2025 Central Hudson

Transmission & Distribution Marginal Cost of Service Study

Prepared for Central Hudson
By
Demand Side Analytics
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ACKNOWLEDGEMENTS

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ABSTRACT

The focus of the study is on quantifying the transmission and distribution marginal costs. As requested by the Commission, the study team adopted the National Economic Research Associates' method. The study only includes costs associated with growth and multi-value (growth and reliability). The study estimates location specific marginal costs for individual feeders, substations, and local transmissions. As requested by the Commission, marginal costs were then aggregated and presented at the substation level.

TABLE OF CONTENTS

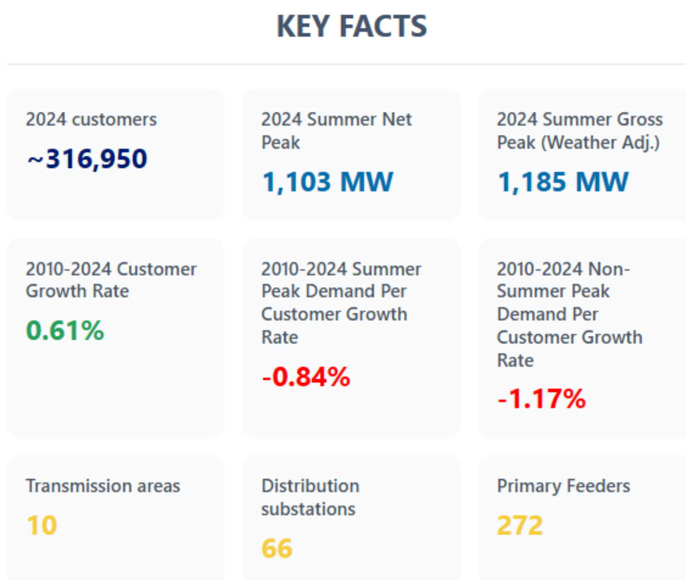
Figures

Tables

1 INTRODUCTION

Central Hudson Gas & Electric Corporation (Central Hudson or Company) is a regulated gas and electric utility serving the Mid-Hudson Valley of New York State. The Company provides electricity and gas transmission and distribution (T&D) services to approximately 315,000 electric customers and 90,000 natural gas customers. Central Hudson territory extends from the suburbs of metropolitan New York City north to the Capital District at Albany, covering approximately 2,600 square miles. The electric system comprises approximately 9,400 miles of transmission and distribution lines.

Figure 1: Central Hudson Key Facts



Central Hudson's actual system peak in 2024 was 1,103 MW.[1] The electric peak forecast for 2030 is projected to be a summer peak of 1,087 MW. Overall, per-customer summer peak demand in Central Hudson has declined at a rate of -0.84% per year, likely due to a mixture of energy efficiency, codes and standards, and other changes in end-use loads. Per-customer winter peak demand has declined at a rate of -1.17% per year. For comparison, Central Hudson's all-time electric system peak demand of 1,295 MW was set in 2006.

On August 19, 2024, the Public Service Commission issued an Order Addressing Marginal Cost of Service studies that specify the marginal cost of service (MCOS) study methodologies for determining several components of the Value of Distributed Energy Resources (VDER) Value Stack. In 2016, 2018, 2020, and 2023, Central Hudson conducted location-specific avoided T&D cost studies that relied on probabilistic analysis and quantified the option value of reducing peak demand. This 2025 study adopts

[1] The value includes loads and net metered distribution connected solar and storage, which is used for revenue requirements. For distribution planning, the loads used also include non-net metered distribution connected solar (e.g., community solar and storage). Gross Peak (Weather Adjusted) includes net loads, net metered solar production, and community-distributed generation solar production.

the traditional National Economic Research Associates' methodology, with modifications required by the Commission to better align approaches across utilities.

In Central Hudson's MCOS study, marginal costs were estimated at three levels: local transmission, substation, and distribution feeder. For each level, all growth-related and multi-value (i.e., growth and reliability) projects in the capital investment plan were included in the analysis. To determine the total marginal cost for each location, Central Hudson aggregated the marginal costs across all three levels.

The key findings from the MCOS study are:

- Many circuits, substations, and local transmission areas are experiencing declining loads or have ample room for growth.
- Transmission and substation-level marginal costs increase over the ten-year timeframe as areas with higher marginal costs have projects with expected in-service dates in the latter half of the planning horizon.

2 CONTEXT AND BACKGROUND

One vital role of the electric utility is to ensure that the electricity supply remains reliable. By projecting future demand along with identifying reliability and/or condition-based infrastructure needs, utilities can reinforce the local transmission and distribution systems to maintain power quality and reliability of the system and ultimately avoid costly outages.

The load forecasts leveraged in the MCOS, were done using econometric forecasts for each of Central Hudson's 272 distribution feeder circuits, 66 substations, and 10 local transmission areas.[2] These forecasts incorporate substation-level growth rates, forecasted changes in household growth, and are weather-adjusted for planning conditions. Modeling was performed on an hourly basis to produce forecasts at the feeder circuit level for evolving technologies, including solar, storage, transportation electrification, and building electrification. Central Hudson produced these granular forecasts for the 10-year horizon as required in the MCOS study.

2.1 REGULATORY BACKGROUND

In its April 18, 2019, Order Regarding Value Stack Compensation in Case 15-E-0751 (Order), the Public Service Commission initiated a new proceeding to examine the Joint Utilities' marginal cost of service (MCOS) studies, which have been used for a variety of purposes, including components of the Value Stack, economic development rates, and the avoided cost benefit associated with energy efficiency load reduction programs. Following a stakeholder process, the Commission issued an order on August 19, 2024, establishing a methodology for estimating marginal costs to inform system-wide applications. The order calls for consistent MCOS study methodologies to reduce the significant variations that previously existed across the Joint Utilities.

In 2016, 2018, 2020, and 2023, Central Hudson conducted location-specific avoided T&D cost studies that relied on probabilistic analysis and quantified the option value of reducing peak demand. This 2025 study adopts the traditional National Economic Research Associates' methodology, incorporating modifications required by the Commission to better align practices across utilities. Compared to previous studies, the 2025 Marginal Cost of Service Study differs in several key areas:

- The study included all growth-related and multi-value projects planned within the 5-year corporate Capital Forecast, along with a handful of capital infrastructure investments currently identified past the 2030 timeframe. Since Central Hudson uses a five-year capital forecast, the proportion of service territory with distribution upgrade needs in years six through ten was assumed to be similar to years one through five.

