requested data for the total planned project in addition to the amounts planned in FY 2022.

Response:

Excluding the Underground Cable Replacement Program, the Company plans to replace cable in FY 2022, as listed below, as part of major asset or capacity projects. Many projects involve new underground cable installations as part of the scope; however only cable replacements or upgrades are listed below.

1. Southeast substation
    - There are no underground cable asset replacements or upgrades included in the Southeast substation project scope.
2. Admiral Street substation
    - Feeder 1110 - Replace approximately 2700 circuit feet (12% of total feeder length) in FY 2022. Total planned replacement for the project is approximately 3400 circuit (15% of total feeder length).
2. Dyer Street substation (install a new 4 kV substation on the South Street property to replace existing Dyer Street substation)
    - There are minor underground cable asset replacements or upgrades included in the Dyer Street substation project scope.
3. Aquidneck Island (Newport & Jepson substations)
    - There are minor underground cable asset replacements or upgrades included in the Newport and Jepson substation project scopes.
4. East Providence & Warren substations
    - There are no underground cable asset replacements or upgrades included in the East Providence & Warren substation project scopes.
5. New Lafayette substation
    - There are no underground cable asset replacements or upgrades included in the new Lafayette substation project scope.

Prepared by or under the supervision of: Caitlin Broderick

R-II-4, page 2

These projects are in varying stages of design and construction and as such, the estimate of underground cable feet to be replaced in FY 2022 could change.

Other than feeder 1110 (associated with the Admiral Street substation project), cable being installed as part of the above projects is that which is required to implement the project scope (such as voltage conversions or feeder reconfigurations).

Cable being replaced or upgraded on Providence area feeders as a result of other projects (such as New Business) is also limited to that required to implement project scope and (where necessary) to make a spliced transition from paper-insulated lead covered cable to solid dielectric cable given the physical constraints of existing cables and manholes.

Andrew S. Marcaccio
Senior Counsel

December 7, 2020

VIA 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 2022 Electric Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – Set 3 (Part 1)

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company"), enclosed, please find the electronic version of the Company's responses to the Division's Third Set of Data Requests (Part 1) issued in the above-referenced matter.

Please note that attached responses are being filed in advance of the due date for Set 3. The remaining responses to Set 3 will be filed on or by the due date for Set 3 (December 11, 2020).

Thank you for your attention to this transmittal. If you have any questions, please contact me at 401-784-7263

Sincerely,

Andrew S. Marcaccio

Enclosure

cc: Leo Wold, Esq.
Christy Hetherington, Esq.
John Bell, Division
Greg Booth, Division
Al Contente, Division

280 Melrose Street, Providence, RI 02907
T: 401.784.4263 ■ andrew.marcaccio@nationalgrid.com ■ www.nationalgrid.com

Andrew S. Marcaccio
Senior Counsel

December 11, 2020

VIA 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 2022 Electric Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – Set 3 (Complete Set)

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company"), enclosed, please find the electronic version of the Company's responses to the Division's Third Set of Data Requests ("Complete Set 3") issued in the above-referenced matter.

The Company submitted its responses to Division 3-1, 3-2, 3-3, and 3-7 on December 7, 2020.

Thank you for your attention to this transmittal. If you have any questions, please contact me at 401-784-7263.

Sincerely,

Andrew S. Marcaccio

Enclosure

cc: Leo Wold, Esq.
Christy Hetherington, Esq.
John Bell, Division
Greg Booth, Division
Al Contente, Division

280 Melrose Street, Providence, RI 02907
T: 401.784.4263 ■ andrew.marcaccio@nationalgrid.com ■ www.nationalgrid.com

R-III-1

Request:

Provide a breakdown of the proposed budget for DER Non-Discretionary by category (e.g. DER 3V0, DER Mobile 3V0, DER Capacitors, DER Reclosers, etc.)

Response:

The Company proposed $5.4 million in capital spending related to Strategic DER Advancement projects in the FY 2022 ISR Plan. As noted in the response to Division's First Set of Data Requests - R-I-11, system issues have been identified at the Chopmist and Hopkins Hill substations. The table below shows the targeted feeders and estimated capital spending budgeted to address the emerging issues resulting from the proliferation of DER. The data in the table below reflects revised estimates for Hopkins Hill based on more detailed information than was used at the time the FY2022 budget was proposed and therefore is $1.3 million less than the proposed budget. In addition, it is likely that the Chopmist work that is being considered for the FY2021 plan is not going to be completed in FY 2021.

Additional costs will be incurred for OPEX and cost of removal.

The Company has not included costs associated with 3V0 or mobile 3V0 devices in the Non-Discretionary Strategic DER Advancement line item in FY 2022's budget.

R-III-1, page 2

Substation	**Chopmist**							
Feeder #	34F1		34F2		34F3			
Voltage	12.47		12.47		12.47			
Mainline Length (miles)	43		23		15		**Total**	
	Count	CAPEX	Count	CAPEX	Count	CAPEX	**Count**	**CAPEX**
Smart Capacitors	4	$120	5	$150	2	$60	**11**	**$330**
Advanced Regulators	0	$0	0	$0	1	$100	**1**	**$100**
Feeder Monitors	3	$75	2	$50	1	$25	**6**	**$150**
Advanced Reclosers	13	$1,040	3	$240	5	$400	**21**	**$1,680**
Substation Regulators	0	$0	0	$0	1	$15	**1**	**$15**
		$1,235		$440		$600		**$2,275**

Substation	**Hopkins Hill**											
Feeder #	63F2		63F2		63F2		63F2		63F2			
Voltage	12.47		12.47		12.47		12.47		12.47			
Mainline Length (miles)	15		12		8		9		36		**Total**	
	Count	CAPEX	Count	CAPEX	Count	CAPEX	Count	CAPEX	Count	CAPEX	**Count**	**CAPEX**
Smart Capacitors	4	$120	4	$120	2	$60	4	$120	4	$120	**18**	**$540**
Advanced Regulators	0	$0	0	$0	0	$0	0	$0	3	$300	**3**	**$300**
Feeder Monitors	2	$50	2	$50	2	$50	2	$50	2	$50	**10**	**$250**
Advanced Reclosers	7	$560	5	$400	6	$480	6	$480	8	$640	**32**	**$2,560**
Substation Regulators	0	$0	1	$100	1	$100	1	$100	1	$100	**4**	**$400**
		$730		$670		$690		$750		$1,210		**$4,050**

FY 2021 Forecast	**$2,000**
FY 2022 Proposed Budget	**$4,325**

R-III-2

Request:

Provide a list of targeted (through FY22) and completed substations under the 3V0 program with the following information:

a) Substation

b) Date complete/Date targeted for completion

c) Actual/projected capital and O&M per installation

Response:

See the summary below.

