Marginal Cost of Service Study

PREPARED FOR

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THE Brattle GROUP

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Executive Summary

The Orange and Rockland Utilities ("O&R") retained the Brattle Group, Inc. ("Brattle") to develop a Marginal Cost-based Cost of Service ("MCCOS") study that estimates marginal costs ("MCs") at the distribution network or feeder level for its New York service territory (hereafter, referred to as the "Study"). Unlike previous MCCOS studies that provide MCs on a system-wide average basis, this Study calculates the O&R New York distribution system's MCs at the substation level granularity using projected costs for the ten years of 2019 through 2028.[1] Study results will be useful for many applications, including supporting the Value of Distributed Energy Resources ("VDER") proceedings. A more granular MC calculation will assist O&R to evaluate the impacts of Distributed Energy Resources ("DERs") on a locational basis, which may ultimately help the state of New York move towards achieving its Reforming the Energy Vision ("NY REV") goals.

The Study calculates MC as the unit investment (in dollars per kilowatts, $/kW) needed to accommodate incremental load growth. This unit investment is based on the net cost of incremental capacity resulting from the investment. Both the numerator (investment cost in $) and denominator (capacity increase in kW) are incremental values. For example, if a 60 kW asset replaces a 50 kW asset of the same type, the net investment cost is the cost of the newly added 60 kW asset net of any salvage value of the retired 50 kW asset, and the incremental capacity is calculated as the difference between the load-serving capacity provided by the new 60 kW asset and the retired 50 kW asset.[2] To account for the difference in installation years, the Study converts the calculated MC values into net present values ("NPVs").[3] Potential investments in this Study are purposely limited to traditional wires options. The Study results can serve as one of the metrics necessary for comparing the costs and benefits of various alternatives, including those of non-wires technology options.

The O&R New York distribution system consists of 50 radial systems (referred to hereafter as "Substation Areas"), representing 49 area substations and the Tuxedo Park load pocket, which is part of the area served by the Sterling Forest substation. The Study is designed to calculate the MC for each of these 50 Substation Areas for the following five cost centers:

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1 This Study relies on data and information that were available as of the summer of 2018.

2 The incremental capacity does not necessarily equal the nominal capacity (and is usually smaller). This occurs for various reasons, including how the engineering planning process takes into account various contingencies to maintain system reliability, or how another element of the system could become the limiting factor after an investment. O&R assumes zero salvage values for smaller distribution projects and only applies salvage values on larger substation projects when applicable. For this Study, salvage values are assumed zero and are subject to future updates.

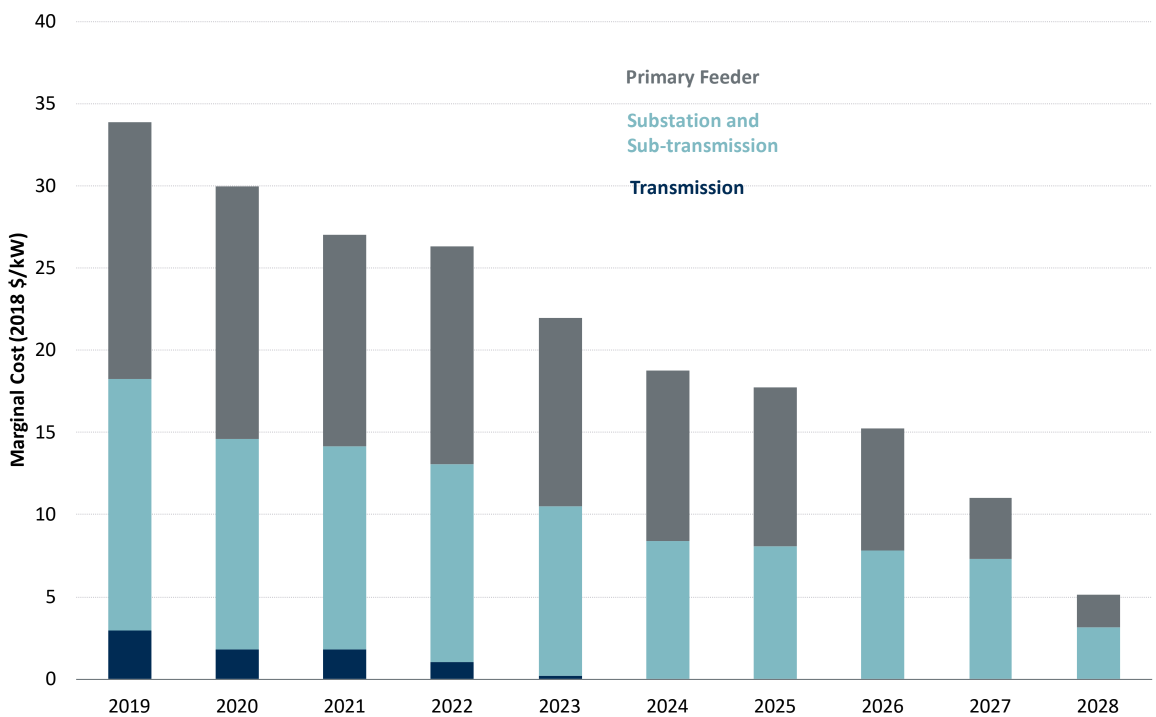
3 An alternative approach for estimating MCs would be to assess the value of delaying (or avoiding) the investments by one year.

1. Transmission Cost Center
2. Substation and Sub-transmission Cost Center
3. Primary Feeder Cost Center
4. Distribution Transformer Cost Center, and
5. Secondary Cable Cost Center

The sources for the investment needs, their timing, and location vary among these five cost centers. The first two cost centers (Transmission, and Substation and Sub-transmission Cost Centers) rely on O&R's ten-year investment budget. Those for the Primary Feeder Cost Center is based on O&R's five-year primary feeder investment budget, with additional assumptions developed for the remaining five years of the Study period. For the last two cost centers (Distribution Transformer, and Secondary Cable Cost Centers) forward-looking studies were not readily available and, as a result, the Study relied on historical investment data.[4]

Figure 1: System Weighted Average MC by Cost Center ($/kW) summarizes the average MC by cost center for the ten year Study period weighted by the 50 Substation Areas by their respective peak loads (2017 weather-normalized load). The Figure shows that the Substation and Sub-transmission and Primary Feeder Cost Centers represent the majority of the total MC.

Figure 1: System Weighted Average MC by Cost Center ($/kW)



[4] The Study assumed zero MC for these two Cost Centers because 1) very few load growth-driven projects have historically been performed at the cost centers, and 2) the projects that did occur had low $/kW values.

Table 1: 2019 MC by Substation Area shows the 2019 MC for the 50 Substation Areas by cost centers. As this Table shows, while the system-weighted average MC for 2019 is approximately $34/kW, the investment needs are not evenly spread among the Substation Areas. Three Substation Areas—Burns, Monroe, and Tuxedo Park—have MCs greater than $100/kW while about half of the Substation Areas have zero investments.

Table 1: 2019 MC by Substation Area and Cost Center

	Marginal Cost by Cost Center ($/kW)					
Substation Area	Transmission	Substation and Sub-transmission	Primary Feeder	Distribution Transformer	Secondary Cable	**Total**
Blooming Grove	0.00	39.76	0.00	0.00	0.00	**39.76**
Bloomingburg	0.00	0.00	0.00	0.00	0.00	**0.00**
Blue Lake	0.00	0.00	0.00	0.00	0.00	**0.00**
Bullville	0.00	0.00	0.00	0.00	0.00	**0.00**
Burns	23.81	48.03	40.81	0.00	0.00	**112.65**
Chester	0.00	0.00	0.00	0.00	0.00	**0.00**
Chester 34.5KV	0.00	0.00	0.00	0.00	0.00	**0.00**
Congers	0.00	41.45	0.00	0.00	0.00	**41.45**
Corporate Drive	0.00	0.00	0.00	0.00	0.00	**0.00**
Cuddebackville	0.00	0.00	0.00	0.00	0.00	**0.00**
Dean	0.00	0.00	0.00	0.00	0.00	**0.00**
East Wallkill	0.00	0.00	0.00	0.00	0.00	**0.00**
Harriman	0.00	0.00	70.55	0.00	0.00	**70.55**
Harriman 34.5KV	0.00	0.00	0.00	0.00	0.00	**0.00**
Hartley Road	0.00	0.00	0.00	0.00	0.00	**0.00**
Highland Falls	0.00	0.00	0.00	0.00	0.00	**0.00**
Hillburn	0.00	0.00	29.77	0.00	0.00	**29.77**
Hunt	0.00	0.00	11.37	0.00	0.00	**11.37**
Mongaup	0.00	0.00	0.00	0.00	0.00	**0.00**
Monroe	0.00	0.00	102.03	0.00	0.00	**102.03**
Monsey	0.00	48.03	0.00	0.00	0.00	**48.03**
Nanuet	0.00	0.00	0.00	0.00	0.00	**0.00**
New Hempstead	0.00	41.45	0.00	0.00	0.00	**41.45**
Orangeburg	18.79	0.00	0.00	0.00	0.00	**18.79**
Otisville	0.00	0.00	0.00	0.00	0.00	**0.00**
Pine Island	0.00	0.00	0.00	0.00	0.00	**0.00**
Port Jervis	0.00	49.81	0.00	0.00	0.00	**49.81**
Rio 34.5KV	0.00	0.00	0.00	0.00	0.00	**0.00**
Shoemaker	0.00	0.00	28.31	0.00	0.00	**28.31**
Shoemaker 34.5KV	0.00	0.00	0.00	0.00	0.00	**0.00**
Silver Lake	0.00	0.00	0.00	0.00	0.00	**0.00**
Sloatsburg	0.00	0.00	0.00	0.00	0.00	**0.00**
Snake Hill	0.00	0.00	35.92	0.00	0.00	**35.92**
South Goshen	0.00	0.00	56.49	0.00	0.00	**56.49**
South Goshen 34.5KV	0.00	0.00	0.00	0.00	0.00	**0.00**
Sparkill	18.79	0.00	0.00	0.00	0.00	**18.79**
Sterling Forest	0.00	0.00	0.00	0.00	0.00	**0.00**
Stony Point	0.00	0.00	0.00	0.00	0.00	**0.00**
Summitville	0.00	0.00	0.00	0.00	0.00	**0.00**
Swinging Bridge	0.00	0.00	24.38	0.00	0.00	**24.38**
Tallman	0.00	48.03	46.13	0.00	0.00	**94.15**
Tuxedo Park	0.00	0.00	151.35	0.00	0.00	**151.35**
Washington Heights	0.00	0.00	32.39	0.00	0.00	**32.39**
Washington Heights 34.5KV	0.00	0.00	0.00	0.00	0.00	**0.00**
West Haverstraw	0.00	41.45	0.00	0.00	0.00	**41.45**
West Nyack	20.03	0.00	0.00	0.00	0.00	**20.03**
Westtown	0.00	0.00	0.00	0.00	0.00	**0.00**
Westtown 34.5KV	0.00	0.00	0.00	0.00	0.00	**0.00**
Wisner	0.00	43.26	0.00	0.00	0.00	**43.26**
Wurtsboro	0.00	0.00	0.00	0.00	0.00	**0.00**
System Weighted Average	**2.94**	**15.32**	**15.62**	**0.00**	**0.00**	**33.87**

The 50 Substation Area MCs are then grouped to assist O&R in evaluating DERs at the distribution level (i.e., how much potential benefit a location may receive from DERs or other measures that reduce load growth). Three fundamental drivers that could impact MCs and DERs provide the basis for the grouping:

- Investment needs associated with load growth (i.e., the existence of planned projects to accommodate load growth)
- Load profile (that can serve as a proxy for identifying DER opportunities)
- PV penetration (as a proxy for the current level of DER penetration level and also for forward-looking potential)

Figure 2: Load Profiles shows the peak day load profiles of the 50 O&R Substation Areas after clustering into three representative load profiles. These 24-hour normalized load profiles can serve as a proxy to identify DER opportunities. For example, Substation Areas with a Lower Load Factor Profile (shown by the navy-colored line) may benefit most from a DER option that can shift load, such as storage. On the other hand, Substation Areas with a Flat Load Profile (shown in the grey line) may be most suitable for a DER option that provides constant power throughout the day.

Figure 2: Load Profiles

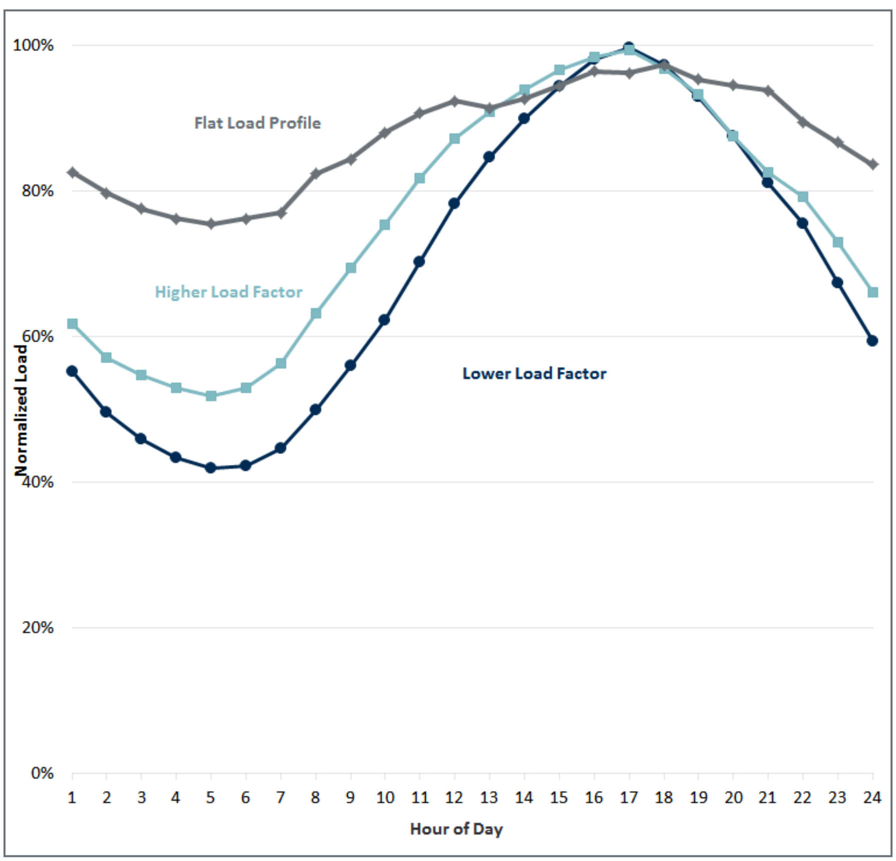
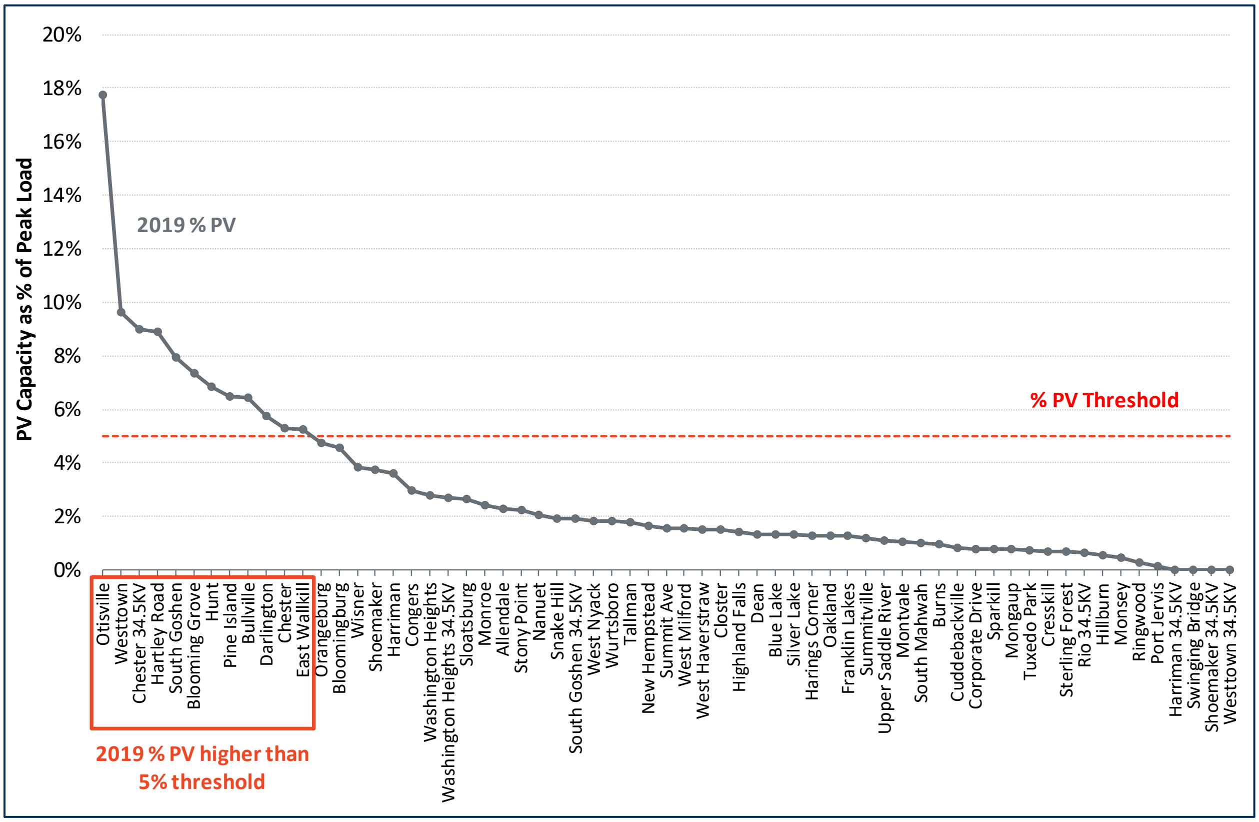


Figure 3: PV Projection shows the PV penetration—represented by 2019 projected PV capacity as a percent of the projected 2019 peak load (adjusted by all load modifiers except PV). Assuming the

projections correlate with where the DER developers see opportunities today, this can serve as a proxy for forward-looking DER opportunities.

