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April 6, 2021

Mark D. Marini, Secretary
Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

Re: DG Interconnection – D.P.U. 20-75

Dear Secretary Marini:

On behalf of NSTAR Electric Company d/b/a Eversource Energy ("Eversource"), enclosed are Eversource's responses to the questions issued by the Department of Public Utilities on March 23, 2021 addressing distributed generation interconnection cost allocation methodologies and system planning.

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

Sincerely,

John K. Habib

John K. Habib

Enclosures

cc: Katie Zilgme, Hearing Officer

Information Request EDC-1

Request:

Identify whether a group or groups of interconnecting customers in the Company's service territory are likely to be presented with interconnection costs in the next 1-1.5 years that are significantly higher than have been historically presented. Include in the Company's response:

a. Detailed information on the group(s), including geographical region, number of distributed generation ("DG") facilities, capacity in megawatt ("MW"), and estimated timing for conclusion of associated distribution and transmission impact studies;

b. High-level planning estimates of expected interconnection costs for the group(s). Provide data in dollar-amount-per-kilowatt ("$/kW") and by group, where possible;

c. High-level planning estimates of timeline for construction of anticipated EPS upgrades that will be required due to interconnection impacts of the group(s). Provide data by group, where possible;

d. High-level estimates of how much DG capacity will be enabled by the anticipated EPS upgrades for the group(s);and

e. Whether additional DG capacity could be enabled in coordination with anticipated EPS upgrades for the group(s), and if so, high-level estimates of costs and timelines for any additional EPS upgrades required to enable additional DG capacity.

f. Will the anticipated EPS upgrades for the group(s) provide benefits to ratepayers and the Commonwealth beyond enabling renewable energy to interconnect to the EPS?

Response:

(a) Figure 1 below shows a map of the Eversource MA service territory annotated with the geographical locations of each distribution group study area. Table 1 shows a breakdown of the group study areas by number of utility scale (not including behind the meter installations) distributed generation ("DG") facilities, capacity in megawatt ("MW"), and anticipated completion date of distribution and transmission (if applicable) impact studies. It should be noted that the overwhelming majority of group study DG (over 95%) is in Southeastern MA (SEMA) coincide with major load centers, which has resulted in saturation, technical impacts and significant upgrades at many of these stations.

Figure 1: Group Study Geographical Region

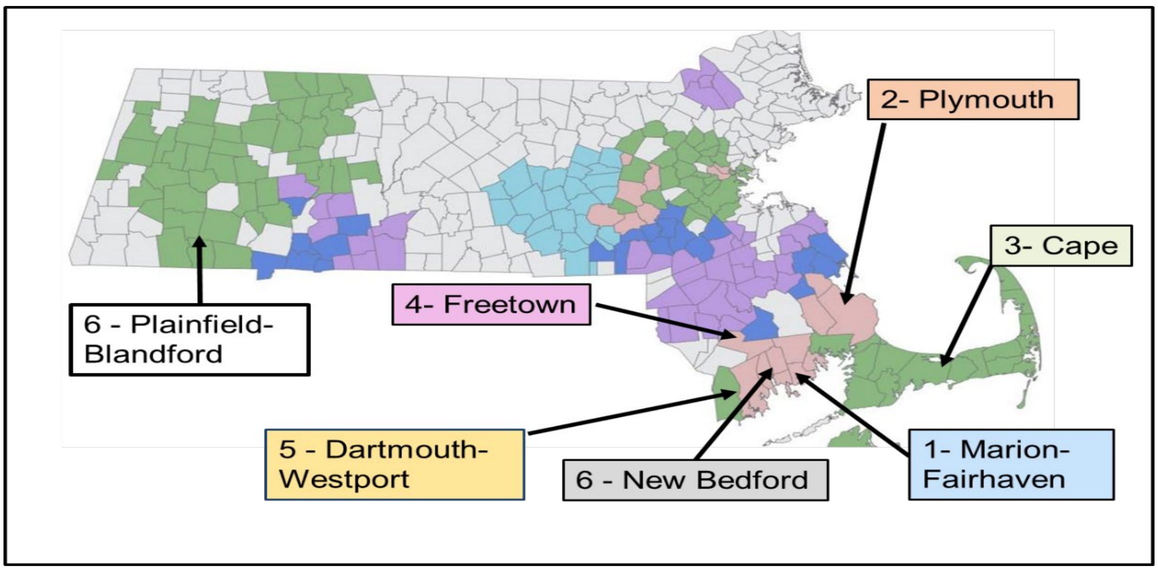

Table 1. Current Group Distribution Studies

Group	Eversource Operating Area	Number of DG Facilities	Capacity in MW	Estimated Timing of Impact Studies (Distribution)
1 - Marion-Fairhaven	SEMA	17	49	October 2021
2 - Plymouth	SEMA	40	126	October 2021
3 - Cape	SEMA	59	74	October 2021
4 - Freetown	SEMA	6	22	August 2021
5 - Dartmouth-Westport	SEMA	6	16	August 2021
6 - New Bedford	SEMA	14	48	August 2021
7 – Plainfield-Blandford	Western MA	3	13	June 2021
TOTAL		145	348	

Estimated Timing for Group ASO Transmission studies: For the Plainfield-Blandford study, two projects have recently completed their ASO studies. The remaining project was sent to ISO-NE on March 19 for review for study level determination.

For the remaining groups, one project (in the Cape group) has completed its transmission ASO study and 86 projects are currently in a Level 3 ASO study which is expected to be completed by the second quarter of 2021. Following that study, Eversource will submit 22 participants to ISO-NE for study level determination. These 22 participants include members of all the Southeast MA groups except Freetown.

For planning purposes, ASO studies typically take about 9 months to complete from commencement.

(b)

Accommodation of Projects Currently in Distribution Group Studies

The expected interconnection costs, including high-level dollar-per-kilowatt, are driven by the technical impacts and planning criteria violations identified at individual substations within the group once the group study DG facilities are added to the existing substations. The table below shows the loadings at the substations (in percent of nameplate) due to the group study DG facilities before the station upgrades needed to interconnect just the DG facilities with no system violations (the "Group Study System Upgrades"), and loadings after completion of those Group Study Upgrades. Based on Eversource System Planning criteria, system modifications are developed when substation limits are expected to exceed 90% of emergency conditions.

Consistent with expectations, the stations in major SEMA load centers that are experiencing high DG growth are most heavily loaded before the Group Study System Upgrades are applied. The DG growth rate in the area suggests that a more comprehensive solution is needed over the planning horizon to integrate as much DG as possible and to allow them to fully participate in supporting the Commonwealth's climate policy goals.

Table 2. Substation loadings due to the group study DG before and after Groups Study Station Upgrades

Dist. Station Group	Stations	% Loaded before Group Study System Upgrade (% of nameplate)	% loaded after Group Study System Upgrade (% of Nameplate)
1	Arsene	122%	55%
1	Crystal Spring	124%	79%
1	Rochester	251%	51%
1	Wing Lane	201%	100%
2	**Tremont**	264%	88%
2	**Wareham**	214%	86%
2	**West Pond**	144%	96%
3	**Cape Group**	No Substation Upgrades	No substation Upgrades
4	**Bell Rock/Assonet**	178%	43%
5	Fisher Road	200%	65%
6	**Industrial Park**	200%	67%
7	Blandford	239%	95%

As discussed above and illustrated in Table 2, a certain level of substation upgrades is required to accommodate the group study DG. In addition, in most cases transmission upgrades as well as distribution line upgrades are required to interconnect the DG facilities. The PowerPoint slides in Attachment Eversource-1(a) show the schematic configuration of each station that requires upgrades. The station changes needed to interconnect the group study DG (and accommodate projected DG beyond the group study) are highlighted. The attachment does not show the distribution line upgrades, but those costs are included in the table and discussions below.

Table 3 below shows the interconnection cost ($/kW) for each group encompassing transmission upgrades from the ASO study, transmission station upgrades (including line extensions), distribution station upgrades and distribution line upgrades for integrating the group study DG (Group Study station upgrades). The table does not include the full cost to interconnect individual DG facilities such as line extensions, POI reclosers, meters, etc.