Substation	Project Estimate		Actual Spend through 11/30/20		Remaining FY21 forecast		FY22 forecast		3V0 Targeted Completion Date	3V0 Actual Completion Date
	Capex	Opex	Capex	Opex	Capex	Opex	Capex	Opex		
Tiverton	$60,000	$10,000	$60,000	$0	$0	$0	$0	$0	3/31/2019	5/30/2019
Kilvert St.	$40,000	$10,000	$13,978	$0	$0	$0	$0	$0	3/31/2019	12/14/2018
Old Baptist Road	$40,000	$10,000	$40,000	$0	$0	$0	$0	$0	3/31/2019	12/14/2018
Davisville	$60,000	$10,000	$33,373	$0	$2,000	$0	$0	$0	3/31/2019	10/21/2020
Wolf Hill	$40,000	$10,000	$60,134	$0	$0	$0	$0	$0	3/31/2020	5/16/2020
Pontiac	$60,000	$10,000	$34,875	$0	$0	$0	$0	$0	3/31/2020	2/21/2020
Riverside	$40,000	$10,000	$225,235	$0	$70,000	$0	$0	$0	3/31/2020	Projected 2/16/2021
Quonset Sub	$430,000	$20,000	$525,000	$0	$0	$0	$0	$0	3/31/2020	6/22/2020
Chopmist	$285,000	$15,000	$92,244	$0	$184,000	$0	$67,000	$0	3/31/2021	Projected 2/4/2021
Putnam Pike	$90,000	$10,000	$6,582	$0	$23,000	$0	$44,000	$0	3/31/2021	Projected 4/15/2021
Eldred	$550,000	$50,000	$47,881	$0	$405,000	$0	$129,000	$0	3/31/2021	Projected 3/30/2021
Natick	$500,000	$0	$0	$0	$0	$0	$500,000	$0	3/31/2022	TBD
Wampanoag	$80,000	$0	$0	$0	$0	$0	$80,000	$0	3/31/2022	TBD
Highland Park #200	$80,000	$0	$0	$0	$0	$0	$80,000	$0	3/31/2022	TBD
Peacedale	$400,000	$0	$0	$0	$0	$0	$123,000	$0	3/31/2022	TBD
TOTAL FORECAST for FY21-FY22					$684,000	$0	$1,023,000	$0		

R-III-3

Request:

Provide an update on the mobile 3V0 program including how many mobile 3V0 units have been purchased by year, how many have been planned for purchase by year, and actual costs for each purchase.

Response:

During FY 2021 four 3V0 mobile units will be purchased. The vendor anticipates delivery prior to year-end, but our forecast assumes a lag into first quarter of Fiscal Year 2022. The current forecast for the four units is $554,000 in FY 2021 and $123,000 in FY 2022. No additional mobile 3V0 units are planned to be purchased.

R-III-4

Request:

Regarding the Providence Area Study:

a) Compare the load growth forecasts used at the time the study was performed to the most current forecasts.

b) Provide an updated Table 5 – Feeder Loads for Year 2030 >= 90% (no new facilities). Also provide projected feeder loads for the year 2035.

c) Provide an updated Table 6 – Calculated MWH Load-at-Risk - Existing Configuration.

d) Provide Figure 9.4.1 – CYME Base (Existing) Case – 2030 Loading using the Company's most recent load growth assumptions. Also provide the CYME model with projected loads in 2035.

Response:

a) The Providence area study used the 2015 New England Electric Peak Forecast. The most current company forecast report is the 2020 Electric Peak Forecast. Load growth forecasts from the two reports are included below.

Source	2015 forecast	2020 forecast
2015	2.4%	
2016	1.3%	
2017	0.4%	
2018	0.3%	
2019	0.3%	
2020	0.4%	11%*
2021	0.4%	-1.0%
2022	0.4%	-0.2%
2023	0.4%	-0.2%
2024	0.4%	-0.2%
2025	0.4%	-0.3%
2026	0.6%	-0.3%
2027	0.6%	-0.3%
2028	0.6%	-0.3%
2029	0.6%	-0.3%
2030	0.6%	-0.5%
2031		-0.5%
2032		-0.5%
2033		-0.5%
2034		-0.5%

*The 11% growth rate in 2020 includes a weather adjustment of +15.1% and an economic growth rate of -4.1%.

Prepared by or under the supervision of: Caitlin Broderick

R-III-4, page 2

b) Updated Table 5 – Feeder Loads for Year 2030 >= 90% (no new facilities) is included below with feeder loads for the year 2034.

The latest forecast report is the 2020 Electric Peak Forecast which only includes forecast information through 2034. The 2021 Electric Peak Forecast report was recently finalized but the 2021 annual planning process is not complete. Until the 2021 annual planning process is complete, the current forecasts from the 2020 Electric Peak Forecast report are used as the most recent, which only includes forecasts out to 2034. Therefore, this response only includes load information through 2034, not 2035.

R-III-4, page 3

Susbtation	Voltage	Feeder	%Summer Normal Rating				
			Providence Study	2020 Update - 2030 (Amps)	2020 Update - 2030	2020 Update - 2034 (Amps)	2020 Update - 2034
CLARKSON STREET 13	12.47	13F3	99%	324	76%	317	75%
CLARKSON STREET 13	12.47	13F4	101%	445	86%	436	84%
CLARKSON STREET 13	12.47	13F5	102%	411	90%	403	89%
CLARKSON STREET 13	12.47	13F7	103%	204	47%	200	46%
CLARKSON STREET 13	12.47	13F9	93%	460	87%	451	85%
ELMWOOD 7 - OUTDOOR	12.47	7F2	92%	368	69%	361	68%
ELMWOOD 7 - OUTDOOR	12.47	7F4	93%	440	83%	431	81%
LIPPITT HILL	12.47	79F2		424	92%	415	90%
POINT STREET 76	12.47	76F1	100%	434	90%	425	88%
POINT STREET 76	12.47	76F2	101%	482	96%	472	94%
POINT STREET 76	12.47	76F4	105%	491	93%	481	91%
POINT STREET 76	12.47	76F5	102%	420	94%	411	92%
POINT STREET 76	12.47	76F6		485	94%	475	92%
POINT STREET 76	12.47	76F7	100%	418	80%	409	78%
POINT STREET 76	12.47	76F8	98%	266	50%	260	49%
ADMIRAL STREET 9	4.16	9J1	96%	348	85%	341	84%
ADMIRAL STREET 9	4.16	9J3	102%	207	81%	203	80%
EAST GEORGE ST 77	4.16	77J1	91%	269	73%	264	71%
EAST GEORGE ST 77	4.16	77J2	99%	378	104%	371	102%
EAST GEORGE ST 77	4.16	77J3	102%	339	91%	332	90%
EAST GEORGE ST 77	4.16	77J4	96%	296	81%	290	80%
GENEVA 71	4.16	71J5	93%	317	78%	311	76%
HUNTINGTON PARK 67	4.16	67J1	96%	258	94%	253	92%
KNIGHTSVILLE 66	4.16	66J1	97%	171	69%	167	67%
KNIGHTSVILLE 66	4.16	66J2	130%	275	87%	269	86%
KNIGHTSVILLE 66	4.16	66J3	94%	264	70%	259	68%
OLNEYVILLE 6	4.16	6J2	90%	251	82%	246	80%
OLNEYVILLE 6	4.16	6J7	91%	242	79%	237	78%
ROCHAMBEAU AVENUE 37	4.16	37J2	91%	240	82%	235	81%
ROCHAMBEAU AVENUE 37	4.16	37J3	98%	271	90%	266	88%
ROCHAMBEAU AVENUE 37	4.16	37J4	91%	234	84%	229	82%
ROCHAMBEAU AVENUE 37	4.16	37J5	95%	283	81%	277	80%
SPRAGUE STREET 36	4.16	36J1	93%	195	82%	191	81%
SPRAGUE STREET 36	4.16	36J2	97%	196	78%	192	76%
SPRAGUE STREET 36	4.16	36J5	90%	282	90%	276	88%

c) Updated Table 6 – Calculated MWH Load-at-Risk - Existing Configuration is included below.

