nationalgrid

Raquel J. Webster
Senior Counsel

January 16, 2018

BY HAND DELIVERY AND ELECTRONIC MAIL

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

RE: Docket 4783 - Proposed FY 2019 Electric Infrastructure, Safety, Reliability Plan
<u>Responses to Division Data Requests – Set 1</u>

Dear Ms. Massaro:

On behalf of National Grid,[1] I have enclosed ten (10) copies of the Company's responses to the first set of data requests issued by the Rhode Island Division Public Utilities and Carriers in the above-referenced docket.

Thank you for your attention to this transmittal. If you have any questions, please contact me at 781-907-2121.

Very truly yours,

Raquel J. Webster

Enclosures

cc: Docket 4783 Service List
Greg Booth, Division
Leo Wold, Esq.
Al Contente, Division

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

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Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

Joanne M. Scanlon

January 16, 2018
Date

Docket No. 4783 National Grid's Electric Infrastructure, Safety and Reliability Plan FY 2019 - Service List as of 1/8/17

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Division 1-1

Request:

Note: These questions pertain to the Central Rhode Island East and the Providence Area Studies, which were provided to the Division during the informal review process prior to the Docket filing with the PUC.

The Company's Providence Area Study references the evaluation of a non-wires alternative (NWA) required in 2030 used to resolve a capacity violation on the Clarkson Street 13F4 and 13F5 feeders. For this evaluation, provide all work papers including a detailed discussion of the violation, calculation of required MW or MWh reduction, cost estimate of the NWA, forecasted feeder loading before the NWA solution is applied, and forecasted feeder loading for a fifteen year period after the NWA solution is installed. Include a detailed comparison of the NWA to the preferred solution.

Response:

Attachment DIV-1-1 includes the work papers used to evaluate the 2030 contingency capacity issue predicted on the 13F4 and 13F5 feeders in the Providence Area Study. Since this was a contingency capacity analysis, forecasted feeder loading for a fifteen-year period before and after NWA solution application was not completed.

The following table, included in National Grid's the 2018 System Reliability Procurement Report, provides a comparison of the NWA to the wires solution.

Table 1: Providence Study – Preliminary Energy Storage Analysis

Station/ Circuit	Contingency Load Relief	Contingency Duration	Traditional Wires Option	Traditional Wires Option	Energy Storage	Energy Storage Cost
Clarkson Street 13F5	3.9 MVA	12 Hours	Geneva New Feeder	$2.0M	6MW/36MWh	$16.2M
Clarkson Street 13F4	2.3 MVA	12 Hours	See above	See above	3MW/15MWh	$9.0M
Total				**$2.0M**		**$25.2M**

As stated in the study report, no alternative is considered 'preferred' at this time. Instead, National Grid has allowed time for reevaluation of this issue in the event that the cost for a non-wires alternatives is reduced.

Prepared by or under the supervision of: Ryan Constable

Appendix: Evaluation of Energy Storage Solution

Energy storage was evaluated as a potential solution for the loss of the 13F4 or 13F5 feeders, specifically for the loss of the getaway cable for an assumed duration of 12 hours.

Assumptions

To evaluate an energy storage solution, 2015 peak-day load curves on the two feeders were extended to an estimated 2030 load, peaking at 11.8 and 9.6MVA for the 13F4 and 13F5, respectively. It was assumed that load could be picked up from other feeders in the case of an outage, specifically 9.5MVA of load on 13F4 and 5.6MVA of load on 13F5. This would leave a peak unmet load of 2.3 and 3.9MVA respectively. These load curves and switching assumptions were used to derive battery specifications that would avoid unserved load for approximately 12 hours in the case of the loss of getaway cables for 13F4 or 13F5.

Resulting storage systems

The analysis identified a solution in the form of two separate battery storage systems, one at Geneva to serve 13F4 and one at Marieville to serve 13F5. The performance of these systems is shown in Figures 1 and 2, assuming a 3MW/15MWh system at Geneva, and a 6MW/36MWh system at Marieville.