Table 3. Total High-Level Estimated Transmission and Distribution Interconnection Costs ($/kW) by Group for Group Study System Upgrades, Allocated Only to Current Group Study DER Customers

Group	$/KW All costs allocated only to DER customers in the current Group Studies
1 - Marion-Fairhaven	$3,270
2 - Plymouth	$1,977
3 - Cape	$3,488
4 - Freetown	$3,680
5 - Dartmouth-Westport	$3,913
6 - New Bedford	$2,880
7 – Plainfield-Blandford	$3,279

Accommodation of Projected DER Beyond Projects in Current Group Studies

It is important to reiterate that the estimated costs above are to interconnect the existing projects in Eversource's current group studies. However, The Group Study System Upgrade costs noted above are inadequate when considering the DG queue beyond the Group Study as well as the near-term DG growth based on historical interconnections. By contrast, Table 4 shows the loadings at the substations (in percent of nameplate) due the total projected DG (sum of online DG, approved DG, group study DG and forecasted DG) before the upgrades needed to interconnect all projected DG facilities with no system violations (the "Comprehensive Station Upgrades"), and loadings after completion of those Comprehensive System Upgrades.

As expected, in most cases, the total projected DG, loads the stations up to or over their nameplate capacity (considering N-1 support constraints) before comprehensive upgrades are applied. After the comprehensive upgrades, the loadings at the most impacted stations are reduced to at or below nameplate. It should be noted that in some cases (Arsene, Crystal Springs, Rochester, West Pond, Fisher Road and Industrial Park), the Group Study system Upgrades (from Table 2) were sufficient to accommodate the full DG projection without loading the stations beyond nameplate capacity. Therefore, there are no incremental upgrades in the comprehensive solution, and the loading before and after is exactly the same. Even so, for these cases there is still some (limited) capacity to accommodate more DG beyond the projection. In two other cases (Bell Rock, Tremont), the incremental comprehensive upgrades create significant headroom for additional DG growth beyond the projection. For the remaining three cases (Wing Lane, Wareham, Blandford) the comprehensive upgrades reduce the station loading significantly, to within nameplate, but do not create much additional headroom for DG growth beyond the projection. Without comprehensive upgrades that account for small and large DG growth, future DG connection in these areas could be significantly constrained.

Table 4. Substation loadings due to the total projected DG before and after Comprehensive Station Upgrades

Dist. Station Group	Stations	% Loaded before Comprehensive Upgrade (% of nameplate)	% Loaded after Comprehensive Upgrade (% of Nameplate)
1	Arsene	78%	78%
1	Crystal Spring	94%	94%
1	Rochester	73%	73%
1	Wing Lane	**156%**	100%
2	Tremont	**127%**	64%
2	Wareham	**113%**	94%
2	West Pond	**155%**	78%
3	Cape	No Substation upgrades	No Substation Upgrades
4	Bell Rock/Assonet	75%	37%
5	Fisher Road	91%	91%
6	Industrial Park	95%	95%
7	Blandford	**176%**	88%

As discussed above and illustrated in Table 4, comprehensive substation upgrades are required to accommodate the projected DG beyond the current queue. In addition, in most cases transmission upgrades as well as distribution line upgrades are required to interconnect the DG facilities. The PowerPoint slides in Attachment Eversource-1(a) show the schematic configuration of each station that requires upgrades. The station changes needed to interconnect the total projected DG (including the group study DG) are highlighted. The attachment does not show the distribution line upgrades, but those costs are included in the table and discussions below.

It is important to note that the incremental cost between the Group Study System Upgrades and the Comprehensive System Upgrades (as shown in the spreadsheet in Attachment

Eversource-1(b)) is relatively small. The range of costs associated with the Comprehensive System Upgrades versus the current Group Study Upgrade costs at these stations are approximately $0 to $5M. This is because the Group Study System Upgrades already includes the fundamental infrastructure requirements for the Comprehensive System Upgrades. This planning approach allows for infrastructure modifications to quickly add capacity for additional growth, which is prudent, given the forecasted DER growth in these areas.

Table 5 below shows the full interconnection cost ($/kW) for each group encompassing transmission upgrades from the Affected System Operator (ASO) study, transmission station upgrades (including line extensions), distribution station upgrades and distribution line upgrades pursuant to Eversource proposed Cost Allocation methodology. While the table includes very high-level indicative distribution feeder costs to interconnect current DG facilities in the Group Study, it does not include costs to interconnect individual DG facilities such as line extensions, point of interconnection (POI) reclosers, meters, etc. for future projected DG necessitating the Comprehensive Station Upgrades. Therefore, the indicative costs below proposed to be allocated to DER customers maybe higher as additional design and engineering is completed to understand specific distribution feeders and associated routes to interconnect all projected DG.

Table 5: Total High-Level Estimated Transmission and Distribution Interconnection Costs ($/kW) by Group for Comprehensive System Upgrades by Group, Allocated to Group Study DER Customers and Future Projected DG

Group	$/KW All costs allocated to current and future projected DER customers in the respective Group Study Areas
1 - Marion-Fairhaven	$554
2 - Plymouth	$340
3 - Cape	$486
4 - Freetown	$367
5 - Dartmouth-Westport	$437
6 - New Bedford	$1,031
7 – Plainfield/Blandford	$504

(c) The chart in Table 6 below shows an estimate of the high-level construction schedule for group study system upgrades. The colored or highlighted bars indicate the approximate timeframe to engineer and construct the transmission and distribution upgrades for each group. These estimates represent high-level projections prior to the completion of any level of engineering and should in no way be considered a binding schedule for required system modifications. The high-level timelines are based on historical estimates for similar work and do not reflect any site-specific engineering design, environmental permitting requirements, physical constraints and rights of way considerations, all of which might significantly impact eventual schedule. Eversource is currently investigating options to accelerate these schedules looking at critical path milestones including but not limited to procurement of major equipment such as Bulk Transformers.

Table 6. High level timeline for station upgrades-shaded areas in each Group represents the preliminary construction timeline

Group	2021	2022	2023	2024	2025	2026
1 - Marion-Fairhaven						
2 - Plymouth						
3 - Cape						
4 - Freetown						
5 - Dartmouth-Westport						
6 - New Bedford						
7 – Plainfield/Blandford						

(d) All DERs currently under Group Study, or 348 MW of DG capacity as shown in Table 1,would be enabled as a result of the proposed EPS upgrades to safely and reliably interconnect the DG. Consistent with our initial comments on the D.P.U. 20-75 straw proposal filed 12-30-2020, the capacity enabled by the anticipated EPS upgrades is part of a comprehensive group study methodology; therefore, the enabled capacity is inclusive of the Comprehensive System Upgrades proposed in Table 7 below which is a total of 1,556 MW.

(e) Table 7 below shows the additional DG capacity enabled by the Comprehensive Station

Upgrades required to interconnect the total projected DG (including online, approved, group study, queued and forecasted DG). The preliminary transmission study performed by incorporating all projected DG that would be enabled by the Distribution Station upgrades indicates Transmission upgrades ranging from $275M to $500M would be needed – and likely be identified on a firm basis from future ASO studies. At this point, Eversource has used very high level per unit assumptions to develop that estimate. The station loading as a result of these upgrades are shown in Table 4. The high-level estimates of costs for transmission and distribution upgrades are included in Attachment Eversource -1(b). Eversource proposes to include the indicative $60M of Transmission upgrades resulting from the current ASO study, $232M of Transmission station upgrades required to reliably interconnect the newer larger and additional bulk transformers as well as the indicative $275M to $500M range of future projected Transmission upgrades likely resulting from future ASO studies (as additional DG interconnects at these upgraded stations) within Eversource's Local Transmission System Plan.

Table 7. Additional DG enabled by comprehensive station upgrades for projected DG

Group	Additional DG Capacity
1 - Marion-Fairhaven	194 MW
2 – Plymouth	569 MW
3 – Cape	386 MW
4 – Freetown	123 MW
5 - Dartmouth-Westport	90 MW
6 - New Bedford	84 MW
7 – Plainfield/Blandford	110

(f) As documented in our initial comments to the D.P.U. 20-75 straw proposal filed on December 23, 2020, the anticipated EPS upgrades, in addition to enabling renewable energy to fully support the Commonwealth's climate goals, also allows the Company to preserve and maintain safe, reliable operation of the EPS for all customers with high penetration levels of potentially disruptive DG, particularly solar PV. The key to maintaining safe, reliable operation is preserving operational flexibility under all scenarios for which the system is planned and designed to accommodate. As systems become more saturated with DG, it becomes increasingly difficult for the Company to preserve reliability and operational flexibility under all scenarios. EDCs policies and programs need to keep pace and be consistent with State policy and programs to maintain send the appropriate message to MA stakeholders. The capacity released by EPS upgrades allows the company to maintain its operational standards despite the challenges presented by the DG. The examples below from actual substation areas with various levels of saturation will illustrate this point.

In addition, new distribution lines and line upgrades are likely to create opportunities to rebalance feeders, reduce exposure and transfer load, which would lead to improved reliability and voltage quality for ratepayers. On completion of detailed distribution analyses, the distribution line costs can then be further delineated between reconciling charges and capital investment fees.