R-III-4, page 4

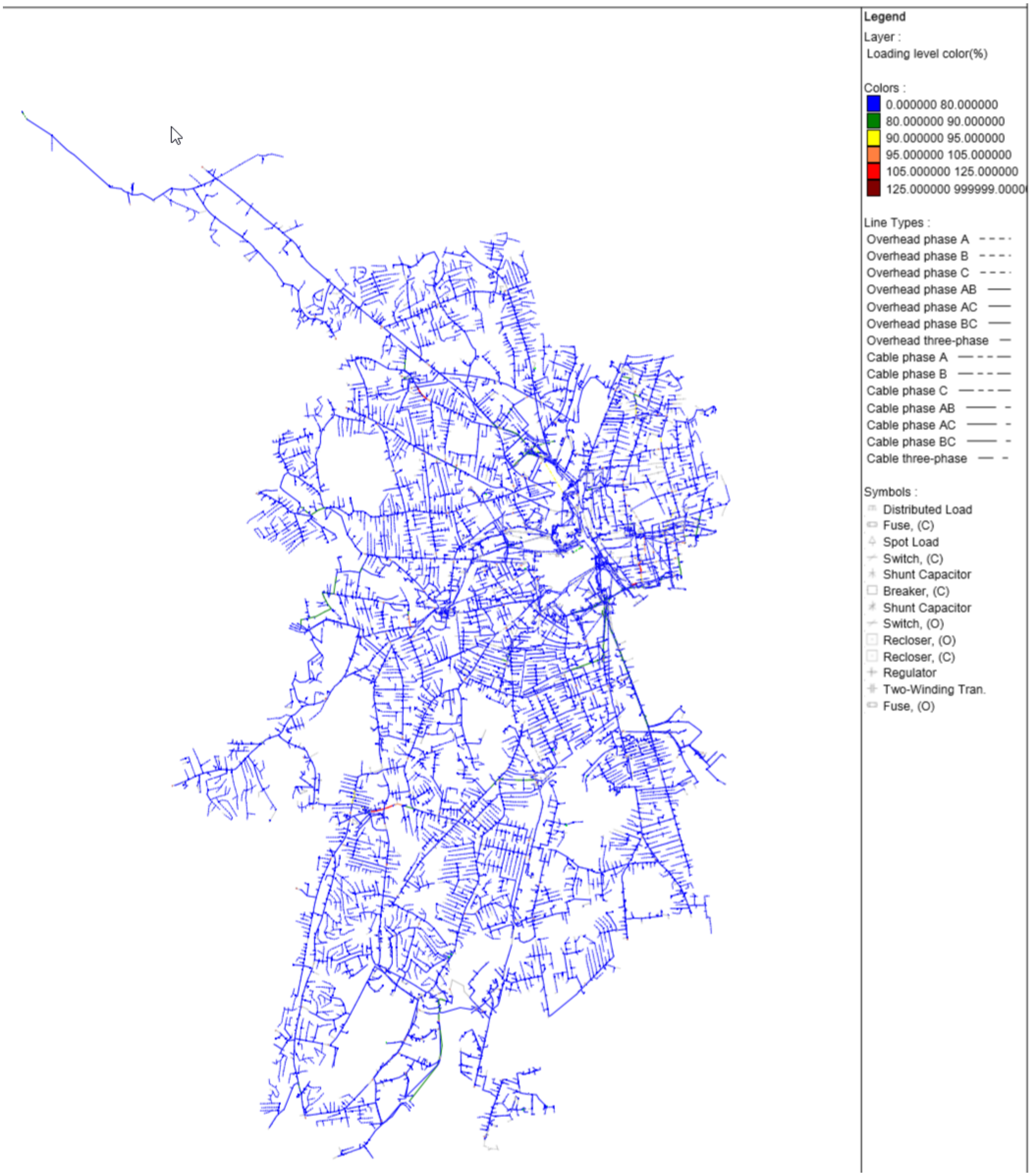
Table 6 - Calculated MWh Load-at-Risk - Existing Configuration			
Feeder	Calculated MWh Load-at Risk 2030		
	Providence Study	Updated 2020 - 2030*	Updated 2020 - 2034*
13F4	16.2	7.2	7.1
13F9	20.7	7.5	7.3
13F10	19.2	4.2	4.1
79F2	27.1	6.9	6.7
76F1	38.3	29.3	28.1
76F2	18.7	10	7.7
76F4	29.5	14.1	12.2
76F5	17.3	15.4	13.5
76F6	20.2	9.3	8.4
76F8	27.6	8.1	6.7

d) Updated Figure 9.4.1 – CYME Base (Existing) Case – 2030 Loading is included below along with a figure with projected loads in 2034.

The latest forecast report is the 2020 Electric Peak Forecast which only includes forecast information through 2034. The 2021 Electric Peak Forecast report was recently finalized but the 2021 annual planning process is not complete. Until the 2021 annual planning process is complete, the current forecasts from the 2020 Electric Peak Forecast report are used as the most recent, which only includes forecasts out to 2034. Therefore, this response only includes load information for 2034, not 2035.

R-III-4, page 5

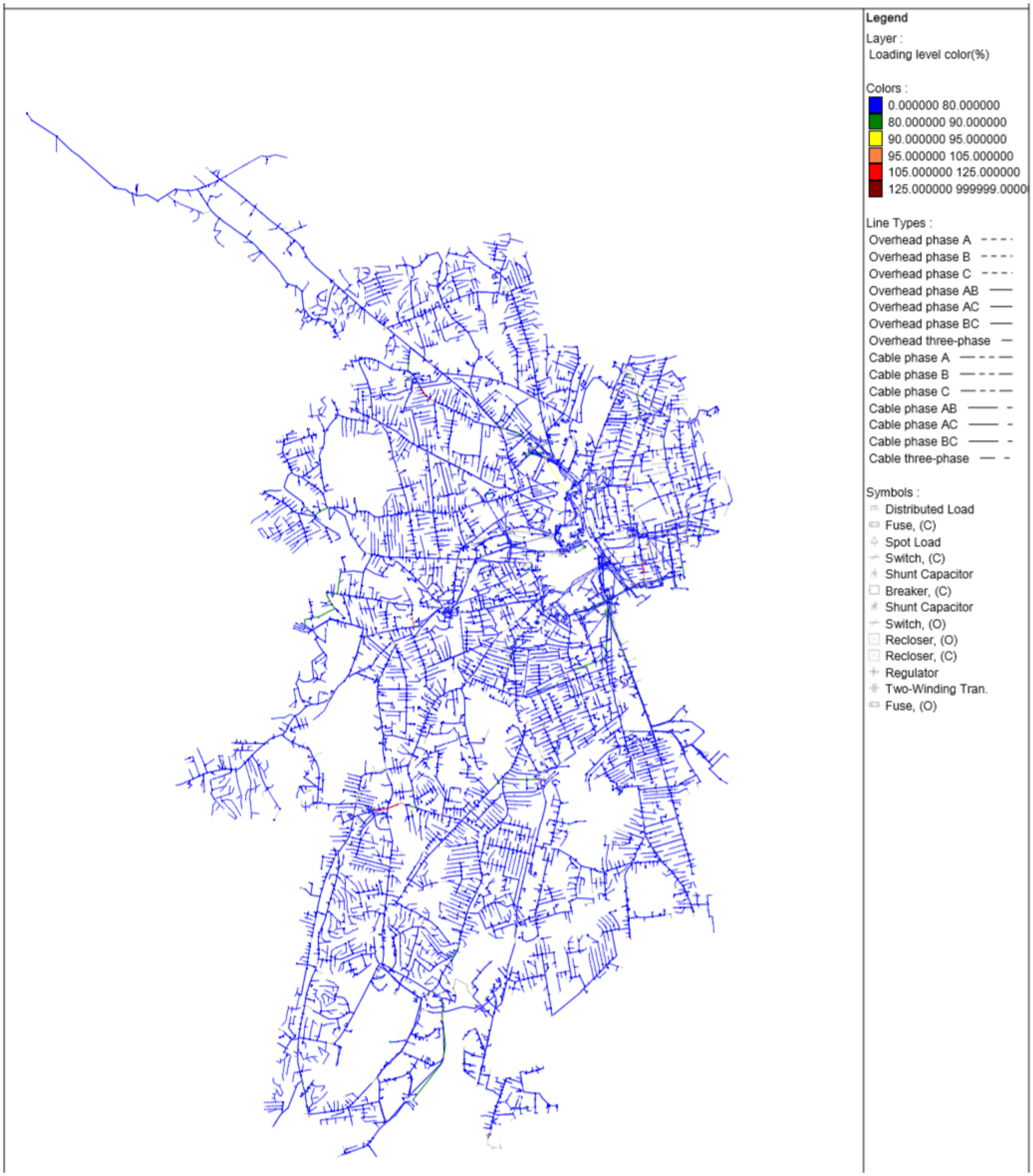
CYME Base (Existing) Case – 2030 Loading