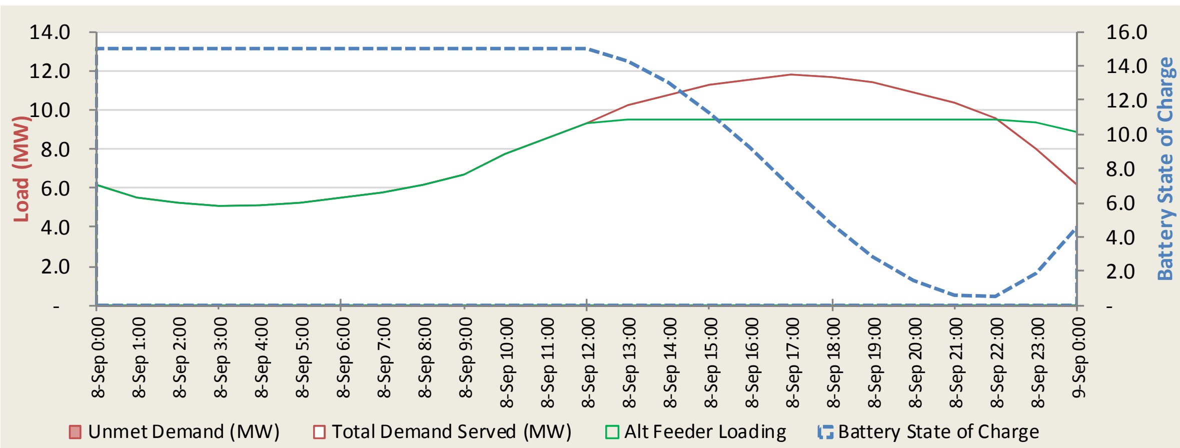

Figure 1: Feeder 13F4, Unmet Demand and State of Charge with 3MW/15MWh battery, 2030 peak day load

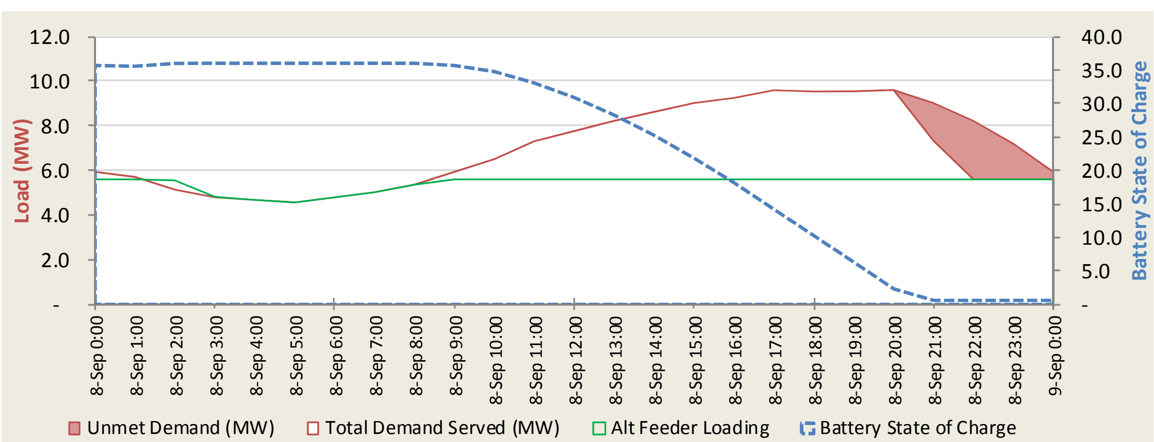

Figure 2: Feeder 13F5, Unmet Demand and State of Charge with 6MW/36MWh battery, 2030 peak day load

As the figures show, the proposed 6MW/36MWh system for 13F5 does not avoid lost load altogether. Rather, both suggested systems achieve approximately 12 hours of relief during peak hours to allow time for getaway cable repair. The main difference between the graphs arises from the severity of the conditions on feeder 13F5, where load requirements even under proposed switching actions would be significantly higher than load requirements on feeder 13F4. In both cases, achieving this level of relief would require that the batteries be held in full state of charge (SOC) during peak months, and at a relatively high SOC during shoulder periods.

Estimated costs and revenues

The cost of the two battery systems were then estimated using a figure of $600,000/MWh for the smaller Geneva system, and $450,000/MWh for the larger Marieville system. In addition, the O&M expenses were estimated at $5,000/MWh/year for the two systems. Both the capital cost and O&M estimates were derived from current industry pricing, as gathered by the Group Technology team at National Grid.