Figure 3: PV Projection



Using these three drivers, the Study groups the 50 Substation Areas into four groups ("Aggregate Groups"), as shown in Figure 4: MC for Aggregate Groups. The Table within this Figure lists the Substation Areas assigned to each of these Aggregate Groups. The 28 Substation Areas not listed in this Table are part of the fourth Aggregate Group (AG 4) with zero MCs.

Figure 4: MC for Aggregate Groups

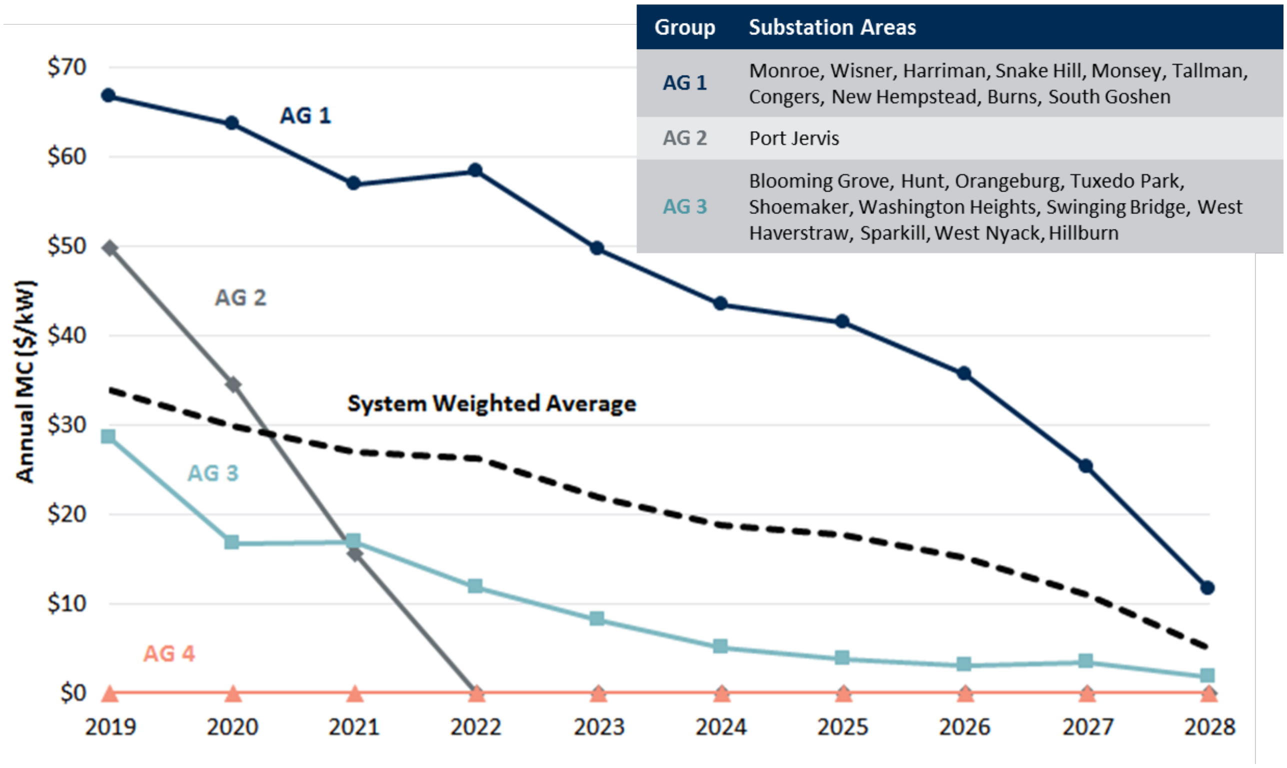
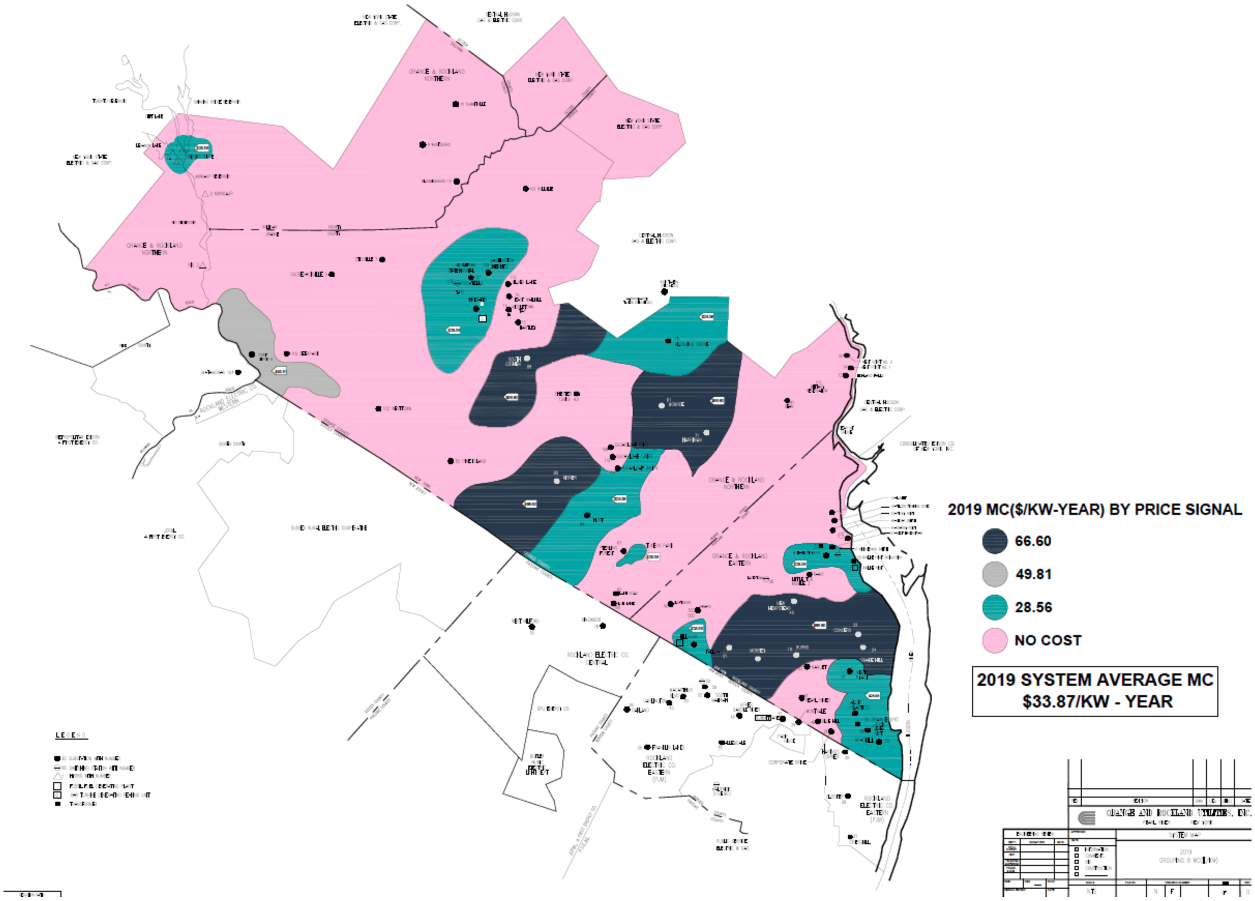


Figure 5: 2019 MC Map illustrates the MCs at the Aggregate Group level for 2019 by Substation Area, identifying the Substation Areas geographically with potentially higher capacity benefits from DERs.

Figure 5: 2019 MC Map



Observations from Figure 4: MC for Aggregate Groups and Figure 5: 2019 MC Map indicate that: 1) MCs change quite rapidly over time, and 2) not all areas benefit equally from DERs, they exhibit geographical concentration. These observations, among others, can be used to value the benefits of DERs, including their location, as part of the VDER process.

Relying on MCs as one of the metrics to evaluate and determine associated values of an area requires caution. DERs, once installed, likely remain in service for many years, some over 20 years. MCs, on the other hand, are studied over a shorter time (ten years in this Study) and rely on assumptions with a shorter horizon. For example, the upgrade needs for Primary Feeders covers five future years and there are no long-term studies for the Distribution Transformer and Secondary Cable Cost Centers. Typically, investment needs for these cost centers are identified and studied on a case-by-case basis with a much shorter lead time. The relative differences in planning horizons suggests that care must be taken in translating MC values to long-term payments. Although relying on MCs may be the best alternative, the MCs alone should not be translated directly as the value. For example, if a DER is installed in a Substation Area with high MCs but is simply providing energy at a time that does not coincide with the distribution systems' capacity needs (i.e., peak hours), the value of such a DER should be considered to be closer to the system average MC. Similarly, DERs installed in Substation Areas with zero MCs does not necessarily indicate that the DERs have no value. Rather, it indicates that the DERs do not provide any significant contribution in delaying capacity-related investments to accommodate load growth, though they may have energy value.

The estimated reliability contribution from DERs must also be considered when assigning a value. The incremental load-serving capacity used for calculating the MCs for the traditional wires options is post-contingency capacity that may be further reduced based on system-specific conditions. If these MC values serve as a guideline for evaluating the benefits of DERs, their use requires caution. For example, DERs' nameplate capacity may not truly reflect their ability to meet load at local system peaks. As a result, the level of reliability provided by the alternatives may not be directly comparable. Another reliability concern may be the future availability of the DERs. If a DER is awarded the avoided cost, will that DER be held responsible at the same level as the utility would for not performing in real time? Or will the DER have options to walk away without paying any penalty other than forgoing the agreed upon payment? In such cases, will the utility be asked to provide a back-stop solution? These differences should also be taken into account when assessing the value DERs may provide.

Finally, as Figure 4: MC for Aggregate Groups shows, the MC is diminishing over time. The MCs for the three groups with non-zero MCs identified in this Study all decrease over time (although with varying degrees), merely because once an investment is made the immediate need for such an investment has been met. The decline in MCs over time indicates the need for a speedy response if a policy (or incentive) to guide DER investments of the appropriate type to the preferred location is desired. It also illustrates the importance of refreshing the MCCOS study periodically and timely modifying such policies and/or incentives to match the updated MCCOS results. There are other considerations for periodically updating the MCCOS. The need for upgrades continues to change as load profiles based on the customers' usage pattern and load growth patterns evolve. Costs also change over time and by location.[5] Even when installing the same equipment in two different locations within the same Substation Area, both the incremental capacity and cost may vary by location and its application. For example, consider a simple project of upgrading cables on two radial systems that are both located within the same Substation Area. Even if the same size cables were installed on both of these radial systems, their contribution to incremental load-serving capacity could vary because of the next binding distribution element that is unique to each location.[6] Similarly, the installation cost of identical cables may vary by location and scope of work. As a result, there is typically a broad range for MCs to vary across when one observes and compares past MCCOS studies.[7] In general, the industry tries to reduce such impacts by performing/updating MCCOS periodically.

In updating future MCCOS, there are several recommendations for improvements. As this study was the first of its kind for O&R, historical data was relatively limited.[8] Historical data collected over multiple years may also be used to estimate future costs—such as by observing a trend in costs over the year—in the case that forecasted project data is not available. Second, the Study assumes zero salvage value for any replaced asset. An internal review of the salvage values could improve the Study results. Similar to the cost estimates, data collected over multiple years can also provide estimates of future salvage values. Should this review be difficult, an alternative approach in calculating the MCs may be to merely assess the benefits of delaying the investment needs by one year. Finally, several Loaders sourced from the Embedded Cost Study should be updated once a new study becomes available.

The remainder of this report is organized as follow. Section I (Introduction) provides an overview and background of the Study. Section II (A More Granular MCCOS for the O&R System) discusses the calculation methodology, assumptions, and calculation results. Section III (Grouping for the VDER Proceeding) discusses the method and approach used for grouping the 50 Substation Area by Substation Area MCs. Lastly, Section IV (Conclusion and Recommendations) summarizes the findings and observations. A Glossary is included at the end of the report.

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5 Even if equipment costs do not change, construction costs associated with installing the needed equipment can change—for example, the cost of digging up the streets in urban areas 20 years ago and today is entirely different.

6 For example, assume the new cable has a capacity of 12 MVA and is replacing an older cable that has a capacity of 8 MVA. If the rest of the sequential cables have a capacity of 10 MVA for the first radial system and a capacity of 11 MVA for the second radial system, the capacity contribution of the same cable will result in 2 MVA for the first system but 3 MVA for the second system.

7 The wide range of MCs can is apparent in Appendix-A of Con Edison's Marginal Cost Study (publicly available at: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BF99CFC43-2D67-44DB-AB02-A7ACDA5E6341%7D). This Appendix catalogs the traditional wires options and the general range of costs observed.

8 Increasing data availability may also be a challenge given the projected flat load growth.

Appendices include:

Appendix-A: Financial Loaders

Appendix-B: O&R MCOS Methodology Summary Report

Appendix-C: Load Profile Clustering

All values are expressed in real 2018 dollars, unless quoted otherwise.

I. Introduction

This report describes a Marginal Cost-based Cost of Service Study ("MCCOS") that estimates Marginal Costs ("MCs") at the distribution substation or feeder level for Orange & Rockland's ("O&R") New York service territory. The Study was developed in collaboration with O&R staff and Con Edison staff, reflecting the various comments received from the New York State Department of Public Service ("DPS") staff during a similar study performed for Con Edison.

Previous MC studies provide system-wide average values and the purposes for which these studies are used typically do not require location-specific measures. With today's changing environment that includes various types and applications of Distributed Energy Resources ("DERs"), some regulators are now moving towards requiring distribution utilities to provide location-specific MC studies. The New York Public Service Commission ("Commission") is no exception and has indicated that a more granular approach may be needed to support the NY REV goals. This Study determines MCs at differing levels of network-level granularity for the ten years of 2019 through 2028.[9] The Study results—granular locational MCs—can be used for a variety of purposes, including supporting New York's Value of Distributed Energy Resources ("VDERs") Proceedings, which is part of the Commission's approach towards achieving the NY REV goals. Specifically, the Study may help O&R identify higher value areas.

The Study focuses on the traditional wires options and provides a baseline comparison for other non-wires solutions.[10] Separate cost-benefit analyses can then be performed for the various non-wires solutions as needed.[11]

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9 The standard industry practice is to perform the calculation over a pre-defined period, such as the ten years assumed for this Study. O&R's prior marginal cost study also covers a ten-year horizon.

10 The Study relies on O&R's existing studies for future investments. These studies do reflect (as load modifiers) non-wires options that exist today or future projects that are recognized by O&R planning.

11 With the myriad of technology options available today, it is impractical to evaluate and reflect all technology options as part of the Study.

II. A More Granular MCCOS for the O&R System

The O&R distribution system for its New York service territory consists of 50 Substation Areas—49 substations and the Tuxedo Park load pocket, part of the area served by the Sterling Forest substation that is treated as a separate Substation Area for this Study. Figure 6: O&R New York Service Territory below shows the O&R New York service territory.

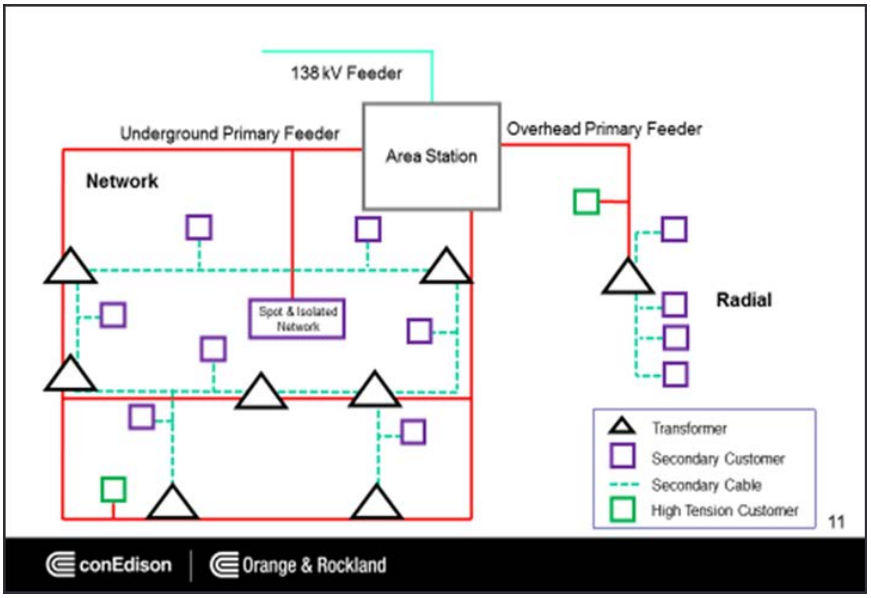
Figure 6: O&R New York Service Territory

Source: O&R.