[2] See 2025 Distributed System Implementation Plan (DSIP) Advanced Forecasting section for a more detailed description.

- Marginal cost estimates are developed using deterministic methods.
- Marginal costs are calculated as the actual planned investment cost net of salvage value divided by the incremental capacity provided by each project and converted into annual revenue requirements per kW of capacity. Most of the capital projects included in the MCOS are multi-value projects driven by reliability/infrastructure needs that would require investments absent any load growth. However, for various reasons, these multi-value projects also increase system capacity.

2.2 STUDY OBJECTIVES

The study focuses on quantifying the marginal costs of increasing the T&D system capacity so that it can accommodate additional loads. The study focuses on feeder, substation, and local transmission costs and was designed to meet the following objectives:

- Analyze the magnitude of expected infrastructure investments at a local level.
- Identify capital investment projects that are growth-related or multi-value.
- Calculate local marginal costs of T&D capacity for projects identified for inclusion in the study, at the local transmission, substation, and distribution feeder levels.
- Estimate the system-wide marginal costs at the local transmission, substation, and distribution feeder.
- Produce avoided T&D costs by substation.

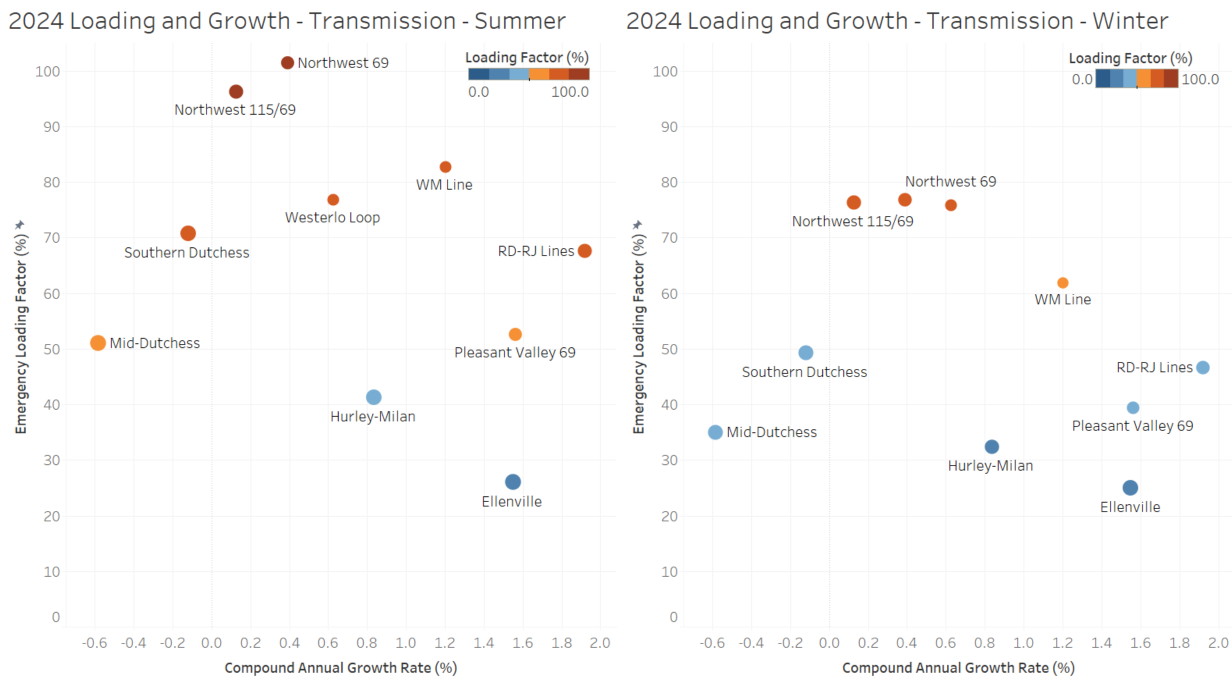
In areas with excess capacity – or areas where local, coincident peaks are declining or growing slowly – the value of capacity relief can be minimal. In areas where a large, growth-related investment is imminent, the value of capacity relief can be quite substantial, especially if it is possible to delay or defer infrastructure upgrades for a substantial time. However, many Central Hudson areas have declining or slowly growing loads, or they have sufficient capacity already built such that investments are not needed in the foreseeable future. In addition, the annual marginal cost values do not reflect whether resources are delivered at the right hours and right seasons by location.

2.3 HISTORIC LOADING FACTORS AND GROWTH RATES

Figure 2, Figure 3, and Figure 4 display the summer and winter loading factors in 2024 and the growth rates for local transmission areas, substations, and distribution feeders. The 2024 loading factor is simply the actual peak divided by the location's operating limit. Locations with a growth factor above 0% are experiencing growth and locations where the loading factor is closer to 100% have less room for growth.

Roughly 70% of the local transmission areas (load-weighted) have been experiencing growth, but approximately 25% (load-weighted) have loading factors above 85%. The two most highly loaded areas Northwest 115/69 kV and Northwest 69kV are part of non-wires alternative project that has deferred capital costs since 2015 and are scheduled for upgrades in 2029. All transmission areas in Central Hudson's territory are currently summer-peaking systems. Some are experiencing slow growth or declining loads or have ample room for growth without having to upgrade them. Several of the local transmission areas have multi-value infrastructure projects. As part of the upgrades, the transmission capacity for those locations will increase in order accommodate increasing amounts of solar, planned battery storage, and load growth.