Prepared by or under the supervision of: Caitlin Broderick

R-III-4, page 6

CYME Base (Existing) Case – 2034 Loading



R-III-5

Request:

Regarding the East Bay Long Term Study:

a) Compare the load growth forecasts used at the time the study was performed to the most current forecasts.

b) Provide an updated Table 4.1.1 – Projected Summer Normal Feeder Loading utilizing current and projected feeder loadings.

c) Provide an updated Table 4.1.2 – Calculated MWH exposure and un-Served Load on Feeders.

d) Provide Figure 9.4.2 – CYME East Bay Existing Configuration – Loading Analysis using current loads. Also provide the CYME model using the Company's most recent load growth assumptions for 2025, 2030 and 2035.

Response:

a) The East Bay area study used the 2014 New England Electric Peak Forecast. The most current company forecast report is the 2020 Electric Peak Forecast. Load growth forecasts from the two reports are included below.

R-III-5, page 1

Source	2014 forecast	2020 forecast
2014	4.7%	
2015	2.3%	
2016	1.4%	
2017	1.0%	
2018	0.6%	
2019	0.7%	
2020	0.7%	11%*
2021	0.7%	-1.0%
2022	0.7%	-0.2%
2023	0.7%	-0.2%
2024	0.8%	-0.2%
2025	0.8%	-0.3%
2026	0.8%	-0.3%
2027	0.8%	-0.3%
2028	0.8%	-0.3%
2029	0.8%	-0.3%
2030	0.8%	-0.5%
2031		-0.5%
2032		-0.5%
2033		-0.5%
2034		-0.5%

*The 11% growth rate in 2020 includes a weather adjustment of +15.1% and an economic growth rate of -4.1%.

b) Updated Table 4.1.1 – Projected Summer Normal Feeder Loading is included below.

Prepared by or under the supervision of: Caitlin Broderick

R-III-5, page 2

Substation	Feeder	2020		2025		2030		2034	
		Amps	%SN	Amps	%SN	Amps	%SN	Amps	%SN
BARRINGTON 4	4F1	397	77%	389	76%	383	74%	375	73%
BARRINGTON 4	4F2	521	102%	511	100%	502	98%	492	97%
BRISTOL 51A	51F1	505	78%	496	77%	487	76%	477	74%
BRISTOL 51A	51F2	506	95%	496	94%	488	92%	478	90%
BRISTOL 51A	51F3	411	82%	404	80%	397	79%	389	77%
WAMPANOAG 48	48F1	482	96%	473	94%	465	93%	456	91%
WAMPANOAG 48	48F2	413	80%	405	79%	398	77%	391	76%
WAMPANOAG 48	48F3	415	81%	407	80%	400	79%	392	77%
WAMPANOAG 48	48F4	482	91%	473	89%	465	88%	455	86%
WAMPANOAG 48	48F5	372	70%	365	69%	359	68%	352	66%
WAMPANOAG 48	48F6	385	73%	378	71%	371	70%	364	69%
WARREN 5	5F1	416	98%	408	96%	401	94%	393	93%
WARREN 5	5F2	354	82%	348	80%	342	79%	335	77%
WARREN 5	5F3	384	75%	376	73%	370	72%	363	70%
WARREN 5	5F4	454	89%	446	87%	438	86%	430	84%
OUT OF PHASE FEEDERS									
PHILLIPSDALE 20	20F1	315	74%	309	73%	304	72%	298	70%
PHILLIPSDALE 20	20F2	250	59%	245	58%	241	57%	236	56%
WATERMAN AVENUE 78	78F3	239	58%	234	57%	230	56%	226	55%
WATERMAN AVENUE 78	78F4	210	51%	206	50%	202	49%	198	48%
4.16 kV POCKET OF LOAD									
KENT CORNERS 47	47J2	302	74%	296	73%	291	71%	285	70%
KENT CORNERS 47	47J3	338	83%	331	81%	326	80%	319	78%
KENT CORNERS 47	47J4	320	78%	314	77%	308	76%	302	74%

R-III-5, page 3

c) Updated Table 4.1.2 – Calculated MWH exposure and un-Served Load on Feeders is included below.

Substation	Feeder	MWh Exposure	Un-Served MW
BARRINGTON 4	4F1	24.1	5.4
BARRINGTON 4	4F2	33.3	7.6
BRISTOL 51A	51F1	22.9	4.5
BRISTOL 51A	51F2	28.1	6.1
BRISTOL 51A	51F3	20.3	4.2
WAMPANOAG 48	48F1	16.7	3.6
WAMPANOAG 48	48F2	4.1	0.0
WAMPANOAG 48	48F3	11.7	1.2
WAMPANOAG 48	48F4	6.7	0.0
WAMPANOAG 48	48F5	17.4	3.3
WAMPANOAG 48	48F6	23.7	4.9
WARREN 5	5F1	12.0	1.8
WARREN 5	5F2	11.6	1.6
WARREN 5	5F3	27.3	6.3
WARREN 5	5F4	20.8	4.6
PHILLIPSDALE 20	20F1	18.0	3.6
PHILLIPSDALE 20	20F2	22.7	4.7
WATERMAN AVEN	78F3	3.9	0.0
WATERMAN AVEN	78F4	3.4	0.0