The Study calculates the MCs for each of the 50 Substation Areas over the ten years of 2019 through 2028. Figure 7: Distribution System Sketch below illustrates the components (primary feeders, distribution transformers, and secondary cables) that comprise a Substation Area. The area station (indicated by the grey square labeled Area Station) is the highest level within a distribution system (i.e., Substation Area) and connects to the transmission system (indicated by the light blue line labeled 138 kV Feeder). Each distribution system (Substation Area) has primary feeders (indicated by the red lines), transformers (indicated by the black triangles), and secondary cables (indicated by the green dotted lines). Figure 7: Distribution System Sketch also identifies two distinct types of distribution systems—a networked system (shown in the left-hand side of the figure, labeled

Underground Primary Feeder), and a radial system (shown in the right-hand side of the figure, labeled Overhead Primary Feeder).[12] The O&R distribution systems are all radial systems.[13]

Figure 7: Distribution System Sketch



Source: Con Edison.

Table 2: O&R Substation Areas below lists the 50 Substation Areas, their 2017 weather-normalized peak load, and forecasted 10-year load growth CAGR. As Table 2: O&R Substation Areas shows, about half of the Substation Areas are expected to experience negative load growth.

12 The physical differences in the networks, i.e., underground vs. overhead, does not necessarily translate as meshed/networked vs. radial. View this figure solely as an illustrative example.

13 As Figure 7: Distribution System Sketch shows, a load (indicated by either a green or purple square) on a networked system can be served through multiple paths while a load on a radial system must rely on a single path (hence radial). This indicates an essential difference between the two distribution system types—e.g., load reduction in a networked system provides benefits to other segments of the distribution system while those on a radial system serve only the specific radial system. Therefore, all else equal, the MCs for radial systems would tend to be higher than those of meshed systems. Also, upgrade needs for radial systems may be more difficult to estimate than network systems because the upgrade needs are localized. For this reason, load growth for a given Substation Area may serve as a good indicator for networked systems while it may not work for radial systems.

Table 2: O&R Substation Areas

Substation Area	2017 Load (MW)	10-Year CAGR %
Blooming Grove	19.00	-0.72%
Bloomingburg	7.83	-0.98%
Blue Lake	4.65	0.84%
Bullville	7.94	-0.79%
Burns	57.88	0.24%
Chester	31.16	-0.75%
Chester 34.5KV	5.40	1.36%
Congers	47.62	0.03%
Corporate Drive	26.21	5.36%
Cuddebackville	30.52	-0.18%
Dean	5.65	0.51%
East Wallkill	34.48	-0.74%
Harriman	40.65	1.00%
Harriman 34.5KV	31.42	1.29%
Hartley Road	21.13	-0.61%
Highland Falls	5.07	0.37%
Hillburn	13.48	-0.26%
Hunt	13.78	-1.17%
Mongaup	1.44	-2.30%
Monroe	53.71	0.71%
Monsey	46.60	-0.01%
Nanuet	38.27	0.63%
New Hempstead	73.94	0.21%
Orangeburg	40.63	0.06%
Otisville	7.69	-4.53%
Pine Island	1.48	0.14%
Port Jervis	13.09	-0.06%
Rio 34.5KV	16.43	0.13%
Shoemaker	28.33	-1.38%
Shoemaker 34.5KV	15.86	-0.14%
Silver Lake	35.31	0.43%
Sloatsburg	6.75	3.29%
Snake Hill	44.55	-0.48%
South Goshen	14.64	-3.02%
South Goshen 34.5KV	4.41	0.75%
Sparkill	24.41	0.28%
Sterling Forest	3.19	0.13%
Stony Point	28.45	0.24%
Summitville	1.44	2.71%
Swinging Bridge	0.08	3.34%
Tallman	53.08	-0.62%
Tuxedo Park	2.13	0.13%
Washington Heights	17.13	-0.07%
Washington Heights 34.5KV	14.84	0.10%
West Haverstraw	49.97	0.11%
West Nyack	37.40	0.38%
Westtown	13.35	3.11%
Westtown 34.5KV	12.89	-0.34%
Wisner	32.25	-0.70%
Wurtsboro	3.48	-0.43%

A. SPECIFIC CALCULATION METHODS APPLIED

MC calculations determine the investment needed to accommodate incremental load growth, identifying the least cost means of meeting an increase in demand without jeopardizing the current level of reliability.[14] There are three fundamental questions:

1. How much does the investment cost (in $/kW)?
2. When will the investment be needed (i.e., what year, within the ten year Study horizon)?
3. Where will the investment be needed (to assess the marginal cost at the appropriate granularity level)?

In answering these three questions, MCCOS studies begin by identifying and reviewing the cost and timing of the investments (addressing the first two questions listed above). The nature of the cost and timing of these investments (defined by the physical nature of the equipment used for the electric power systems—i.e., they are typically substantial and have different economic life-spans) drives the overall MC calculation method. First, investment costs (from the first question) are annualized to include their economic carrying charge and fixed O&M expenses. Then, to account for the different timing of the investment needs (second question), the annualized costs are converted into Net Present Values ("NPVs").[15] The need for greater locational granularity introduces the third question of "where." While there are various levels of locational granularity, this Study calculates the MC on a Substation Area basis.[16] Details of the steps identifying the cost and timing of the investments are discussed next.

MC calculation focuses specifically on the investment needs to accommodate incremental load growth.[17] Naturally, investments to accommodate the incremental load growth, in many cases,

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14 Maintaining the same reliability level requires conforming to the utility's design standard. There is no practical alternative to this approach in guaranteeing the level of reliability.

15 NPV calculation can also potentially address varying lengths of the investments' economic lifespan, which may differ much more in the future. In this approach, the size and type of investment may not be as important unless the information is needed for corollary purposes.

16 Also, the location could potentially assist in assessing the investment costs through clustering when sufficient data are not available. For example, urban locations will often cost more to install a piece of equipment compared to rural areas,

17 MC calculation focuses specifically on the investment needs to accommodate incremental load growth and not on any other investment needs—for example, replacing an existing asset because of its age, or the cost of interconnecting a new customer, such as a newly developed commercial complex, should not be accounted for as part of the MC calculation. However, costs for projects to accommodate new load, such as increasing the capacity of existing equipment to interconnect new load without reducing the reliability of existing loads, should be included in the MC calculation. The two distinct investment goals associated with new loads may be recorded under one project, leading to the need for separating the project costs so it can appropriately be applied to the MCCOS calculations. Often equipment and

require replacing the same asset type—retiring an existing asset with smaller capacity that still has usable life and adding a new more substantial asset of the same type. The existing asset would not need an upgrade if it weren't for the load growth. Therefore, this Study assumes the proper cost to use is the incremental (or net cost of) investment—i.e., the cost of the new investment net of the salvage value of the asset replaced/retired to accommodate the increase in load—rather than the entire cost of the new asset. Investments that do not replace any assets (i.e., projects that only include new assets) have no salvage values. Many utilities do repurpose certain assets, such as transformers, so there are positive salvage values. However, at the time of the Study, there is insufficient sample information to reasonably estimate salvage values and, therefore, the Study conservatively sets salvage values to zero (subject to future updates).[18]

Similarly, the Study uses incremental load serving capacity (or net capacity)—i.e., the load-serving capacity of the new asset net of the load-serving capacity of the asset that is being replaced/retired—for the MC calculation.[19] This load serving capacity does not necessarily match the nameplate capacity of the assets, and frequently is adjusted to be smaller. Such capacity adjustment occurs mainly for two reasons. First is to comply with the existing reliability requirements by conforming to the utility's design standards. For example, engineering planning of the electric power system accounts for contingency conditions and therefore requires system redundancy. Therefore, the load-serving capacity rating is usually based on post-contingency capacity, which is smaller than nominal capacity. Second, not all capacity of a given asset will contribute to the capacity needs for accommodating load growth. This has several different reasons. Investments to accommodate load growth may be optimized together with investments for other

labor costs associated with such projects are difficult to separate precisely by purpose, leading to some assumptions and approximations. The "lumpiness" of asset size leads to even more cost approximations because one cannot increase the system capacity on a strictly marginal basis—all assets have certain capacities and cannot be purchased in 1 kVA increments. Also, economies of scale affect these assets; typically, larger equipment exhibits lower unit costs. This "lumpiness" leads to further difficulties in assessing the appropriate costs for the electricity system, which can comprise a number of different pieces of equipment all of which have an impact on each other. For example, the cost of two projects which are both installing identical cables of the same capacity could differ because one project had excess taps in the substation while another did not, thereby requiring additional investments for taps in the second project. All in all, it should be understood that acquiring cost estimates may be difficult, and may result in some approximations.

18 If the salvage value data were known not to be available, an alternative and, perhaps, more straightforward approach in calculating MCs may have been to assess the benefits of delaying the investments by a year. In such case, the denominator (capacity) for the investment cost ($/kW) also does not need to be adjusted. Therefore, the investment cost ($/kW) will merely be the total cost ($) divided by the total load-serving capacity of the new asset (kW).

19 The load-serving capacity kilo-watts (kW) reflect only active power (i.e., real power and not reactive power.) In many cases, utility equipment is measured in apparent power units, or kilo-volt-amperes (kVA). kVA units are converted to kW using relevant power factors.

purposes. In such cases, the combined capacity must be properly allocated between the two different purposes. It can also arise because of the physical system and lumpiness of investment options. Upgrading one section of the system by a given quantity does not necessarily mean that the entire system capacity has been bolstered by the same amount.[20] The Study relies on O&R engineers to determine the incremental load serving capacities, where applicable.[21]

The investment cost (in $/kW) calculated using incremental values for both the numerator and denominator—investment costs (net of salvage value) as the numerator and incremental capacity (net of existing asset capacity) as the denominator—is then annualized.[22] Finally, to account for the different timing of investments, the NPV of the annualized investment costs are calculated. Figure 8: Annualizing Investment Costs below shows the process for annualizing the investment costs. Table 3: Parameters Used for Annualizing Investment Costs summarizes the values of the various parameters shown in Figure 8: Annualizing Investment Costs. Details on the parameters included in Table 3: Parameters Used for Annualizing Investment Costs are discussed later in Appendix-A: Financial Loaders.

Figure 8: Annualizing Investment Costs

Total Annualized Cost = Annual Investment Cost (incl. G&A) + O&M (incl. G&A) + Revenue Requirement for Working Capital (incl. G&A)

=

Investment Cost x Economic Carrying Charge x (1+Plant G&A) x (1+Common Plant)

+

Investment Cost x Historical O&M per $ Cost Center x (1+Non-Plant G&A)

+

Investment Cost x Revenue Requirement for Working Capital x (1+Plant G&A) x (1+Plant Loading) x Working Capital/Total Plant x Return Rate

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[20] An illustrative example may be upgrading assets in series. Assume a radial system with two cable segments installed in series. The first segment has a capacity of 8 kVA, the second segment has a capacity of 10 kVA, and upgrade options for the first segment are only available in incremental capacities of 3 kVA. In this example, upgrading the first cable segment by 3 kVA (from a capacity of 8 kVA to 11 kVA) will only enhance the system's capacity by 2 kVA, not by 3 kVA.

[21] O&R's project selection process is summarized in Appendix-B. Although project selection was a collaborative process between Brattle and O&R planning engineers, the final projects and associated costs used in this study were determined by O&R.

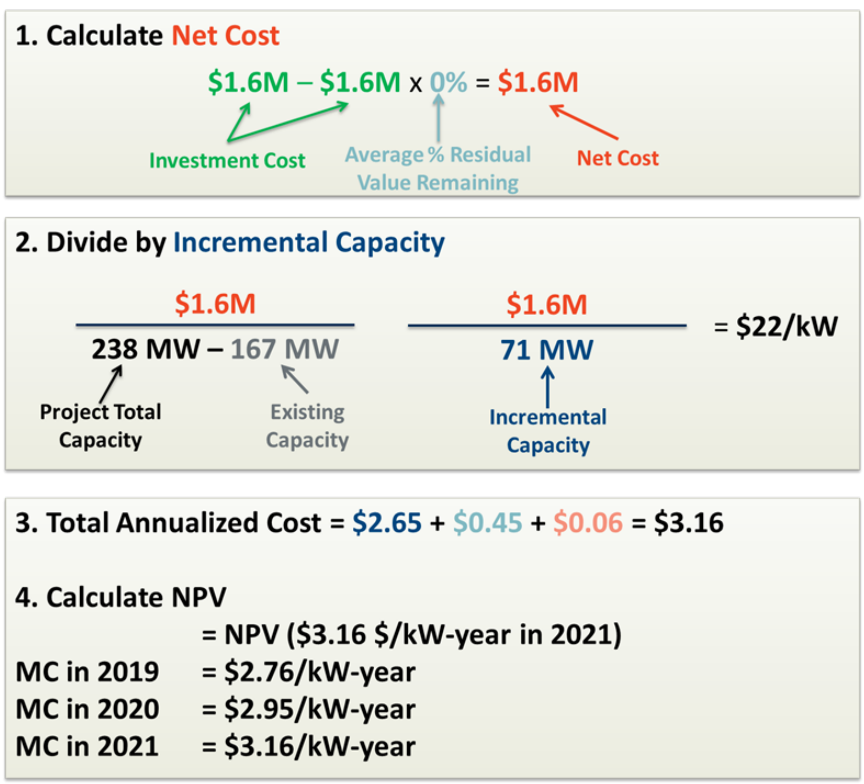
[22] The Study annualizes costs over ten years, which matches the Study period. While many assets' economic lives could be longer than ten years, there is no guarantee that any asset will serve its entire economic life (for example, upgrades may be needed to accommodate additional load growth).

Table 3: Parameters Used for Annualizing Investment Costs

Varies Across Equipment and Application	
Plant A&G Costs	0.00% - 0.07%
Cost Center O&M	2.77% - 7.86%
Common Across Equipment and Application	
Inflation Rate	3.00%
Common Plant %	12.75%
Economic Carrying Charge	8.14%
Working Cap as % of Electric PIS	3.98%
Income Tax Rate	6.36%
Regulated WACC	9.85%
Non-Plant A&G	3.05%
Revenue Requirement for Working Capital	16.21%

Figure 9: Illustrative Calculation Example below describes the four steps discussed above through an illustrative example. In this example, a new 238 MW asset is installed in 2021 and replaces an existing 167 MW asset. The cost of the new asset is $1.6 million (in 2021) and the salvage value of the existing asset is assumed to be zero.

Figure 9: Illustrative Calculation Example



Step 1 calculates the net investment cost (net of salvage value, which is assumed zero) that occurs in 2021. Step 2 divides the net investment cost calculated in Step 1 by the incremental capacity increase and derives the incremental investment cost. Step 3 annualizes the incremental investment costs using the formula shown in Figure 8: Annualizing Investment Costs. The total annualized cost is the sum of Annual Investment Cost (in the navy-colored text), O&M (in the teal-colored text), and Revenue Requirement for Working Capital (in red text), all including G&A costs. Step 4 calculates the NPV of the annualized investment costs that occur in 2021 by year.[23] These values are the avoidable costs by year for this investment—or in other words, the value of reducing a kW of load growth in 2019 is worth $2.76/kW. An important note here is that the calculations do not show any value for 2022 and after in this example. This results from the lumpiness of the investment—i.e., once the investment is made in 2021, no more upgrades are needed until the aggregated load growth outgrows the excess capacity provided by the 71 MW investment (i.e., aggregated load growth exceeds 71 MW). The MC falls initially to zero, but grows in proportion to capacity needs.

B. MC Calculation and Cost Centers

The Study calculates MCs on a Substation Area by Substation Area basis for the following five cost centers with costs properly allocated among Substation Areas.

1. Transmission Cost Center
2. Substation and Sub-transmission Cost Center
3. Primary Feeder Cost Center
4. Distribution Transformer Cost Center
5. Secondary Cable Cost Center

As discussed briefly in Section II (A More Granular MCCOS for the O&R System), the O&R distribution system is primarily composed of radial systems. Upgrade needs for radial systems are often more difficult to estimate than network systems because the upgrade needs can be localized, and the overall load growth for a given Substation Area may not serve as a good indicator for investment needs. Therefore, the Study primarily relies on O&R planning studies to identify the upgrade needs, their location, and costs. Alternative approaches, such as estimating investment needs through load growth, are used to augment where there were no studies readily available. Appendix-B: O&R MCOS Methodology Summary Report discusses how the projects that qualify as marginal costs were selected and the selection rationale behind several projects identified in this Study where the Substation Area load growth may appear to be anomalous.

Detailed calculation approaches for each of these five cost centers are discussed next.

23 For investments that have different timings, such as investments in 2020 and 2021 for an asset that placed into service in 2022, the NPV calculation is performed prior to annualizing the investment costs.

1. Transmission Cost Center

A Transmission Cost Center is defined as any asset that is upstream of the area substation (Substation Area level) and includes the transmission system (excluding transmission congestion contracts) and switching stations. O&R's transmission systems operate primarily at 345kV, 138kV, and 69kV. Investments in this cost center may bridge over multiple Substation Areas and are assigned appropriately to the relevant Substation Areas. Upgrade needs for the Transmission Cost Centers were identified from O&R's most current ten-year forecast and capital investment plan ("CIP").[24] Table 4: Transmission Projects lists the transmission projects identified in the CIP, their associated Substation Areas, , and capacity.