Low DER Saturation Area

In areas of low DER penetration, substations and circuits can typically be analyzed independently and not as part of an interconnected, inter-dependent group. This is because, even though substations might still have N-1 dependency, the DER penetration has not reached the critical point of affecting the reliability and operational flexibility of the larger EPS. Individual and nearby substations are not saturated to the point of restricting permanent, emergency, and planned system reconfigurations. The low DER penetration scenario is illustrated in Figure 2 below. In this scenario, lines 1, 2, and 3 provide transfer capability between substations A-C, C-D, and B-D, respectively, and Line 4 provides transfer capability between Circuits 1-4 and 4-3. In this system, reliability and operational flexibility are not affected because system reconfigurations under contingent conditions do not result in adverse conditions (thermal issues, steady-state or transient voltage violations) at individual substations or adjacent substations. Moreover, each substation can be analyzed independently to determine the trigger points for upgrades required to accommodate future DER, i.e., cost causation can be easily determined when looking at individual substations within this static system.

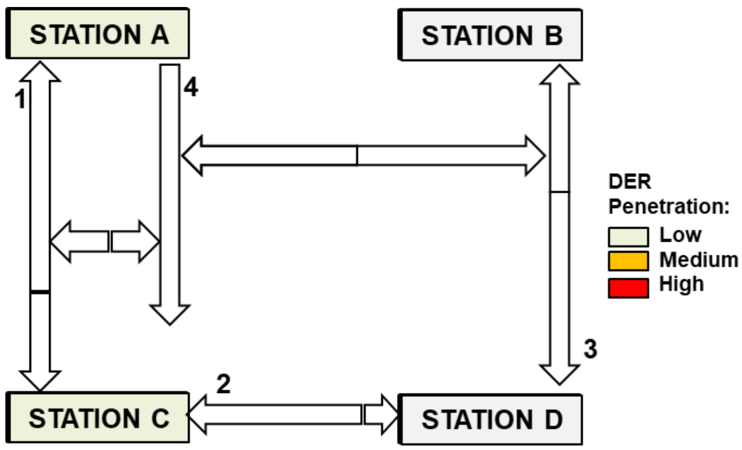

Figure 2. Low DER Penetration Scenario

<u>Medium/High DER Saturation Area</u>

This is representative of the group study areas shown Table 1. A high DER penetration scenario is depicted in Figure 3 below. In this figure both Substations B and C are expected to have high DER penetration (or saturated) which affects the system reconfiguration capability between A-C, A-B, C-D and B-D. Moreover, reconfigurations that were previously available between circuits 1-4 and 4-3 could also be limited depending on the amount and location of new DER connected to the circuits. Not only are Substations B and C saturated, but this condition may also result in saturation at Substations A and D since transfer capability that was previously available via circuits 1, 4, and 3 is now limited due to saturation at Substations B and C. This is because under scheduled or forced outage conditions, the station tie-lines that traditionally help boost station load serving capability, serve as conduits to transfer additional DERs (in excess of load) to neighboring stations.

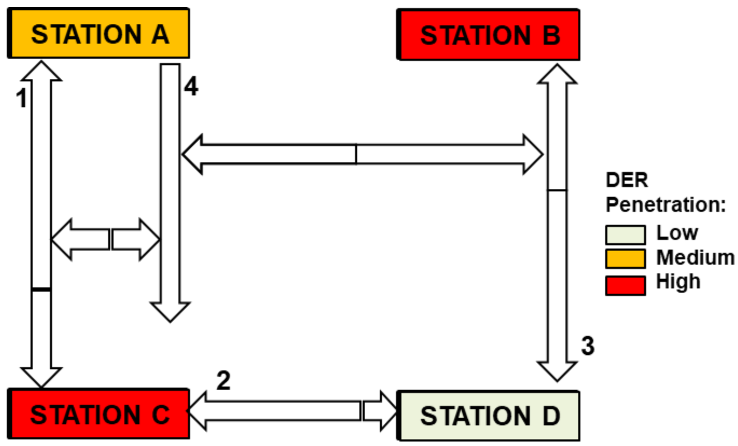

Figure 3. Medium to High DER Penetration Scenario

In areas of medium to high DER penetration, the substations must be analyzed as a Study Group to find the most cost beneficial solution that integrates new DER while maintaining the current level of reliability and operational flexibility of the EPS. In this scenario, the standard approach of analyzing individual substations used for areas of low DER penetration, has the potential of increasing cost, reducing reliability, and limiting operational flexibility. For example, even if upgrades are completed at Substation B and C to reduce the negative effects of increased DER penetration at those stations, this could still result in saturation at Substation A and D by limiting the transfer capability between A-C, D-C, and B-C, and lines 4-3. The Group Study analyzes the group as a whole to determine the most cost beneficial solution for all stations in the group, and to evaluate the need to reserve or build the capacity to maintain safe, reliable operation of the EPS.

Similarly, Figure 4 below, illustrates some of the operational challenges that can result at the distribution feeder level in areas of medium to high DER penetration. The left side picture shows the existing "as is" system under Normal conditions where 3 of the 4 substations are already at medium level DER saturation.

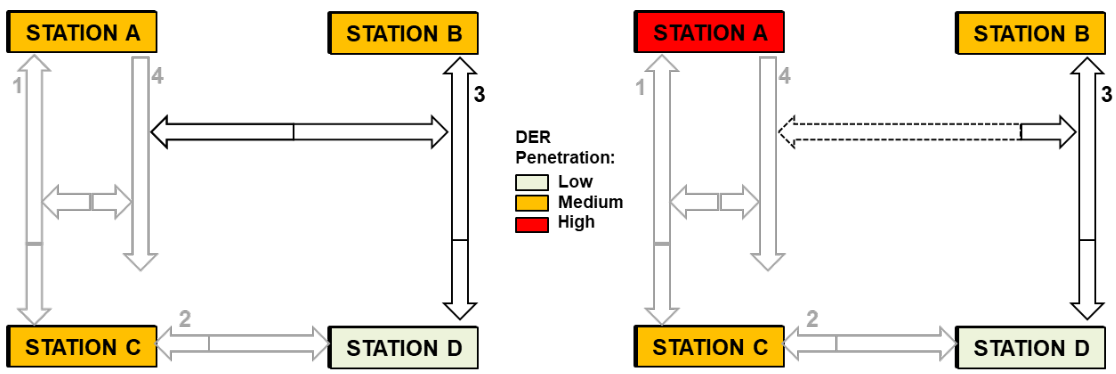

Figure 4. Operational Challenges at Distribution Feeder Level

The right side shows a potential scenario in which Substation A saturates as a result of reliability improvement work that is completed at the distribution feeder level. The work could consist of transferring a section of a circuit from Line 3 to Line 4, a common operation used to balance load or customer count between the two circuits or substations or to reduce exposure for customers on a poor performing circuit. In this scenario, depending on the ratio of DER to load connected to the section, transfer of both load and DER from Line 3 to Line 4 might not be constrained unless a significant amount of reinforcement work is completed on both Circuit 4 and Substation A. This "constrained" condition that results from having a system at high saturation levels limits the flexibility of operators during normal and emergency conditions.

Moreover, the constrained condition also limits the ability of planners and engineers to propose system design changes that will improve the performance of the EPS and enhance service to existing ratepayers. Utilities faced with significant DER growth, without the ability to address these types of conditions, could experience reliability deficiencies in the near-term when low DER saturated areas progress to medium or high saturation and left unaddressed. DERs would be forced offline for long periods to facilitate any scheduled work at these stations as well as under forced (unplanned) outage scenarios.

DPU 20-75
Group Study

Attachment EDC-1 b.