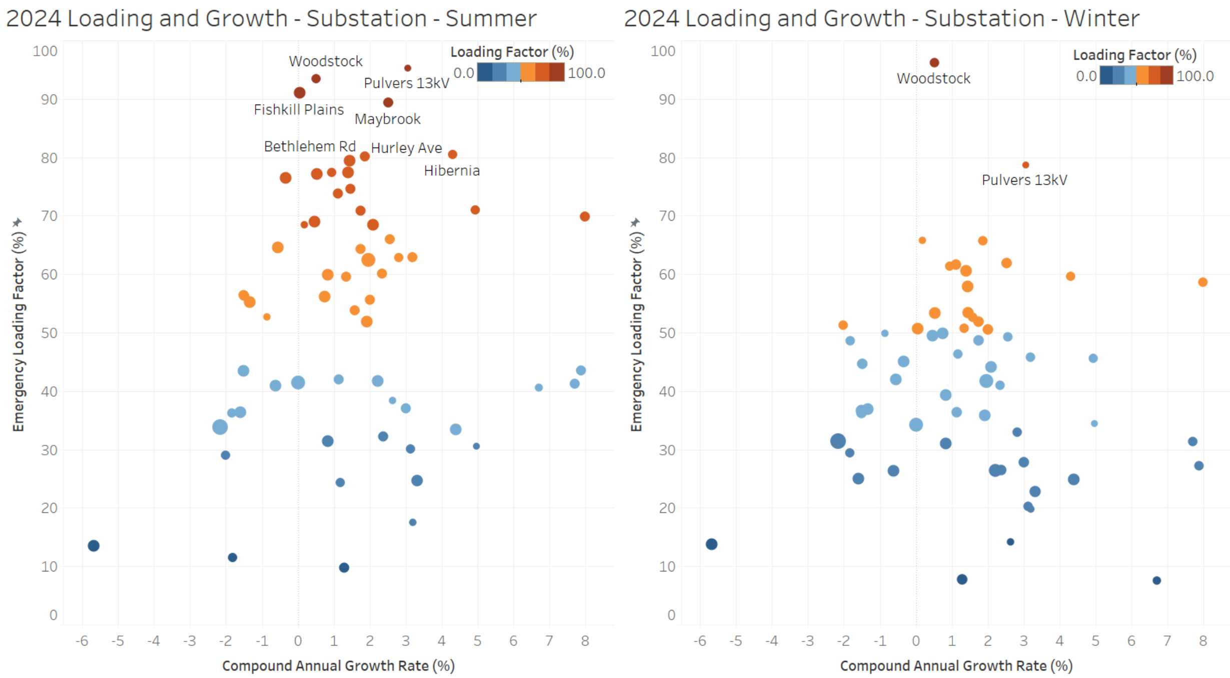
Figure 2: Growth Rates Versus Room for Growth – Local Transmission



Notes: Bubble size is proportional to the LTE rating of the site. The color reflects the 2024 loading for each site.

Figure 3 compares the annual load growth rate to the 2024 loading factor for each of Central Hudson's load serving distribution substations. Roughly 75% of the substations have been experiencing growth, most of which has been driven by growth in customers. On average, peak demand per customer has been declining across Central Hudson's service territory. A small share of the substations, less than 8%, are at 85% or more of the operating limit. Most of the substations, 87% of them, remain summer peaking. With a few exceptions, most of the substations have room to accommodate electric vehicles and building electrification loads over the next five years. One of the highly loaded substations, Fishkill Plains, is part of non-wires alternative project that has deferred capital costs since 2015 and is scheduled for upgrades in 2027.

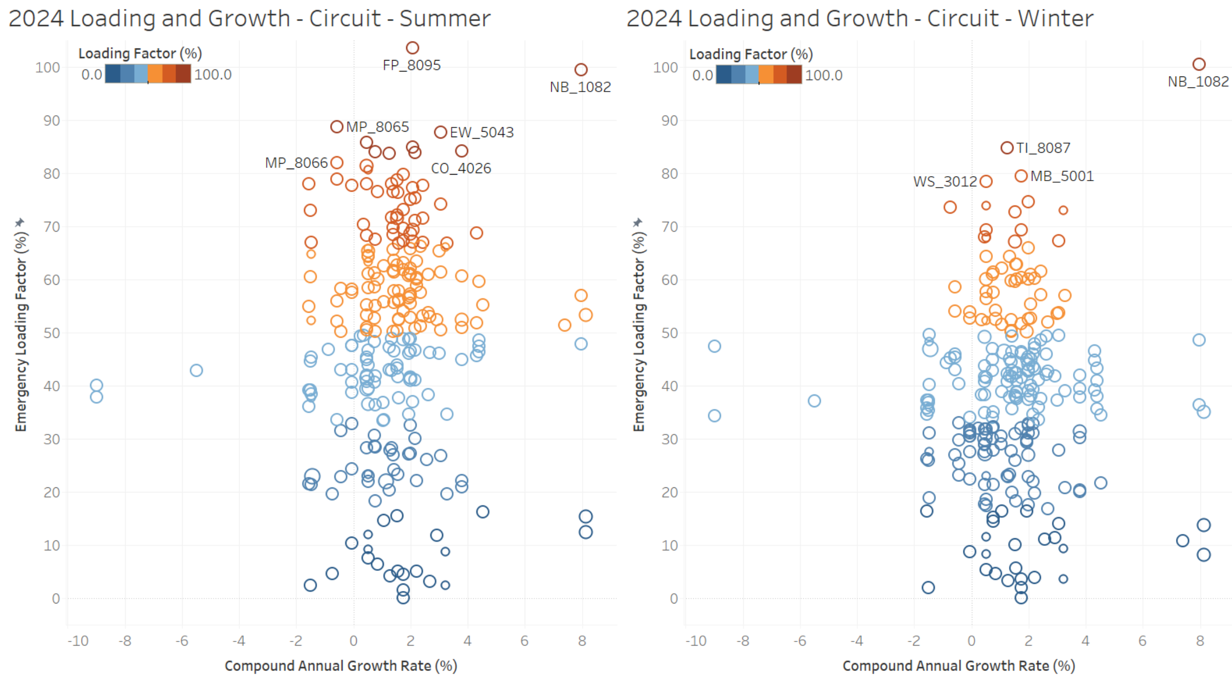
Figure 3: Growth Rates Versus Room for Growth - Substation



Notes: Bubble size is proportional to the LTE rating of the site. The color reflects the 2024 loading for each site.

Figure 4 compares the annual load growth rate to the 2024 loading factor for each of Central Hudson's distribution feeders. Central Hudson operates most of its distribution feeders so that two nearby feeders can pick accommodate peak loads in case of outages or maintenance, ensuring a high level of service reliability and operations flexibility. Generally, the feeders can accommodate more load, if needed, without exceeding the thermal limits and the main limitation for additional load is the substation transformer.