Table 4: Transmission Projects

Project Name	Project Description	Substation Area(s)	Online Year	Incremental Capacity *MVA*
New UG T/L 47	Install new 69kV underground line from Harings Corner to Closter	West Nyack, Orangeburg, Sparkill	2020	45
New UG T/L 705, Burns to West Nyack	Install new 138kV underground line from Burns to West Nyack	Burns, West Nyack	2023	20

2. Substation and Sub-transmission Cost Center

A Substation and Sub-transmission Cost Center is defined as any asset that is downstream of the Transmission Cost Center and typically transforms power from the transmission voltages (mostly 138 kV or 69 kV) to the distribution primary voltage (predominantly 13.2 kV for the O&R system). Similar to the Transmission Cost Center, some of these assets may bridge over multiple Substation Areas but most are defined within a Substation Area. Upgrade needs for the Substation and Sub-transmission Cost Center were also identified from O&R's CIP. Table 5: Substation and Sub-transmission Projects identifies the projects from the CIP. As a general rule, Area Substation Projects are mapped to the both 1) the Substation Areas at which the project takes place, and 2) other beneficiary Substation Areas whose load reduction can defer the project. As this table shows, several Area Station projects (for example, the Little Tor Substation project) are common among multiple Substation Areas.

24 As part of O&R's overall integrating process, the CIP is developed on an annual basis for the transmission and distribution system. The CIP identifies projects (primarily at the transmission, substation, and distribution mainline feeder levels) that are needed to maintain sufficient capacity to meet growing customer load in accordance to O&R's risk analysis and design standards. The capital projects identified are then incorporated into O&R's annual capital budget and multi-year capital forecast.

Table 5: Substation and Sub-transmission Projects

Project Name	Project Description	Primary Beneficiary Substation Area	Other Beneficiary Substation Area(s)	Online Year	Incremental Capacity *MVA*
Port Jervis Subst 2-40MVA Bank, 6 Ckts	Upgrade existing 35kV 20 MVA single-bank station to 69kV two 40 MVA bks	Port Jervis		2021	4.4
Little Tor Substation	Construct a new two bank station with 56 MVA transformers & ckts	New Hempstead	West Haverstraw, Congers	2023	12.0
Blooming Grove Bank Upgd & 2nd 56MVA Bk	Upgrade single 25 MVA-bank station to two 56 MVA bank station	Blooming Grove		2025	3.3
West Warwick Substation	Install two 56 MVA 138/13kV banks	Wisner		2028	8.4
Monsey 40MVA Banks	Upgrade existing two 25MVA bank station with two 40 MVA bks	Monsey	Burns, Tallman	2028	3.6

3. Primary Feeder Cost Center

A Primary Feeder Cost Center includes assets that emanate radially from an area substation and supply power at medium or lower voltages. Upgrade needs in this cost center are assigned to a single Substation Area. There are two distinct project types. The first is the stand-alone primary feeder upgrade needed for accommodating load growth. The second is the system reconfiguration primary projects at Substation Areas that require both area station and primary feeder upgrades. The costs for this second type are included at the Substation and Sub-transmission Cost Center.[25]

Upgrade needs for the Primary Feeder Cost Center were identified from O&R's five-year primary feeder investment budget, with additional assumptions for the remaining five years of the Study period. Five Substation Areas, namely Harriman, Monroe, South Goshen, Snake Hill, and Hillburn, were identified as potential candidates for primary feeder upgrades in the second five years of the Study period, based on forecasted load growth at those Substation Areas.[26]

Table 6: Primary Feeder Projects from the O&R Five-Year Budget lists the projects identified in the primary feeder investment budget, associated Substation Areas, and incremental capacity. When there are multiple projects for a given year in one Substation Area, the Study assumes the MC to be the average $/kW, weighted by the projects' incremental capacity.

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25 Table 6: Primary Feeder Projects from the O&R Five-Year Budget shows only Primary Feeder Cost Center projects of the first type. While several projects of the second type were found, they were deemed to be more reliability-driven based on conversations with O&R staff. See Appendix B for further details.

26 Load growth is primarily driven by economic development and population growth.

Table 6: Primary Feeder Projects from the O&R Five-Year Budget

Project Name	Project Description	Substation Area	Online Year	Incremental Capacity *MVA*
Tuxedo Park - Mountain Farm Rd to Continental	4kV conversion-removal of step and upgrade conductor	Tuxedo Park	2019	1.5
Pine Island - Pulaski Highway to Pine Island Sub	4kV conversion	South Goshen	2019	3.0
Harriman - Larkin Drive	System expansion - future Mainline-Woodbury(new load)	Harriman	2019	4.8
Middletown - Dolson Ave	System expansion - Mainline-upgrade conductor	Shoemaker	2019	2.4
Forestburg - Swing Bridge Exit CR 43N to Mohican	System expansion - future Mainline-fill in the gap	Swinging Bridge	2019	2.6
Suffern - Mile Road to Viola	System expansion - future Mainline-fill in the gap	Tallman	2020	2.6
Tuxedo Park - Front gate	4kV conversion-removal of step and upgrade conductor	Tuxedo Park	2020	1.1
Tuxedo Park - East lake Reconductor	4kV conversion-removal of step and upgrade conductor	Tuxedo Park	2020	1.1
Monroe - lakes Road - Cedar Cliff to Laroe	4kV conversion-removal of step and upgrade conductor	Monroe	2020	3.0
Tuxedo Park - Continental Rd - Warwick Brook to Club Hse Rd	4kV conversion-removal of step and upgrade conductor	Tuxedo Park	2021	1.5
Tuxedo - Mombasha Rd - Benjamin Meadow to Step	System expansion - future Mainline-single to three phase	Hunt	2021	2.6
Circleville - Goshen Tpke - Shawangunk Rd Conver to 17k step	4kV conversion-removal of step and upgrade conductor	Washington Heights	2021	1.5
Spring Valley - Church St - 4kV conversion	4kV conversion-removal of step and upgrade conductor	Burns	2022	1.5
Spring Valley - Madison Ave - reconductor & conv	4kV conversion-removal of step and upgrade conductor	Burns	2022	1.5
Monroe - Cromwell Hill - Quaker to Lakes Rd - 4kv conv	4kV conversion-removal of step and upgrade conductor	Monroe	2023	3.0

Table 7: Substation Areas with Expected Primary Feeder Projects, 2024-2028 below identifies the Substation Areas at which Primary Feeder projects are expected to take place in the last five years of the study period. These Substation Areas are assigned the incremental capacity-weighted average project cost ($/kW) of projects from the five-year budget.[27]

[27] The average primary feeder project cost is $204/kW.

Table 7: Substation Areas with Expected Primary Feeder Projects, 2024-2028

2024	2025	2026	2027	2028
Harriman	Harriman	Harriman		
		Monroe	Monroe	Monroe
South Goshen	South Goshen			
	Snake Hill	Snake Hill		
			Hillburn	Hillburn

4. Distribution Transformer and Secondary Cable Cost Centers

Investment needs for the Distribution Transformers and Secondary Cables (everything below the area substation level in Figure 7: Distribution System Sketch)—are typically studied and identified on a case-by-case basis and with a much shorter lead time. Therefore, the Study relied on historical observations to estimate future costs and investment timing. Reviewing historical data indicated that very few load growth-driven projects were performed at these cost centers, and the projects that did occur had low $/kW values.[28] Therefore the Study assumes the MCs for these two cost centers to be de minimis.

C. Calculated Marginal Costs

Figure 10: Average MC by Year ($/kW) displays the O&R system average MCs weighted by the 2017 weather-normalized peak load by Substation Area. As this Figure shows, the share of the Substation and Sub-transmission and Primary Feeder Cost Centers represents the majority of the total MC.

[28] Partially due to the projects for the Secondary Cable Cost Center being so infrequent and inexpensive, O&R had not been tracking these projects.

Figure 10: Average MC by Year ($/kW)

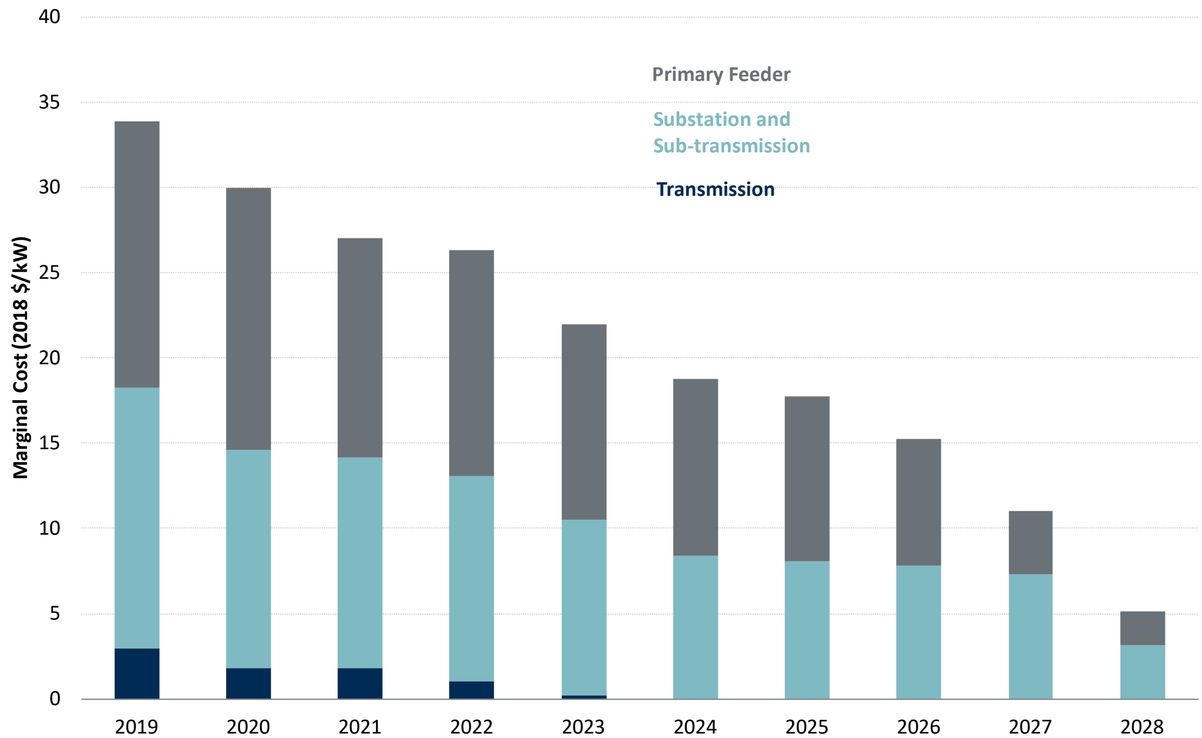


Table 8: 2019 Marginal Costs by Substation Area and Cost Center ($/kW) below shows the calculated 2019 MCs by cost centers for all Substation Areas.

Table 8: 2019 Marginal Costs by Substation Area and Cost Center ($/kW)

	Marginal Cost by Cost Center ($/kW)					
Substation Area	Transmission	Substation and Sub-transmission	Primary Feeder	Distribution Transformer	Secondary Cable	**Total**
Blooming Grove	0.00	39.76	0.00	0.00	0.00	**39.76**
Bloomingburg	0.00	0.00	0.00	0.00	0.00	**0.00**
Blue Lake	0.00	0.00	0.00	0.00	0.00	**0.00**
Bullville	0.00	0.00	0.00	0.00	0.00	**0.00**
Burns	23.81	48.03	40.81	0.00	0.00	**112.65**
Chester	0.00	0.00	0.00	0.00	0.00	**0.00**
Chester 34.5KV	0.00	0.00	0.00	0.00	0.00	**0.00**
Congers	0.00	41.45	0.00	0.00	0.00	**41.45**
Corporate Drive	0.00	0.00	0.00	0.00	0.00	**0.00**
Cuddebackville	0.00	0.00	0.00	0.00	0.00	**0.00**
Dean	0.00	0.00	0.00	0.00	0.00	**0.00**
East Wallkill	0.00	0.00	0.00	0.00	0.00	**0.00**
Harriman	0.00	0.00	70.55	0.00	0.00	**70.55**
Harriman 34.5KV	0.00	0.00	0.00	0.00	0.00	**0.00**
Hartley Road	0.00	0.00	0.00	0.00	0.00	**0.00**
Highland Falls	0.00	0.00	0.00	0.00	0.00	**0.00**
Hillburn	0.00	0.00	29.77	0.00	0.00	**29.77**
Hunt	0.00	0.00	11.37	0.00	0.00	**11.37**
Mongaup	0.00	0.00	0.00	0.00	0.00	**0.00**
Monroe	0.00	0.00	102.03	0.00	0.00	**102.03**
Monsey	0.00	48.03	0.00	0.00	0.00	**48.03**
Nanuet	0.00	0.00	0.00	0.00	0.00	**0.00**
New Hempstead	0.00	41.45	0.00	0.00	0.00	**41.45**
Orangeburg	18.79	0.00	0.00	0.00	0.00	**18.79**
Otisville	0.00	0.00	0.00	0.00	0.00	**0.00**
Pine Island	0.00	0.00	0.00	0.00	0.00	**0.00**
Port Jervis	0.00	49.81	0.00	0.00	0.00	**49.81**
Rio 34.5KV	0.00	0.00	0.00	0.00	0.00	**0.00**
Shoemaker	0.00	0.00	28.31	0.00	0.00	**28.31**
Shoemaker 34.5KV	0.00	0.00	0.00	0.00	0.00	**0.00**
Silver Lake	0.00	0.00	0.00	0.00	0.00	**0.00**
Sloatsburg	0.00	0.00	0.00	0.00	0.00	**0.00**
Snake Hill	0.00	0.00	35.92	0.00	0.00	**35.92**
South Goshen	0.00	0.00	56.49	0.00	0.00	**56.49**
South Goshen 34.5KV	0.00	0.00	0.00	0.00	0.00	**0.00**
Sparkill	18.79	0.00	0.00	0.00	0.00	**18.79**
Sterling Forest	0.00	0.00	0.00	0.00	0.00	**0.00**
Stony Point	0.00	0.00	0.00	0.00	0.00	**0.00**
Summitville	0.00	0.00	0.00	0.00	0.00	**0.00**
Swinging Bridge	0.00	0.00	24.38	0.00	0.00	**24.38**
Tallman	0.00	48.03	46.13	0.00	0.00	**94.15**
Tuxedo Park	0.00	0.00	151.35	0.00	0.00	**151.35**
Washington Heights	0.00	0.00	32.39	0.00	0.00	**32.39**
Washington Heights 34.5KV	0.00	0.00	0.00	0.00	0.00	**0.00**
West Haverstraw	0.00	41.45	0.00	0.00	0.00	**41.45**
West Nyack	20.03	0.00	0.00	0.00	0.00	**20.03**
Westtown	0.00	0.00	0.00	0.00	0.00	**0.00**
Westtown 34.5KV	0.00	0.00	0.00	0.00	0.00	**0.00**
Wisner	0.00	43.26	0.00	0.00	0.00	**43.26**
Wurtsboro	0.00	0.00	0.00	0.00	0.00	**0.00**
System Weighted Average	**2.94**	**15.32**	**15.62**	**0.00**	**0.00**	**33.87**

Table 9: Ten Year MC by Substation Area ($/kW) shows the total MCs by Substation Area for 2019-2028. The Study assumes the MC to fall to zero once an investment is made. Furthermore, the Study does not make any estimates of investment needs beyond the ten years. Therefore, as seen in this Table, the MCs will naturally decline over years (because there is less that can be saved by avoiding incremental load growth).