- DPU 20-75 Information Request
  - Schematic configuration of each substation that requires upgrade
  - Station Changes needed to interconnect the group study DG
  - Comprehensive Solution beyond the group study

MA DER Group Study Area

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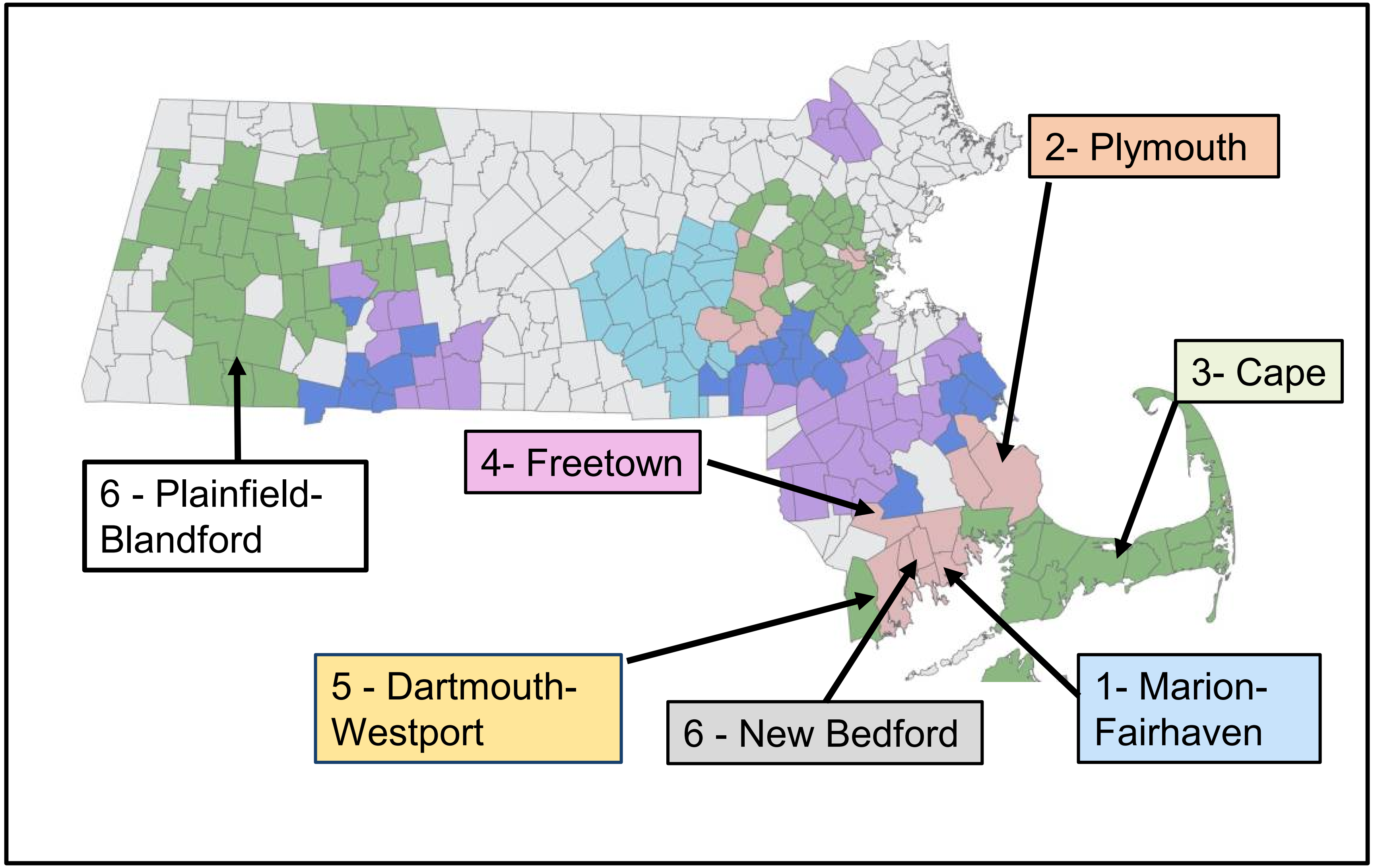
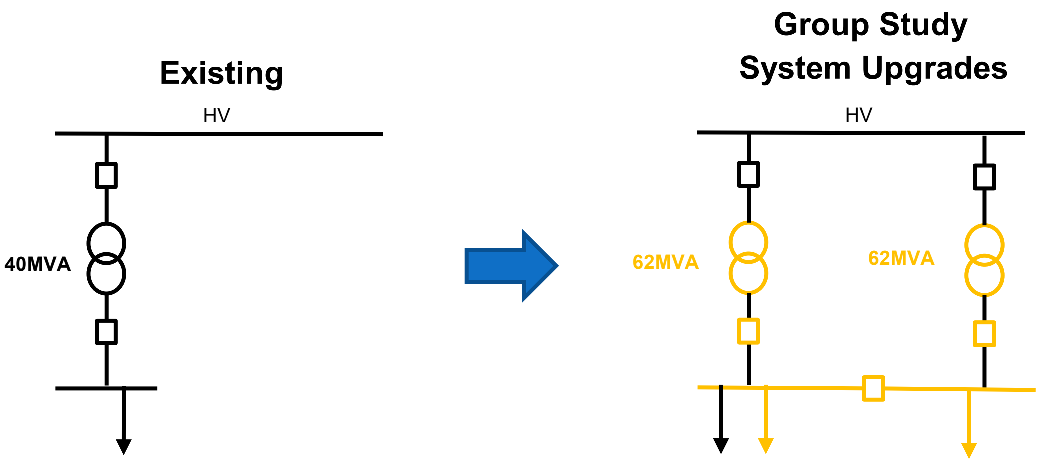


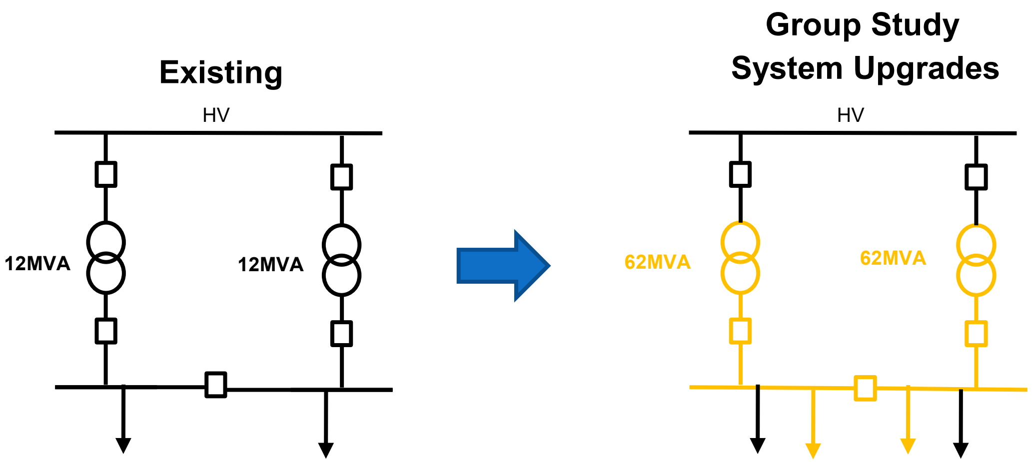
Crystal Spring (Marion-Fairhaven)



Group Study System Upgrades:

- Upgrade existing 40MVA transformers and sections of switchgear
- Add a second transformer and section of switchgear
- New feeder positions and one double bus tie breaker
- ~3 miles of Transmission Line Extension

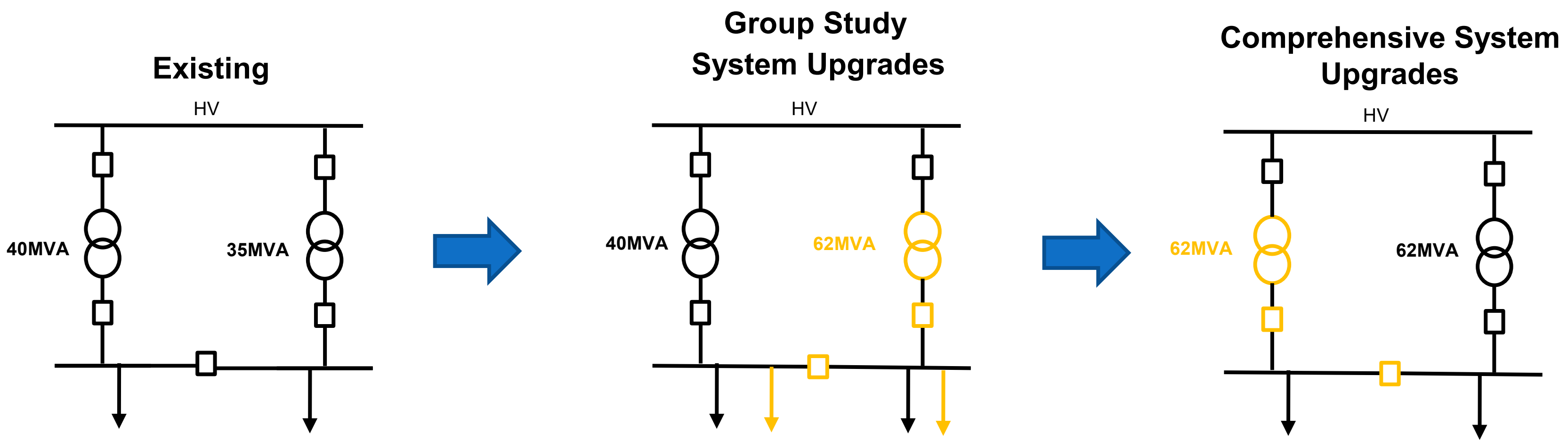
EMA Rochester Substation (Marion-Fairhaven)



Group Study System Upgrades:

- Upgrade 2 existing transformers and switchgear sections
- New feeder positions and one double bus tie breaker

EMA Wing Lane Substation (Marion-Fairhaven)



Group Study System Upgrades:

- Upgrade existing 35MVA transformers
- New feeders and one double bus tie breaker

Comprehensive System Upgrades

- Upgrade existing 40MVA transformers

EMA Tremont (Plymouth)

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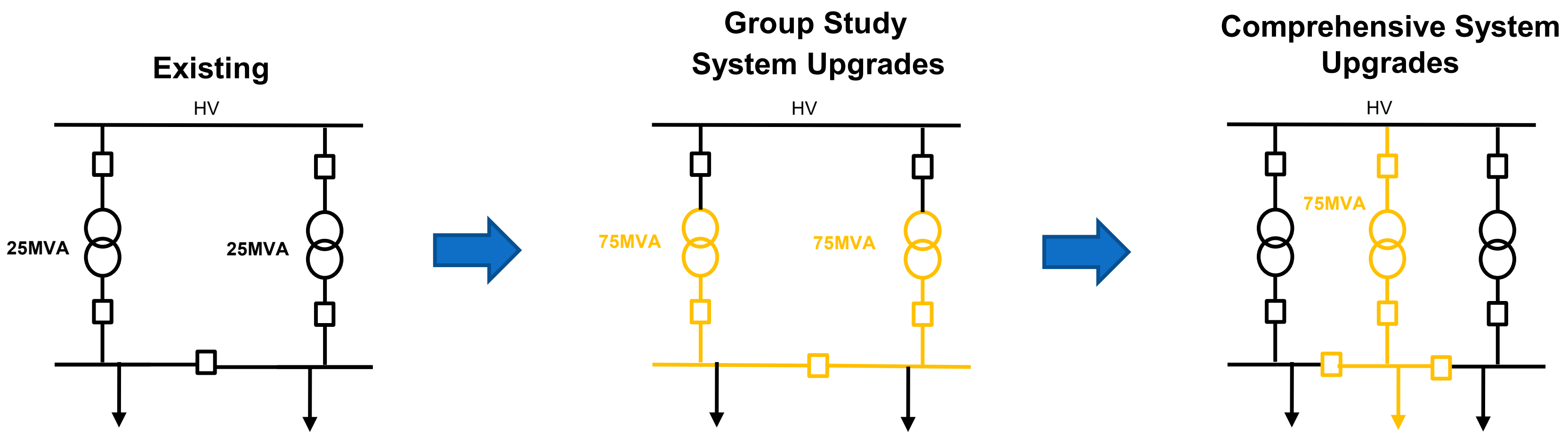


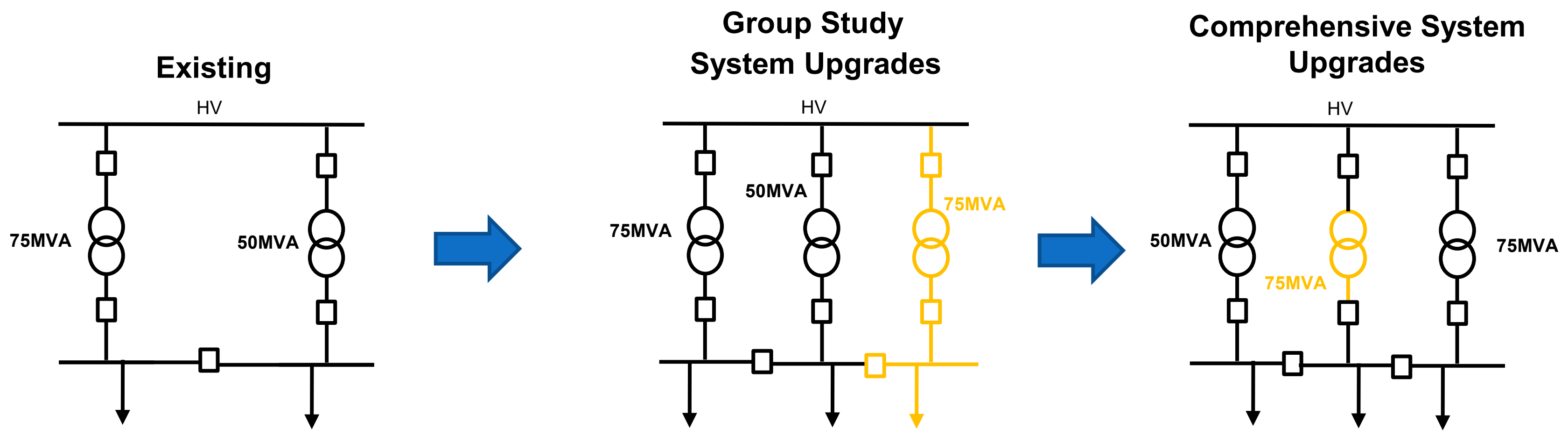
Group Study System Upgrades:

- Upgrade two existing transformers and switchgear
- One double bus tie breaker and new feeder positions

Comprehensive System Upgrades

- Add a third transformers and switchgear
- One double bus tie breaker and four feeder positions

EMA Wareham (Plymouth)



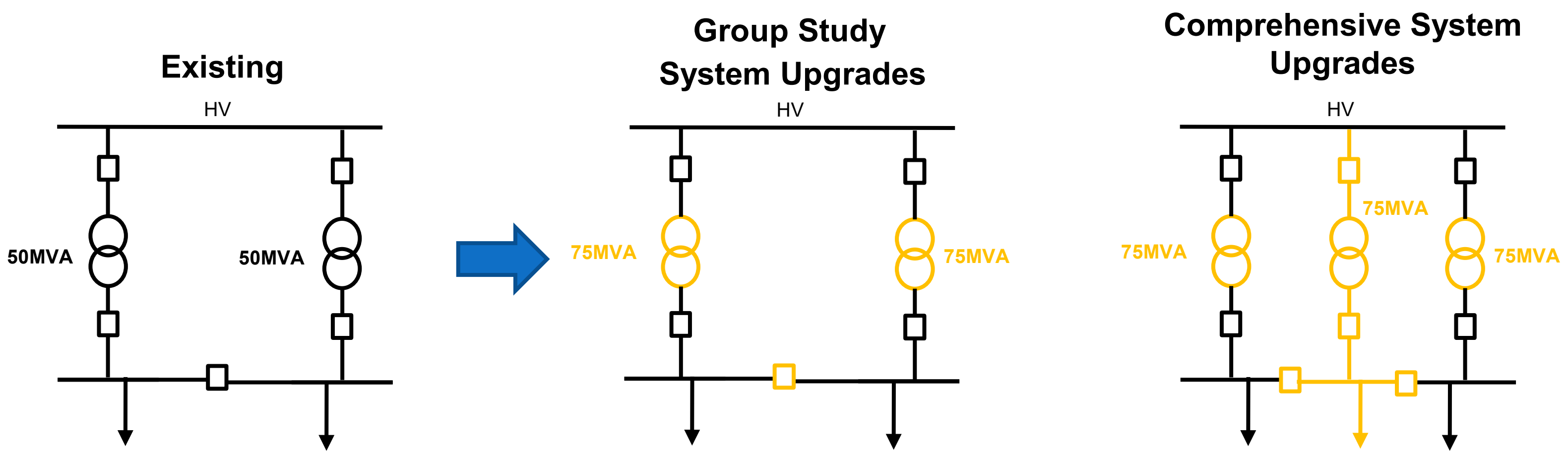
Group Study System Upgrades:

- Add third transformer and switchgear and new feeder positions
- Upgrade on 50MVA transformers and add double bus tie breaker

Comprehensive System Upgrades

- Upgrade existing 50MVA transformers

EMA West Pond (Plymouth)