Figure 4: Growth Rates Versus Room for Growth – Distribution Feeders



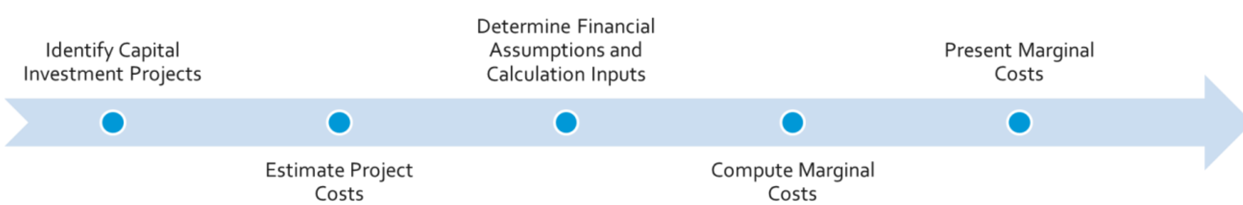
Notes: Bubble size is proportional to the emergency rating of the site. The color reflects the 2024 loading for each site.

3 METHODOLOGY

The analysis involved five (5) main steps, as shown below:

1. **Identify Capital Investment Projects.** Central Hudson included all the load growth and multi-value projects in its 5-year capital forecast and a few projects identified past the 5-year timeframe. In addition, Central Hudson included yet-to-be-identified projects in the remaining 10-year timeframe at the average cost per kW of capacity. A total of 9 specific projects were identified, with total capital expenditures of about $111M over the 2026-2035 horizon. While most of the projects are reliability/infrastructure driven, they also include a load growth component and thus were identified as a multi-value project.
2. **Estimate Project Costs.** The project costs included were consistent with the capital plan. For growth-driven projects (i.e., not multi-value), no salvage value is applied. For multi-value projects, Central Hudson assigned a salvage value of 2.5% for distribution feeder, substation, and local transmission-level investments.
3. **Determine Financial Assumptions and Calculation Inputs** for carrying charge and expense factors.
4. **Compute Marginal Costs.** The calculations simply reflect revenue requirements associated with the capital costs and are presented on $/kW-year of T&D capacity. The values are in nominal dollars and are included starting the year after the projected project in-service year. The 10-year levelized values reflect the in-service years and the time value of money.
5. **Present Marginal Costs.** The local transmission, substation, and feeder circuit value was stacked at the feeder level and aggregated to the substation level.

Figure 5: MCOS Key Analysis Steps



Additional considerations in the analysis include:

- In accordance with the Order's requirement to present costs at a granular level by including the substation serving area, Central Hudson layered marginal costs from local transmission, substation, and feeder circuit levels to the substation level. To allocate local transmission-level marginal costs, each substation within a specific local transmission area was assigned the local transmission-level marginal cost. Circuit-level marginal costs were rolled up to the substation level by weighing each circuit's marginal cost by its peak load, accounting for differences in circuit size.

- Marginal costs will vary by year depending on the projects being placed into service in that year. In addition to showing marginal costs over each of the ten years, a ten-year levelized marginal cost is presented as the net present value of the investments, factoring in the in-service year of the planned capital projects.
- In accordance with the Order, the marginal costs are shown at the local transmission, substation, and feeder level for all projects identified within the ten-year planning horizon and are representative of areas with identified projects over the study period.
- In addition, Central Hudson's study presents system-wide marginal costs, inclusive of areas with ample room for load growth. All areas were included in the study and weighed according to their share of Central Hudson's load.

4 RESULTS

Table 1 and Table 2 present the annual and 10-year levelized total marginal cost estimates by local transmission, substation and distribution feeder. Table 1 reflects the marginal costs in areas with identified projects. As indicated previously, many feeders, substations and local transmission areas in Central Hudson's territory are experiencing declining loads or have ample room for growth. As a result, the marginal costs applicable to areas with growth-related and multi-value projects are not representative of all areas of Central Hudson's system. The values also should not be stacked (i.e. added across local transmission, substation and feeder circuit), unless a specific location has upgrade projects scheduled at all three grid levels. Most locations do not have upgrades in the 10-year horizon, or, if they do, have upgrades scheduled for a specific component (e.g., transmission upgrade, but not substation, and feeder). Table 2 reflects total marginal costs on a system-wide basis, factoring in areas with no marginal costs or yet-to-be identified projects over the 10-year planning horizon. Such a value would be more appropriate for use in circumstances where a single marginal cost value is utilized regardless of where on the system a resource is located.

Table 1: Marginal Costs for Areas with Projects by Component ($ nominal)

Year	Local Transmission	Substation	Feeder Circuit
2026	$0.00	$0.00	$12.37
2027	$0.00	$0.52	$12.63
2028	$0.00	$12.65	$12.63
2029	$0.00	$12.65	$12.63
2030	$0.00	$42.84	$12.63
2031	$0.00	$99.50	$12.63
2032	$0.00	$99.50	$12.63
2033	$27.92	$127.47	$12.63
2034	$27.92	$127.47	$12.63
2035	$27.92	$127.47	$12.63
10-year levelized ($2025)	**$6.56**	**$55.51**	**$12.60**

Table 2: System-wide Marginal Costs ($ nominal)

Year	Local Transmission	Substation	Feeder Circuit	Total Marginal Costs
2026	$0.00	$0.00	$3.03	**$3.03**
2027	$0.00	$0.07	$3.10	**$3.17**
2028	$0.00	$1.80	$3.10	**$4.89**
2029	$0.00	$1.80	$3.10	**$4.89**
2030	$0.00	$6.08	$3.10	**$9.18**
2031	$0.00	$14.13	$3.10	**$17.23**
2032	$0.00	$14.13	$3.10	**$17.23**
2033	$11.62	$18.10	$3.10	**$32.81**
2034	$11.62	$18.10	$3.10	**$32.81**
2035	$11.62	$18.10	$3.10	**$32.81**
10-year levelized ($2025)	**$2.73**	**$7.88**	**$3.09**	**$13.70**

In accordance with the Order's requirement to present marginal costs at a granular level by including the substation serving area, the study team layered marginal costs from local transmission, substation, and feeder levels to the substation level. To allocate local transmission-level values, each substation within a specific transmission area was assigned the transmission-level marginal cost. Feeder-level avoided costs were rolled up to the substation level by weighting each feeder's marginal cost by its peak load, accounting for differences in feeder size.