Batteries are unique in that they can also generate revenue from wholesale market activities during hours when not held in full state of charge. While it is unclear whether National Grid operating companies can directly participate in – and monetize -- such activities, revenues can be approximately estimated. ISO-NE frequency regulation revenues were estimated assuming 80% availability around the year, and $20/MWh clearing prices. The resulting revenues were $400,000/yr for the Geneva 13F4 system, and $840,000/yr for the Marieville 13F5 system. Neither system assumed revenues from ISO-NE forward capacity markets, since responding to an ISO-NE capacity call would conflict with holding the batteries in full SOC.

Feeder	Battery Location	Power rating (MW)	Duration (hours)	Energy rating (MWh)	Assumed cost ($/MWh installed)	Est. capital cost	Estimated O&M costs	Estimated Annual Revenues (ISO-NE markets)
13F4	Geneva	3	5	15	$600,000	$9.0M	$75k/yr	$400K/yr
13F5	Marieville	6	6	36	$450,000	$16.2M	$180k/yr	$840K/yr
						$25.2M	**$255/yr**	**$1.3M/yr**

The expected life for these systems would be approximately 12 years, with regular augmentation of battery capacity beginning in year 5, to mitigate the effects of degradation that occurs both through use (cycle fade) and time (calendar fade). These augmentation costs are included in the O&M estimates.

Summary

In sum, the estimated capital cost of the energy storage solution is estimated at $25.2M dollars. O&M costs would be approximately $255K per year, and revenues would be approximately $1.3M per year. Assuming full monetization of wholesale market activities (frequency regulation), net annual cash flow would be positive – approximately $1M per year. If full monetization of these wholesale market activities were not available, net annual cash flow would be negative, in the form of ~$255K per year in O&M costs.

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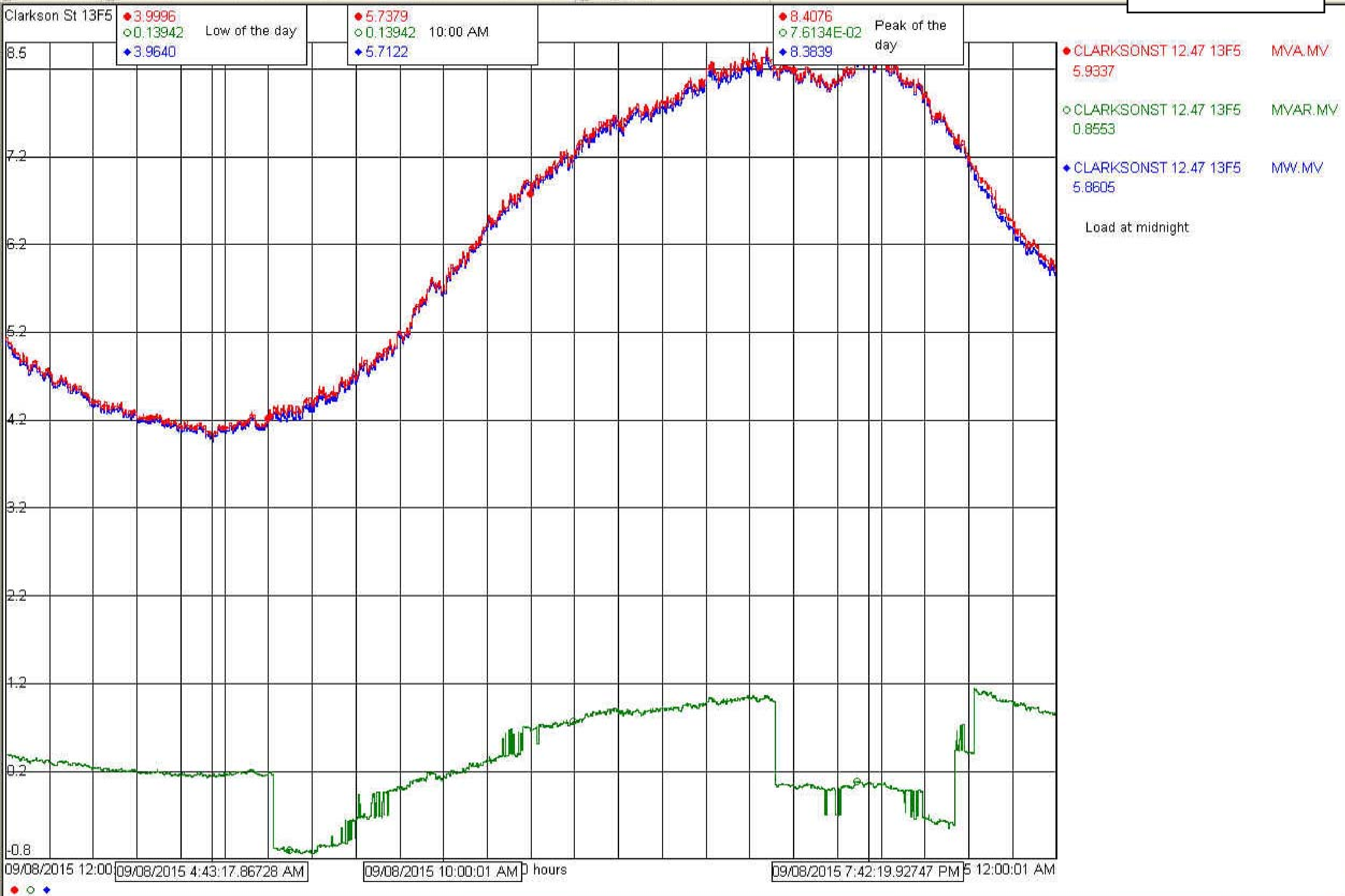