Prepared by or under the supervision of: Caitlin Broderick

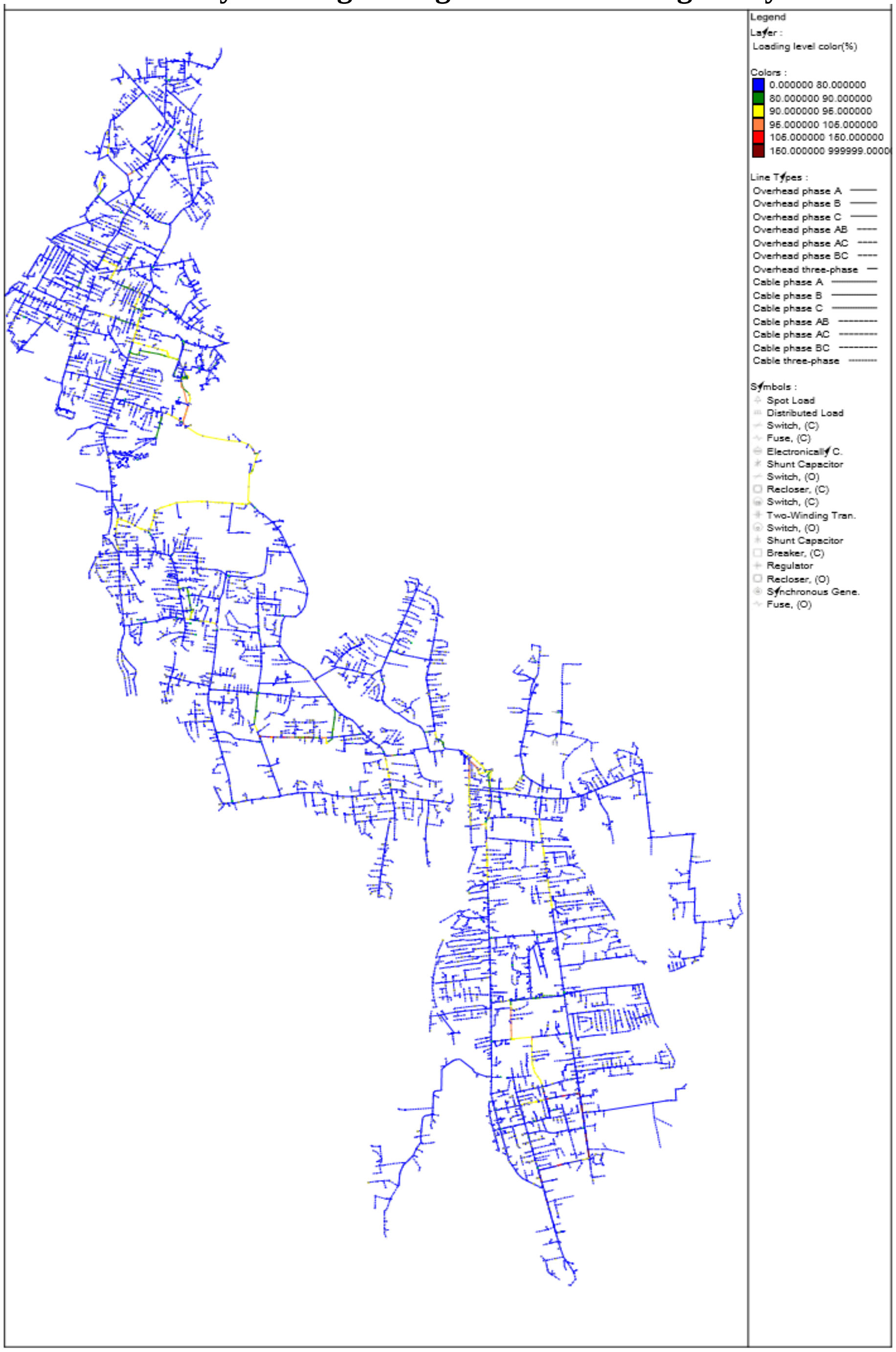
R-III-5, page 4

d) Updated Figure 9.4.2 – CYME East Bay Existing Configuration – Loading Analysis is included below along with the Company's most recent load growth assumptions for 2025, 2030 and 2034.

The latest forecast report is the 2020 Electric Peak Forecast which only includes forecast information through 2034. The 2021 Electric Peak Forecast report was recently finalized but the 2021 annual planning process is not complete. Until the 2021 annual planning process is complete, the current forecasts from the 2020 Electric Peak Forecast report are used as the most recent, which only includes forecasts out to 2034. Therefore, this response only includes load information for 2034, not 2035.

R-III-5, page 5

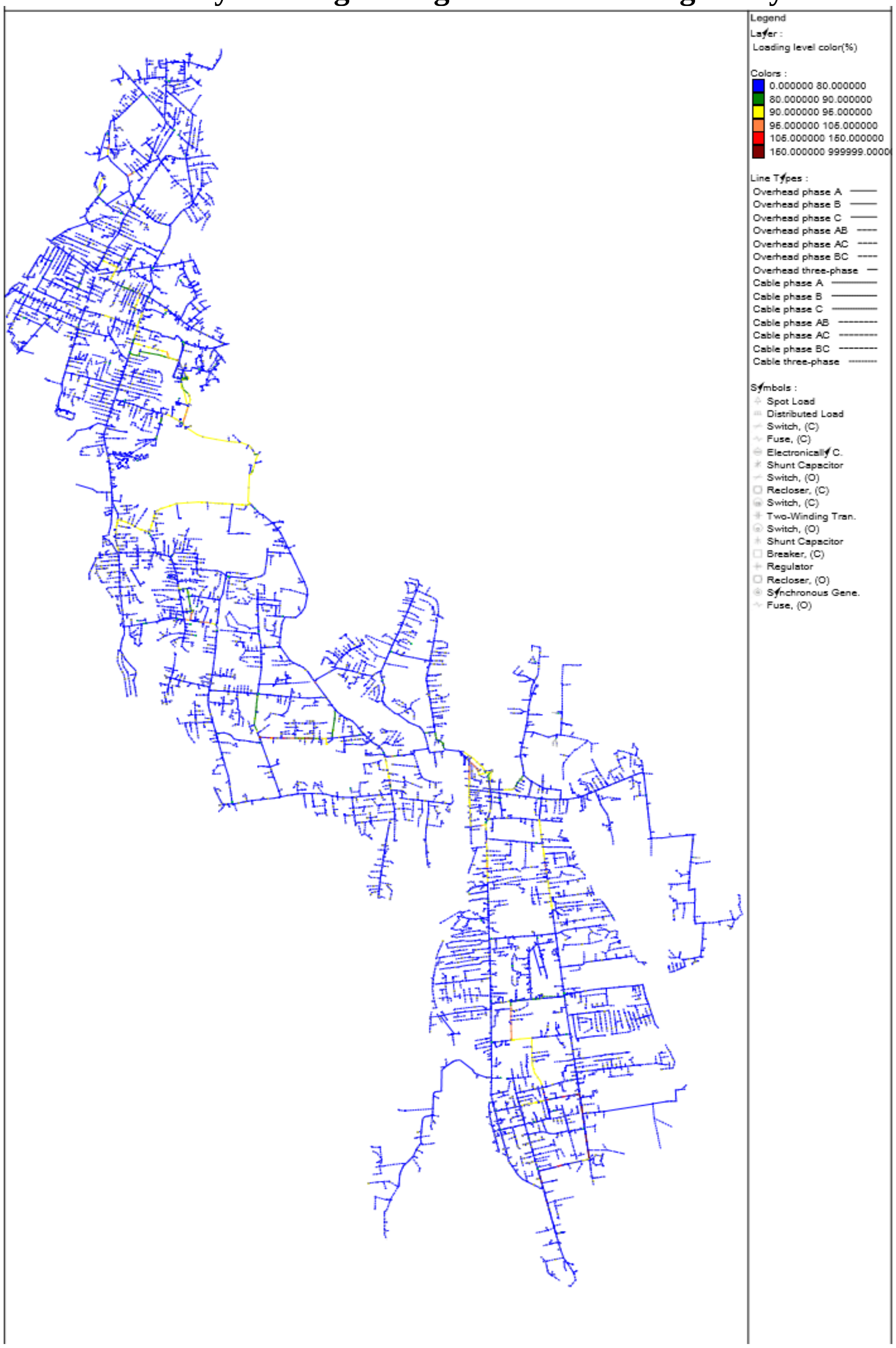
CYME East Bay Existing Configuration – Loading Analysis 2020