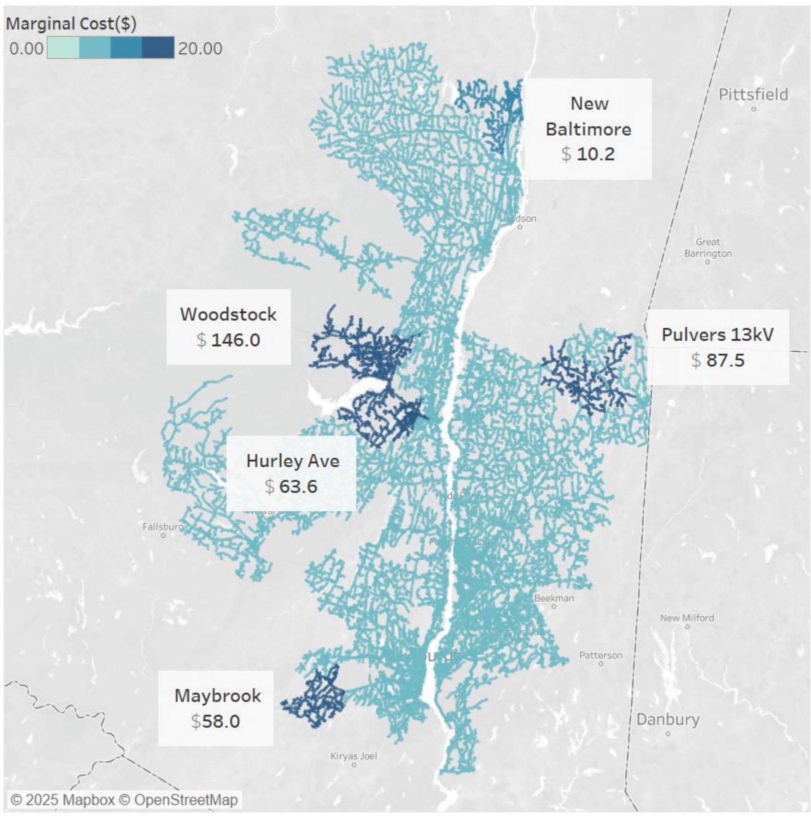
Table 3: 10-Year Levelized Marginal Cost at Substation Level

Local Transmission	Substation	Local Transmission	Substation	Feeder	Total Marginal Costs
Ellenville	Clinton Ave	$2.73	$3.37	$3.04	$9.14
Ellenville	Galeville	$2.73	$3.37	$3.06	$9.16
Ellenville	Greenfield Rd	$2.73	$3.37	$3.27	$9.37
Ellenville	Grimley Rd X1	$2.73	$3.37	$3.03	$9.13
Ellenville	Grimley Rd X2	$2.73	$3.37	$1.77	$7.86
Ellenville	High Falls	$2.73	$3.37	$3.07	$9.17
Ellenville	Honk Falls	$2.73	$3.37	$3.03	$9.13
Ellenville	Kerhonkson	$2.73	$3.37	$3.10	$9.20
Ellenville	Neversink	$2.73	$3.37	$3.05	$9.15
Hurley-Milan	East Kingston	$2.73	$3.37	$3.03	$9.13
Hurley-Milan	Lincoln Park	$2.73	$3.37	$3.10	$9.20
Hurley-Milan	Rhinebeck	$2.73	$3.37	$3.22	$9.32
Mid-Dutchess	Knapps Corners	$2.73	$3.37	$3.23	$9.33
Mid-Dutchess	Manchester	$2.73	$3.37	$3.03	$9.13
Mid-Dutchess	Sand Dock-Distribution	$2.73	$3.37	$3.03	$9.13
Mid-Dutchess	Sand Dock-Industrial	$2.73	$3.37	$3.03	$9.13
Mid-Dutchess	Spackenkill	$2.73	$3.37	$3.03	$9.13
Northwest 115/69	North Catskill	$0.00	$3.37	$3.12	$6.49

Local Transmission	Substation	Local Transmission	Substation	Feeder	Total Marginal Costs
Northwest 115/69	Woodstock	$0.00	$142.90	$3.09	$145.99
Northwest 69	Saugerties	$2.73	$3.37	$3.14	$9.24
Pleasant Valley 69	Ancram	$2.73	$3.37	$3.03	$9.13
Pleasant Valley 69	East Park	$2.73	$3.37	$3.03	$9.13
Pleasant Valley 69	Hibernia	$2.73	$3.37	$3.11	$9.21
Pleasant Valley 69	Millerton	$2.73	$3.37	$3.03	$9.13
Pleasant Valley 69	Pulvers 13kV	$2.73	$81.54	$3.28	$87.55
Pleasant Valley 69	Pulvers 34kV	$2.73	$3.37	$3.03	$9.13
Pleasant Valley 69	Smithfield	$2.73	$3.37	$3.03	$9.13
Pleasant Valley 69	Staatsburg	$2.73	$3.37	$3.04	$9.14
Pleasant Valley 69	Stanfordville	$2.73	$3.37	$3.54	$9.64
Pleasant Valley 69	Tinkertown	$2.73	$3.37	$3.05	$9.15
RD-RJ Lines	Bethlehem Rd	$0.00	$3.37	$3.25	$6.62
RD-RJ Lines	Union Ave	$0.00	$3.37	$3.23	$6.60
Southern Dutchess	Forgebrook	$2.73	$3.37	$3.55	$9.65
Southern Dutchess	Merritt Park	$2.73	$3.37	$3.20	$9.30
Southern Dutchess	Shenandoah-Distribution	$2.73	$3.37	$3.03	$9.13
Southern Dutchess	Tioronda	$2.73	$3.37	$3.15	$9.25
Southern Dutchess	Wiccopee	$2.73	$3.37	$8.66	$14.76
Stand Alone	Boulevard	$2.73	$3.37	$3.08	$9.18
Stand Alone	Coldenham	$2.73	$3.37	$3.06	$9.16
Stand Alone	East Walden	$2.73	$3.37	$3.03	$9.13
Stand Alone	Fishkill Plains	$2.73	$3.37	$3.03	$9.13
Stand Alone	Highland	$2.73	$3.37	$3.06	$9.15
Stand Alone	Hurley Ave	$2.73	$57.70	$3.17	$63.60
Stand Alone	Inwood Ave	$2.73	$3.37	$3.11	$9.21
Stand Alone	Marlboro	$2.73	$3.37	$3.10	$9.20
Stand Alone	Milan	$2.73	$3.37	$3.04	$9.14
Stand Alone	Modena	$2.73	$3.37	$3.41	$9.51
Stand Alone	Myers	$2.73	$3.37	$3.04	$9.14
Stand Alone	North Chelsea	$2.73	$3.37	$3.30	$9.40
Stand Alone	Ohioville	$2.73	$3.37	$3.05	$9.15
Stand Alone	Reynolds Hill	$2.73	$3.37	$3.09	$9.19
Stand Alone	Sturgeon Pool	$2.73	$3.37	$3.03	$9.13
Stand Alone	Todd Hill	$2.73	$3.37	$3.38	$9.48
Stand Alone	West Balmville	$2.73	$3.37	$3.11	$9.21
WM Line	Maybrook	$2.73	$52.25	$3.06	$58.03
WM Line	Montgomery	$2.73	$3.37	$3.19	$9.29
Westerlo Loop	Coxsackie	$2.73	$3.37	$3.16	$9.25
Westerlo Loop	Freehold	$2.73	$3.37	$3.21	$9.31
Westerlo Loop	Hunter	$2.73	$3.37	$3.03	$9.13
Westerlo Loop	Lawrenceville	$2.73	$3.37	$3.03	$9.13
Westerlo Loop	New Baltimore	$2.73	$4.32	$3.17	$10.22
Westerlo Loop	South Cairo	$2.73	$3.37	$3.19	$9.29
Westerlo Loop	Vinegar Hill	$2.73	$3.37	$3.03	$9.13
Westerlo Loop	Westerlo	$2.73	$3.37	$3.04	$9.14