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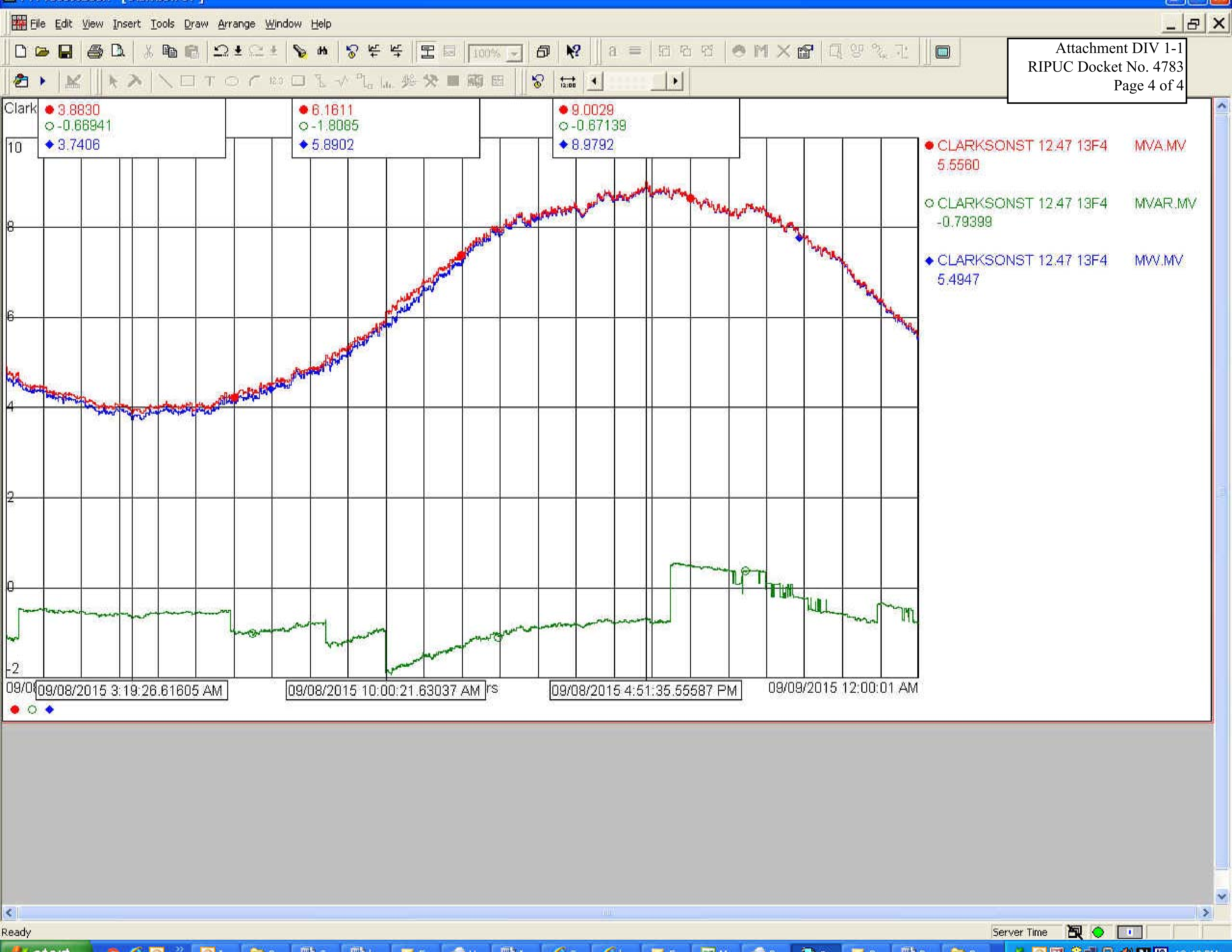
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Division 1-2