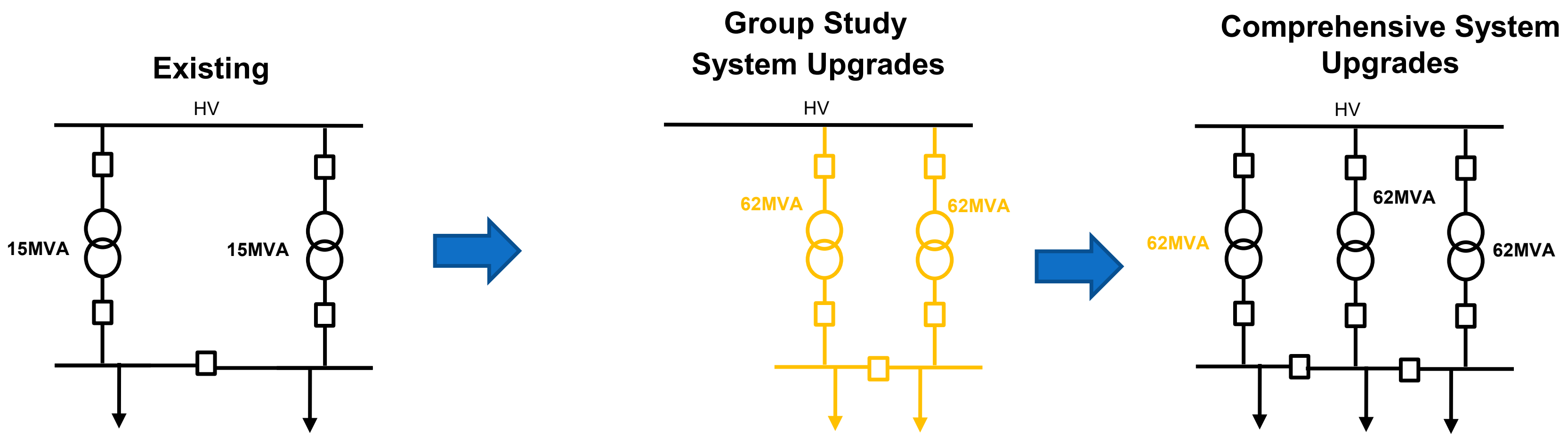
Group Study System Upgrades:

- Upgrade two existing transformers
- One double bus tie breaker and additional feeders

Comprehensive System Upgrades

- Add a third transformers and switchgear
- One double bus tie breaker and additional feeder positions

EMA Bell Rock / Assonet (Freetown)



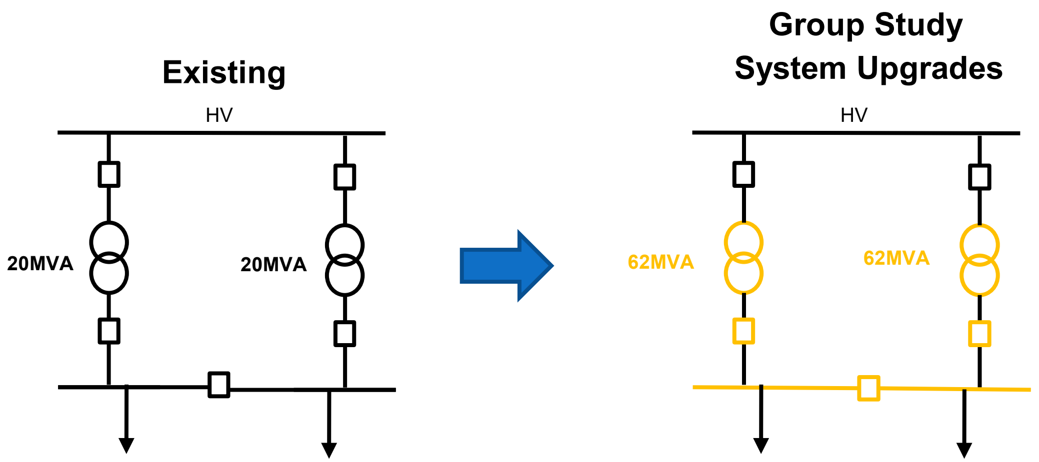
Group Study System Upgrades:

- Upgrade Substation
- Additional feeder positions and one double bus tie breaker

Comprehensive System Upgrades

- Add a third transformers
- Four feeder positions per bus and one double bus tie breaker

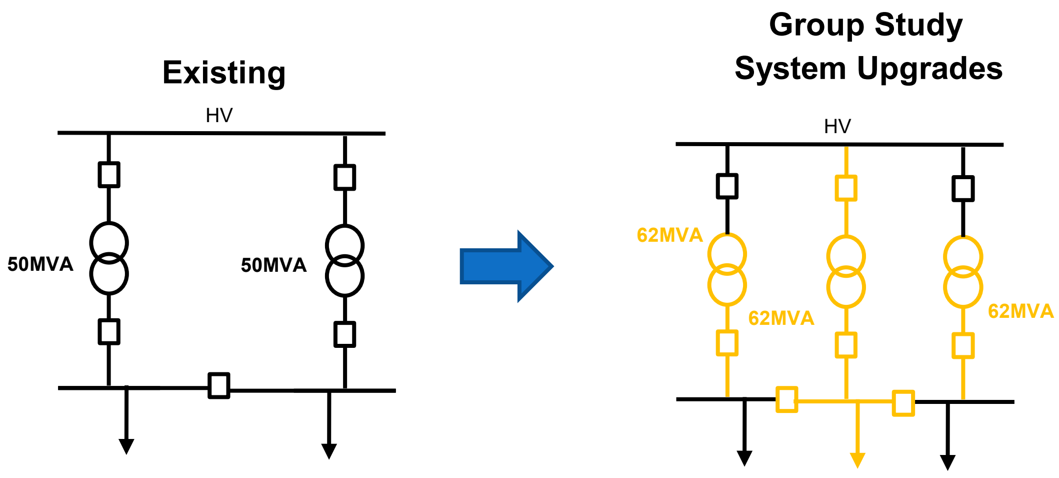
EMA Fisher Road (Dartmouth-Westport)



Group Study System Upgrades:

- Upgrade 2 existing transformers and 2 new sections of switchgear
- Additional feeder positions and one double bus tie breaker

EMA Industrial Park (New Bedford)



Group Study System Upgrades:

- Upgrade 2 existing transformers
- Additional feeder positions and one double bus tie breaker
- Add a third transformers and 1 additional section of switchgear
- Add additional feeder positions and double bus tie breaker

WMA Blandford Substation

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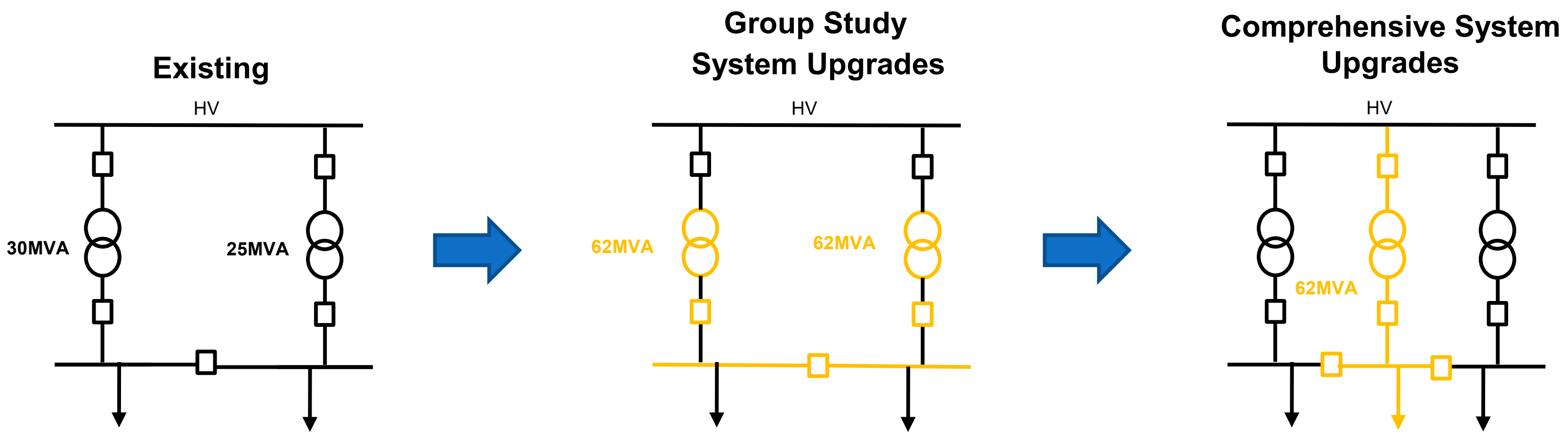

Group Study System Upgrades:

- Upgrade 2 existing transformers and 2 new sections of switchgear
- Additional feeder positions and one double bus tie breaker

Comprehensive System Upgrades

- Add a third transformers and 1 additional section of switchgear
- Add additional feeder positions and double bus tie breaker

Information Request EDC-2

Request:

If the estimates of expected interconnection costs identified in response to EDC-1 were allocated pursuant to the cost assignment and recovery provisions of the Department's straw proposal, provide high-level estimates of bill impacts for ratepayers if the costs were amortized for recovery over 10, 20, and 30 years.

Response:

Please refer to Attachment Eversource-2 for estimated bill impacts from assignment and recovery provisions included in the Department's straw proposal and subject to clarifications recommended by the Company in its prior comments. Bill impacts are based upon the annual revenue requirement for Common System Modifications and transmission system upgrades identified in Table 1 and Table 2 below which the Company anticipates will benefit customers at large. Resulting average annual bill impacts for residential customers are expected to range from 0.1% to 0.4% over a 5-year period.