Table 9: Ten Year MC by Substation Area ($/kW)

	Marginal Cost ($/kW)									
Substation Area	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Blooming Grove	39.76	39.66	39.66	39.66	39.54	33.74	13.28	0.00	0.00	0.00
Bloomingburg	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Blue Lake	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bullville	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Burns	112.65	115.08	118.59	114.78	50.80	48.03	48.03	48.03	46.43	19.82
Chester	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chester 34.5KV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Congers	41.45	25.67	24.58	23.24	11.54	0.00	0.00	0.00	0.00	0.00
Corporate Drive	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cuddebackville	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dean	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
East Wallkill	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Harriman	70.55	62.15	68.27	75.00	82.39	90.50	63.12	33.04	0.00	0.00
Harriman 34.5KV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hartley Road	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Highland Falls	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hillburn	29.77	32.70	35.92	39.46	43.35	47.62	52.31	57.46	63.12	33.04
Hunt	11.37	12.49	13.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mongaup	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Monroe	102.03	112.08	92.97	102.13	112.19	75.00	82.39	90.50	63.12	33.04
Monsey	48.03	48.03	48.03	48.03	48.03	48.03	48.03	48.03	46.43	19.82
Nanuet	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
New Hempstead	41.45	25.67	24.58	23.24	11.54	0.00	0.00	0.00	0.00	0.00
Orangeburg	18.79	6.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Otisville	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pine Island	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Port Jervis	49.81	34.62	15.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rio 34.5KV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Shoemaker	28.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Shoemaker 34.5KV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Silver Lake	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sloatsburg	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Snake Hill	35.92	39.46	43.35	47.62	52.31	57.46	63.12	33.04	0.00	0.00
South Goshen	56.49	43.35	47.62	52.31	57.46	63.12	33.04	0.00	0.00	0.00
South Goshen 34.5KV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sparkill	18.79	6.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sterling Forest	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Stony Point	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Summitville	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Swinging Bridge	24.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tallman	94.15	98.70	48.03	48.03	48.03	48.03	48.03	48.03	46.43	19.82
Tuxedo Park	151.35	46.44	17.73	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Washington Heights	32.39	35.58	39.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Washington Heights 34.5KV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
West Haverstraw	41.45	25.67	24.58	23.24	11.54	0.00	0.00	0.00	0.00	0.00
West Nyack	20.03	10.10	21.31	12.66	2.78	0.00	0.00	0.00	0.00	0.00
Westtown	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Westtown 34.5KV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wisner	43.26	43.26	43.26	43.26	43.26	43.26	43.26	41.53	31.64	15.33
Wurtsboro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
System Weighted Average	**33.87**	**29.95**	**26.99**	**26.28**	**21.99**	**18.79**	**17.71**	**15.21**	**11.02**	**5.12**

III. Grouping for the VDER Proceeding

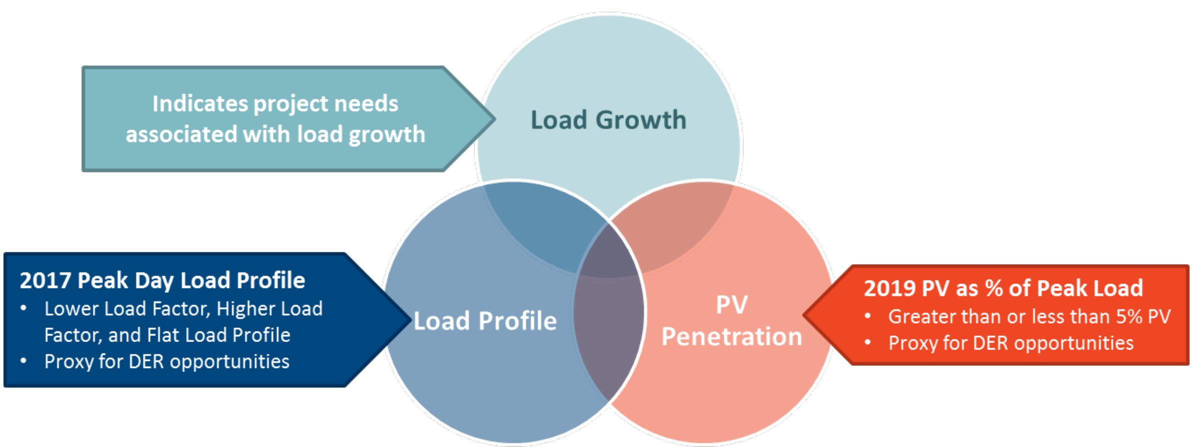
The locationally granular MCs can be used for a variety of purposes. For the VDER proceeding, locational MCs can aid O&R in evaluating the impacts of DER on a locational basis, establish common-valued areas, and set their values. For this purpose, the 50 Substation Areas are aggregated into groups. Representative MCs for these Substation Area groups can be used to set the value. There are two key purposes for grouping, rather than setting a separate marginal cost for each Substation Area, resulting in 50 distinct values. First, aggregation simplifies and eases the process of identifying Substation Areas with higher MCs that may benefit from DERs. Grouping also reduces the artefactual noise caused by MC differences among the Substation Areas, which are likely a result of the approximations used in the MC calculations. The preferred number of groupings, from the administrative and processing perspective, is less than ten (ideally five or less).

A. Grouping by Drivers

Grouping the 50 Substation Areas can be done in a variety of ways. With so many variables, it is easy to lose sight of the forest for the trees. One approach may be to group the Substation Areas solely based on the calculated MCs; another may be to group them by the underlying drivers of investment needs that lead to positive MCs. Reasonableness and practicality guide the choices.

The Study uses a hybrid approach and uses the three variables as shown in Figure 11: Grouping Drivers.

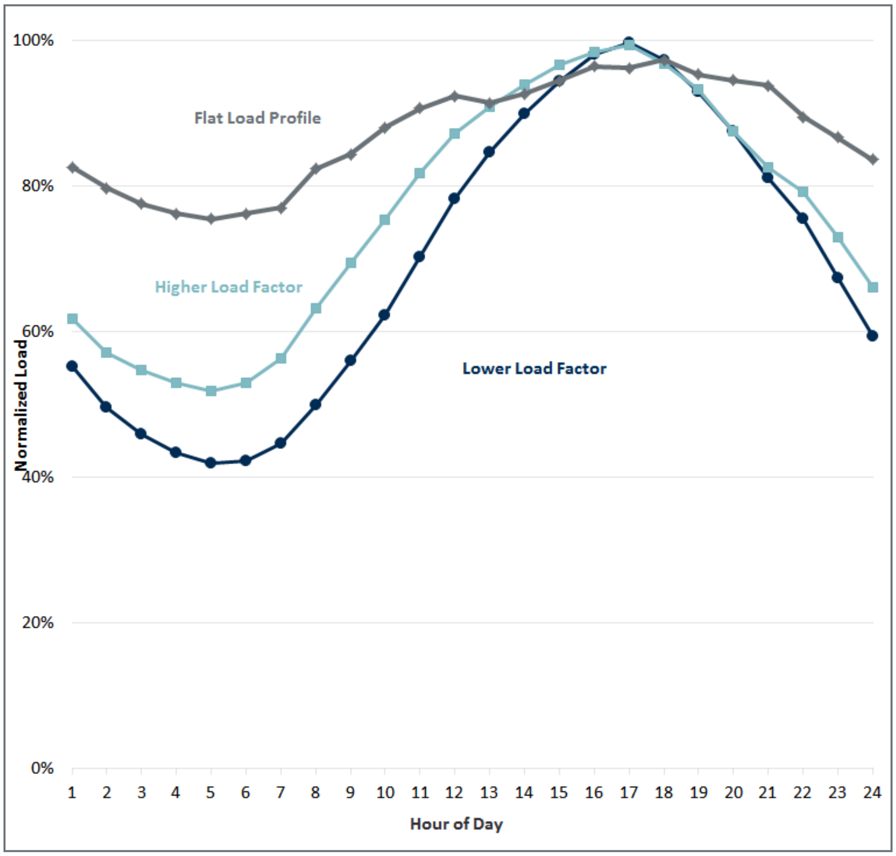
Figure 11: Grouping Drivers



The MC calculation for this Study heavily relies on project estimates from the CIP. The radial systems' characteristics make it difficult to rely solely on the underlying drivers. For example, load growth data were only available at the Substation Area level, not for the individual radial feeders. Therefore, the Study uses the MCs calculated through CIP and associated analyses. The MC calculation by itself does not sufficiently distinguish DER needs for individual Substation Areas or their components. Therefore, the Study looks at two potential drivers of DERs—the load profile by Substation Area, and the potential of DER development.

The load profile helps identify the characteristics of potential DERs that may best help avoid the investment needs to accommodate incremental load growth. For example, solar PVs' contribution to peak load reduction may be substantially limited in a Substation Area that has higher load after sunset. To assess such a potential distinction, cluster analysis of the daily load profile of all Substation Areas was performed. The cluster analysis—details of which are in Appendix-C: Load Profile Clustering—indicates that the 50 Substation Areas' load profiles can be clustered into three representative load profiles, as shown in Figure 12: Load Profile Cluster Centers below.

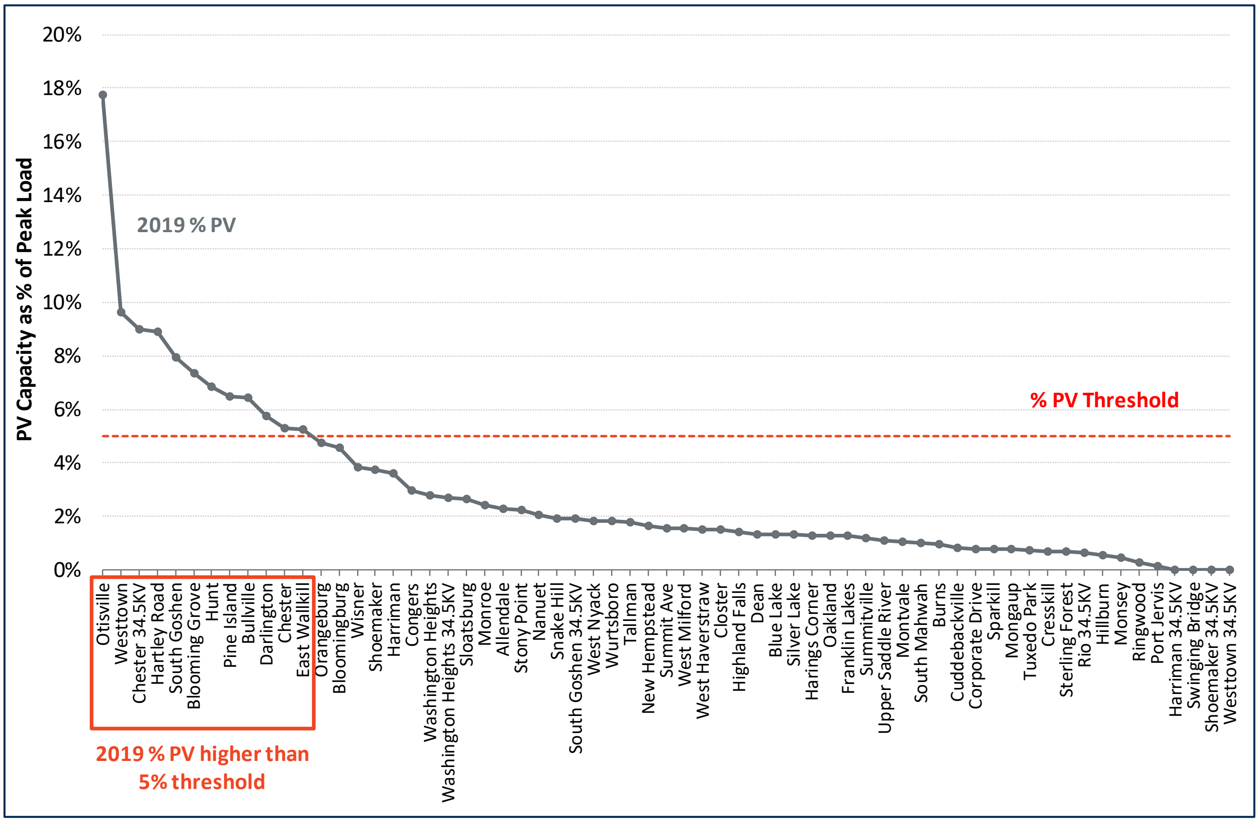
Figure 12: Load Profile Cluster Centers



These 24-hour normalized load profiles can serve as a proxy to identify DER opportunities. For example, Substation Areas with a Lower Load Factor Profile (shown by the navy-colored line) may benefit most from a DER option that can shift load, such as storage. On the other hand, Substation Areas with a Flat Load Profile (shown in the grey line) may be most suitable for a DER option that provides constant power throughout the day. Both the Higher Load Factor Profile (shown by the teal-colored line) and Lower Load Factor profile (shown by the navy-colored line) have a short peak around 5 PM. This may indicate that solar PVs that are facing west, rather than the typical eastern facing set-up, would be preferred for avoiding investments.

Opportunities for DERs may not be equal among Substation Areas, even if they share the same representative load profiles. Each Substation Area (or a part of) may have different limitations on developing DERs. Such limitations may include the hosting capacities of the distribution system, the number of dwellings that could accommodate DERs (areas with single-family houses may be easier to develop rooftop PV systems than areas with high-rise apartments), demographics (affluent areas vs. others), local ordinances, and many other factors. Rather than analyzing these individual factors (while it would be ideal to do so), the Study assumes that the projected PV capacity for 2019 as the percent of the peak load (adjusted by all load modifiers except PV) can be used as a good indicator of these limitations. Assuming the projections are correlated with where DER developers see opportunities today, this can serve as a proxy for forward-looking DER opportunities. Figure 13: 2019 PV Penetration Rate shows the PV penetration—represented by 2019 projected PV capacity as a percent of the peak load (adjusted by all load modifiers except PV). For this Study, a threshold of 5% was used to identify whether a Substation Area had high or low PV penetration.

Figure 13: 2019 PV Penetration Rate



B. Grouping Results

Based on these three drivers, the 50 Substation Areas were initially grouped into the six groups ("Initial Groups"). Table 10: Initial Groups shows the six Initial Groups, their drivers, and count of Substation Areas.

Table 10: Initial Groups

IG #	Project Existence	Load Profile	PV Penetration	Substation Area Count	Avg IG 2019 MC ($/kW)
IG 1	Yes	Low Load Factor	Low	9	$67
IG 2	Yes	High Load Factor	High	1	$56
IG 3	Yes	Flat	Low	1	$50
IG 4	Yes	High Load Factor	Low	9	$29
IG 5	Yes	Low Load Factor	High	2	$28
IG 6	No	n/a	n/a	28	$0

The two Initial Groups with high PV penetration only included a total of three Substation Areas. The PV penetration levels of these four Substation Areas ranged between 6.9% and 7.9%, averaging 7.4%. Initial Group 6 (the group with no projects and therefore zero MC) contained eight Substation Areas with high PV penetration, ranging from 5.3% to 17.7%, averaging 8.6%. With these observations, the PV penetration level driver, while a potentially useful driver to identify in the future, was dropped.

Upon foregoing the PV penetration level driver, the six Initial Groups were further aggregated into four groups ("Aggregate Groups") based on the similarity of their load profile and average MCs for 2019. Table 11: Initial Groups and Aggregate Groups below shows the six Initial Groups, their characteristics and average 2019 MCs, and the resulting four Aggregate Groups and their average 2019 MCs (weighted by the Substation Areas' 2017 weather-normalized peak load). AG 1, which includes ten Substation Areas, mostly consisting of those with Lower Load Factor Profiles (there is one Substation Area with a Higher Load Factor Profile), has the highest MC. AG 2 with the second highest MC consists of a single Substation Area with a Flat Load Profile. AG 3, which includes 11 Substation Areas, mostly consisting of those with Higher Load Factor Profiles (there are two Substation Areas with Lower Load Factor Profiles), has the lowest non-zero MC. AG 4 includes the remaining Substation Areas, all with estimated MCs of zero.

Table 11: Initial Groups and Aggregate Groups

IG #	Project Existence	Load Profile	Substation Area Count	Avg IG 2019 MC ($/kW)	AG #	Substation Area Count	Avg AG 2019 MC ($/kW)
IG 1	Yes	Low Load Factor	9	$67	AG 1	10	$67
IG 2	Yes	High Load Factor	1	$56			
IG 3	Yes	Flat	1	$50	AG 2	1	$50
IG 4	Yes	High Load Factor	9	$29	AG 3	11	$29
IG 5	Yes	Low Load Factor	2	$28			
IG 6	No	n/a	28	$0	AG 4	28	$0

Figure 14: MC and Combined Load of the Groups visualizes the average (weighted by the weather-normalized 2017 peak load) 2019 MC and combined load (sum of the 2017 peak load) of the Substation Areas for the six Initial Groups and four Aggregate Groups. The blue and red boxes represent the Initial Groups and Aggregate Groups respectively in the order shown in Table 11: Initial Groups and Aggregate Groups above. The black text indicates the Initial Groups (abbreviated as IG #) and red text/values indicate the Aggregate Groups (abbreviated as AG #) and their corresponding average 2019 MCs (in $/kW). The combined load of the Substation Areas that are assigned to each Aggregated Group (a sum of the weather-normalized 2017 peak load of the corresponding Substation Areas) are shown at the bottom of this figure.