Prepared by or under the supervision of: Caitlin Broderick

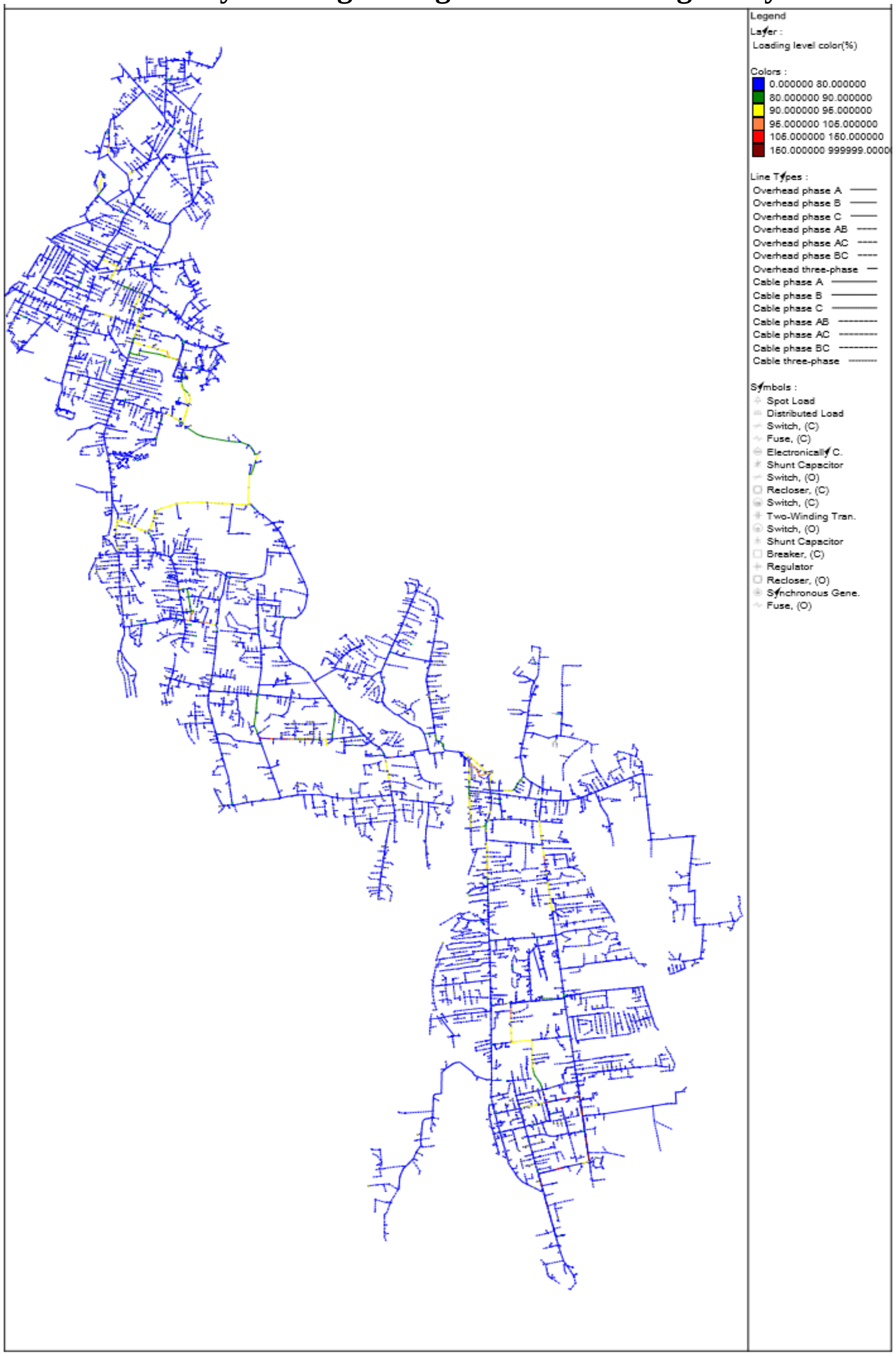
R-III-5, page 6

CYME East Bay Existing Configuration – Loading Analysis 2025



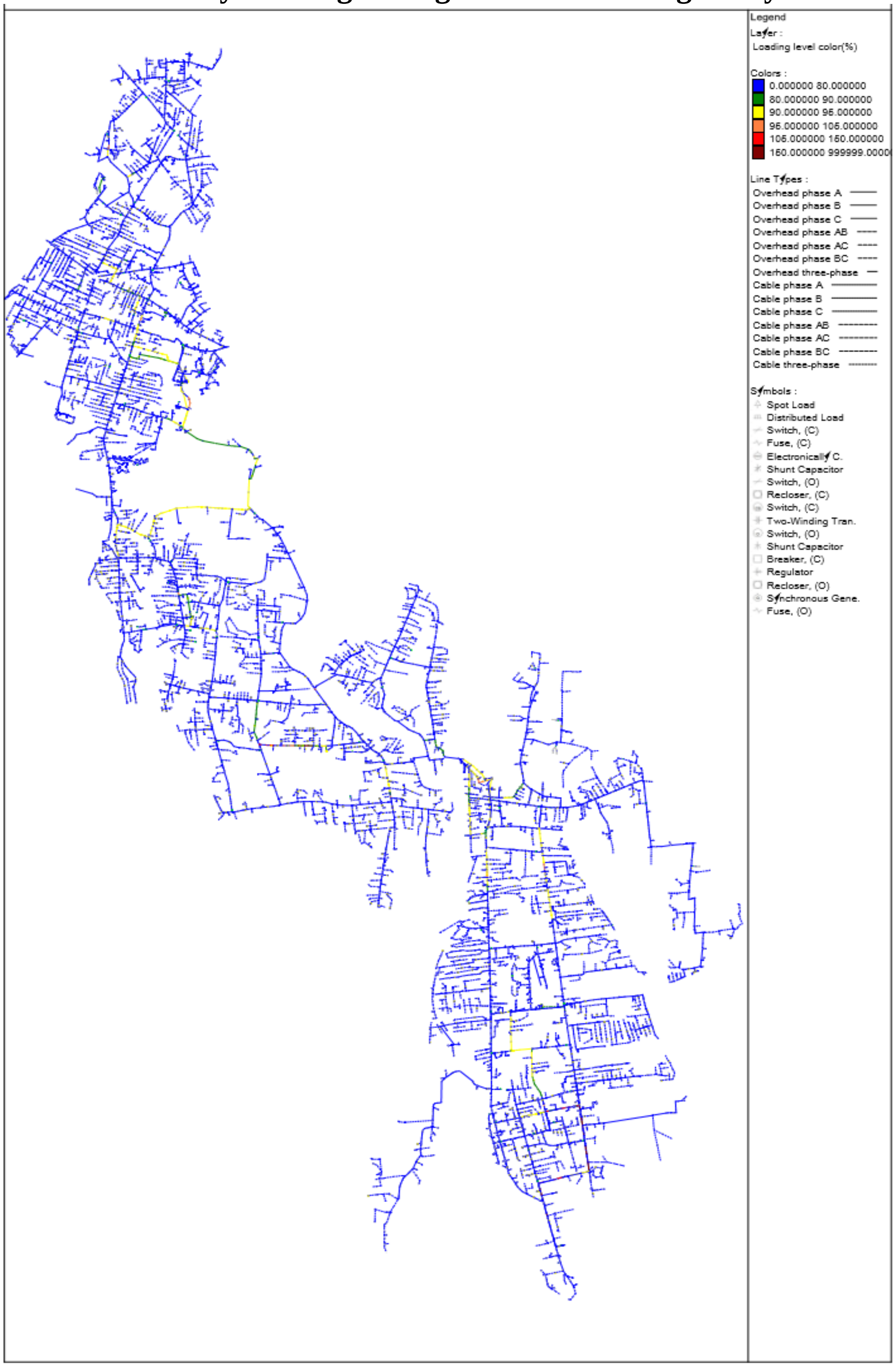
<u>R-III-5, page 7</u>

CYME East Bay Existing Configuration – Loading Analysis 2030



R-III-5, page 8

CYME East Bay Existing Configuration – Loading Analysis 2034



R-III-6

Request:

Discuss how the Company determines when capacity related projects recommended in Area Studies should be implemented and what steps are taken when actual loads do not reach the level of initially projected loads. Describe analysis the Company performs on an annual basis to support advancing capacity related projects within an ISR Plan.

Response:

The Company determines when capacity related projects recommended from Area Studies should be implemented based on the need date identified during the area study. The Company reviews completed Area Study projects at the initiation of Stage 4.3 in Complex Capital Delivery process to validate the need has not changed based on the most recent actual loads and forecast. If the review indicates that the need or need date of the proposed project(s) has changed or no longer exists, the project(s) will be reanalyzed to align with the new need or need date or when applicable, removed from the plan.

As described in System Planning, Section 2 of the FY 2022 ISR Plan, the Company performs an Annual Capacity Review on all the feeders, substation transformers and sub-transmission lines in Rhode Island. The implementation schedule of capacity related area study projects is adjusted as needed based on the annual capacity review. The annual capacity review will validate and confirm the need date and implementation schedule of capacity related projects before inclusion in the ISR plan.

Prepared by or under the supervision of: Caitlin Broderick

R III-7

Request:

For the FY22 ISR Plan, the Company proposes a budget of $265,000 for Recloser Replacement in the Asset Replacement category. Explain how the budget is derived, including specific planned recloser replacements and rationale for the replacement. Explain how the program is correlated to strategic DER.

Response:
Asset replacement programs are distributed over a multi-year work period depending on program size, urgency of need, and constraints such as budget allowances. Planning for a five-year duration is typical for programs of this size. The budgets for the asset replacement programs are determined during the initial program creation phase. Preliminary estimates for the required asset replacements are developed and combined to create a spending plan for the entirety of the program duration. This spending plan is used as the basis for determining the annual budget for each program.

There are two Recloser Replacement programs referenced in the FY22 ISR. To maintain confidentiality, the two programs will be referred to as Program A and Program B. The main objective of Program A is to address the multiple issues and concerns with regards to the safety, reliability and asset condition of a specific type of pole top reclosers in the distribution system due to aging and obsolescence of these assets.

Construction activities for Program A started in FY17 with thirty-nine (39) total units in the field scheduled for replacement over a five-year program duration. After the initial year (FY17) completion of four (4) units, the plan called for seven (7) replacements per year from FY18-FY21 and six (6) replacements in FY22. Due to two (2) of these types of reclosers failing in service, there will only be four (4) remaining for completion in FY22 to complete the program.

Worker safety and system reliability were the primary drivers for implementing Program B. Concerns exist with specific Reclosers produced by this manufacturer between 2012 and 2015 due to the 3 Dipped Neoprene Overmolding manufacturing process which is no longer being used by the manufacturer because it has resulted in the premature failures of the bushings.