Request:

The Company's Central Rhode Island Study Table 4.1.1.1 indicates that the Pontiac Feeder 27F4 is loaded above 100% of its summer normal capacity rating in 2018. Please provide the recommended plan, installation timeline, and cost to alleviate the feeder capacity violation. In addition, for illustrative purposes, please provide an evaluation of non-wires alternatives that would alleviate the feeder capacity violation including a description of the technology or load reduction strategy, anticipated timeline for implementation, and installation cost. For both the recommended plan and non-wires alternatives, provide the feeder loading before and after a solution is applied, through 2030.

Response:

The Central Rhode Island Study, which began in 2016, used the latest feeder load forecast at that time as the basis for the study. Considering the long-term nature of the planning study, it is common for the long-term planner to proceed with minor near term issues that can be easily addressed through day-to-day or month- to-month system management. In this case, the study planner worked with other area planners and field engineers to complete simple switching transferring a portion of the 27F4 feeder to the 27F5 feeder prior to the 2017 summer peak period. This switching effort costs approximately a few thousand dollars for truck and labor time. As a result, a non-wires alternative analysis is not necessary. The study planner did not adjust the study basis because of the minor nature of the issue as compared to other area concerns. A review of the study recommendations shows that no scope was added for normal loading issues. National Grid acknowledges that studies need clearer documentation of such details for external review.

If the planner had adjusted the study basis, the 27F4 and 27F5 feeders would have had a 2018 predicted loading of approximately 90% growing to approximately 95% by the end of the study period.

Prepared by or under the supervision of: Ryan Constable

Division 1-3

Request:

Note: These questions pertain to the Central Rhode Island East and the Providence Area Studies, which were provided to the Division during the informal review process prior to the Docket filing with the PUC.

For the Company's NWA analysis, provide a list of all technologies or projects considered as viable alternatives to traditional wires solutions. Include a description, implementation cost (for applicable unit such as per kW or per kWH), annual O&M cost, and life of asset. Identify which NWAs provide firm capacity or energy reduction. For each technology, provide an implementation cost estimate for the current year and a ten year forecast, and include any supporting documentation or references used to determine costs such as pilot programs implemented by the Company, IEEE, NREL, etc.

Response:

The alternative analysis documented in the Central Rhode Island East and the Providence Area Studies noted that the primary issue driver was asset condition. Therefore, neither NWA technologies nor projects were considered as viable alternatives to the traditional wires solutions addressing the asset condition issues.

However, the Providence Area Study considered a battery storage NWA as a possible solution for a far forecasted contingency capacity issue. Since the contingency capacity issue requires a dispatchable energy resource at any time and day, energy storage seemed a reasonable technology. Attachment DIV 1-1 contains the cost per kWH, annual O&M cost, and life of the asset. The Company used current industry pricing at the time of the analysis.

Generally, National Grid considers the Non-wires alternatives (NWA) listed below to advance the goals of the System Reliability Procurement (SRP) Plan and optimize grid performance. Technologies and strategies considered as viable alternatives can be classified as:

- Customer-Side NWA, which may include but are not limited to:
    - Least Cost Procurement energy efficiency baseline services
    - Peak demand and geographically-focused supplemental energy efficiency strategies
    - Distributed generation generally, including combined heat and power and renewable energy resources
    - Demand response
    - Direct load control
    - Energy storage
    - Electric vehicles
    - Controllable or dispatchable electric heat or cooling
    - Alternative metering and tariff options, including time-varying rates

- Grid-Side NWA, which may include but are not limited to:
    - Energy storage
    - Voltage management
    - Communications systems
    - Grid-optimization technologies
    - Generation to provide or in support of any or all grid-side NWA options, consistent with Rhode Island General Law.

The estimates of costs, lifetimes, or load reductions for these technologies are variable and case-specific.