Figure 14: MC and Combined Load of the Groups

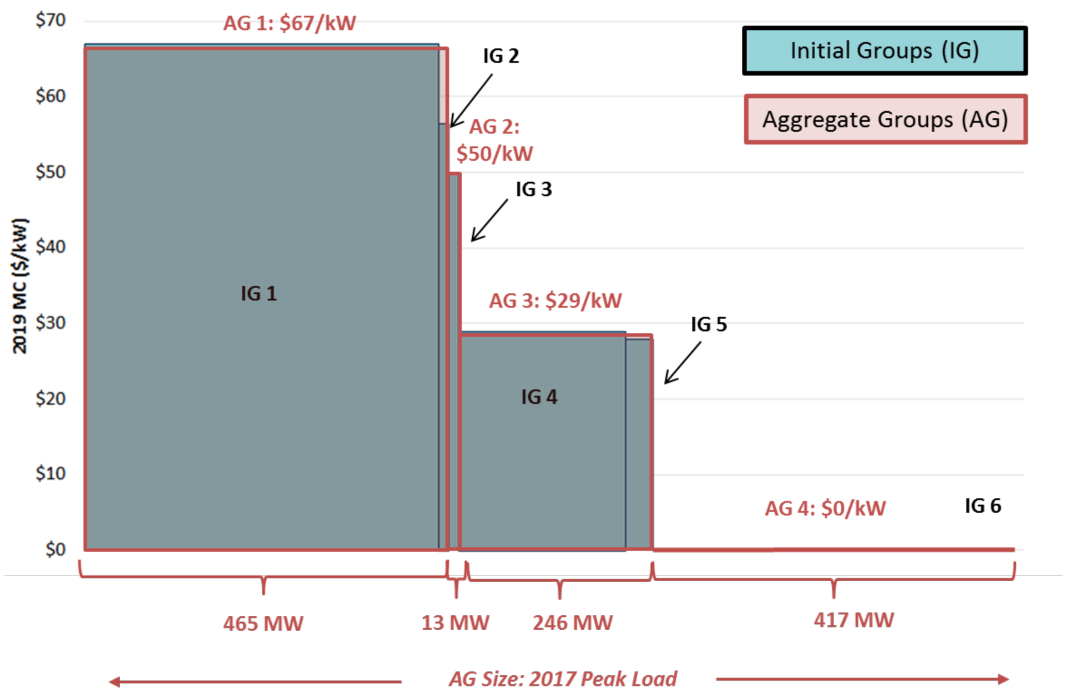
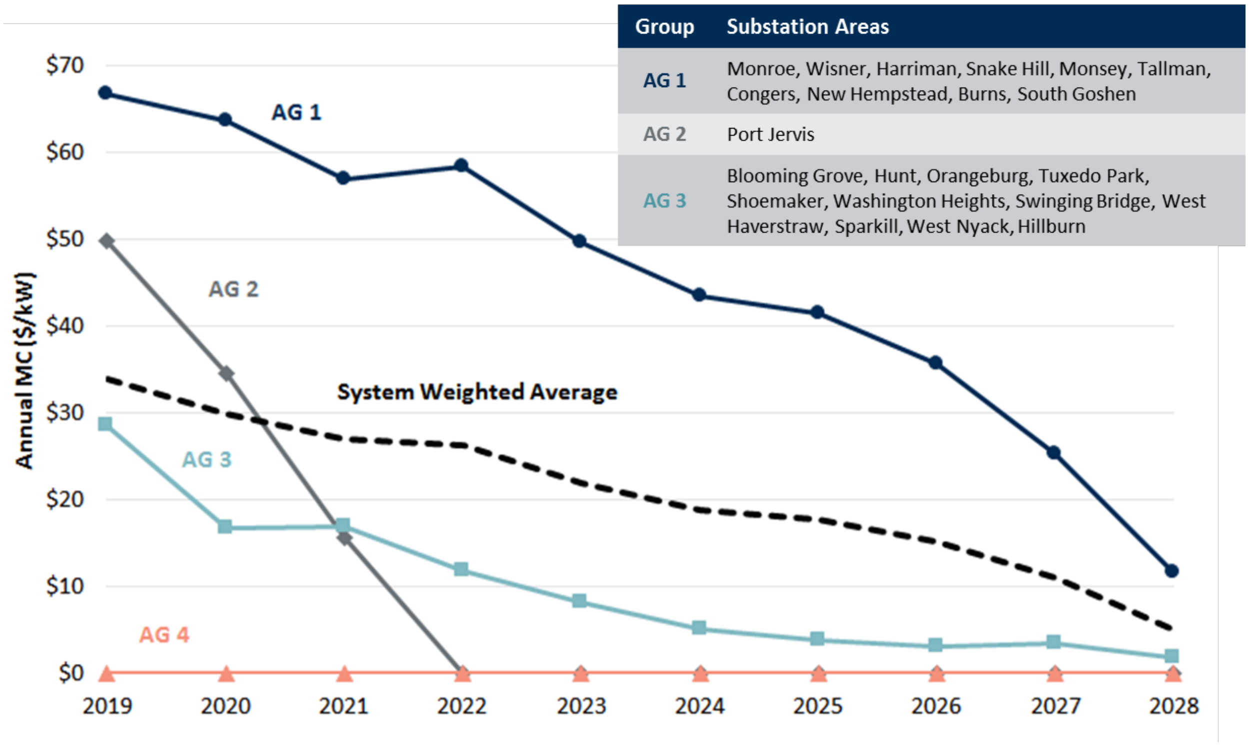


Figure 15: Ten Year Average MC for Aggregate Groups and System Average shows the MC for the four aggregate groups, along with the system average MC (weighted by the forecasted future years' peak loads), for the ten year Study period. The Table within this Figure indicates the Substation Areas that belong to each Aggregate Group.

Figure 15: Ten Year Average MC for Aggregate Groups and System Average

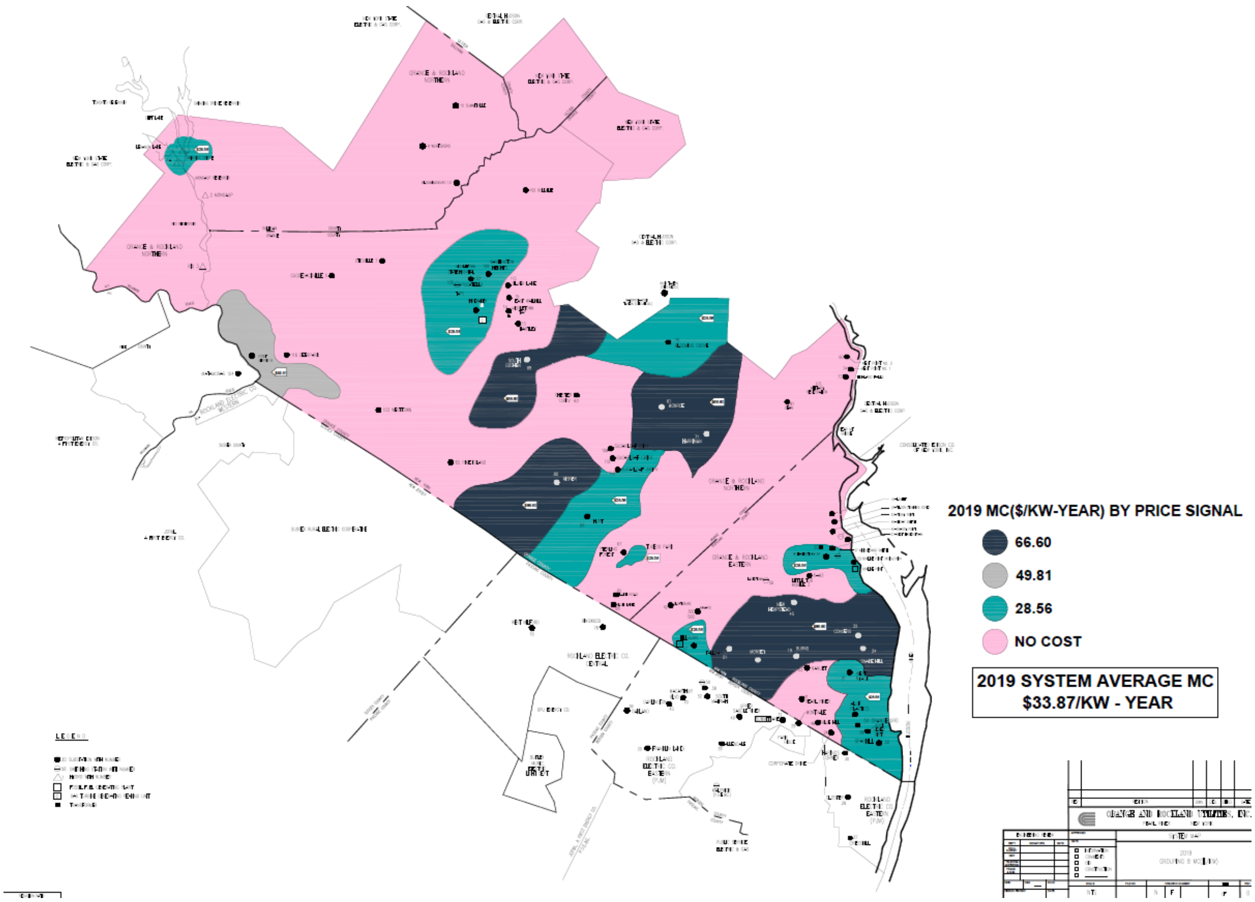


Group	Substation Areas
AG 1	Monroe, Wisner, Harriman, Snake Hill, Monsey, Tallman, Congers, New Hempstead, Burns, South Goshen
AG 2	Port Jervis
AG 3	Blooming Grove, Hunt, Orangeburg, Tuxedo Park, Shoemaker, Washington Heights, Swinging Bridge, West Haverstraw, Sparkill, West Nyack, Hillburn

This figure clearly distinguishes two Aggregate Groups (AG 1 shown in the navy-colored line and AG 2 shown in the gray-colored line) to have MCs significantly above the system average in the early years and are likely to benefit more from peak load reductions, which DERs may be able to provide. In particular, the Load Profiles for AG 1 are either Higher Load Factor or Lower Load Factor Profiles (most are Lower Load Factor Profiles), which both indicate a short peak around 5 PM. A load shifting type of DER could benefit these Substation Areas, even if it only shifts load for a few hours. For solar PVs to be installed in these Substation Areas, a west-facing system would be preferred over the typical east facing system for the goal of deferring capacity investments (i.e., investments to accommodate incremental load growth). AG 2 with a Flat Load Profile may benefit from a DER that provides constant power throughout the day; however, as the declining MC curve indicates, the opportunity window is limited to the immediate years. The benefits DERs may bring to AG 3 and particularly AG 5 may be limited. These observations can be used to value the benefits of DERs, including their location, as part of the VDER process. Another observation is the difference that could be a result of the load profiles. AG 2 with Flat Load Profiles show a much steeper decline in MC, compared to AG 1 or AG 3, which are both a mixture of Higher and Lower Load Factor Profiles. The difference in the MC decline rate among the Aggregate Groups can be used to time the DER investments, and any policy or incentives being designed for such purpose should consider this difference.

Figure 16: 2019 MC Map illustrates the MCs at the Aggregate Group level for 2019 by Substation Area, identifying geographically the Substation Areas with potentially higher capacity benefits from DERs.

Figure 16: 2019 MC Map



C. Applying the Grouping Results

Using these MC observations as part of the VDER process requires caution and understanding of the underlying assumptions made through the MC calculations. Once installed, many DERs can be expected to last twenty years or more. The Study only covers ten years. Furthermore, a large portion of the underlying assumptions used for the MC calculation can change year by year rendering that locational MCs may not always be the most appropriate option for assessing the 20-year payment to a new DER.

Even if relying on MCs is the best alternative available, there are cases where the MCs by themselves do not represent the potential benefits (i.e., avoided costs) that can be provided by DERs. For example, the MCs for Burns and West Nyack Substation Areas include a new 138kV underground line—a Transmission Cost Center investment that is scheduled to go in service in 2023. Investments began prior to 2018 and are expected to continue through 2023. Because the initial investment has been made and the project cannot be cancelled in any practical way, a DER that reduces peak load for the Burns or West Nyack Substation Area today (or in the near future) will likely not avoid the investment costs for 2020 through 2023. Another example may be when multiple projects of the same cost center are observed in a given Substation Area—for example, at the Primary Feeder Cost Center, there are two projects for the Tuxedo Park Substation Area in 2020 and Burns Substation Area in 2022. The Study assumes that in a radial system a single upgrade will only eliminate the needs for the specific location and not benefit other parts within the same Substation Area, as a networked system may—therefore, a single upgrade may not be sufficient to avoid the MC.[29]

It should also be noted that the incremental load-serving capacity used for calculating the MCs is the post-contingency capacity that may be further reduced based on system-specific conditions. Therefore if these MC values are used as a guideline for evaluating the benefits of DERs, the capability of DERs should not be taken at face value—the level of reliability provided by these alternatives may not be comparable.[30] Another reliability concern may be the availability of the DERs. If DERs are awarded the avoided cost, will the DERs be held responsible at the same level as the utility would for not performing in real time? Or will the DERs have options to walk away without paying any penalty other than forgoing the agreed upon payment? And in such cases, will the utility be asked to provide a back-stop solution? These differences should also be taken into account when assessing the value DERs may provide.

Finally, timeliness in action is important. As Figure 15: Ten Year Average MC for Aggregate Groups and System Average shows, the MCs for three out of the four Aggregate Groups will converge and become less than $10/kW or so by the fourth year. Even the outlying AG 1 with the high MCs will converge and become about $10/kW by the tenth year. This should demonstrate to DER developers the diminishing return (as observed in most investments) and also the first runner advantage. For policy makers, this MC change indicates the need for a speedy response should a policy (or incentive) to guide DER investments of the appropriate type to the best locations be needed. And these policies need to be adjusted periodically. The changing MC over time also illustrates the importance of refreshing the MCCOS every two to three years and modifying such policies and/or incentives in a timely manner to reflect the updated MCCOS results.

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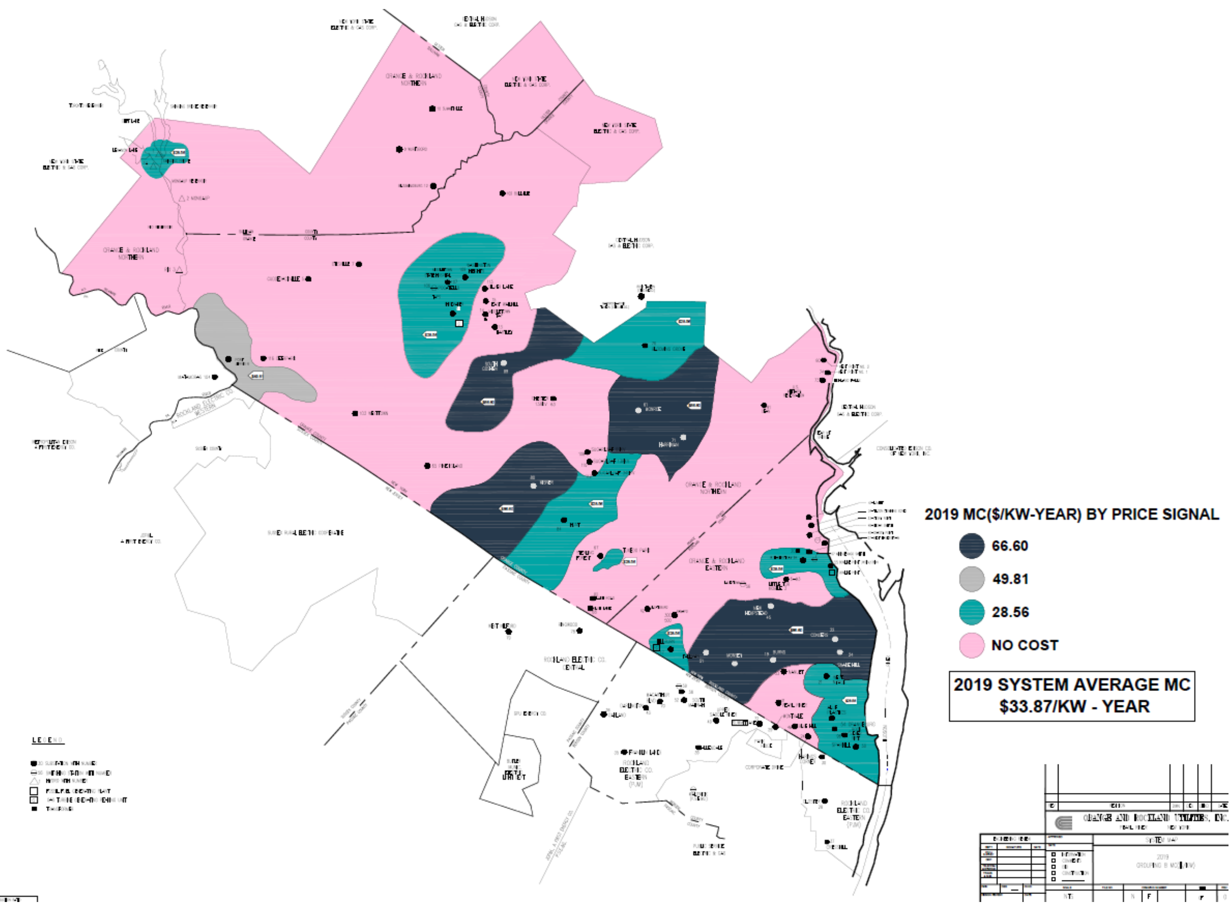
29 For example, assume a given radial Substation Area requires two upgrades, one with a higher cost and the other with a lower cost. The MC will likely be a value between these two costs (such as a weighted average value). Compensating a DER that relieves the need for the lower cost upgrade need will not avoid the MC entirely.

30 A study performed by EPRI titled "Time and Locational Value of DER – Method and Applications" dated October 2016 (available at: https://www.epri.com/#/pages/product/3002008410/) reviews methods for valuing the temporal and spatial impacts of DER on both radial and network distribution systems of Con Edison and Southern California Edison. One of the findings is that: "For radial systems, DER located downstream from a capacity-constrained asset (relative to the substation) can contribute directly to relieving the violation. However, radial systems are often reconfigured in order to meet new load growth, perform maintenance, or for other operational considerations, to the point where the DER could have little or even an adverse impact."

IV.Conclusion and Recommendations

This Study developed MCs for the 50 different Substation Areas within the O&R New York service territory. The MCs were developed for five cost centers over ten years from 2019 through 2028. These 50 Substation Areas are further aggregated into four groups (Aggregate Groups). The grouping has shown significant variation among the Substation Areas with more than half of the Substation Areas indicating zero MCs for all years, while the highest Aggregate Group that includes ten Substation Areas shows about $67/kW in 2019, gradually dropping to approximately $10/kW over the ten year Study period. This Aggregate Group's load profile indicates that the peak load of these Substation Areas occur over a short time, over a few hours, approximately around 5 PM. Therefore DERs that can shift the peak load, even for a few hours, or reduce load around the early evening timing when the sun is starting to set, would be beneficial to the systems. Two other Aggregate Groups also show positive values in the early years; however, by the fourth year the MCs converge to around $10/kW or less. This drop potentially indicates that the benefits of DERs (as means to delay or avoid MCs) are limited to a number of Substation Areas, within a concentrated geographical footprint, as identified in navy, grey, teal, and pink in Figure 17: 2019 MCs below.

Figure 17: 2019 MC Map



Relying on MCs as one of the metrics to evaluate and determine a value requires caution. DERs, once installed, may be in service for as long as 20 years. MCs, on the other hand, are estimated over a shorter period (ten years in this Study) and rely on assumptions that are for a shorter horizon on a case by case basis. Even if relying on MCs is the best alternative, the MCs by themselves should not be translated directly as the value. The estimated reliability contribution from DERs among other factors, including the underlying assumptions used in calculating MCs, need to be considered and adjusted for appropriately.