National Grid is in the second year of the five-year program to replace twenty-four (24) of these Reclosers in Rhode Island.

Prepared by or under the supervision of: Caitlin Broderick

R III-7, page 2

Construction activities for Program B started in FY20, with twenty-four (24) total units in the field scheduled for replacement over a five-year program duration. The plan calls for six (6) replacements per year from FY20-FY21 and four (4) replacements per year from FY22-FY24.

Program A reclosers are being replaced with the Company's current standard reclosers: G&W Viper reclosers available with radio communications. The radio communications allow for remote monitoring and operation. Program A units being replaced were not originally designed to have communications added and as such, required a qualified worker to manually operate the unit in person. The Program A recloser replacements are the same standard reclosers, with communications, control, and monitoring capabilities as the Strategic DER Enabling Investments.

The Program B reclosers targeted for replacement are already modern reclosers with communications capabilities. Therefore, National Grid is only replacing the recloser head unit as part of the program. Factory refurbished and certified units are replacing the units which have the failing Neoprene bushing type targeted by the program. These refurbished units will extend the overall usable life of the of the recloser and are in the same existing class of reclosers that have communications, control, and monitoring capabilities as the Strategic DER Enabling Investments.

Therefore, the recloser replacement programs are aligned with the strategic DER enabling investments' goals of promoting the advancement of monitoring and control capabilities on the distribution system, which can contribute to DER enablement.

However, the strategy for the Recloser Replacement Programs in Asset Condition differs from the strategic DER investments in their drivers and the targeting of deployments for these functionalities. DER enabling recloser installations target areas with significant levels of DER penetration, where these capabilities can be leveraged to support the efficient operation of a distribution system with high amounts of DER. The Recloser Replacement Programs are targeting specific recloser populations that have known asset condition concerns, with the primary goal of ensuring that the existing reclosers continue to operate safely and reliably, as intended.

Prepared by or under the supervision of: Caitlin Broderick

R-III-8

Request:

Provide details for the Non-Infrastructure budget of $1.3 million in both FY22 and FY23, and explain the basis for the increase from previous actual spending averaging closer to $500,000 per year.

Response:

The non-infrastructure category of spending is for capital expenditures that do not fit into one of the other spending rationales. This capital spending is necessary to run the electric system, such as general and telecommunications equipment.

In FY 2022 and FY 2023 the Company has proposed increased non-infrastructure spending related to the purchase and installation of communication equipment for substations due to the retirement of Verizon's DS0 communication lines. The Company has proposed an additional $800,000 per year in FY 2022 and FY 2023 to purchase and install JMUX devices, DC-AC inverters and wall mount brackets inside several electric substations. These devices will be installed within the Company substations in coordination with Verizon as they convert DS0 circuits to T1 circuits. The work will ensure continued operation of substation protection systems and allow for telecommunication operations at each station. Verizon's schedule for DS0 retirements is communicated to National Grid on a year to year basis.