Eversource notes that full operation of the assignment and recovery provisions in the straw proposal present a number of complexities that are difficult to estimate. The Company has not attempted to estimate the rate at which DER facilities beyond the current queue will interconnect and provide offsetting CIP fees. The revenue requirement for system upgrades that the Company may fund on only an interim basis are not included in the estimated bill impacts. Eversource has also included what it expects is a representative annual transmission-related revenue requirement within its estimates but reiterates its prior comments that recovery of transmission infrastructure modifications will need to be provided for differently from distribution investments and that there may be variation in the recovery mechanism across the EDCs. The Company will continue to consider methods for recovery of transmission upgrade costs as the specific transmission upgrades are identified and subject to considerations discussed in response to EDC-5. Associated transmission costs may be recoverable through existing transmission tariffs, but recovery of transmission costs may also require the establishment of a regulatory asset to enable recovery through retail distribution rates.

Lastly, the Company has estimated bill impacts for recovery periods of 10, 20 and 30 years as requested by the Department but notes that nearly all of the proposed expenditures are plant additions that are typically depreciated over their estimated useful lives. The Company would not recommend applying an amortization period for ratemaking purposes that would vary from the accounting treatment of assets.

Table 1. Common System Modification/Multi-Value Investment (Distribution Station + Line) broken out by year according to construction schedule

Group	Cost	2022	2023	2024	2025	2026	2027
1 - Marion-Fairhaven	**$59.66**	$6.56	$10.74	$12.53	$20.88	$8.95	
2 - Plymouth	**$70.73**	$3.54	$7.07	$10.61	$14.15	$24.76	$10.61
3 - Cape	**$10.63**	$1.59	$3.19	$4.25	$1.59		
4 - Freetown	**$12.71**	$1.40	$2.29	$2.67	$4.45	$1.91	
5 - Dartmouth-Westport	**$29.05**		$3.20	$7.26	$14.23	$4.36	
6 - New Bedford	**$26.24**	$1.31	$2.62	$3.94	$5.25	$9.18	$3.94
7 – Plainfield/Blandford	**$21.52**	$3.23	$6.45	$8.61	$3.23		
Total	**$230.52**	**$17.63**	**$35.56**	**$49.86**	**$63.78**	**$49.15**	**$14.54**

Table2:. Transmission Costs (non-ASO) broken out by year according to construction schedule

Group	Cost	2022	2023	2024	2025	2026	2027
1 - Marion-Fairhaven	**$12.00**	$1.32	$2.16	$2.52	$4.20	$1.80	
2 - Plymouth	**$73.90**	$3.70	$7.39	$11.09	$14.78	$25.87	$11.09
3 - Cape	--						
4 - Freetown	**$82.00**	$9.02	$14.76	$17.22	$28.70	$12.30	
5 - Dartmouth-Westport	**$1.20**		$0.13	$0.30	$0.59	$0.18	
6 - New Bedford	**$31.20**	$1.56	$3.12	$4.68	$6.24	$10.92	$4.68
7 – Plainfield/Blandford	**$31.20**	$4.68	$9.36	$12.48	$4.68		
Total	**$231.50**	**$20.28**	**$36.92**	**$48.29**	**$59.19**	**$51.07**	**$15.77**

Prepared by or under the supervision of: Brian Rice

Information Request EDC-3

Request:

Based on historical data, estimate the threshold $/kW at or below which interconnecting customers have agreed to pay to interconnect. Provide data by group, where possible.

Response:

The significant majority of interconnecting customers have paid less than $500/kW as shown in Figure 1. While the Company lacks comprehensive data on DER project economics, it expects interconnection costs approaching or above that point would be a financial barrier for many proposed DER facilities.

In the course of developing recommendations filed with the Department in DPU 19-55 Eversource and the other Massachusetts EDCs directed their consultant, ScottMadden, Inc., to assess the potential relationship between interconnection costs and estimated project returns. Results for Eversource' West and East service territories are presented in Figure 2 and Figure 3. They illustrated that facilities receiving only base compensation under the Massachusetts SMART Program could fail to achieve target rates of return of 10% at interconnection costs above $100-$300/kW. Variation in estimated thresholds were based on up differences in compensation rates between the Company's service territories under the initial launch of the SMART Program. Eversource recognizes there is a likely relationship between project revenues and interconnection cost thresholds. Facilities eligible for additional performance-based compensation through various adders under the SMART Program may support higher interconnection costs, as might larger facilities that achieve economies of scale or have other cost efficiencies.

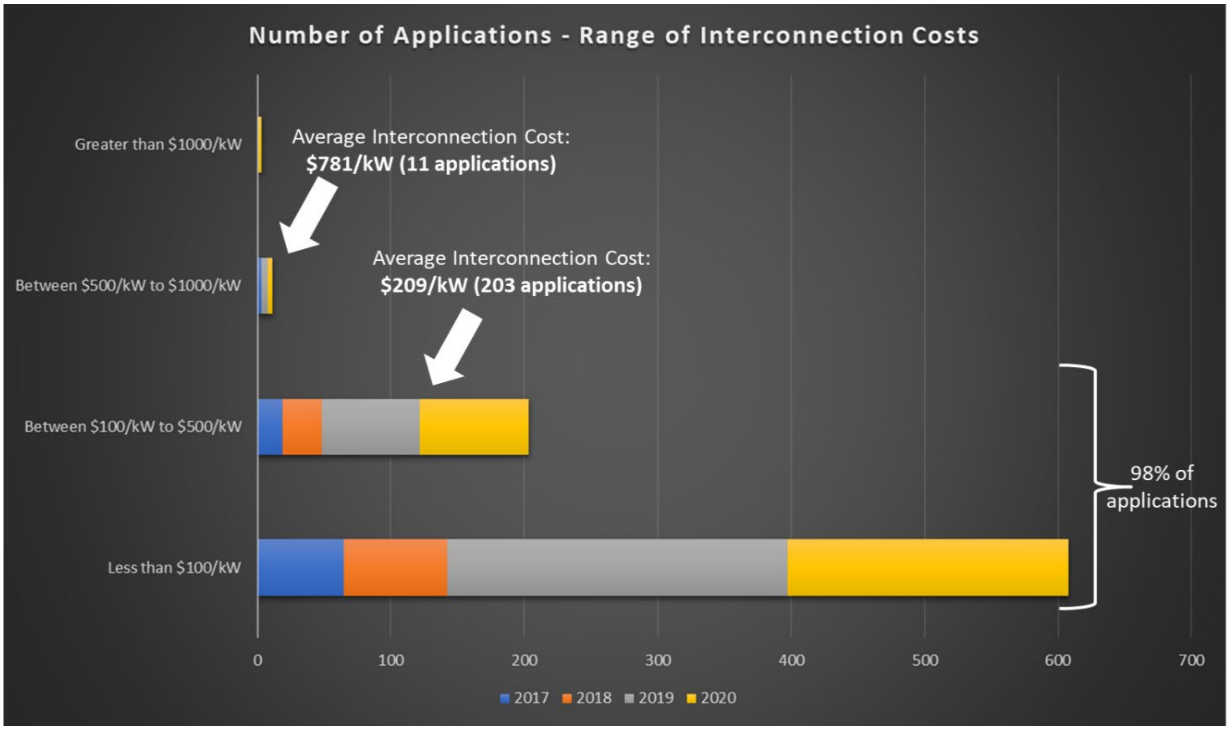

Figure 1. Range of interconnection costs for projects of various sizes from 2017 to 2020