Figure 6 shows the map of the 10-year levelized total marginal cost at the substation level, which includes cost at all levels. The total marginal costs represent the sum of marginal costs at the local transmission, substation, and feeder levels. These locations peak at different seasons and hours, with most substation being summer-peaking, while some are winter-peaking. Darker blue indicates higher marginal costs. Several substations show strong potential for DER benefits: Woodstock, Pulver 13kV, Hurley Ave, Maybrook, and New Baltimore.

Figure 6: Map of 10-Year Levelized Marginal Cost by Substation



APPENDIX A: LOCAL TRANSMISSION DETAIL

Table 4 presents the interim marginal cost calculations for local transmission level projects in the capital plan. The table shows the cost of associated with a 1 kW increase in transmission capacity, converted into revenue requirements, and annualized over the book life of the asset. The interim marginal costs calculation does not reflect the timing of the upgrades, whether resources are at the right locations, or if resources are delivered at the right hours and right seasons.

Table 4: Local Transmission Interim Marginal Cost Calculations

				Local Transmission Location-Specific		Avg. Cost of Increasing Local Transmission Capacity
		Local Transmission	Local Transmission Future Unidentified Projects	Northwest 115/69	RD-RJ Lines	
		In Service Year	2032	2035	2035	
(1)	Number of projects considered			1	1	
	Share of Central Hudson Coincident Peak Load		20.97%	12.25%	8.39%	
	Marginal investment with general plant loading:					
(2)	Investment in growth projects net of 2.5% salvage value ($)		77,240,000	68,250,000	8,990,000	77,240,000
(3)	Investment in growth projects (kW)		296,500	166,500	130,000	296,500
(4)	Investment in growth projects ($/kW)	(2)/(3)	260.51	409.91	69.15	260.51
(5)	Typical reserve margin (%)		30.00%	30.00%	30.00%	30.00%
(6)	Investment in growth projects after reserve margin ($/kW)	(4)*[1+(5)]	338.66	532.88	89.90	338.66
(7)	Portion of the system that is affected (%)		100.00%	100.00%	100.00%	100.00%
(8)	Marginal investment ($/kW)	(6)*(7)	338.66	532.88	89.90	338.66
(9)	General plant loading (%)		16.10%	16.10%	16.10%	16.10%
(10)	Marginal investment with general plant loading ($/kW)	(8)*[1+(9)]	393.18	618.68	104.37	393.18
	Annual cost before O&M and working capital:					
(11)	Annual economic carrying charge related to capital investment (%)		13.72%	13.72%	13.72%	13.72%
(12)	A&G loading (plant-related) (%)		0.00	0.00	0.00	-
(13)	Total annual carrying charge (%)	(11)+(12)	13.72%	13.72%	13.72%	13.72%
(14)	Annual cost before O&M and working capital ($/kW-year)	(10)*(13)	53.94	84.88	14.32	53.94
	Annual O&M charge:					
(15)	O&M expenses before spreading ($/kW-year)		-	-	-	-
(16)	O&M expenses after spreading ($/kW-year)	(7)*(15)	-	-	-	-
(17)	With A&G loading (non-plant-related) ($/kW-year)	(16)*0.61%	-	-	-	-
(18)	Annual O&M charge ($/kW-year)	(16)+(17)	-	-	-	-
	Annual working capital charge:					
(19)	Material and supplies ($/kW-year)	(10)*0.96%	3.77	5.94	1.00	3.77
(20)	Prepayments ($/kW-year)	(10)*1.00%	3.93	6.19	1.04	3.93
(21)	Cash working capital allowance ($/kW-year)	(18)*14.29%	-	-	-	-
(22)	Total working capital ($/kW-year)	(19)+(20)+(21)	7.71	12.13	2.05	7.71
(23)	Annual working capital charge ($/kW-year)	(22)*8.95%	0.69	1.09	0.18	0.69
(24)	Total annual cost before losses ($/kW-year)	(14)+(18)+(23)	54.63	85.97	14.50	54.63
(25)	Loss factor		1.01	1.01	1.01	1.01
(26)	**Total annual cost ($/kW-year)**	**(24)*(25)**	**55.40**	**87.17**	**14.71**	**55.40**

Table 5 show the annualized marginal cost for each project by year. The projects do not impact revenue requirement before they are in service and, thus, are shown after they local transmission projects are projected to go into service. The 10-year levelized cost accounts for the fact that most revenue requirements associated with the projects are in the future and account for the time value of money. The study also produced two aggregate metrics: (1) average marginal cost for areas with identified local transmission projects and (2) system-wide marginal cost. The system-wide marginal cost factors in areas with no marginal costs or yet-to-be identified projects over the 10-year planning horizon and is more appropriate for use in circumstances where a single marginal cost value is utilized regardless of where on the system a resource is located.