The rapid year by year change in MCs should also be noted. As discussed above, the MCs for two out of the three non-zero Aggregate Groups identified in this Study converge within the first four years to become roughly $10/kW or less, indicating the need for a speedy response should a policy (or incentive) to guide DER investments of the appropriate type to the preferred location is desired. It also illustrates the importance of refreshing the MCCOS study periodically and modifying such policies and incentives promptly to match the updated MCCOS results.

In updating future MCCOS, there are several recommendations for improvements. As this study was the first of its kind for O&R, historical data was relatively limited.[31] Data collected over multiple years may also be used to estimate future costs—such as by observing a trend in costs over the year—when planning studies are not available. Second, the Study assumes zero salvage value for any replaced asset. An internal review of the salvage values could improve the Study results. Similar to the cost estimates, data collected over multiple years can also be used to estimate future salvage values. Should this review or data collection be difficult, an alternative approach in calculating the MCs may be to simply assess the benefits of delaying the investment by one year. Lastly, financial loaders that are sourced from relatively older studies should be updated once new information becomes available.

[31] Increasing data samples may also be a challenge given the projected flat load growth.

Glossary

Commission–The New York Public Service Commission

DER –Distributed Energy Resource

DPS –Department of Public Service

kVA –kilo-volt-amperes

kW -kilo-watts, equal to 1000 watts

CIP–Capital Investment Plan

LSRV –Locational System Relief Value

MC – Marginal Cost

MCCOS– Marginal Cost-based Cost of Service

NPV–Net Present Value

O&R-Orange and Rockland Utilities

PV–Photovoltaic

REV–Reforming the Energy Vision

VDER –Value of Distributed Energy Resources

Appendix-A: Financial Loaders

The investment cost (in $/kW) calculated using the incremental investment costs (net of salvage value) as the numerator and incremental capacity (net of existing asset capacity) as the denominator, is annualized. This appendix discusses the parameters ("Loaders") used for the annualizing calculation and the sources they are derived from. It then compares these Loaders values to those used in previous MCCOS.

Table A-1: Parameters Used for Annualizing Investment Costs below summarizes the Loaders used for this Study.

Table A-1: Parameters Used for Annualizing Investment Costs

Varies Across Equipment and Application	
Plant A&G Costs	0.00% - 0.07%
Cost Center O&M	2.77% - 7.86%

Common Across Equipment and Application	
Inflation Rate	3.00%
Common Plant %	12.75%
Economic Carrying Charge	8.14%
Working Cap as % of Electric PIS	3.98%
Income Tax Rate	6.36%
Regulated WACC	9.85%
Non-Plant A&G	3.05%
Revenue Requirement for Working Capital	16.21%

The first half of this table shows the following two Loaders that vary across cost centers:

- Plant A&G Costs are calculated by dividing total plant A&G cost in a historical year by total insurable values in the same year, which results in 0.07% Plant A&G. Plant A&G is set to 0% for Primary Feeders and Secondary Cables.

- Cost Center O&M values are unique to each cost center and are based on 2015 O&R Electric Embedded Cost of Service ("ECOS") Study Workpapers. These values have not been updated since then because more recent studies have not been performed.

The second half of this table shows Loaders that are common across all cost centers:

- Inflation Rate is the commonly used value among other O&R filings.

- Common Plant % is calculated by dividing the common plant value by the electric plant value. These values are pulled from the 2015 O&R ECOS Study.

- Economic Carrying Charge is calculated using the following formula:

  ((r-i)×(1+r)^n)/((1+r)^n-(1+i)^n)×Cost of Capital
  where
  r = Discount Rate = 9.85%
  i = inflation rate = 3.16%
  n = Service life (years) = 54
  Cost of Capital = 1.1761

- Working Capital as % of Electric Plant in Service (PIS) is calculated by dividing working capital by total electric plant in service, with Purchase Power excluded. Both values are derived from the 2015 O&R Electric ECOS.

- Income Tax Rate is calculated by applying the weighted costs of debt, customer deposits, and common equity to the tax rate.

- Regulated WACC is calculated by summing up pre-tax weighted costs of debt, customer deposits, and common equity. All values are from the 2014 O&R Rate Case Capital Structure.

- Non-Plant A&G is calculated by dividing social security and unemployment taxes by O&M less fuel, purchased power and transmission by others. Both values are from the 2016 Con Edison Annual Report filed with the PSC.

- Revenue Requirement for Working Capital is calculated by summing up the Regulated WACC (i.e., the composite incremental cost of capital) and the income tax component, both of which are described above.

Table A-2: Comparison of Loaders Used in Current and Past Studies below summarizes the loaders from this Study.

Table A-2: Comparison of Loaders Used in Current and Past Studies

Loader	2015	2018
Plant A&G	0.07%	0.07%
Common Plant %	15.58%	12.75%
Economic Carrying Charge	8.14%	8.14%
Working Cap as % of Electric PIS	3.51%	3.98%
Income Tax Rate	2.79%	6.36%
Regulated WACC	7.06%	9.85%
Non-Plant A&G	1.86%	3.05%
Revenue Requirement for Working Capital	9.85%	16.21%

Appendix-B: O&R MCOS Methodology Summary Report

3/8/2019

Marginal Cost of Service Study

2018 O&R Traditional Wires Options Methodology to meet Load Growth

Distribution Engineering
ORANGE AND ROCKLAND UTILITIES, SPRING VALLEY, NY 10977

SUMMARY

Orange and Rockland Utilities, Inc. (“O&R’, “the Company”) designs and plans for investments and solutions to maintain the reliability of its electric transmission and distribution (“T&D”) infrastructure many years in advance to have sufficient capacity to meet customer energy requirements in a manner that satisfies the Company’s design standards and risk tolerances. This report briefly describes the methodology and parameters utilized to develop the locational marginal cost of service (“MCOS”) based on the Company current ten-year forecast and capital investment plan (“CIP”).

These marginal cost (“MC”) results were developed for the Company’s New York service territory, and can serve to support locational valuation for the integration of DER and other alternative solutions such as those being evaluated and considered in regulatory policy and proceedings, such as the Value of Distributed Energy Resources (“VDER”). The results provide for multiple and varying MC values across O&R’s service territory in New York.

Ten-year infrastructure investment plans are developed annually for the electric T&D system to identify projects well in advance that will maintain sufficient capacity to meet growing customer load, and to be in accordance with the Company’s risk analysis and design standards. As part of the Company’s overall integrated planning process, an annual CIP is developed that identifies numerous capital projects primarily at the transmission, substation and distribution mainline feeder levels of the system, which are incorporated into O&R’s annual capital budget and a multi-year capital forecast. As such, the latest CIP was utilized to provide key information for this study, and the project results were grouped into three categories based on their implementation within three distinct segments of power delivery infrastructure: (1) Transmission, (2) Substation, which both correspond to the Substation and Sub-transmission Cost Center, and (3) Primary Feeders. The other lower voltage cost centers, namely Distribution Transformer and Secondary Cable Cost Centers were considered as well, however, the analysis of the marginal cost impacts at these levels of the system were determined to be de minimis.

Appropriate selection of project or solution type for incremental / marginal cost consideration depends on multiple factors that are system need and location dependent, and include other key criteria. These are described more fully in the sections that follow.

1. TRANSMISSION

Transmission systems are comprised of a high voltage interconnected network that serves to provide reliable and redundant service to substations; O&R's transmission network operates primarily at 345kV, 138kV and 69kV, with key transformation points between these systems. This section describes the various types of traditional project options to enhance the capacity of transmission systems.

Applicable MC values for transmission projects may include replacing feeder sections and/or adding new feeders. Feeder section replacements refers to installing a higher rating cable or conductor in place of an already existing one of a lower rating. The capability to serve more capacity at a substation may require a capacity increase at a transmission or sub transmission level by the addition of new feeder or upgrading existing feeders between transmission switching station and/or area substations.

Appropriate capacity related transmission projects from the Company's latest CIP were selected. Projects that are driven predominantly to solve reliability and redundancy were not considered. Projects that are driven by customer requirements, safety, or to solve operational issues, aging or obsolescence were excluded from the study. Project benefits and MC's for the selected projects were linked to the terminating substations. The marginal capacity (MVA) increase is determined as the amount needed to reach design standards and the total capacity (MVA) increase is the total increase in capacity of the project is determined by the new infrastructure ratings. The ratio of the marginal capacity increase to meet design standards over total capacity increase is used to determine the prorated cost of the project. The formula below represents the way the adjusted cost of the projects are calculated:

$$Prorated\ Cost\ of\ project = \frac{Capacity\ Increase\ to\ reach\ criteria}{Total\ Capacity\ Increase}\ X\ Total\ Cost\ of\ the\ Project$$

2. SUBSTATION

Substations transform power from transmission voltages (69kV and 138kV) to distribution primary voltages (predominantly 13.2kV for the O&R system). The main components of a substation include transformers, switchgear, breakers and buswork.

The substantial MCs for substation projects could include replacing a transformer, adding a transformer and / or constructing a new substation. Transformer replacement refers to installing a new transformer of higher ratings in place of an existing transformer. A new transformer is added to a station when the capacity of existing transformers cannot adequately or reliably meet the demand. The addition of a new substation may be required if existing area stations cannot be adequately or cost efficiently upgraded or expanded.

Appropriate capacity related substation projects from the Company's latest CIP were selected. Projects that may have had varying levels of growth but that were also failing design standards were selected. Projects that are driven predominantly for reliability and redundancy were not considered in this study. Projects that are driven by customer requirements, safety, or to solve operational issues, aging or obsolescence were excluded from the study. Project benefits and MC's for the selected projects were linked to the projected new substation areas and customers the new projects would be serving. The marginal capacity increase (MVA) is calculated as the amount needed to meet design standards, and the total capacity (MVA) is determined by the new infrastructure ratings. The ratio of the marginal capacity increase to meet design standards over total capacity increase is used to determine the prorated cost of the project. The formula below represents the way the adjusted cost of the projects are calculated:

$$Prorated\ Cost\ of\ project = \frac{Capacity\ Increase\ to\ reach\ criteria}{Total\ Capacity\ Increase}\ X\ Total\ Cost\ of\ the\ Project$$

3. PRIMARY FEEDER

Primary distribution mainline feeders emanate radially from a substation and supply power at medium and lower voltages to local area businesses and customers.

The substantial MCs for primary feeder projects could include load growth projects related to load transfers, replacing feeder sections and/or installing new feeders. Load transfer between substations to address potential overload conditions on a feeder is common practice. Equipment costs associated with load transfer projects could include adding and upgrading segments, and/or installing switches to facilitate moving and switching load. Feeder replacement or the installation of new feeders could be required if a station has the capacity to supply forecasted load growth, but the existing local area primary feeder(s) are limiting the acceptable delivery of power on the distribution system within appropriate thermal and voltage limits.

Appropriate capacity related primary feeder projects from the Company's latest CIP were selected. Projects that may have had varying levels of growth but that were also failing design standards were selected. Projects that are driven predominantly for reliability and redundancy were not considered in this study. Projects that are driven by customer requirements, safety, or to solve operational issues, aging or obsolescence were excluded from the study. Projects that are already considered and needed to accommodate solutions in the substation projects portion of this study were not considered. Project benefits and MC's for the selected projects were linked to the projected new substation areas and customers the new projects would be serving.

The marginal capacity increases for the primary feeder projects are calculated differently depending on the solution types. If a project includes future mainline upgrade (e.g., fill in the gap), the full capacity of the conductor is utilized and a factor is applied depending on the position of the circuit to the station (refer to Table 1). If a project involves the removal of stepdown transformer (e.g., 4kV conversion) and an upgrade from #4 conductor (normal rating-180Amps) to #4/0 conductor (normal rating- 341 Amps), the limiting factor is the conductor. In this case, the required increase in capacity is that of the conductor and the same Table 1 factors are applied depending on the position of the circuit to the station. The other type of primary feeder project could be a system expansion project that involves additional new business load growth. The capacity increase includes only the new business load and then a factor being applied depending on the position of the circuit to the station (Table 1).

Table 1-Derating factor used for primary projects to represent position of the project with respect to the circuit

Position of the Circuit	Percentage (%)
Head end of the circuit	100%
4/5th position of the circuit	80%
3/5th position of the circuit	60%
2/5th position of the circuit	40%
Tail end of the circuit	20%

Since primary feeder projects are identified only for a five-year forecast period, projects were projected to be constructed in areas linking to future substation related projects in the 2024 to 2028 timeframe as a proxy for probable primary feeder project requirements during that time period of the study. The primary feeder projects in 2024 to 2028 years were based on forecasted load growth resulting from economics and population growth that is expected to evolve in future years.

The only exception was, Tuxedo Park which was made into its own substation area. Tuxedo park is a small village fed from mutliple step down transformers whose load behavior is confined to the park and do not justify applying MCOS value to the whole substation. The substation area was created as it was a load pocket issue and not a substation issue. To determine the capacity of the primary projects in Tuxedo Park, the derating factor of 50% was used to represent that the two feeds to the park was split equally between them (and Table 1 was then applied). Additionally, as the load of Tuxedo

Park was 40% of overall Sterling Forest Substation load, 40% was applied as a derating factor for the Tuxedo Park project costs.

4. DISTRIBUTION TRANSFORMER

Secondary distribution transformers convert primary voltage to customer utilization voltage. The MC's for adding or replacing distribution transformers were de minimis and thus were not included in the study.

5. SECONDARY CABLE

Secondary cable/feeders connect the low side of distribution transformers with customer services. The reinforcements of secondary systems are needed in case load growth results in low voltage or thermal problems. The secondary feeder capacity enhancement projects are not frequent, not expensive and are not tracked by the Company. Any MC's for this portion of the electric delivery system are de minimis and thus were not included in the study.

MCOS RESULTS

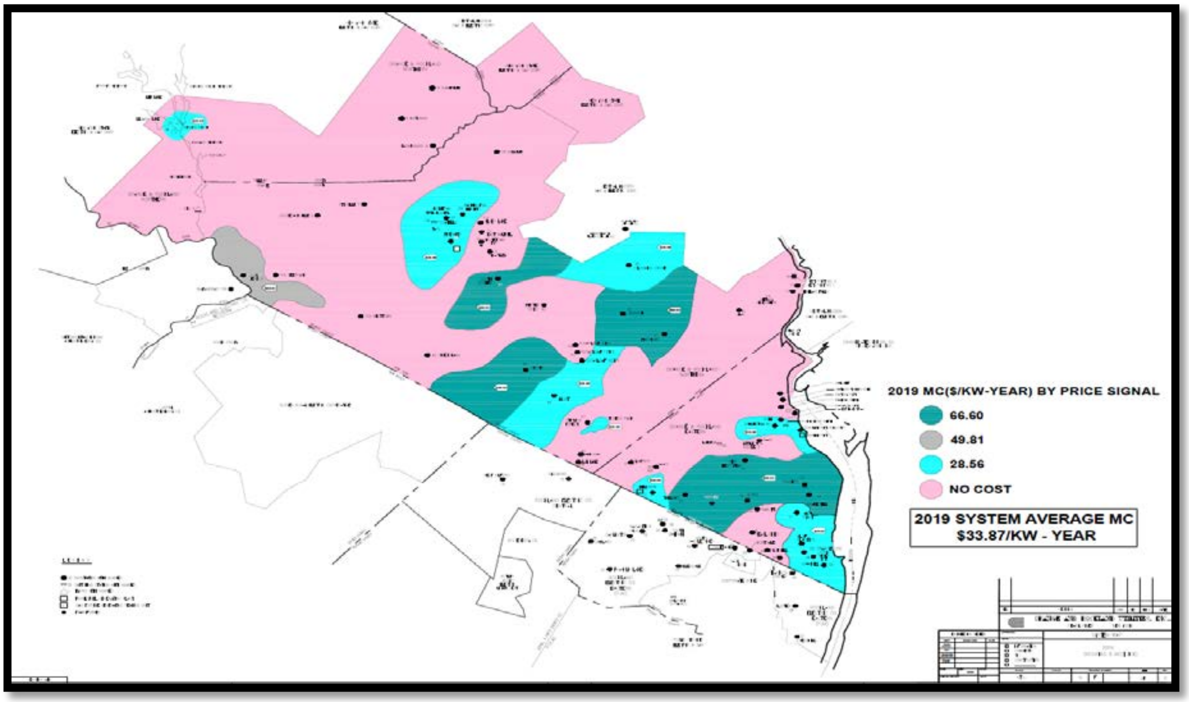
The information and details that follow provide the results of this MCOS study. These marginal MC results were developed for the Company's New York service territory, and can serve to support locational valuation for the integration of DER and other alternative solutions such as those being evaluated and considered in regulatory policy and proceedings, such as VDER. The results provide for multiple and varying MC values across O&R's service territory in New York.