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

R-III-9

Request:

Identify the underlying Area Study and provide the scope and details for the Weaver Hill Rd. and New London Expansion projects in the System Capacity and Performance Category that are in pre-project development stage. How does the proposed work for the New London Expansion project correlate to the previous New London Sub #150 project?

Response:

The New London Expansion and Weaver Hill Rd projects that have spending forecasted to begin in FY 2024 per Page 57 are still in the Plan Development stage of the Central Rhode Island West Area Study. These projects do not have forecasted spend until FY24 and were only included since they are included in the Company's five-year forecast. The Company will follow the process for reviewing the Central Rhode Island West Area Study and any recommended projects from that study with Division consistent with previous Studies before formally including them in the plan.

Prepared by or under the supervision of: Caitlin Broderick

R-III-10

Request:

In its FY 2021 ISR Plan Second Quarter Update, the Company estimates that $600,000 of work performed under Damage/Failure will be reclassified to Asset Replacement. Please provide additional information on the screening criteria and process utilized by the Company to determine appropriate classification of Damage/Failure blanket work.

Response:

The work under this item relates to work charged to blanket projects for Damage/Failure and Asset Condition categories. Blanket projects are used for high volume, low-dollar work. Below describes the criteria and processes used for classification.

The Company performed a review during FY 2020 which resulted in revised definitions of Damage/Failure and Asset Replacement work such that work related to failed assets would be treated as Non-Discretionary costs and other work would be treated as Discretionary.

- Under the revised definition, work can only be classified as Non-Discretionary, when the replacement of equipment results from equipment failure. Failure work is performed when equipment fails and has created an outage or contingency condition, or the asset condition aligns with Type 1 assessment per the I&M program. This work restores the electric system to its original configuration and capability following the equipment failure and now excludes risk of imminent failure. This is Non-Discretionary work.

- The Company did not make any changes to work done related to property damage that is billable to third parties, so all such work is still classified as Non-Discretionary.

- Replacement of equipment to reduce the risk and consequences of failures and to maintain the overall reliability of the system is classified as Discretionary. This work replaces equipment that has had deterioration due to age or condition.

In May 2020 the Company began implementing the new definitions and developed a new form that includes a new box for differentiating work between Failure and Asset Replacement. To create more visibility to Asset Replacement blanket work, a separate work request must be used for each event.

To monitor adoption of the new process, an internal working team was established and has been meeting monthly to review each month's activity. The internal working team includes representatives from Field Operations, Engineering Design, Distribution Planning & Asset

R-III-10, page 2

Management, Resource Planning, Resource Coordination, Inspection & Maintenance, Work Support and Electric Planning and Strategy.

The review process for Non-Discretionary work includes work performed under Individual Work Requests and Monthly Confirming Work Requests and varies due the nature of the information available for both. Through September 2020 we have reviewed spending in the following manner for $5.4 million in the Non-Discretionary category.

- Individual Work Request information available in the system includes a brief description of the work performed and represents approximately $2.5 million of the spending through September. The descriptions are reviewed and when the description is not clearly indicating a failed asset, all work requests with costs over $10,000 are reviewed further. To date, there have not been any adjustments recommended to transfer costs to Discretionary after the review is complete.

- We had a lag beyond May 2020 in implementing the new process for Monthly Confirming Work Requests. Descriptions of the work performed are not available in the system for Monthly Conforming Work Requests, so we determined the only way to review that work is to perform a manual review of each form to see if the Asset Replacement Box is used. The review of those forms through the first half of FY 2021, noted approximately 21% of the Monthly Confirming Work Request forms had the Asset Replacement box checked but were still being classified as Failed in the Non-Discretionary category. The $600,000 estimate was calculated by multiplying the 21% times the spending for April 2020 through September 2020 of $2.9 million.

Adoption of the new process continues to improve, and the working team continues to review adoption of the processes to support this new method.

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

R-III-11

Request:

In its FY 2021 ISR Plan Second Quarter Update, the Company forecasts a $4.4 million underspend for the Aquidneck project as a result of COVID-19 work restrictions and that construction will shift into FY22. Does the proposed budget of $6 million for Aquidneck related projects in FY22 reflect the shift?

Response:

The FY 2022 proposed budget reflects the shift in construction schedule.

R-III-12

Request:

Compare and contrast the proposed work under the Meter Programs and Meters-Distribution categories.

Response:

To provide clarity and transparency in the Company's capital plan, when grouping funding projects related to meters, the Company separates the on-going business of installing meters for new connection or scheduled replacements from programs with defined goals and time periods.

Project #	**Project Description**	**Purpose of Project**	**FY 2022 Capital $**
CN04904	Narragansett Meter Purchases	Recording the purchase of meters	$1.975
COS0004	Ocean St – Dist – Meter Blanket	Recording the field work associated with meter changes and installations	$0.800
C083649	RI Landline Meter Replacement	Purchase and replacement of 386 analog devices that will leverage 4G wireless communication technology starting in FY21. Approximately a 3 year program.	$0.400
C085793	RI Meter Reprogramming	Meter reprogramming maintenance required for 12,000 demand meters. Requires the uploading of a new billing calendar into each meter which, if not completed by April 2022, could lead to the untimely and inaccurate billing of customers.	$0.200

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

---

R-III-13

Request:

In its FY 2021 ISR Plan Second Quarter Update, the Company forecasts that Meter Purchases and Installations will be underbudget by $800,000 from decreased activity due to COVID work rules. Provide additional details on how the COVID work rules impact meter installations. Has the reduction in meter installations impacted reliability? Does the Company expect modified work rules to extend into FY22 and if so, how will the ISR Plan budget be impacted?

Response:

In the beginning of FY21, the Company paused non-essential related services such as some meter change work that would require access to customers homes or businesses and customer facing interaction. Also, the COVID pandemic and its resurgence has created a higher volume of quarantined employees which has impacted Customer Meter Services (CMS) availability to perform field activities. Meter installations ensure customers receive accurate bills and do not directly impact reliability. As of December, CMS has resumed their normal meter change work load and will continue to deliver customer meter services changes in compliance with state regulations governing meter accuracy and measurement of electric usage for customer bills. Though CMS has resumed their normal meter change work load its possible that a refreshed round of work restrictions could be imposed in the future. This could impact the FY22 forecasted budget for the Installation program.

Meters are purchased annually to support CMS meter change work plan. The decreased field activity over the first two quarters of FY21 has led to more meter inventory at the Company's meter lab than expected when the FY21 budget was set. As a result, the meter lab scaled back meter orders over the first two quarters of FY21 to align with CMS field activity. As of December, CMS has resumed their normal meter change work load and the meter lab anticipates an uptick in orders to support field work over the remainder of FY21. If any work restrictions are imposed on CMS in the future, they could impact the FY22 forecasted budget for the Meter Purchase program.

Lastly, the Landline meter replacement project is forecasted to be underbudget due to the availability of CMS resources to perform the replacement work this FY21. Higher priority meter remediation work has impacted the availability of CMS manpower to begin the Landline meter replacement work this FY21.

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