Table 5: Local Transmission Marginal Costs by Year and Project

Year	Local Transmission System-wide (Share of Central Hudson Coincident Peak Load)	Local Transmission Location-Specific Marginal Costs: Future Unidentified Projects 20.97%	Local Transmission Location-Specific Marginal Costs: Northwest 115/69 12.25%	Local Transmission Location-Specific Marginal Costs: RD-RJ Lines 8.39%	Cost of Increasing Capacity for Typical Project Areas
2026	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ -	$ -	$ -	$ -
2030	$ -	$ -	$ -	$ -	$ -
2031	$ -	$ -	$ -	$ -	$ -
2032	$ -	$ -	$ -	$ -	$ -
2033	$ 11.62	$ 55.40	$ -	$ -	$ 27.92
2034	$ 11.62	$ 55.40	$ -	$ -	$ 27.92
2035	$ 11.62	$ 55.40	$ -	$ -	$ 27.92
2036	$ 23.53	$ 55.40	$ 87.17	$ 14.71	$ 56.55
2037	$ 23.53	$ 55.40	$ 87.17	$ 14.71	$ 56.55
2038	$ 23.53	$ 55.40	$ 87.17	$ 14.71	$ 56.55
2039	$ 23.53	$ 55.40	$ 87.17	$ 14.71	$ 56.55
2040	$ 23.53	$ 55.40	$ 87.17	$ 14.71	$ 56.55
2041	$ 23.53	$ 55.40	$ 87.17	$ 14.71	$ 56.55
2042	$ 23.53	$ 55.40	$ 87.17	$ 14.71	$ 56.55
2043	$ 23.53	$ 55.40	$ 87.17	$ 14.71	$ 56.55
2044	$ 23.53	$ 55.40	$ 87.17	$ 14.71	$ 56.55
2045	$ 23.53	$ 55.40	$ 87.17	$ 14.71	$ 56.55
Ten-year Levelized ($2025)	**$ 2.73**	**$ 13.01**	**$ -**	**$ -**	**$ 6.56**
Twenty-year Levelized ($2025)	**$ 9.84**	**$ 27.51**	**$ 30.61**	**$ 5.16**	**$ 23.66**

APPENDIX B: SUBSTATION DETAIL

Table 6 presents the interim marginal cost calculation process at substation level.

Table 6: Substation Interim Marginal Cost Calculation

				Substation Location-Specific					Avg. Cost of Increasing Substation Capacity ($/kW-Year)
		Local Transmission		WM Line	Pleasant Valley 69	Northwest 115/69	Westerlo Loop	Stand Alone	
		Substation	Future Unidentified Projects	Maybrook	Pulvers 13kV	Woodstock	New Baltimore	Hurley Ave	
		In Service Year	2030	2027	2027	2029	2026	2032	
(1)	Number of projects considered			1	1	1	1	1	
	Share of Central Hudson Coincident Peak Load		7.35%	1.69%	0.49%	1.56%	1.50%	1.62%	
	Marginal investment with general plant loading:								
(2)	Investment in growth projects net of 2.5% salvage value ($)		29,715,500	7,388,000	2,632,500	8,190,000	292,500	11,212,500	29,715,500
(3)	Investment in growth projects (kW)		61,850	24,000	7,250	6,800	13,400	10,400	61,850
(4)	Investment in growth projects ($/kW)	(2)/(3)	480.44	307.83	480.44	1,204.41	21.83	1,078.13	480.44
(5)	Typical reserve margin (%)		30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
(6)	Investment in growth projects after reserve margin ($/kW)	(4)*[1+(5)]	624.58	400.18	624.58	1,565.74	28.38	1,401.56	624.58
(7)	Portion of the system that is affected (%)		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
(8)	Marginal investment ($/kW)	(6)*(7)	624.58	400.18	624.58	1,565.74	28.38	1,401.56	624.58
(9)	General plant loading (%)		16.10%	16.10%	16.10%	16.10%	16.10%	16.10%	16.10%
(10)	Marginal investment with general plant loading ($/kW)	(8)*[1+(9)]	725.14	464.61	725.14	1,817.82	32.95	1,627.21	725.14
	Annual cost before O&M and working capital:								
(11)	Annual economic carrying charge related to capital investment (%)		13.33%	13.33%	13.33%	13.33%	13.33%	13.33%	13.33%
(12)	A&G loading (plant-related) (%)		1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%
(13)	Total annual carrying charge (%)	(11)+(12)	14.66%	14.66%	14.66%	14.66%	14.66%	14.66%	14.66%
(14)	Annual cost before O&M and working capital ($/kW-year)	(10)*(13)	106.30	68.11	106.30	266.49	4.83	238.55	106.30
	Annual O&M charge:								
(15)	O&M expenses before spreading ($/kW-year)		-	-	-	-	-	-	-
(16)	O&M expenses after spreading ($/kW-year)	(7)*(15)	-	-	-	-	-	-	-
(17)	With A&G loading (non-plant-related) ($/kW-year)	(16)*0.61%	-	-	-	-	-	-	-
(18)	Annual O&M charge ($/kW-year)	(16)+(17)	-	-	-	-	-	-	-
	Annual working capital charge:								
(19)	Material and supplies ($/kW-year)	(10)*0.96%	6.96	4.46	6.96	17.45	0.32	15.62	6.96
(20)	Prepayments ($/kW-year)	(10)*1.00%	7.25	4.65	7.25	18.18	0.33	16.27	7.25
(21)	Cash working capital allowance ($/kW-year)	(18)*14.29%	-	-	-	-	-	-	-
(22)	Total working capital ($/kW-year)	(19)+(20)+(21)	14.21	9.11	14.21	35.63	0.65	31.89	14.21
(23)	Annual working capital charge ($/kW-year)	(22)*8.95%	1.27	0.82	1.27	3.19	0.06	2.85	1.27
(24)	Total annual cost before losses ($/kW-year)	(14)+(18)+(23)	107.58	68.93	107.58	269.68	4.89	241.40	107.58
(25)	Loss factor		1.02	1.02	1.02	1.02	1.02	1.02	1.02
(26)	**Total annual cost ($/kW-year)**	(24)*(25)	**109.51**	**70.17**	**109.51**	**274.54**	**4.98**	**245.75**	**109.51**

Table 7 shows marginal costs for each year of 10-year horizon at substation level. The values are in nominal dollars. The 10-year levelized marginal cost is $55.51/kW-year for areas with projects and $7.88/kW-year system-wide.