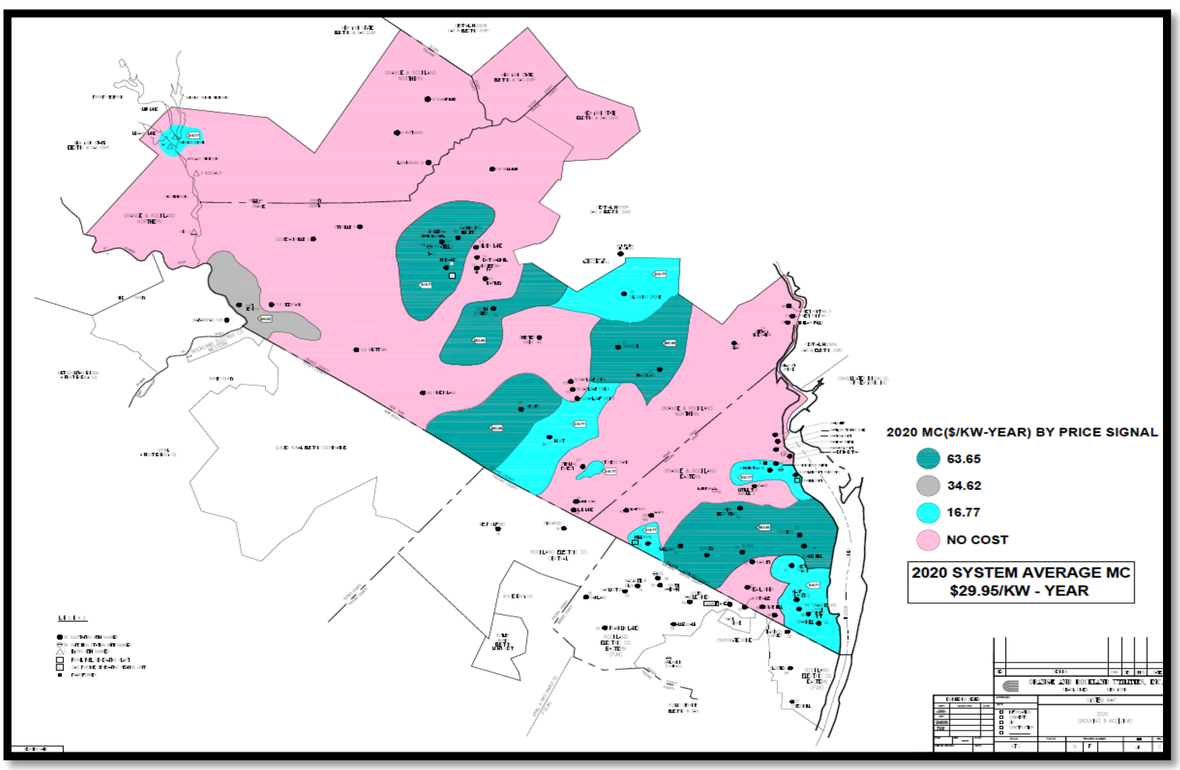
Grouping Approach: Load Type + 2019 PV Penetration + Project

		Aggregate Group MC ($/kW)									
Substation Area	Aggregate Group	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Monroe	Aggregate Group 1	66.60	63.65	56.85	58.23	49.62	43.35	41.40	35.67	25.22	11.60
Wisner	Aggregate Group 1	66.60	63.65	56.85	58.23	49.62	43.35	41.40	35.67	25.22	11.60
Harriman	Aggregate Group 1	66.60	63.65	56.85	58.23	49.62	43.35	41.40	35.67	25.22	11.60
Snake Hill	Aggregate Group 1	66.60	63.65	56.85	58.23	49.62	43.35	41.40	35.67	25.22	11.60
Monsey	Aggregate Group 1	66.60	63.65	56.85	58.23	49.62	43.35	41.40	35.67	25.22	11.60
Tallman	Aggregate Group 1	66.60	63.65	56.85	58.23	49.62	43.35	41.40	35.67	25.22	11.60
Congers	Aggregate Group 1	66.60	63.65	56.85	58.23	49.62	43.35	41.40	35.67	25.22	11.60
New Hempstead	Aggregate Group 1	66.60	63.65	56.85	58.23	49.62	43.35	41.40	35.67	25.22	11.60
Burns	Aggregate Group 1	66.60	63.65	56.85	58.23	49.62	43.35	41.40	35.67	25.22	11.60
South Goshen	Aggregate Group 1	66.60	63.65	56.85	58.23	49.62	43.35	41.40	35.67	25.22	11.60
Port Jervis	Aggregate Group 2	49.81	34.62	15.57	-	-	-	-	-	-	-
Blooming Grove	Aggregate Group 3	28.56	16.77	16.89	11.86	8.18	5.21	3.89	3.14	3.45	1.81
Hunt	Aggregate Group 3	28.56	16.77	16.89	11.86	8.18	5.21	3.89	3.14	3.45	1.81
Orangeburg	Aggregate Group 3	28.56	16.77	16.89	11.86	8.18	5.21	3.89	3.14	3.45	1.81
Tuxedo Park	Aggregate Group 3	28.56	16.77	16.89	11.86	8.18	5.21	3.89	3.14	3.45	1.81
Shoemaker	Aggregate Group 3	28.56	16.77	16.89	11.86	8.18	5.21	3.89	3.14	3.45	1.81
Washington Heights	Aggregate Group 3	28.56	16.77	16.89	11.86	8.18	5.21	3.89	3.14	3.45	1.81
Swinging Bridge	Aggregate Group 3	28.56	16.77	16.89	11.86	8.18	5.21	3.89	3.14	3.45	1.81
West Haverstraw	Aggregate Group 3	28.56	16.77	16.89	11.86	8.18	5.21	3.89	3.14	3.45	1.81
Sparkill	Aggregate Group 3	28.56	16.77	16.89	11.86	8.18	5.21	3.89	3.14	3.45	1.81
West Nyack	Aggregate Group 3	28.56	16.77	16.89	11.86	8.18	5.21	3.89	3.14	3.45	1.81
Hillburn	Aggregate Group 3	28.56	16.77	16.89	11.86	8.18	5.21	3.89	3.14	3.45	1.81
East Wallkill	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Chester	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Westtown	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Bloomingburg	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Hartley Road	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Pine Island	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Chester 34.5KV	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Shoemaker 34.5KV	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Washington Heights 34.5KV	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Bullville	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Blue Lake	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Highland Falls	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Dean	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
South Goshen 34.5KV	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Sterling Forest	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Harriman 34.5KV	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Silver Lake	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Westtown 34.5KV	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Mongaup	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Cuddebackville	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Otisville	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Wurtsboro	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Rio 34.5KV	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Summitville	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Stony Point	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Nanuet	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Sloatsburg	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
Corporate Drive	Aggregate Group 4	-	-	-	-	-	-	-	-	-	-
System Weighted Average		**33.87**	**29.95**	**26.99**	**26.28**	**21.99**	**18.79**	**17.71**	**15.21**	**11.02**	**5.12**

Note: System weighted average MCs are calculated by taking the average of ungrouped Substation Area-level MCs, weighted on 2017 peak load.

The maps below represent the 2019 and 2020 MCOS by price signal





* More details about the map can be obtained from Distribution Engineering

The table below represents location of the station and their boundaries.

Station	Boundaries
Monroe	Circuits: 61-1-13, 61-2-13, 61-3-13, 61-4-13, 61-5-13, 61-6-13, 61-7-13, 61-8-13, 61-9-13, 61-10-13
Wisner	Circuits: 80-1-13, 80-2-13, 80-3-13, 80-4-13, 80-5-13
Harriman	Circuits: 71-1-13, 71-2-13, 71-3-13, 71-4-13, 71-5-13, 71-6-13, 71-7-3, 71-8-13
Snake Hill	Circuits: 24-1-13, 24-2-13, 24-3-13, 24-4-13, 24-8-13, 24-10-13, 24-11-13, 24-12-13
Monsey	Circuits: 44-1-13, 44-2-13, 44-3-13, 44-4-13, 44-5-13, 44-6-13
Tallman	Circuits: 51-1-13, 51-2-13, 51-3-13, 51-4-13, 51-5-13, 51-6-13, 51-7-13, 51-8-13
Congers	Circuits: 22-1-13, 22-2-13, 22-3-13, 22-4-13, 22-5-13, 22-6-13, 22-7-13, 22-8-13
New Hempstead	Circuits: 45-1-13, 45-2-13, 45-3-13, 45-4-13, 45-5-13, 45-6-13, 45-7-13, 45-8-13, 45-9-13, 45-1-13
Burns	Circuits: 19-8-13, 19-9-13, 19-10-13, 19-11-13, 19-12-13, 19-13-13, 19-14-13, 19-15-13
South Goshen	Circuits: 89-1-13, 89-2-13, 89-3-13
Port Jervis	Circuits: 6-7-13, 6-8-13, 6-9-13
Blooming Groove	Circuits: 76-1-13, 76-2-13, 76-3-13, 76-4-13
Hunt	Circuits: 84-1-13, 84-2-13, 84-3-13
Orangeburg	Circuits: 54-1-13, 54-2-13, 54-3-13, 54-4-13, 54-5-13, 54-6-13, 54-7-13, 54-8-13
Tuxedo Park	Tuxedo Park, NY
Shoemaker	Circuits: 11-1-13, 11-2-13, 11-3-13, 11-4-13, 11-5-13
Washington Heights	Circuits: 109-1-13, 109-2-13, 10-3-13
Swinging Bridge	Circuit: 1-1-13
West Haverstraw	Circuits: 27-1-13, 27-2-13, 27-3-13, 27-4-13, 27-5-13, 27-6-13, 28-7-13, 27-8-13

Sparkill	Circuits: 50-1-13, 50-2-13, 50-3-13, 50-4-13
West Nyack	Circuits: 21-9-13, 21-11-13, 21-12-13, 21-13-13, 21-14-13 21-15-13, 21-16-13
Hillburn	Circuits: 17-1-13, 17-2-13

The table below is provided to explain to the reader what could be interpreted as anomalous results (i.e., area with low or negative growth that have higher prices signals, and areas of higher growth that have low or zero price signals).

	Stations	Price Signal-MC($/KW)(**)	Reasons
Low Growth	Snake Hill	High	Localized growth in the Village of Nyack is driving the need to bring relief to the distribution circuits feeding this area that emanate from the West Nyack Substation. Installing a new circuit from the Snake Hill Substation will bring circuit relief and redundancy to West Nyack and defer the need to perform major West Nyack infrastructure upgrades. Current EE and DER penetration are masking the load growth in the area.
	Tallman	High	Localized growth in the area has been increasing for several years. Current and forecasted EE and DER penetration, as well as the loss of a large customer load on the Tallman station that recently closed in the area attributes to the negative growth. Creating ties between the Tallman and Monsey Substations will provide circuit relief and redundancy to Monsey and defer the need to perform major area infrastructure upgrades which drives the price signal.
	South Goshen	High	Current and expected/forecasted growth in this area is being masked by large DER projects in the area. The price signal is driven by the need to implement primary reinforcement projects at the distribution level to provide circuit relief and contingency redundancy.
	Wisner	High	The Wisner Substation area has been experiencing growth for many years. The area circuits are long, have high exposure and do not meet design standards. Relief to the circuits will help local area operating conditions until the West Warwick Substation, scheduled for 2028, can be constructed. The new station and local area infrastructure investments drive the price signal in the area. Current and continued forecast growth in this area is masked by EE and large DERs recently installed and projected in the area.

** Price Signal MC ($/kW): Low - No price point, Medium - $ 28.56 and $49.81, High - $66.60.

	Stations	Price Signal-MC($/KW)(**)	Reasons
High Growth	Corporate drive	Low	Approx. 17MW of increased commercial load has been proposed by various existing and potential new Data Centers over the next ten-years. Although there is significant growth in the area, the newly constructed Corporate Drive Substation that would assume most of this load growth has sufficient capacity to handle the expected load increases, and new infrastructure investments are not needed/proposed in this area.
	Sloatsburg	Low	Significant load increases resulting from a proposed new large residential development is expected over the next ten years. There is sufficient capacity in the existing infrastructure at the Sloatsburg Substation to serve the expected increased load growth and for contingency conditions.
	Harriman 34.5KV	Low	This infrastructure is a sub-transmission loop that serves a large contract commercial complex and two area stations. Growth is driven by single large power contract customer and there are no investments identified in the Company's current CIP at this time.
	Summitville	Low	The substation is a 5MVA bank. There is no growth in the first 5 years and for years 6 to 10 there is potential EV adoption. The growth will be monitored in the future and no investment is needed to support the additional load in the area.
	Westtown	Low	The growth is due to a single large customer. The Westtown Substation has sufficient capacity to serve projected future loads. There are multiple large PV projects that are in construction that will mask any future load growth.

** Price Signal MC ($/kW): Low - No price point, Medium - $ 28.56 and $49.81, High - $66.60.

Appendix-C: Load Profile Clustering

This Appendix discusses the approach used to cluster the Substation Areas by hourly load profiles. The goal of this clustering exercise is to group the Substation Areas based on their normalized peak day loads (on a scale of 0 to 100 percent of peak load on that day), as part of the overall grouping exercise. The load profiles by themselves may not contribute much to identifying load growth or associated investments to accommodate load growth. However, characteristic load shapes provide a proxy for the combined factors of load factor, timing of peak, and length of peak. These factors combined could be distinct enough to serve as a proxy for similar types of investment requirements/types (i.e., indicate DER types that are most beneficial for a given load profile cluster), which may become important for the VDER procedure.

The clustering is performed for the 2017 system peak day hourly load profiles of all Substation Areas. The hourly profile data is first normalized on a scale of 0 to 100 percent of peak load on that day. Then using the R model (a software environment for statistical computing and graphic), clustering is performed using statistical k-means approach.[32]

A. Using the R package KmL to Cluster Hourly Load Data

The set of normalized loads over 24 hours for each Substation Area is called a set of trajectories. The KmL algorithm assigns each trajectory to one of *k* clusters. The center of each cluster is determined, in a phase called the "Expectation" phase. Then, each trajectory is assigned to its "nearest" cluster in the "Maximization" phase. The Expectation and Maximization phases are repeated alternately until equilibrium is reached—i.e. no more changes occur in the clusters.

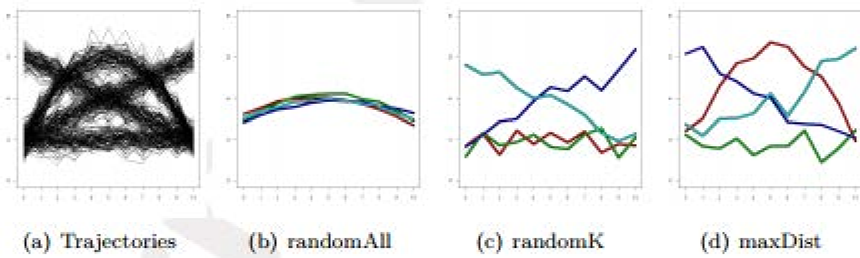
KmL allows the user to specify the distance measure used when determining the "nearest" cluster, such as Euclidean distance or Manhattan distance. The distance measures calculate the distance between observations—hourly loads, in this Study—at each time *t*. For this Study, the Euclidean distance (which is the default distance measure) is used and implemented into the KmL algorithm.

The optimal number of clusters is the number that maximizes distance between trajectories in different clusters, and minimizes distance between trajectories within a cluster. By default, KmL divides the data into clusters of two, then three, all the way up to six, and chooses the optimal number of clusters. The algorithm determined three to be the optimal number of clusters for the 50 Substation Area trajectories.

The starting condition can also be specified, and these conditions can lead to very different clusters. Figure C-1: Effect of Starting Condition on Clusters below illustrates how the set of trajectories in (a) can lead to different partitions shown as (b) through (d), depending on the starting conditions:

32 Further details of R are available at https://www.r-project.org/.

Figure C-1: Effect of Starting Condition on Clusters



Source: Genolini, Christopher and Bruno Falissard, "KmL: A Package to Cluster Longitudinal Data," Available at:
http://christophe.genolini.free.fr/recherche/aTelecharger/genolini2011.pdf

The Study explored both the "nearlyAll" starting condition (the default) and the "maxDist" starting condition. Both starting conditions resulted in assigning each Substation Area to the same clusters.

B. Substation Area Clustering Results

Figure C-2: Hourly Load Trajectories and Clusters below summmarizes the clustering results from running the KmL algorithm using the hourly trajectories. The black lines in this figure shows the 50 individual Substation Area tragectories, and the colored lines show the centers of each of the three clusters.

Figure C-2: Hourly Load Trajectories and Clusters

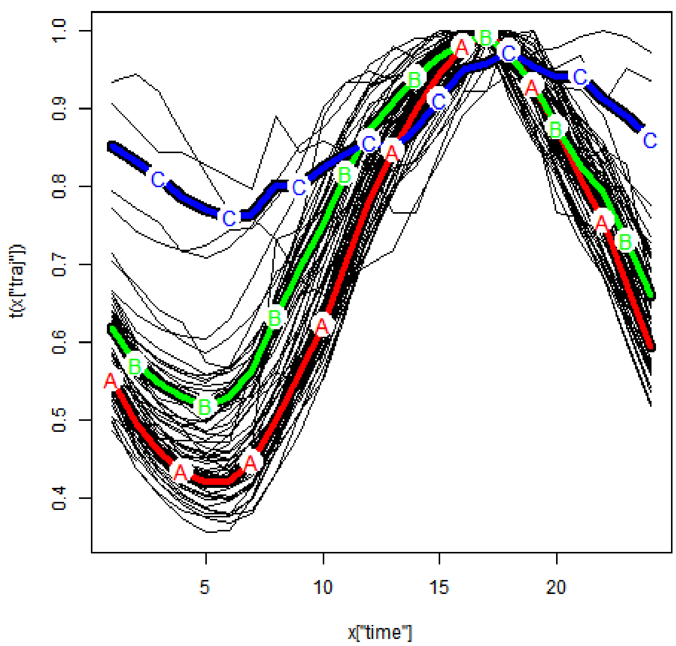


Table C-1: Substation Areas per Cluster below shows the breakdown of the Substation Areas in each cluster.

Table C-1: Substation Areas per Cluster

Cluster	Cluster Name	Number of Substation Areas in Cluster	Percent of Substation Areas in Cluster
1	Lower Load Factor	19	38%
2	Higher Load Factor	27	54%
3	Flat Load Profile	4	8%