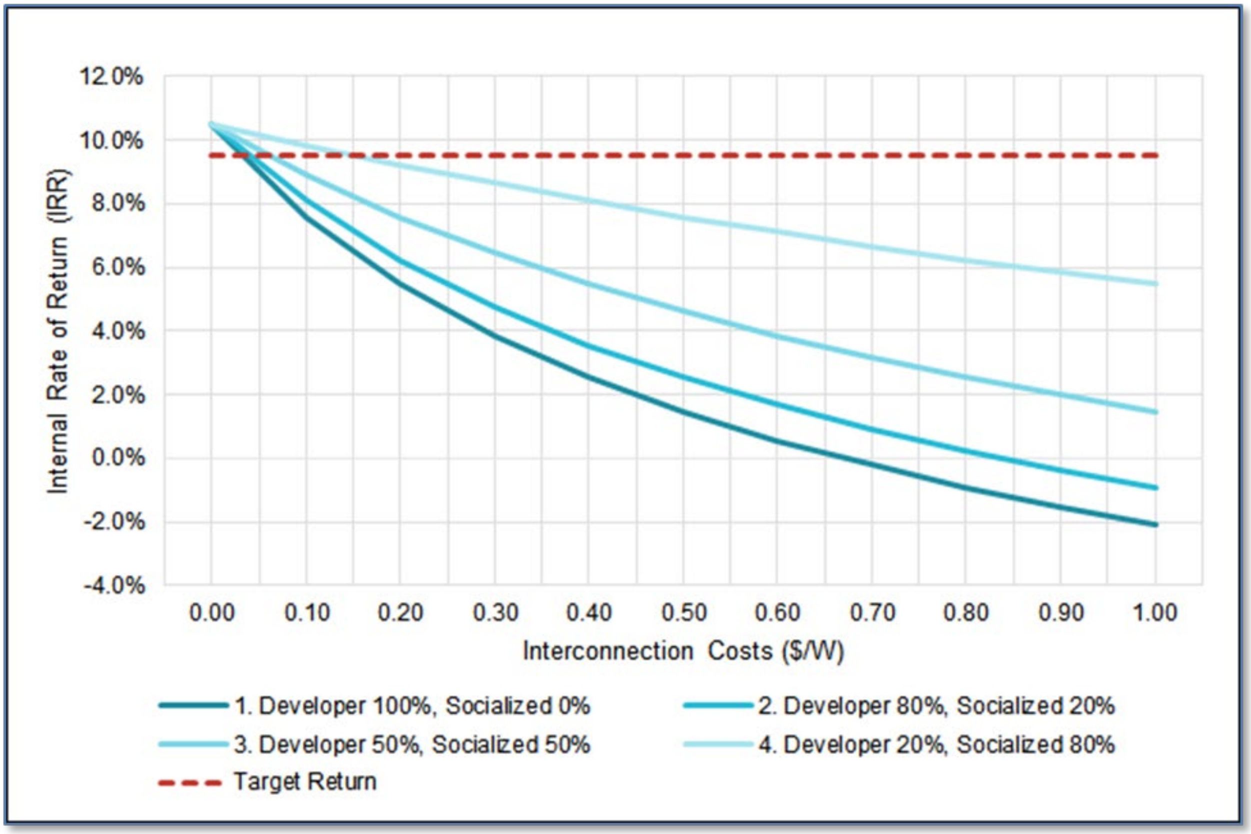

Figure 2. Eversource West Service Area DG Developer IRR Comparison

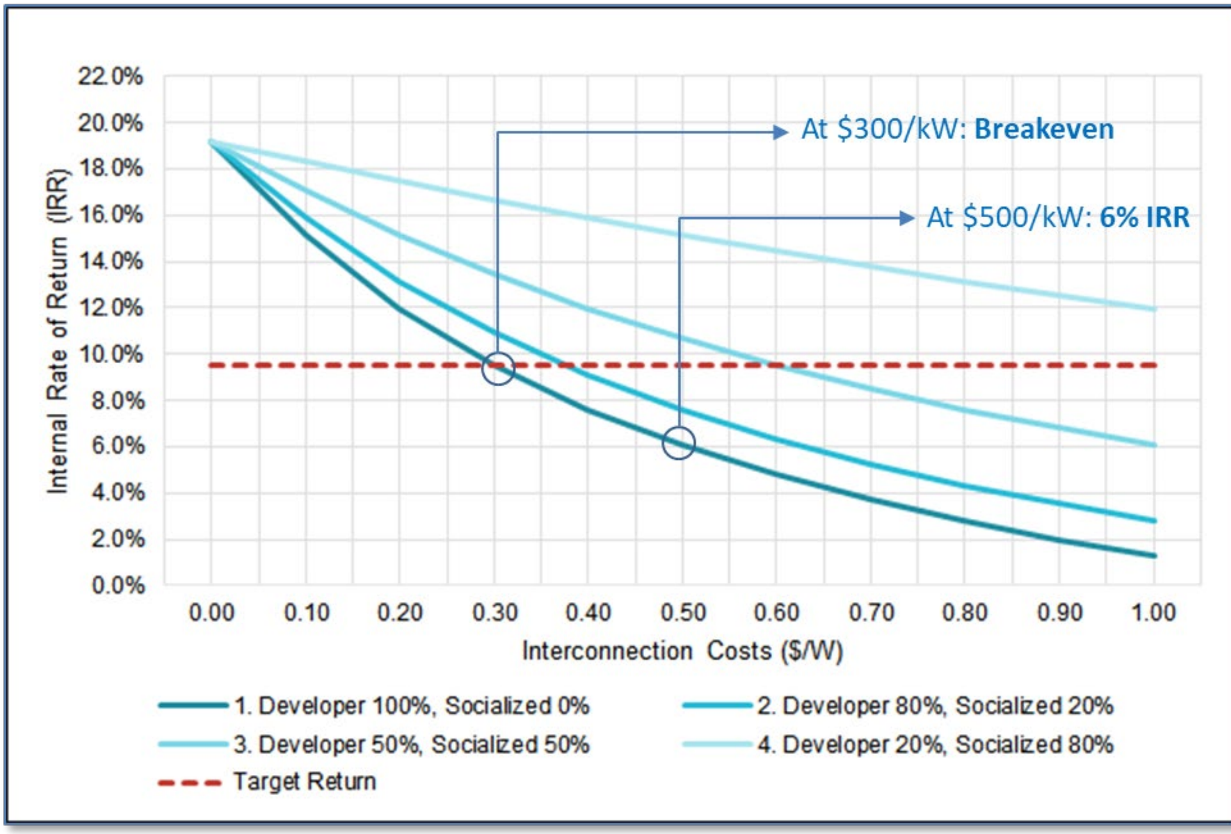

Figure 3. Eversource East Service Area DG Developer IRR Comparison (Illustrative)

Information Request EDC-4

Request:

If the Department seeks to implement a provisional system planning program based on the study results of the above referenced group(s), how quickly following the completion of associated impact studies could the company prepare and submit a proposal to the Department?

Response:

Eversource anticipates being able to develop and submit a proposal to implement "a provisional system planning program" within three (3) months of completion of impact studies for all groups.

Prepared by or under the supervision of: Digaunto Chatterjee

Information Request EDC-5

Request:

Are there any federal law implications that should be considered concerning sharing costs of EPS upgrades with interconnecting customers over an extended period of time and in particular after the EPS upgrade has been constructed?

Response:

Although states have jurisdiction over the interconnection and costs of DERs interconnecting to state jurisdictional distribution facilities, sometimes those interconnections can necessitate upgrades to the transmission system. Those transmission upgrades and the cost recovery for those upgrades, trigger FERC jurisdiction. Currently, there is no FERC-approved process for sharing interconnection upgrade costs among generators, with the limited exception of instances where ISO New England Inc. (ISO-NE) initiates a cluster study and those cluster study results can be shared among participating interconnection customers. However, this provision only applies to generators that are in the ISO-NE interconnection queue.

The absence of a FERC-approved tariff mechanism is not a bar to a state pursuing a unique cost recovery method for state-jurisdictional interconnection customers. FERC precedent holding FERC-jurisdictional interconnection customers to a strict cost causation principle should not be a bar to FERC approval of a different cost sharing methodology, since the interconnections at issue would be state jurisdictional. Theoretically, FERC's main concern should be an examination to prevent any cross-subsidization by transmission customers in other states that may not benefit from the upgrades. One mechanism to implement a state-approved cost sharing proposal for transmission costs would involve a FERC-filing to approve the payment for the transmission asset through creation of a regulatory asset. Another possible mechanism, applicable where circumstances support it, may be by recovering costs of Transmission through the incumbent Transmission Owner's Local System Plan.

Transmission Owners in New England perform Local System Planning in accordance with Attachment K of the tariff. As part of the local system planning process, each Transmission Owner lists the identified transmission needs driven by reliability as well as state, federal, or local Public Policy Requirements. Further, Attachment K specifically states that generation resources that could impact local planning shall be taken into account when developing the Local System Plan, consistent with Good Utility Practice. The LSP undergoes Planning Advisory Committee review but is not be subject to approval by the ISO-NE or the ISO-NE Board.

Prepared by or under the supervision of: Digaunto Chatterjee/Counsel

That said, under any funding mechanism, a practical consideration that could be difficult to overcome is to preserve transmission capacity created by EPS upgrades or LSP upgrades for DER interconnection customers. Those upgrades, once constructed, would create available interconnection capacity on the system and would be available on a first-come, first served basis to any interconnection customer regardless of the queue it is in. Utilities cannot withhold this capacity, creating the potential for a free rider problem in cases where state jurisdictional interconnection customers may contribute toward to cost of the upgrades but an ISO-NE queued interconnection customer would not be subject to the cost sharing mechanism and would be able to interconnect without any contribution where the interconnection capacity exists.