Table 7: Substation Marginal Costs by Year and Project

Year	Substation System-wide	Substation Future Unidentified Projects	Substation Location-Specific					Cost of Increasing Capacity for Typical Project Areas
			Maybrook	Pulvers 13kV	Woodstock	New Baltimore	Hurley Ave	
	(Share of Central Hudson Coincident Peak Load)	7.35%	1.69%	0.49%	1.56%	1.50%	1.62%	
2026	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 0.07	$ -	$ -	$ -	$ -	$ 4.98	$ -	$ 0.52
2028	$ 1.80	$ -	$ 70.17	$ 109.51	$ -	$ 4.98	$ -	$ 12.65
2029	$ 1.80	$ -	$ 70.17	$ 109.51	$ -	$ 4.98	$ -	$ 12.65
2030	$ 6.08	$ -	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ -	$ 42.84
2031	$ 14.13	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ -	$ 99.50
2032	$ 14.13	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ -	$ 99.50
2033	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2034	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2035	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2036	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2037	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2038	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2039	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2040	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2041	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2042	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2043	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2044	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2045	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
Ten-year Levelized ($2025)	**$ 7.88**	**$ 45.88**	**$ 52.25**	**$ 81.54**	**$ 142.90**	**$ 4.32**	**$ 57.70**	**$ 55.51**
Twenty-year Levelized ($2025)	**$ 11.38**	**$ 67.65**	**$ 58.38**	**$ 91.11**	**$ 187.93**	**$ 4.54**	**$ 122.04**	**$ 80.13**

APPENDIX C: DISTRIBUTION FEEDER DETAIL

Table 8 presents the interim marginal cost calculation process at feeder level.

Table 8: Distribution Feeder Interim Marginal Cost Calculation

				Feeder Location-Specific	
		Local Transmission Substation		Southern Dutchess Wiccopee	Avg. Cost of Increasing Feeder Capacity
		Feeder	Feeder Future Unidentified Projects	WI_8031	
		In Service Year	2025	2026	
(1)	Number of projects considered			1	
	Share of Central Hudson Coincident Peak Load		24.14%	0.38%	
	Marginal investment with general plant loading:				
(2)	Investment in growth projects net of 2.5% salvage value ($)		725,400	750,000	1,475,400
(3)	Investment in growth projects (kW)		16,459	13,000	29,459
(4)	Investment in growth projects ($/kW)	(2)/(3)	44.07	57.69	50.08
(5)	Typical reserve margin (%)		**30.00%**	**30.00%**	**30.00%**
(6)	Investment in growth projects after reserve margin ($/kW)	(4)*[1+(5)]	57.30	75.00	65.11
(7)	Portion of the system that is affected (%)		**100.00%**	**100.00%**	**100.00%**
(8)	Marginal investment ($/kW)	(6)*(7)	57.30	75.00	65.11
(9)	General plant loading (%)		**16.10%**	**16.10%**	**16.10%**
(10)	Marginal investment with general plant loading ($/kW)	(8)*[1+(9)]	66.52	87.08	75.59
	Annual cost before O&M and working capital:				
(11)	Annual economic carrying charge related to capital investment (%)		**17.83%**	**17.83%**	**17.83%**
(12)	A&G loading (plant-related) (%)		**0.00**	**0.00**	**-**
(13)	Total annual carrying charge (%)	(11)+(12)	17.83%	17.83%	17.83%
(14)	Annual cost before O&M and working capital ($/kW-year)	(10)*(13)	11.86	15.53	13.48
	Annual O&M charge:				
(15)	O&M expenses before spreading ($/kW-year)		-	-	-
(16)	O&M expenses after spreading ($/kW-year)	(7)*(15)	-	-	-
(17)	With A&G loading (non-plant-related) ($/kW-year)	(16)*0.61%	-	-	-
(18)	Annual O&M charge ($/kW-year)	(16)+(17)	-	-	-
	Annual working capital charge:				
(19)	Material and supplies ($/kW-year)	(10)*0.96%	0.64	0.84	0.73
(20)	Prepayments ($/kW-year)	(10)*1.00%	0.67	0.87	0.76
(21)	Cash working capital allowance ($/kW-year)	(18)*14.29%	-	-	-
(22)	Total working capital ($/kW-year)	(19)+(20)+(21)	1.30	1.71	1.48
(23)	Annual working capital charge ($/kW-year)	(22)*8.95%	0.12	0.15	0.13
(24)	Total annual cost before losses ($/kW-year)	(14)+(18)+(23)	11.98	15.68	13.61
(25)	Loss factor		1.05	1.05	1.05
(26)	**Total annual cost ($/kW-year)**	**(24)*(25)**	**12.57**	**16.45**	**14.28**

Table 9 shows marginal costs for each year of 10-year horizon at distribution feeder level.

Table 9: Distribution Feeder Marginal Cost by Year and Project

Year	Feeder System-wide (Share of Central Hudson Coincident Peak Load)	Feeder Future Unidentified Projects 24.14%	Feeder Location-Specific WI_8031 0.38%	Cost of Increasing Capacity for Typical Project Areas
2026	$ 3.03	$ 12.57	$ -	$ 12.37
2027	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2028	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2029	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2030	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2031	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2032	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2033	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2034	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2035	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2036	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2037	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2038	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2039	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2040	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2041	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2042	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2043	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2044	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2045	$ 3.10	$ 12.57	$ 16.45	$ 12.63
Ten-year Levelized ($2025)	**$ 3.09**	**$ 12.57**	**$ 14.28**	**$ 12.60**
Twenty-year Levelized ($2025)	**$ 3.09**	**$ 12.57**	**$ 15.03**	**$ 12.61**